International Energy Agency



# WORLD ENERGY OUTLOOK 2013

# WORLD ENERGY OUTLOOK 2013

**In a world where big differences in regional energy prices impact competitiveness, who are the potential winners and losers?**

**Huge volumes of oil are needed to meet growing demand and offset declines in existing fields. Where will it all come from?**

**What could trigger a rapid convergence in natural gas prices between Asia, Europe and North America, and how would it affect energy markets?**

**Is the growth in renewable energy self-sustaining and is it sufficient to put us on track to meet global climate goals?**

**How much progress is being made in phasing-out fossil-fuel subsidies and expanding access to modern energy services to the world's poor?**

The answers to these and many other questions are found in *WEO-2013*, which covers the prospects for all energy sources, regions and sectors to 2035. Oil is analysed in-depth: resources, production, demand, refining and international trade. Energy efficiency – a major factor in the global energy balance – is treated in much the same way as conventional fuels: Its prospects and contribution are presented in a dedicated chapter. And the report examines the outlook for Brazil's energy sector in detail and the implications for the global energy landscape.

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# WORLD ENERGY OUTLOOK

# 2013

## INTERNATIONAL ENERGY AGENCY

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

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

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This year's *World Energy Outlook*, *WEO-2013*, should make us all stop and think.

Dr. Fatih Birol and his dedicated team at the IEA, supported by many others in the Agency and over 200 highly-qualified external reviewers, have given us another arresting view of the main developments in the energy world over the last year and drawn out the implications for the future. We have been privileged to work this year with many experts on Brazilian energy to analyse that country's prospects. We have done the same with governments and external experts with respect to Southeast Asia – and have published our findings separately to respond to the timetable of important regional discussions.

From a wealth of information and analysis, I select some of the key findings which have seized my attention and will guide my thinking during the coming months:

- On the basis of the intentions already expressed by governments, energy efficiency is set to "supply" more additional energy than oil through to 2035. Energy efficiency is the only "fuel" that simultaneously meets economic, energy security and environmental objectives.
- Half the increase in the world's electricity output to 2035 comes from renewables. Variable sources – wind and solar – make up a large part of the increase. As integrating these variable renewables can be complex and costly, policies to support their deployment need to be complemented by action on infrastructure development and, in some cases, market structure.
- On the back of light tight oil output, the United States is on the verge of becoming the world's largest oil producer and is well on its way to realising the American dream of net energy self-sufficiency.
- The Middle East, long thought of primarily as a supplier to world energy markets, is becoming a major energy consumer. Growth in Middle East oil consumption by 2035 entirely offsets the reduction in consumption in OECD Europe. Growth in Middle East gas demand to 2035, in absolute terms, is second only to that of China.
- The world of oil refining is in transition. Markets are shifting east, as demand grows in the developing world and falls in OECD countries, while feedstock changes redefine the required characteristics of refineries.

Anyone with special interest in one of the fuels – especially oil, which we analyse in depth this year – will find their own insights in the relevant chapters. Energy efficiency – the ultimate alternative fuel – is explored on an equal basis in its own chapter. Chapter 8, on competitiveness, informs the growing debate about the implications for industrial competitiveness of differences in energy prices across the regions of the world.

Our purpose in the *WEO* is objective: to draw attention to the course on which the energy world is set and to point out the issues that arise. But we have ideas for solutions and stand ready to discuss them with all members of the community touched by the fortunes and operations of the energy sector.

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

**Maria van der Hoeven**
**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**, Chief Economist of the IEA. **Laura Cozzi** co-ordinated the analysis of climate change, energy efficiency and modelling; **Tim Gould** co-ordinated the analysis of oil, natural gas and Brazil; **Amos Bromhead** co-ordinated analysis of ASEAN and fossil-fuel subsidies; **Christian Besson** co-ordinated the analysis of oil; **Dan Dorner** co-ordinated the analysis of Brazil and energy access; **Marco Baroni** co-ordinated the power and renewables analysis; **Paweł Olejarnik** co-ordinated the analysis of coal and competitiveness; **Timur Gül** co-ordinated the transport analysis. 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** (Brazil, oil); **Alessandro Blasi** (ASEAN, Brazil); **Ian Cronshaw** (coal, natural gas); **Capella Festa** (Brazil, oil); **Matthew Frank** (oil, power); **Shigetoshi Ikeyama** (ASEAN, policies); **Bartosz Jurga** (unconventional gas); **Fabian Kęsicki** (energy efficiency, petrochemicals); **Soo-Il Kim** (industry, policies); **Catur Kurniadi** (ASEAN; power); **Atsuhito Kurozumi** (assumptions, policies); **Jung Woo Lee** (fossil-fuel subsidies, buildings); **Bertrand Magné** (competitiveness, energy efficiency), **Chiara Marricchi** (power, renewables); **Kristine Petrosyan** (oil refining and trade); **Katrin Schaber** (buildings, renewables); **Nora Selmet** (fossil-fuel subsidies, energy access); **Shigeru Suehiro** (industry, assumptions); **Timur Topalgoekceli** (oil, natural gas); **Johannes Trüby** (power, coal); **Kees Van Noort** (oil, natural gas); **Brent Wanner** (Brazil, power); **David Wilkinson** (power, renewables); **Shuwei Zhang** (transport). **Sandra Mooney**, **Magdalena Sanocka** and **MaryRose Cleere** provided essential support. More details about the team can be found at *www.worldenergyoutlook.org.*

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- Unconventional Gas Forum, Paris: 22 March 2013
- Brazil Energy Outlook, Rio de Janeiro: 11 April 2013
- The Future of the Tight Liquids Revolution, Paris: 30 April 2013
- Southeast Asia Energy Outlook, Bangkok: 7 May 2013
- International Energy Workshop, Paris: 19-21 June 2013

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

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## Part C: OUTLOOK FOR OIL MARKETS

## *Orientation for a fast-changing energy world*

**Many of the long-held tenets of the energy sector are being rewritten.** Major importers are becoming exporters, while countries long-defined as major energy exporters are also becoming leading centres of global demand growth. The right combination of policies and technologies is proving that the links between economic growth, energy demand and energy-related $CO_2$ emissions can be weakened. The rise of unconventional oil and gas and of renewables is transforming our understanding of the distribution of the world's energy resources. Awareness of the dynamics underpinning energy markets is essential for decisionmakers attempting to reconcile economic, energy and environmental objectives. Those that anticipate global energy developments successfully can derive an advantage, while those that fail to do so risk making poor policy and investment decisions. This edition of the *World Energy Outlook* (*WEO-2013*) examines the implications of different sets of choices for energy and climate trends to 2035, providing insights along the way that can help policymakers, industry and other stakeholders find their way in a fast-changing energy world.

**The centre of gravity of energy demand is switching decisively to the emerging economies, particularly China, India and the Middle East, which drive global energy use one-third higher.** In the New Policies Scenario, the central scenario of *WEO-2013*, China dominates the picture within Asia, before India takes over from 2020 as the principal engine of growth. Southeast Asia likewise emerges as an expanding demand centre (a development covered in detail in the *WEO* Special Report: *Southeast Asia Energy Outlook*, published in October 2013). China is about to become the largest oil-importing country and India becomes the largest importer of coal by the early 2020s. The United States moves steadily towards meeting all of its energy needs from domestic resources by 2035. Together, these changes represent a re-orientation of energy trade from the Atlantic basin to the Asia-Pacific region. High oil prices, persistent differences in gas and electricity prices between regions and rising energy import bills in many countries focus attention on the relationship between energy and the broader economy. The links between energy and development are illustrated clearly in Africa, where, despite a wealth of resources, energy use per capita is less than one-third of the global average in 2035. Africa today is home to nearly half of the 1.3 billion people in the world without access to electricity and one-quarter of the 2.6 billion people relying on the traditional use of biomass for cooking. Globally, fossil fuels continue to meet a dominant share of global energy demand, with implications for the links between energy, the environment and climate change.

**As the source of two-thirds of global greenhouse-gas emissions, the energy sector will be pivotal in determining whether or not climate change goals are achieved.** Although some carbon abatement schemes have come under pressure, initiatives such as the President's Climate Action Plan in the United States, the Chinese plan to limit the share of coal in the domestic energy mix, the European debate on 2030 energy and climate targets and Japan's discussions on a new energy plan all have the potential to limit the growth in energy-related $CO_2$ emissions. In our central scenario, taking into account the impact of measures already announced by governments to improve energy efficiency, support renewables, reduce fossil-fuel subsidies and, in some cases, to put a price on carbon, energy-related $CO_2$ emissions still rise by 20% to 2035. This leaves the world on a trajectory consistent with a long-term average temperature increase of 3.6 °C, far above the internationally agreed 2 °C target.

## *Who has the energy to compete?*

**Large differences in regional energy prices have sparked a debate about the role of energy in unleashing or frustrating economic growth.** Brent crude oil has averaged $110 per barrel in real terms since 2011, a sustained period of high oil prices that is without parallel in oil market history. But unlike crude oil prices, which are relatively uniform worldwide, prices of other fuels have been subject to significant regional variations. Although gas price differentials have come down from the extraordinary levels seen in mid-2012, natural gas in the United States still trades at one-third of import prices to Europe and one-fifth of those to Japan. Electricity prices also vary, with average Japanese or European industrial consumers paying more than twice as much for power as their counterparts in the United States, and even Chinese industry paying almost double the US level. In most sectors, in most countries, energy is a relatively minor part of the calculation of competitiveness. But energy costs can be of crucial importance to energy-intensive industries, such as chemicals, aluminium, cement, iron and steel, paper, glass and oil refining, particularly where the resulting goods are traded internationally. Energy-intensive sectors worldwide account for around one-fifth of industrial value added, one-quarter of industrial employment and 70% of industrial energy use.

**Energy price variations are set to affect industrial competitiveness, influencing investment decisions and company strategies.** While regional differences in natural gas prices narrow in our central scenario, they nonetheless remain large through to 2035 and, in most cases, electricity price differentials persist. In many emerging economies, particularly in Asia, strong growth in domestic demand for energy-intensive goods supports a swift rise in their production (accompanied by export expansion). But relative energy costs play a more decisive role in shaping developments elsewhere. The United States sees a slight increase in its share of global exports of energy-intensive goods, providing the clearest indication of the link between relatively low energy prices and the industrial outlook. By contrast, the European Union and Japan both see a strong decline in their export shares – a combined loss of around one-third of their current share.

## *Searching for an energy boost to the economy*

**Countries can reduce the impact of high prices by promoting more efficient, competitive and interconnected energy markets**. Cost differentials between regional gas markets could be narrowed further by more rapid movement towards a global gas market. As we examine in a Gas Price Convergence Case, this would require a loosening of the current rigidity of liquefied natural gas (LNG) contracting structures and oil-indexed pricing mechanisms, spurred by accelerated gas market reforms in the Asia-Pacific region and LNG exports from North America (and an easing of costs for LNG liquefaction and shipping). There is also potential in some regions, notably China, parts of Latin America and even parts of Europe, to replicate at smaller scale the US success in developing its unconventional gas resources, though uncertainty remains over the quality of the resources, the costs of their production and, in some countries, public acceptance for their development.

**A renewed focus on energy efficiency is taking hold and is set to deliver benefits that extend well beyond improvements in competitiveness.** Notable policies introduced over the past year include measures targeting efficiency improvements in buildings in Europe and Japan, in motor vehicles in North America and in air conditioners in parts of the Middle East, and energy pricing reforms in China and India. As well as bringing down costs for industry, efficiency measures mitigate the impact of energy prices on household budgets (the share of energy in household spending has reached very high levels in the European Union) and on import bills (the share of energy imports in Japan's GDP has risen sharply). But the potential for energy efficiency is still far from exhausted: two-thirds of the economic potential of energy efficiency is set to remain untapped in our central scenario. Action is needed to break down the various barriers to investment in energy efficiency. This includes phasing out fossil-fuel subsidies, which we estimate rose to $544 billion worldwide in 2012.

**Enhancing energy competitiveness does not mean diminishing efforts to tackle climate change.** The *WEO* Special Report: *Redrawing the Energy-Climate Map*, published in June 2013 identified four pragmatic measures – improving efficiency, limiting the construction and use of the least-efficient coal-fired power plants, minimising methane emissions in upstream oil and gas, and reforming fossil-fuel subsidies – that could halt the increase in emissions by 2020 without harming economic growth. This package of measures would complement the developments already envisaged in our central scenario, notably the rise in deployment of renewable energy technologies. Governments need, though, to be attentive to the design of their subsidies to renewables, which surpassed $100 billion in 2012 and expand to $220 billion in 2035. As renewables become increasingly competitive on their own merits, it is important that subsidy schemes allow for the multiple benefits of low-carbon energy sources without placing excessive burdens on those that cover the additional costs. A carefully conceived international climate change agreement can help to ensure that the energy-intensive industries in countries that act decisively to limit emissions do not face unequal competition from countries that do not.

## *Light tight oil shakes the next ten years, but leaves the longer term unstirred*

**The capacity of technologies to unlock new types of resources, such as light tight oil (LTO) and ultra-deepwater fields, and to improve recovery rates in existing fields is pushing up estimates of the amount of oil that remains to be produced.** But this does not mean that the world is on the cusp of a new era of oil abundance. An oil price that rises steadily to $128 per barrel (in year-2012 dollars) in 2035 supports the development of these new resources, though no country replicates the level of success with LTO that is making the

United States the largest global oil producer. The rise of unconventional oil (including LTO) and natural gas liquids meets the growing gap between global oil demand, which rises by 14 mb/d to reach 101 mb/d in 2035, and production of conventional crude oil, which falls back slightly to 65 mb/d.

**The Middle East, the only large source of low-cost oil, remains at the centre of the longer-term oil outlook.** The role of OPEC countries in quenching the world's thirst for oil is reduced temporarily over the next ten years by rising output from the United States, from oil sands in Canada, from deepwater production in Brazil and from natural gas liquids from all over the world. But, by the mid-2020s, non-OPEC production starts to fall back and countries in the Middle East provide most of the increase in global supply. Overall, national oil companies and their host governments control some 80% of the world's proven-plus-probable oil reserves.

**The need to compensate for declining output from existing oil fields is the major driver for upstream oil investment to 2035.** Our analysis of more than 1 600 fields confirms that, once production has peaked, an average conventional field can expect to see annual declines in output of around 6% per year. While this figure varies according to the type of field, the implication is that conventional crude output from existing fields is set to fall by more than 40 mb/d by 2035. Among the other sources of oil, most unconventional plays are heavily dependent on continuous drilling to prevent rapid field-level declines. Of the 790 billion barrels of total production required to meet our projections for demand to 2035, more than half is needed just to offset declining production.

**Demand for mobility and for petrochemicals keeps oil use on an upward trend to 2035, although the pace of growth slows.** The decline in oil use in OECD countries accelerates. China overtakes the United States as the largest oil-consuming country and Middle East oil consumption overtakes that of the European Union, both around 2030. The shifting geography of demand is further underlined by India becoming the largest single source of global oil demand growth after 2020. Oil consumption is concentrated in just two sectors by 2035: transport and petrochemicals. Transport oil demand rises by 25% to reach 59 mb/d, with one-third of the increase going to fuel road freight in Asia. In petrochemicals, the Middle East, China and North America help push up global oil use for feedstocks to 14 mb/d. High prices encourage efficiency improvements and undercut the position of oil wherever alternatives are readily available, with biofuels and natural gas gaining some ground as transport fuels.

## *The great migration in oil refining and trade*

**Major changes in the composition of oil supply and demand confront the world's refiners with an ever-more complex set of challenges, and not all of them are well-equipped to survive.** Rising output of natural gas liquids, biofuels and coal- or gas-to-liquids technologies means that a larger share of liquid fuels reaches consumers without having to pass through the refinery system. Refiners nonetheless need to invest to meet a surge of more than 5 mb/d in demand for diesel that is almost triple the increase in gasoline use. The shift in the balance of oil consumption towards Asia and the Middle East sees a continued build-up of refining capacity in these regions; but, in many OECD countries, declining demand and competition in product export markets intensify pressure to shut capacity. Over the period to 2035, we estimate that nearly 10 mb/d of global refinery capacity is at risk, with refineries in OECD countries, and Europe in particular, among the most vulnerable.

**The new geography of demand and supply means a re-ordering of global oil trade flows towards Asian markets, with implications for co-operative efforts to ensure oil security.** The net North American requirement for crude imports all but disappears by 2035 and the region becomes a larger exporter of oil products. Asia becomes the unrivalled centre of global oil trade as the region draws in – via a limited number of strategic transport routes – a rising share of the available crude oil. Deliveries to Asia come not only from the Middle East (where total crude exports start to fall short of Asian import requirements) but also from Russia, the Caspian, Africa, Latin America and Canada. New export-oriented refinery capacity in the Middle East raises the possibility that oil products, rather than crude, take a larger share of global trade, but much of this new capacity eventually serves to cater to increasing demand from within the region itself.

## *The power sector adjusts to a new life with wind and solar*

**Renewables account for nearly half of the increase in global power generation to 2035, with variable sources – wind and solar photovoltaics – making up 45% of the expansion in renewables.** China sees the biggest absolute increase in generation from renewable sources, more than the increase in the European Union, the United States and Japan combined. In some markets, the rising share of variable renewables creates challenges in the power sector, raising fundamental questions about current market design and its ability to ensure adequate investment and long-term reliability of supply. The increase in generation from renewables takes its share in the global power mix above 30%, drawing ahead of natural gas in the next few years and all but reaching coal as the leading fuel for power generation in 2035. The current rate of construction of nuclear power plants has been slowed by reviews of safety regulations, but output from nuclear eventually increases by two-thirds, led by China, Korea, India and Russia. Widespread deployment of carbon capture and storage (CCS) technology would be a way to accelerate the anticipated decline in the $CO_2$ emissions intensity of the power sector, but in our projections only around 1% of global fossil fuel-fired power plants are equipped with CCS by 2035.

## *Economics and policies, in different doses, are key to the outlook for coal and gas*

**Coal remains a cheaper option than gas for generating electricity in many regions, but policy interventions to improve efficiency, curtail local air pollution and mitigate climate change will be critical in determining its longer-term prospects.** Policy choices in China, which has outlined plans to cap the share of coal in total energy use, will be particularly important as China now uses as much coal as the rest of the world combined. In our central scenario, global coal demand increases by 17% to 2035, with two-thirds of the increase occurring by 2020. Coal use declines in OECD countries. By contrast, coal demand expands by one-third in non-OECD countries – predominantly in India, China and Southeast Asia – despite China reaching a plateau around 2025. India, Indonesia and China account for 90% of the growth in coal production. Export demand makes Australia the only OECD country to register substantial growth in output.

**Market conditions vary strikingly in different regions of the world, but the flexibility and environmental benefits of natural gas compared with other fossil fuels put it in a position to prosper over the longer term.** Growth is strongest in emerging markets, notably China, where gas use quadruples by 2035, and in the Middle East. But in the European Union, gas remains squeezed between a growing share of renewables and a weak competitive position versus coal in power generation, and consumption struggles to return to 2010 levels. North America continues to benefit from ample production of unconventional gas, with a small but significant share of this gas finding its way to other markets as LNG, contributing – alongside other conventional and unconventional developments in East Africa, China, Australia and elsewhere – to more diversity in global gas supply. New connections between markets act as a catalyst for changes in the way that gas is priced, including more widespread adoption of hub-based pricing.

## *Brazil is at the leading edge of deepwater and low-carbon development*

**Brazil, the special focus country in this year's *Outlook*, is set to become a major exporter of oil and a leading global energy producer**. Based mainly on a series of recent offshore discoveries, Brazil's oil production triples to reach 6 mb/d in 2035, accounting for one-third of the net growth in global oil production and making Brazil the world's sixth-largest producer. Natural gas production grows more than five-fold, enough to cover all of the country's domestic needs by 2030, even as these expand significantly. The increase in oil and gas production is dependent on highly complex and capital-intensive deepwater developments, requiring levels of upstream investment beyond those of either the Middle East or Russia. A large share of this will need to come from Petrobras, the national oil company, whose mandated role in developing strategic fields places heavy weight on its ability to deploy resources effectively across a huge and varied investment programme. Commitments made to source goods and services locally within Brazil add tension to a tightly stretched supply chain.

**Brazil's abundant and diverse energy resources underpin an 80% increase in its energy use, including the achievement of universal access to electricity.** Rising consumption is driven by the energy needs of an expanding middle class, resulting in strong growth in demand for transport fuels and a doubling of electricity consumption. Meeting this demand requires substantial and timely investment throughout the energy system – $90 billion per year on average. The system of auctions for new electricity generation and transmission capacity will be vital in bringing new capital to the power sector and in reducing pressure on end-user prices. The development of a well-functioning gas market, attractive to new entrants, can likewise help spur investment and improve the competitive position of Brazilian industry. A stronger policy focus on energy efficiency would ease potential strains on a rapidly growing energy system.

**Brazil's energy sector remains one of the least carbon-intensive in the world, despite greater availability and use of fossil fuels.** Brazil is already a world-leader in renewable energy and is set to almost double its output from renewables by 2035, maintaining their 43% share of the domestic energy mix. Hydropower remains the backbone of the power sector. Yet reliance on hydropower declines, in part because of the remoteness and environmental sensitivity of a large part of the remaining resource, much of which is in the Amazon region. Among the fuels with a rising share in the power mix, onshore wind power, which is already proving to be competitive, natural gas and electricity generated from bioenergy take the lead. In the transport sector, Brazil is already the world's second-largest producer of biofuels and its production, mainly as sugarcane ethanol, more than triples. Suitable cultivation areas are more than sufficient to accommodate this increase without encroaching on environmentally sensitive areas. By 2035, Brazilian biofuels meet almost one-third of domestic demand for road-transport fuel and its net exports account for about 40% of world biofuels trade.

# PART A
# GLOBAL ENERGY TRENDS

## PREFACE

Part A of this *WEO* (Chapters 1-8) presents energy projections to 2035. It covers the prospects for all energy sources, regions and sectors and an assessment of the impact of energy use on climate change. Three scenarios are presented – the New Policies Scenario, the Current Policies Scenario and the 450 Scenario – together with several special cases.

Chapter 1 defines the scenarios and sets out the various inputs and modelling assumptions utilised in the analysis.

Chapter 2 summarises the results of the projections for global energy in aggregate and draws out the implications for energy security, environmental protection and economic development. The chapter also provides special features on Southeast Asia's emergence as a key player in the global energy system, achieving universal energy access and developments in subsidies to fossil fuels and renewables.

Chapters 3-6 analyse the outlook for natural gas, coal, electricity and renewables.

Chapter 7 covers the current status and future prospects for energy efficiency, which is treated for the very first time in the same way as the conventional energy sources, with its own standalone chapter.

Chapter 8 examines energy and competitiveness, assessing what major disparities in regional energy prices might mean for economies, particularly their energy-intensive industries.

# Scope and methodology

## What underlies the analysis?

### Highlights

- The New Policies Scenario – the central scenario in *WEO-2013* – analyses the evolution of energy markets based on the continuation of existing policies and measures as well as cautious implementation of policies that have been announced by governments but are yet to be given effect. The Current Policies Scenario takes account only of policies already enacted as of mid-2013. The 450 Scenario shows what it takes to set the energy system on track to have a 50% chance of keeping to 2 °C the long-term increase in average global temperature.

- More than five years after the worst recession since the 1930s began in 2008, the economic recovery continues to be fragile and uneven. We assume world GDP grows at an average rate of 3.6% per year through to 2035. This equates to a more than doubling in the size of the global economy. Developing Asia accounts for over half of the increase in economic activity. China's income per capita grows by around three-and-a-half times, overtaking that of the Middle East.

- Demographic factors will continue to drive changes in the energy mix. The world population is set to rise from 7.0 billion in 2011 to 8.7 billion in 2035, led by Africa and India. China's population changes little and by around 2025 India becomes the world's most populous country. Most OECD countries see small changes in population, with the notable exception of the United States, which sees an increase of about 60 million people. Global population growth is concentrated entirely in urban areas.

- The world is experiencing a period of historically high oil prices. Brent crude oil has averaged over $110/barrel in real terms since 2011, a sustained period of high oil prices that is without parallel in oil market history. In the New Policies Scenario, oil prices reach $113/barrel in 2020 and $128/barrel in 2035. Big differences remain between gas prices in regional markets, despite some convergence. Coal prices remain much lower than oil and gas prices in energy equivalent terms. The share of global $CO_2$ emissions subject to a $CO_2$ price rises from 8% today to one-third in 2035.

- Energy technologies that are already in use or are approaching commercialisation are assumed to achieve ongoing cost reductions as a result of increased learning and deployment. Although there are exceptions that create some basis for optimism, recent progress in deploying clean energy technologies has not matched policy expectations and, in many cases, their future uptake hinges on dedicated policy support and/or subsidies.

## Scope of report

This edition of the *World Energy Outlook* (*WEO*) presents an assessment of the prospects for global energy markets in the period to 2035 and draws out the implications for energy security, environmental protection and economic development. The objective is to provide policymakers, industry and the general public in countries all over the world with the data, analysis and insights needed to make judgements about our energy future, as a basis for sound energy decisionmaking.

Part A of the report is built around projections of energy demand and supply through to 2035. The three main scenarios – the New Policies Scenario, the Current Policies Scenario and the 450 Scenario – are underpinned by assumptions about economic and population growth, and about energy and climate policies and technology deployment. Energy prices are derived from a modelling process. Our analysis takes into account all of the historical energy data available to the IEA at the time of writing, as well as more recent preliminary data from a wide variety of sources. For the first time, energy efficiency – a major factor in the global energy balance – is treated in much the same way as the conventional fuels, its prospects being presented in a dedicated chapter that builds on the special focus on energy efficiency included in *WEO-2012* (IEA, 2012a). Part A also includes, in Chapter 2, an update on three key areas of critical importance to energy and climate trends: (i) achieving universal energy access; (ii) developments in subsidies to fossil fuels and renewables; and (iii) the impact of energy use on climate change. Prospects for unconventional gas production, including the uptake of the IEA's "Golden Rules" to address the associated environmental and social impacts, are included in Chapter 3 (IEA, 2012b). Part A ends with an examination of energy and competitiveness, assessing what major disparities in regional energy prices might mean for consumers and the economy at large, and offering insights into the policies that might be pursued to improve energy competitiveness.

Consistent with recent practice, *WEO-2013* includes a particular focus on one country and on one energy source. The country of focus is Brazil, presented in Part B. We analyse how Brazil's vast and diverse energy resource base – from renewables to new offshore discoveries – can meet its growing domestic needs and help it to open up new export markets. The highlighted energy source is oil, presented in Part C. We provide a fresh look at the oil resource base, the economics and decline rates of different types of oil production, the outlook for light tight oil in North America and beyond, oil demand by product and the prospects for the refining sector.

### *Introducing the scenarios*

Throughout the last year, significant new energy and environmental policies have been adopted in many parts of the world. A number of national energy strategy reviews have also been launched, which can be expected to lead to further new policy announcements in the near future. And some important progress has been made in bilateral and multilateral energy co-operation. These developments guide the different policy assumptions adopted in the three scenarios (Box 1.1).

**Box 1.1 ▷ Recent key developments in energy and environmental policy**

Important policy developments in 2013 have been taken into account, to varying degrees, in the three scenarios presented in *WEO-2013*. Early in the year, the **United States** extended various tax credits for renewable energy, energy efficiency and alternative fuel vehicles. The US administration also announced a major climate action plan that seeks to introduce (i) new standards for power plants; (ii) more funding and incentives for energy efficiency and renewables; (iii) preparations to safeguard the country from the impacts of climate change; and (iv) steps to provide more global leadership to reduce carbon emissions. **Canada** adopted new fuel-economy standards for cars and light trucks, to take effect in 2017 with targets for 2025 (mirroring the US Corporate Average Fuel Economy standards approved in 2012), and regulations to improve the fuel efficiency of new heavy-duty vehicles. **Japan** widened the scope of its Top-Runner Program to include building materials and released a new economic growth strategy that includes a call to restart the country's nuclear reactors, most of which have lain idle since the Fukushima Daiichi accident (subject to meeting new safety requirements). **Italy** introduced a new energy plan, which calls for further development of renewable energy as well as oil and gas. **China** announced plans to reduce the share of coal in total primary energy demand to 65% by 2017 and to speed up the introduction of new vehicle emissions standards. **India** mandated a 5% ethanol blend in gasoline and announced a target to expand power generation from renewables.

In addition to these new measures and targets, many important reviews have been underway, some of which could lead to new policies. **Japan** is working on a new energy plan to be released in late 2013. The **European Commission** has been consulting on a 2030 framework for climate and energy policies, including the nature of any targets that may be set. **Germany** has an ongoing debate on its Energiewende (energy transition), which is aimed at ambitious decarbonisation of its energy system. **France** has been holding a national debate on energy (Débat sur la Transition Energétique) in advance of a new energy policy bill. **India's** Planning Commission constituted an expert group to propose a low-carbon strategy for growth. **Brazil** is updating its long-term energy strategy to 2050 (Plano Nacional de Energia 2050), while **Saudi Arabia** is developing plans to diversify its energy mix and free-up more oil for export.

Important developments have also occurred in bilateral and multilateral energy co-operation. These include the "Power Africa" partnership between the United States and governments and companies in sub-Saharan Africa, which was launched mid-year with the aim of doubling access to electricity within the region. The United States and China also agreed on a (non-binding) plan to cut their carbon emissions from heavy-duty vehicles and coal-fired power plants. And on the road to the reform of fossil-fuel subsidies – an issue on the agenda of both the G-20 and APEC – a growing number of countries, including China, India and Indonesia, have introduced major energy pricing reforms (see fossil-fuel subsidies section in Chapter 2). In terms of schemes that place a price on carbon, some new initiatives have been introduced, but others have come under challenge (see carbon markets section towards the end of this chapter).

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-2013, it also takes account of other relevant commitments that have been announced, even when the precise implementation measures have yet to be fully defined (Table 1.1). These commitments include programmes to support renewable energy and improve energy efficiency, initiatives to promote alternative fuels and vehicles, carbon pricing and policies related to the expansion or phase-out of nuclear energy, and initiatives taken by G-20 and Asia-Pacific Economic Cooperation (APEC) economies to reform fossil-fuel subsidies. We take a cautious view as to the extent to which these commitments will be implemented, as there are institutional, political and economic circumstances in all regions that could stand in the way. Details of the key policy targets and measures taken into account in the New Policies Scenario (as well as in the other two scenarios presented in *WEO-2013*) are set out in Annex B.

**Table 1.1 ▷ Overview of key assumptions and energy prices in the New Policies Scenario**

| Factor | Assumptions |
|---|---|
| **Policies** | Continuation of policies that had been legally enacted as of mid-2013 plus cautious implementation of announced commitments and plans. |
| **GDP growth** | Global GDP increases at an average rate of 3.6% per year over 2011-2035 (based on GDP expressed in year-2012 dollars in purchasing power parity terms). |
| **Population growth** | World population rises at an average rate of 0.9% per year, to 8.7 billion in 2035. The proportion of people living in urban areas rises from 52% in 2011 to 62% in 2035. |
| **Energy pricing** | Average IEA crude oil import price reaches $128/barrel (in year-2012 dollars) in 2035. A degree of convergence in natural gas prices occurs between the three major regional markets of North America, Asia-Pacific and Europe. Coal prices remain much lower than oil and gas prices on an energy-equivalent basis. |
| **Fossil-fuel subsidies** | Phased out in all net-importing regions within ten years (at the latest) and in net-exporting regions where specific legislation has already been adopted. |
| **$CO_2$ pricing** | New schemes that put a price on carbon are gradually introduced, with price levels gradually increasing. |
| **Technology** | Energy technologies – both on the demand and supply sides – that are in use today or are approaching the commercialisation phase achieve ongoing cost reductions. |

We also present the ***Current Policies Scenario***, which takes into account only those policies and measures affecting energy markets that were formally enacted as of mid-2013. In other words, it describes a future in which governments do not implement any recent commitments that have yet to be backed-up by legislation or introduce other new policies bearing on the energy sector. The scenario is designed to provide a baseline picture of how global energy markets would evolve if established trends in energy demand and supply continue unabated. It both illustrates the consequences of inaction and makes it possible to evaluate the potential effectiveness of recent developments in energy and climate policy.

The ***450 Scenario*** shows what is needed to set the global energy sector on a course compatible with a near 50% chance of limiting the long-term increase in the average global temperature to two degrees Celsius (2 °C). This scenario leads to a peak in the concentration of greenhouse gases in the atmosphere around the middle of this century, at a level above 450 parts per million (ppm), but not so high as to be likely to precipitate changes that make the 2 °C objective unattainable. The concentration of greenhouse gases stabilises after 2100 at around 450 ppm. For the period to 2020, policy action aiming at fully implementing the commitments under the Cancun Agreements, which were made at the 2010 United Nations Climate Change Conference in Mexico, is assumed to be undertaken (in the New Policies Scenario these commitments are only partly implemented). After 2020, OECD countries and other major economies are assumed to implement emissions reduction measures that, collectively, ensure a trajectory consistent with the target. From 2020, OECD countries are assumed to mobilise $100 billion in annual financing from a variety of sources for abatement measures in non-OECD countries. The 450 Scenario is not given the same coverage in *WEO-2013* as in previous editions as the specific short-term opportunities for action in the energy sector to mitigate climate change and their potential results were covered in detail in *Redrawing the Energy-Climate Map*, a *WEO* special report that was released in June 2013 (IEA, 2013b). The results of the 450 Scenario are, however, included in many of the tables and figures in this report.

## Building blocks of the scenarios

### *Economic growth*

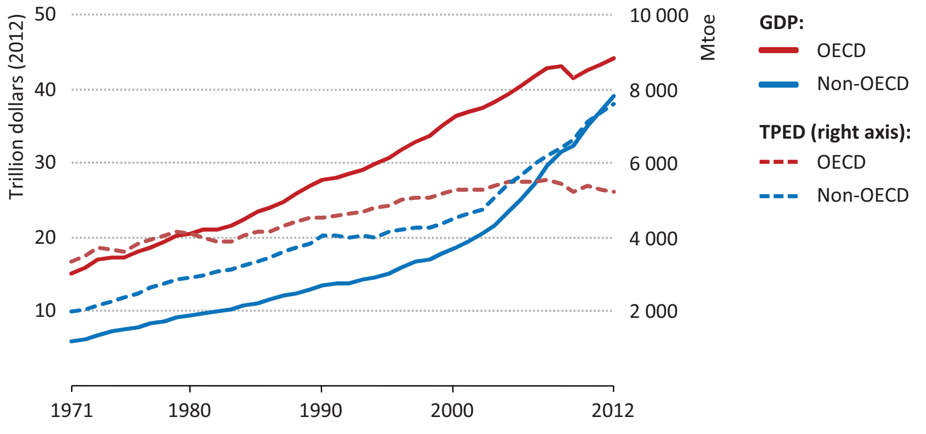
More than five years after the worst economic recession since the 1930s began in 2008, positive signs of recovery in some economies cannot hide the fact that, overall, the recovery remains fragile and downside risks remain. It has been characterised as a two-speed recovery. Developing economies have been growing at much faster rates than advanced economies and make up the first group (though many of them, including China, Russia, Brazil, India and in Southeast Asia have, more recently, been showing signs of slowing momentum [Box 1.2]). Advanced economies make up the second group, though here too, there are divergences. Growth in the United States, Canada, Australia, New Zealand, Korea and Japan has outpaced most parts of Europe, where gross domestic product (GDP) growth has either been low or negative for significant periods.

Over the last several decades, global energy consumption has grown at a much slower rate than GDP, primarily because of structural changes in the economy, energy efficiency improvements and fuel switching. Global energy intensity – defined as the amount of energy used to produce a unit of GDP at market exchange rates – fell by 32% between 1971 and 2012.[1] Despite this partial decoupling of energy demand and economic growth, which

1. The average rate of improvement, however, was much lower in 2000-2011 than in 1980-2000 (and energy intensity actually increased in 2009 and 2010) due to a shift in the balance of global economic activity to countries in developing Asia which have relatively high energy intensities (see Chapter 7).

has been particularly evident in the OECD, the two still remain closely tied (Figure 1.1). It follows that the projections in this *Outlook* are highly sensitive to assumptions about the rates and patterns of GDP growth.

**Figure 1.1 ▷ Primary energy demand and GDP**




Notes: Calculated on the basis of GDP in year-2012 dollars expressed in real purchasing power parity terms. TPED = total primary energy demand.

In each of the scenarios in this *Outlook*, world GDP (expressed in real purchasing power parity [PPP] terms) is assumed to grow at an average annual rate of 3.6% between 2011 and 2035 (Table 1.2).[2] This means that the global economy more than doubles in size over the period. Although this is just marginally faster overall than what was assumed in last year's *Outlook*, there have been more significant revisions in some regions. These include downward revisions in the period to 2020 for India, Brazil, Russia and the European Union and upward revisions in the same period for the United States, among others. For the medium term, our GDP growth assumptions have been based primarily on International Monetary Fund (IMF) forecasts, with some adjustments to reflect information available from regional, national and other sources. The latest IMF forecasts are for global economic growth of 2.9% in 2013 and 3.6% in 2014, before accelerating to 4.1% annually in 2018 (IMF, 2013). Longer-term GDP assumptions are based on our assessment of prospects for growth in labour supply and improvements in productivity, supplemented by projections made by various economic forecasting bodies, most notably the OECD.

2. Across the scenarios presented in this *Outlook*, the various policies that are assumed to be introduced and the different energy price levels that prevail could be expected to lead to some variations in GDP, as a result of the potentially important interactions of these variables on the economy. However, due to the uncertainty associated with estimating these effects and in order to more precisely identify the implications of different policy options on energy trends, the same level of GDP growth is assumed in each scenario.

### Box 1.2 ▷ Uncertainties around the economic outlook

Risks to the economic recovery have eased in the last year, but momentum is proving to be slow to build. Global demand for products and services remains depressed, with sustained economic growth yet to take hold in many developed countries and growth forecasts being revised downward for many developing countries.

In Japan, there has been a noticeable recovery, although it remains to be seen how tapering of government stimulus spending and scheduled increases in sales tax will impact growth rates going forward. The Eurozone – as a whole – reported a return to modest growth in the second quarter of 2013, however many of its economies are still experiencing low demand, relatively high unemployment, weakness in the financial sector and the effects of austerity measures. Some countries remained in recession at the time of writing, depressing energy demand: demand for both gas and electricity in Europe are at levels last seen in the early 2000s, with implications for energy sector revenues and investments. The economic crisis is also constraining the ability of governments to support a transition to a low-carbon economy. The United States appears to be on a more promising growth trajectory, even having managed to weather the fiscal shock of automatic budget cuts relatively well. However, the potential tapering of central bank liquidity measures has caused some financial market volatility, which has been transmitted quickly through global bond and equity markets.

Emerging economies have been the main engines of global growth over the past decade, but many are now facing slower growth at home on top of challenging economic conditions globally. China, in particular, has played a defining role, contributing more than three times as much (35%) to global GDP growth as the United States (11%) over the years 2011-2012. But sustained high growth has also seen a build up of risks within China's economy, including reliance on export-led growth, weaknesses in the financial sector (both within and outside the formal banking sector) and local government finances, and concerns about the affordability of property. China has policy levers available to support growth while also tackling vulnerabilities in the system, *i.e.* to achieve a "soft landing", but achieving this is not a foregone conclusion. While China and the United States are the world's largest energy consumers, China's energy demand is much more sensitive to GDP trends. Given this and its growing oil, gas and coal imports, China's economic outlook has potentially large repercussions for global energy markets.

The assumed rates of growth in non-OECD countries imply that their combined GDP will surpass that of the OECD countries by around 2015; by 2035 their combined GDP will be 1.6 times larger. Some of the most rapid rates of growth are in developing Asia, which collectively accounts for over half of the increase in global economic activity during the period. China's growth rate averages 5.7% in 2011-2035, despite falling after 2020 to less than half the rate seen over the last decade, as its economy matures and its population growth levels off. Of all of the countries or regions that we have modelled as distinct entities, India's GDP grows at the fastest rate, averaging 6.3% over the period. Brazil, the country focus in this *Outlook* (Part B), grows at 3.7% per year on average, well above our assumed rates of growth for the rest of Latin America.

**Table 1.2 ▷ Real GDP growth assumptions by region**

| | Compound average annual growth rate | | | |
|---|---|---|---|---|
| | 1990-2011 | 2011-2015 | 2011-2020 | 2011-2035 |
| **OECD** | **2.2%** | **1.9%** | **2.2%** | **2.1%** |
| Americas | 2.5% | 2.7% | 2.9% | 2.5% |
| United States | 2.4% | 2.6% | 2.8% | 2.4% |
| Europe | 2.0% | 0.9% | 1.5% | 1.7% |
| Asia Oceania | 1.9% | 2.1% | 2.1% | 1.8% |
| Japan | 0.9% | 1.5% | 1.4% | 1.2% |
| **Non-OECD** | **5.0%** | **5.6%** | **5.8%** | **4.8%** |
| E. Europe/Eurasia | 0.7% | 3.3% | 3.5% | 3.3% |
| Russia | 0.6% | 3.7% | 3.6% | 3.4% |
| Asia | 7.5% | 6.8% | 7.1% | 5.6% |
| China | 10.0% | 8.0% | 8.1% | 5.7% |
| India | 6.5% | 5.7% | 6.5% | 6.3% |
| ASEAN | 5.0% | 5.5% | 5.5% | 4.6% |
| Middle East | 4.6% | 3.2% | 3.7% | 3.7% |
| Africa | 3.8% | 5.1% | 5.0% | 4.0% |
| Latin America | 3.4% | 3.4% | 3.7% | 3.3% |
| Brazil | 3.0% | 3.0% | 3.6% | 3.7% |
| **World** | **3.3%** | **3.6%** | **4.0%** | **3.6%** |
| European Union | 1.8% | 0.7% | 1.3% | 1.6% |

Note: Calculated based on GDP expressed in year-2012 dollars in purchasing power parity terms.

Sources: IMF (2013); OECD (2013); Economist Intelligence Unit and World Bank databases; IEA databases and analysis.

### *Population and demographics*

Population is a fundamental driver of energy demand, although the relationship is not linear, as it depends on many other factors. Based on the medium variant of the latest United Nations projections, the world population is set to rise from 7.0 billion in 2011 to 8.7 billion in 2035 (UNPD, 2013) (Table 1.3). Africa, India and Southeast Asia are the biggest contributors to the increase. By contrast, the population of China changes very little over the period; by around 2025, India becomes the world's most populous country. Population growth is slow in OECD countries, although some see relatively fast increases, including Australia, Canada, Chile, Mexico and the United States. The population of the United States increases by almost one-fifth, underpinned by relatively high levels of immigration. As has been the case since the late 1960s, world population growth slows, falling from 1.2% in 2012 to 0.7% in 2035.

SPOTLIGHT

## How does the IEA model future energy trends?

The IEA has used its World Energy Model (WEM) as the principal tool to generate the projections that underpin the *WEO* scenarios for some two decades. The WEM is a large-scale simulation model designed to replicate how energy markets function. It consists of three main modules: (i) final energy consumption; (ii) energy transformation; and (iii) oil, natural gas, coal and bioenergy supply. Detailed, timely and reliable statistics form a crucial input to the WEM. These are sourced primarily from the IEA's historical statistics on energy supply, trade, stocks, transformation and demand, but are supplemented by additional data from governments, international organisations, energy companies, consulting firms and investment banks worldwide. Another crucial input is information on government policies that affect energy demand and supply.

The WEM is updated on an annual basis with new and more detailed features to ensure that it continues to reflect the changing dynamics of global energy markets and to enable greater disaggregation of results. Key changes made for *WEO-2013* include the following:

- Oil demand has been split to show consumption by individual oil product.
- A new oil refining module allows a significant extension of the analysis of this sector, as well as to present international trade flows of crude and oil products.
- Coverage of the chemical and petrochemical sector has been improved to enable energy consumption and feedstock use to be modelled for each major product.
- The modelling of efficiency measures in the buildings sector (such as insulation and retrofit programmes) has been revised and improved.
- In preparation of the *WEO-2013* Special Report *Southeast Asia Energy Outlook*, separate models have been built for Thailand, Malaysia and the Philippines (previously Indonesia was the only country in the region modelled on an individual basis) (IEA, 2013a).
- Reflecting the accession of Croatia to the European Union in July 2013, the models for Europe have been expanded to include all 28 member states.

In June 2013, the IEA hosted the International Energy Workshop to bring together the leading analysts from all over the world to discuss the latest developments in energy and climate modelling. The agenda included a special session dedicated to the IEA's WEM, which generated feedback and suggestions that are expected to enrich the IEA's energy analysis in future years. More details on the WEM are available at *www.worldenergyoutlook.org/weomodel/*.

Urban areas are set to accommodate all of the growth in population, as the share of the world's population living in towns rises from 52% to 62% over 2011-2035. The number of people living in rural areas declines over the period. These changes will have implications for the amount and type of energy used. The concentration of activities in urban areas can facilitate improved energy efficiency through economies of scale, however, people living in cities and towns in developing countries typically use more energy than their rural counterparts. Other demographic changes taking place are also set to influence energy demand patterns, most notably the rising share of older people and a decline in household size. These changes highlight the importance of long-term strategic planning to ensure that cities and metropolitan areas develop in an energy-efficient manner.

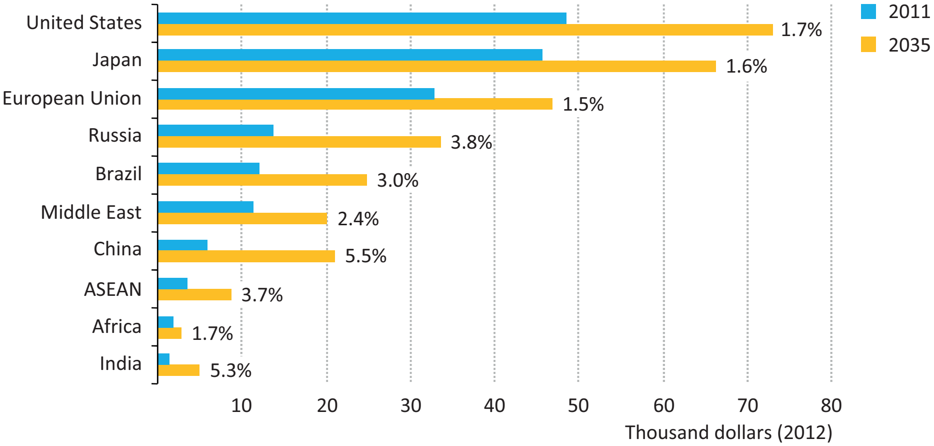
**Table 1.3 ▷ Population assumptions by region**

| | Population growth* | | | Population (million) | | Urbanisation | |
|---|---|---|---|---|---|---|---|
| | 1990-2011 | 2011-2020 | 2011-2035 | 2011 | 2035 | 2011 | 2035 |
| **OECD** | **0.7%** | **0.5%** | **0.4%** | **1 245** | **1 379** | **80%** | **86%** |
| Americas | 1.1% | 0.9% | 0.8% | 477 | 572 | 82% | 88% |
| United States | 1.0% | 0.8% | 0.7% | 316 | 374 | 83% | 88% |
| Europe | 0.5% | 0.4% | 0.3% | 563 | 600 | 75% | 81% |
| Asia Oceania | 0.4% | 0.2% | 0.0% | 205 | 207 | 89% | 93% |
| Japan | 0.2% | -0.2% | -0.3% | 128 | 118 | 91% | 97% |
| **Non-OECD** | **1.5%** | **1.2%** | **1.0%** | **5 715** | **7 322** | **46%** | **58%** |
| E. Europe/Eurasia | -0.1% | 0.0% | -0.1% | 337 | 327 | 63% | 68% |
| Russia | -0.2% | -0.3% | -0.4% | 142 | 129 | 74% | 80% |
| Asia | 1.3% | 0.9% | 0.7% | 3 664 | 4 343 | 41% | 55% |
| China | 0.8% | 0.5% | 0.2% | 1 351 | 1 431 | 51% | 73% |
| India | 1.7% | 1.1% | 0.9% | 1 241 | 1 551 | 31% | 42% |
| ASEAN | 1.4% | 1.1% | 0.9% | 597 | 737 | 45% | 59% |
| Middle East | 2.4% | 1.9% | 1.5% | 209 | 297 | 67% | 73% |
| Africa | 2.4% | 2.4% | 2.3% | 1 045 | 1 790 | 40% | 51% |
| Latin America | 1.4% | 1.0% | 0.8% | 460 | 564 | 79% | 84% |
| Brazil | 1.3% | 0.8% | 0.6% | 197 | 226 | 85% | 89% |
| **World** | **1.3%** | **1.1%** | **0.9%** | **6 960** | **8 701** | **52%** | **62%** |
| European Union | 0.3% | 0.2% | 0.1% | 508 | 518 | 74% | 79% |

* The assumed compound average annual growth rates are the same for all scenarios presented in this *Outlook*. Sources: UNPD and World Bank databases; IEA analysis.

Growth in energy demand is closely correlated with growth in per-capita income, although the relationship has decoupled in several advanced countries and may be weaker in the future in economies that are emerging today, should they "leapfrog" to more efficient energy-use practices. Nonetheless, rising incomes will continue to lead to increased demand for goods that require energy to produce and to use, such as cars, refrigerators and air conditioners. Vehicle ownership rates, for example, have historically taken off once per-capita incomes pass a threshold of around $4 000 to $5 000. Based on our assumptions for population and GDP growth, global GDP per capita is set to increase at 2.3% per year, from around \$10 300 in 2011 to around \$17 200 in 2035 (calculated using market exchange rate). GDP per capita will grow quickest in the developing countries, notably China and India, though in OECD countries it will still be over five times higher than the average of the rest of the world in 2035. China's GDP per capita increases by three-and-a-half times, surpassing the average of the Middle East around 2030 (Figure 1.2).

**Figure 1.2 ▷ GDP per capita by region**




Notes: Calculated on the basis of GDP expressed in year-2012 dollars at market exchange rate. The percentages to the right of each bar represent the respective compounded annual growth rates for the period 2011-2035.

## *Energy prices*

Prices affect energy demand and supply through a wide variety of channels. The evolution of energy pricing is, accordingly, a crucial determinant of future energy trends. On the demand side, it will affect the amount of each fuel end-users choose to consume and their choice of technology and equipment to provide a particular energy service. On the supply side, it will affect production and investment decisions.

The international fossil fuel prices in each of the scenarios reflect analysis of the price levels that would be needed to stimulate sufficient investment in supply to meet projected demand over the period (Box 1.3). Average retail prices in end-uses, power generation and other transformation sectors in each region are derived from iterative runs of the World Energy Model. These end-use prices take into account local market conditions, including taxes, excise duties, carbon-dioxide ($CO_2$) emissions penalties and pricing, as well as any subsidies. In the three scenarios, the rates of value-added taxes and excise duties on fuels are assumed to remain unchanged, except where future tax changes have already been adopted or are planned. In the 450 Scenario, administrative arrangements (price controls or higher taxes) are assumed to be put in place to keep end-user prices for oil-based transport fuels at a level similar to those in the New Policies Scenario.

### Box 1.3 ▷ Deriving the fossil fuel prices used in *WEO* analysis

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 demand over the period. The resulting price trajectories are deceptively smooth: in reality prices are likely to be more volatile and cyclic.

The price trajectories have been derived through an iterative modelling exercise. First, the demand modules of the IEA's World Energy Model (WEM) are run under a given set of prices (based on end-user prices). Once the resultant demand level is determined, the supply modules of the WEM calculate the levels of production of oil, natural gas and coal that result from the given price levels, taking account of the costs of various supply options and the constraints on production rates of various types of resources (see Chapter 13 for a more detailed discussion in relation to oil). In the event that the price is not sufficient to generate enough supply to cover global demand, price levels are increased and a new level of demand and supply is quantified. This procedure is carried out repeatedly with prices adjusting until demand and supply are in balance as a trend through the projection period.

In the near to medium term, the supply trajectories take into account our assessment of specific individual projects that are currently operating or have already been sanctioned, planned or announced. For the longer term, they are consistent with our top-down assessment of the costs of exploration and development of the world's oil, natural gas and coal resources and our judgements of the feasibility and the rate of investment required in different regions to turn these resources into production.

The price paths vary across the three scenarios presented in *WEO-2013*. In the Current Policies Scenario, policies adopted to reduce the use of fossil fuels are limited. This leads to higher demand and, consequently, higher prices, although prices are not high enough to trigger widespread substitution of fossil fuels by renewable energy sources. Lower energy demand in the 450 Scenario means that limitations on the production of various types of resources are less significant and 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. However, this does not translate into lower end-user prices for oil-based transport fuels as price controls or higher taxes are assumed to keep them at a level similar to the New Policies Scenario.

In the New Policies Scenario, subsidies to fossil fuel consumption are phased out in all net-energy importing countries within ten years at the latest. However, in net-energy exporting countries, they are phased out only if specific policies to do so have been announced, in recognition of the added difficulties these countries are likely to face in reforming energy pricing. A survey undertaken for this report has identified some 40 economies around the world that provide fossil-fuel consumption subsidies. Within the group, the average rate of subsidisation was 23% in 2012, meaning that consumers in those countries paid on average 77% of international reference prices (see Chapter 2).

## Oil prices

The world is experiencing a period of historically high oil prices. Brent crude oil has averaged over \$110/barrel in real terms since 2011, a sustained period of high oil prices that is without parallel in oil market history. This has generated responses on the demand and supply sides. Higher oil prices have given consumers and industry extra incentive to improve energy efficiency and have increased interest in substituting away from oil, for example to natural gas in road transport. Oil demand in the OECD is in decline. In the emerging economies, which have driven global demand, growth rates have slowed. The price rise has also led to increased interest in developing resources that were previously considered too difficult or too costly to produce. This is best exemplified by the spectacular rise in light tight oil production in the United States, and by growing interest in oil exploration and production in deepwater. Demand and supply side trends suggest that the global oil balance could ease over the next few years, despite concerns about oil supply security stemming from geopolitical instability in parts of the Middle East and North Africa. In the 2020s, however, the balance is likely to shift again, as non-OPEC supply levels off and starts to decline.

In this *Outlook*, oil prices vary across the scenarios in line with the degree of policy effort made to curb demand growth. In the New Policies Scenario, the average IEA crude oil import price – a proxy for international oil prices – reaches \$113/barrel (in year-2012 dollars) in 2020 and \$128/barrel in 2035; the oil price picks up more quickly in the latter half of the period in line with tighter market conditions (Table 1.4). In the Current Policies Scenario, substantially higher prices are needed to balance supply with faster growth in demand, reaching \$145/barrel in 2035. In the 450 Scenario, lower oil demand means there is less need to produce oil from costly fields in non-OPEC countries, which are higher up the supply curve. As a result, the oil price peaks at around \$110/barrel by 2020 and then falls slowly, reaching \$100/barrel in 2035.

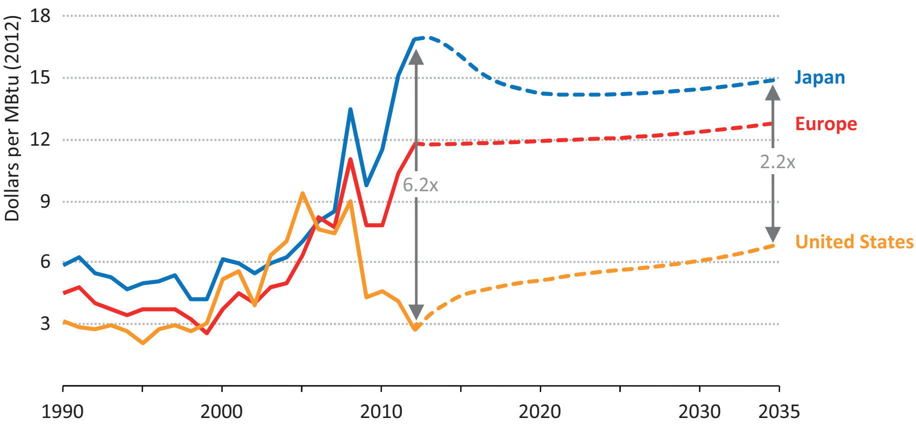
In Chapter 14, the possibility of a Low Oil Price Case is examined, premised on supply developments in several countries turning out more positively than projected in the New Policies Scenario. In this case, output growth is rapid enough to ease the market balance, bringing on and meeting additional oil consumption at a price that stabilises at \$80/barrel.

## Natural gas prices

Although international trade in natural gas continues to expand rapidly, there is no global pricing benchmark for natural gas, as there is for oil. Rather, there are three major regional markets – North America, Asia-Pacific and Europe – with prices established by different mechanisms. In North America, gas trade relies on hub-based pricing, with prices reflecting local gas supply and demand. In Asia-Pacific, trade is dominated by long-term contracts in which prices are at least partly indexed to the price of oil. Gas trade in Europe is gradually moving to gas-to-gas competition, though about half of European trade today is governed by long-term oil-indexed contracts. A notable exception in Europe is the United Kingdom, where prices have generally been set by market fundamentals since the mid-1990s.

There have always been differences in natural gas prices across the three major markets, reflecting primarily their different demand and supply balances and pricing systems. Since mid-2008, the gap has widened considerably. Prices in North America have fallen thanks to spectacular growth in shale gas output and reduced demand (owing to the economic crisis). By contrast, prices in Asia-Pacific (and to a lesser extent Europe) have risen, mostly due to the prevalence of oil-price indexation at a time of persistently high oil prices. In 2012, average natural gas prices in the United States were less than one-quarter of the prices in Europe and one-sixth of those in Japan. By mid-2013, however, spot prices for gas at Henry Hub – the leading trading hub in the United States – had more than doubled from the lows reached in early 2012, narrowing regional price divergences. Nonetheless, low prices continue to generate strong interest in exporting liquefied natural gas (LNG) from North America and raise questions about the long-term sustainability of oil-linked pricing mechanisms.

**Figure 1.3 ▻ Natural gas prices by region in the New Policies Scenario**




In *WEO-2013*, large geographical spreads in natural gas prices persist during the *Outlook* period, albeit with a degree of convergence brought about by rising LNG supplies, increased short-term trading and greater operational flexibility (Figure 1.3). These developments allow price changes in one part of the world to be reflected more quickly elsewhere, but are unlikely to be sufficient to create a single global price for gas, particularly given the significant costs associated with liquefaction and shipping. In each of the scenarios, North American prices are lowest, reflecting abundant and relatively low-cost unconventional resources. But prices rise in absolute terms and relative to the other regions, particularly later in the period, as the costs of unconventional gas production increases and as oil indexation loosens gradually in other markets, notably Europe, as long-term contracts expire and are renegotiated. In the New Policies Scenario, gas prices in 2035 are $6.8 per million British thermal units (MBtu) (in year-2012 dollars) in North America, $12.7/MBtu in Europe and $14.9/MBtu in Asia-Pacific. Prices in Japan are more than double those in the

United States in 2035, meaning that the spread is much narrower than observed recently, but much greater than before US production of shale gas took off. Gas prices vary across the three scenarios in line with the degree of policy effort to curb $CO_2$ emissions.

The Gas Price Convergence Case, presented in Chapter 3, investigates the conditions under which convergence between pricing mechanisms and prices could be more pronounced than in the New Policies Scenario. The case rests on three main conditions: (i) a larger volume of LNG export from North America; (ii) new supply contracts weakening or breaking the link with oil-price indexation, and an accelerated pace of regulatory change for the gas sector across the Asia-Pacific region; and (iii) an easing of costs of constructing liquefaction plants and of shipping LNG. Compared with the New Policies Scenario, gas prices are slightly higher in North America but lower in Europe and in the Asia-Pacific region. The differential between the US price and the European import price narrows to $4.5/MBtu, with an extra $1/MBtu to Asia-Pacific reflecting additional transport costs.

### *Steam coal prices*

The global coal market consists of various regional sub-markets that are typically separated by geography, coal quality or infrastructure constraints. As a result, coal prices vary markedly across the regions. International coal trade is a comparatively small sub-market, yet it links various domestic markets through imports, exports and price movements. The degree to which regional coal prices fluctuate with price movements on the international market depends on how well they are connected to it. Around one-fifth of global steam coal production is traded internationally, with the remainder used closer to where it is mined. International trade has historically been divided into two market areas – Asia-Pacific and Atlantic – reflecting the wide geographical spread of production and the significance of transportation costs as a share of the total delivered cost of coal. However, trade between the two market areas is growing, owing to increased supply sources and lower freight costs. The market in internationally traded coal is dominated by spot market transactions, though long-term contracts with prices fixed annually remain important in some cases.

Prices of internationally traded coal have fluctuated widely over the last decade. Strong demand saw prices climb throughout the early 2000s to record highs, above $200/tonne in mid-2008. Prices then plummeted in the wake of the global economic crisis, before staging a recovery, underpinned by robust demand and weather-related supply constraints in a number of key producer countries. Since mid-2011, prices have again fallen, on weak demand and growing supply in the market and, by mid-2013, they were less than half their peak of 2008. Coal consumption in China has been subdued because of slower growth in its electricity demand and increased hydropower output. As the world's largest coal buyer, China exerts a major influence on international prices. The boom in US unconventional gas production has also been a factor in depressing international coal prices: some of the coal displaced by cheaper gas in US power generation has found its way onto export markets.

**Table 1.4 ▷ Fossil fuel import prices by scenario** (dollars per unit)

| | Unit | 2012 | New Policies Scenario | | | | Current Policies Scenario | | | | 450 Scenario | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2020 | 2025 | 2030 | 2035 | 2020 | 2025 | 2030 | 2035 | 2020 | 2025 | 2030 | 2035 |
| **Real terms (2012 prices)** | | | | | | | | | | | | | | |
| IEA crude oil imports | barrel | 109 | 113 | 116 | 121 | 128 | 120 | 127 | 136 | 145 | 110 | 107 | 104 | 100 |
| Natural gas | | | | | | | | | | | | | | |
| United States | MBtu | 2.7 | 5.1 | 5.6 | 6.0 | 6.8 | 5.2 | 5.8 | 6.2 | 6.9 | 4.8 | 5.4 | 5.7 | 5.9 |
| Europe imports | MBtu | 11.7 | 11.9 | 12.0 | 12.3 | 12.7 | 12.4 | 12.9 | 13.4 | 14.0 | 11.5 | 11.0 | 10.2 | 9.5 |
| Japan imports | MBtu | 16.9 | 14.2 | 14.2 | 14.4 | 14.9 | 14.7 | 15.2 | 15.9 | 16.7 | 13.4 | 12.8 | 12.2 | 11.7 |
| OECD steam coal imports | tonne | 99 | 106 | 109 | 110 | 110 | 112 | 116 | 118 | 120 | 101 | 95 | 86 | 75 |
| **Nominal terms** | | | | | | | | | | | | | | |
| IEA crude oil imports | barrel | 109 | 136 | 156 | 183 | 216 | 144 | 171 | 205 | 245 | 132 | 144 | 157 | 169 |
| Natural gas | | | | | | | | | | | | | | |
| United States | MBtu | 2.7 | 6.1 | 7.5 | 9.1 | 11.6 | 6.2 | 7.7 | 9.3 | 11.7 | 5.8 | 7.2 | 8.6 | 10.0 |
| Europe imports | MBtu | 11.7 | 14.2 | 16.1 | 18.5 | 21.5 | 14.9 | 17.3 | 20.2 | 23.6 | 13.8 | 14.7 | 15.4 | 16.0 |
| Japan imports | MBtu | 16.9 | 17.1 | 19.1 | 21.7 | 25.1 | 17.7 | 20.4 | 24.0 | 28.2 | 16.1 | 17.2 | 18.4 | 19.7 |
| OECD steam coal imports | tonne | 99 | 127 | 146 | 165 | 186 | 134 | 155 | 178 | 202 | 121 | 128 | 129 | 127 |

Notes: 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 2.3% per year from 2012.

The outlook for coal prices depends heavily on the stringency of climate policy measures and competition between natural gas and coal in power generation. International steam coal prices (which are used to derive prices for coking coal and other coal qualities) vary markedly across the three scenarios. In the New Policies Scenario, the average OECD steam coal import price reaches $106/tonne (in year-2012 dollars) in 2020, from its average of $99/tonne in 2012, before rising slowly to about $110/tonne in 2035. Coal prices rise more quickly in the Current Policies Scenario, on stronger demand growth, but fall sharply in the 450 Scenario, reflecting the impact of much stronger policy action to reduce $CO_2$ emissions.

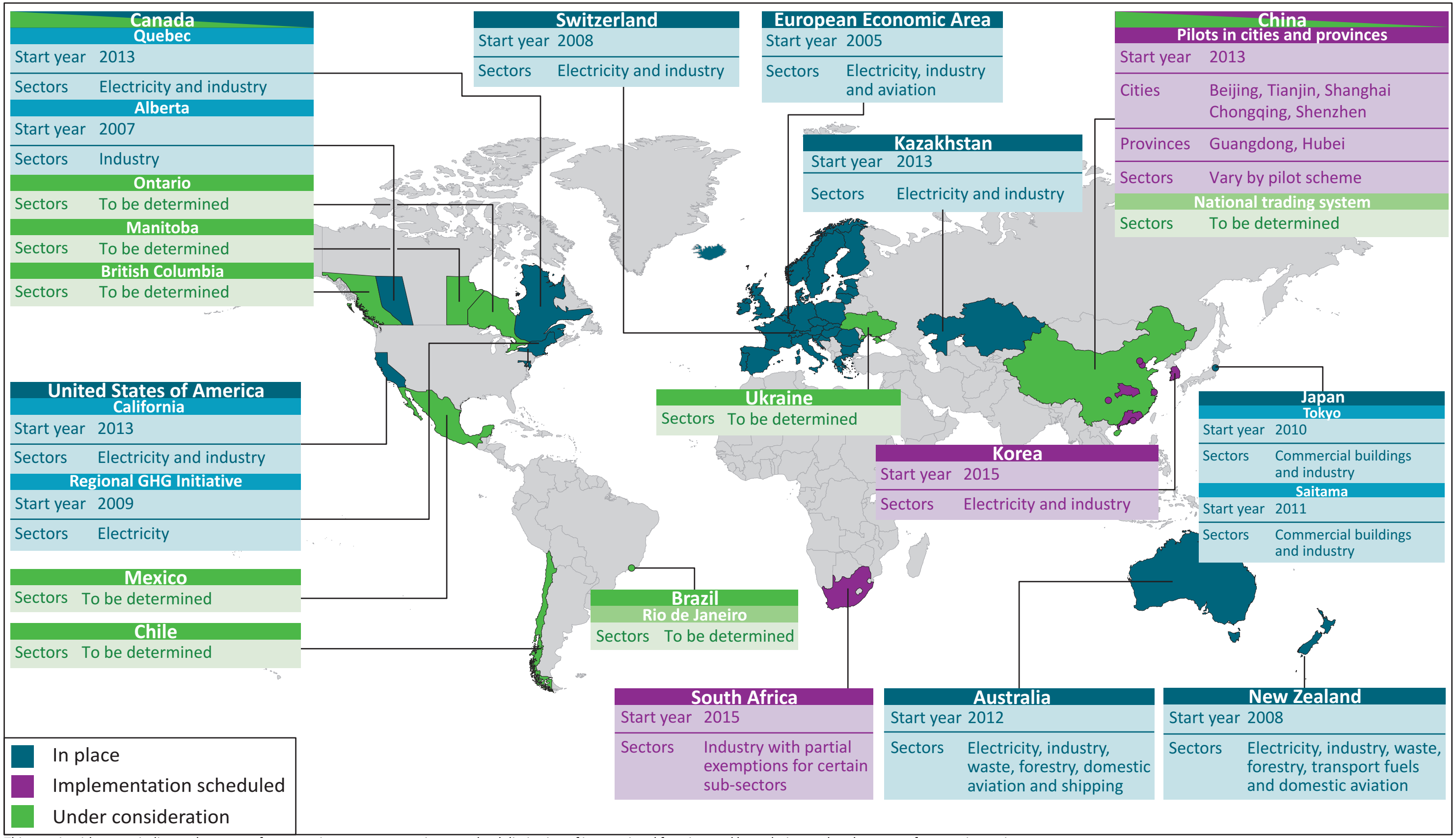
### *Carbon markets*

The last year has seen an increase in the number of schemes that put a price on carbon emissions. The EU Emissions Trading System (ETS) remains the world's largest scheme, covering all 28 member states of the European Union, plus Norway, Iceland and Liechtenstein. Programmes are also in place in New Zealand, Australia, California (United States), Quebec and Alberta (Canada) and Kazakhstan (Figure 1.4). These will soon be joined by a scheme in Korea. The city of Shenzhen in China started a pilot emissions trading scheme in June 2013, which aims to cut its emissions by 21% by 2015. Several other pilot schemes are expected to start in China in the near term, aimed at informing the possible implementation of a nationwide scheme post-2015. South Africa has proposed phased implementation of a carbon tax over an initial ten-year period from January 2015, starting at rand 120 (around $12) per tonne of $CO_2$ equivalent, with a tax-free threshold set at 60% of actual emissions, plus other exemptions for certain sectors.

But despite evidence that carbon pricing is becoming more widespread, some schemes are facing significant challenges. Carbon prices under the EU ETS have fallen in recent years, reaching levels unlikely to stimulate significant investment in low-carbon technologies. From almost €30/tonne in mid-2008, the price dropped to less than €3/tonne in April 2013, following an inconclusive vote by the European Parliament on a plan to delay the introduction of 900 million of the 16 billion tonnes-worth of allowances on the market for 2013-2020. It has recovered a little since with a new vote on an amended European Commission proposal, which limits the extent to which allowances can be delayed. In September 2013, the proposal awaited approval by the European Council. There are also indications that some existing schemes may be abolished, while some in the planning stage may not eventuate. Most notably, Australia has announced an intent to repeal the country's carbon pricing scheme, following a change of government in September 2013.

Our assumptions on carbon pricing vary across the scenarios, reflecting the different levels of policy intervention to curb growth in $CO_2$ emissions. We assume each of the existing and planned programmes that are described above continue, with the price of $CO_2$ rising under each programme over the projection period (Table 1.5). In Europe, the price increases from an average of $10/tonne (in year-2012 dollars) in 2012 to $20/tonne in 2020 and $40/tonne in 2035. A $CO_2$ price covering all sectors is introduced in China starting in 2020,

**Figure 1.4 ▷ Current and proposed schemes that put a price on carbon**




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.

starting at $10/tonne and then rising to $30/tonne in 2035. As a result of these schemes, the share of global $CO_2$ emissions subject to a carbon price increases from around 8% in 2012 to around one-third in 2035. This result is particularly sensitive to our assumption that a scheme is introduced in China, without which the share would drop to 6% in 2035. We also assume that, from 2015 onwards, all investment decisions in the power sector in Canada, the United States and Japan include an implicit or "shadow" price for carbon. In general, the $CO_2$ price levels assumed in *WEO-2013* are lower than in *WEO-2012*, reflecting the low prices over the past year and lower expectations in the longer term.

**Table 1.5 ▷ $CO_2$ price assumptions in selected regions by scenario**
(in year-2012 dollars per tonne)

| | Region | Sectors | 2020 | 2030 | 2035 |
|---|---|---|---|---|---|
| Current Policies Scenario | European Union | Power, industry and aviation | 15 | 25 | 30 |
| | Australia and New Zealand | All* | 15 | 25 | 30 |
| | Korea | Power and industry | 15 | 25 | 30 |
| New Policies Scenario | European Union | Power, industry and aviation | 20 | 33 | 40 |
| | Australia and New Zealand | All* | 20 | 33 | 40 |
| | Korea | Power and industry | 20 | 33 | 40 |
| | China | All | 10 | 24 | 30 |
| | South Africa | Power and industry | 8 | 15 | 20 |
| 450 Scenario | United States and Canada | Power and industry | 20 | 95 | 125 |
| | European Union | Power, industry and aviation | 35 | 95 | 125 |
| | Japan | Power and industry | 20 | 95 | 125 |
| | Korea | Power and industry | 35 | 95 | 125 |
| | Australia and New Zealand | All | 35 | 95 | 125 |
| | China, Russia, Brazil and South Africa | Power and industry** | 10 | 70 | 100 |

* Agriculture is not assumed to be included in New Zealand's Emissions Trading Scheme. ** All sectors in China. Note: In the New Policies Scenario, a shadow price for $CO_2$ in the power sector is assumed to be adopted as of 2015 in the United States, Canada and Japan (starting at $15/tonne and rising to $35/tonne in 2035).

## *Technology*

Successive editions of the *WEO* have demonstrated the need for ongoing improvements in efficiency, including energy conservation and management, and the adoption of a portfolio of existing and new technologies in order to address the challenges posed by the world's rising fossil energy use. It follows that the rate at which energy efficiency improves and new technologies for supplying and using energy are developed and deployed will have a major impact on future energy balances, both in terms of the overall amount of energy used and the fuel mix. An IEA review released in mid-2013 concluded that recent progress in developing and deploying clean energy technologies and in improving energy efficiency has not been sufficient to achieve announced policy objectives and is being limited by market failures (IEA, 2013c). But it saw some reasons for optimism. For example, annual sales of hybrid vehicles in 2012 passed the 1 million mark for the first time and solar photovoltaic (PV) systems and wind turbines were installed at a rapid pace by historical standards (Table 1.6).

**Table 1.6 ▷ Recent progress and key conditions for faster deployment of clean energy technologies**

| Technology | Recent progress | Key conditions for faster deployment |
|---|---|---|
| **Renewable power** | Investment fell by 11% in 2012 from 2011 due to tougher financing conditions, policy uncertainty and falling technology costs. Solar PV capacity still grew by 42% and wind by 19%, compared with 2011 cumulative levels. | Ongoing subsidies (as renewables generally remain more expensive than other sources of power). Reforms to facilitate grid integration. Increased RD&D in emerging technologies, such as concentrating solar power, ocean and enhanced geothermal. |
| **Nuclear power** | Seven projects started construction in 2012, an increase from 2011 when new projects fell to only four after the Fukushima Daiichi accident. In 2010 there were 16 new projects. | More favourable electricity market mechanisms and investment conditions to reduce risk and allow investors to recover high upfront capital costs. Quick implementation of post-Fukushima safety upgrades to foster public confidence. |
| **Carbon capture and storage (CCS)** | 13 large-scale CCS demonstration projects are in operation or under construction. Construction began on two new integrated projects in 2012, while eight projects were cancelled. | Financial and policy commitment by governments to accelerate demonstration efforts. Sufficiently high price on $CO_2$ emissions or a commercial market for captured $CO_2$ for enhanced oil recovery. |
| **Biofuels** | New investment was 50% lower in 2012 than in 2011, as a result of over-capacity, and a review of biofuels support policies and higher feedstock prices. | A longer-term policy framework to build investor confidence. RD&D to improve cost and efficiency, and to develop sustainable feedstocks. Development and application of internationally agreed sustainability criteria and standards. |
| **Hybrid (HV) and electric vehicles (EV)** | HV sales reached 1.2 million in 2012, up 43% on 2011, led by Japan and the United States. EV sales more than doubled from 2011 to 2012, from a low base. Government targets for EV sales increased. | Further reductions in battery costs and other measures to enhance competitiveness. Non-financial incentives, such as priority access to parking and restricted highway lanes. Installation of recharging infrastructure. |
| **Energy efficiency** | Evidence of renewed focus from governments, with many major energy-consuming countries announcing new measures. | Policy action to remove the barriers obstructing the implementation of energy efficiency measures that are economically viable (see Chapter 7). |

Sources: IEA (2013c and 2013d).

*WEO-2012* found that even though there is a renewed policy focus on energy efficiency, two-thirds of the economic potential to improve energy efficiency is set to remain untapped in the period to 2035. While investment in many energy-efficient technologies and practices appear to make good economic sense, the level of their deployment is often much lower than expected due to the persistence of a number of barriers. Key steps that would need to be taken to overcome these barriers, and thereby allow the market to realise the potential of all known energy efficiency measures which are economically viable, include: (i) strengthening the measurement and reporting of energy efficiency to make the gains more visible to consumers; (ii) introducing regulations to prevent the sale of inefficient technologies; (iii) eliminating market distortions, such as fossil-fuel subsidies; and (iv) increasing the availability of financing instruments.

Carbon capture and storage (CCS) has been identified as an essential technology to meet the internationally agreed goal of limiting the temperature increase to 2 °C. Deploying CCS technologies and retrofitting fossil fuel plants with CCS avoids the need to retire large parts of this fleet prematurely. This improves the economic feasibility of attaining the climate objective, in particular in regions where geological formations allow for $CO_2$ storage. However, progress in developing CCS has been disappointingly slow. Only a handful of large-scale CCS projects, mainly in natural gas processing, are operating, together with some low-cost schemes in industrial applications. While projects are more economically viable if the captured $CO_2$ can be used for enhanced oil recovery, there is, to date, no commercial CCS application in the power sector or in energy-intensive industries. Beyond technological and economic challenges, there could be legal challenges related to the potential for $CO_2$ gas escape from underground storage. Although some progress has been made in developing regulatory frameworks, deployment support is lacking and the absence of a substantial price signal has so far impeded necessary technological development and more widespread uptake.

Ambitious carbon abatement also necessitates a shift to low-carbon fuels in the transport sector, as vehicle fuel-economy improvements alone will not lead to the steep emissions reductions required. While natural gas and biofuels are promising alternatives to oil, their potential to reduce emissions, relative to oil, is limited, owing to their carbon content (natural gas) or concerns about their sustainability and conflicts over land use or other uses for the feedstock (conventional biofuels). High expectations rest on the deployment of electric and plug-in hybrid electric vehicles. But increasing their market penetration will require major cost reductions and addressing issues crucial to consumer acceptability, such as driving range (for example, through fast-recharging infrastructure).

In each of the scenarios presented in this *Outlook*, energy technologies – both on the demand and supply sides – that are in use today or are approaching commercialisation are assumed to achieve ongoing cost reductions as wider deployment contributes to more efficient production. No complete technological breakthroughs are assumed to be made, as it cannot be known what they might involve, whether or when they might occur and how quickly they might be commercialised. The pace of efficiency gains for end-use technologies varies for each fuel and each sector, depending on our assessment of the potential for improvements and the stage reached in technology development and commercialisation. Technological advances are also assumed to improve the efficiency of producing and supplying energy. For many regions and technologies, energy derived from renewable sources is today more costly than energy from fossil fuels and therefore requires subsidies in order to aid its deployment (see Chapter 6). We assume that existing subsidies for renewable energy technologies are retained until sufficient cost reductions have been achieved to enable them to compete on their own merits with conventional technologies. At that point, we assume subsidies cease to be awarded to additional production.

# Global energy trends to 2035

## Finding our way in a new energy world

### Highlights

- Global energy demand will grow to 2035, but government policies can influence the pace. In the New Policies Scenario, our central scenario, global energy demand increases by one-third from 2011 to 2035. Demand grows for all forms of energy: oil by 13%, coal by 17% (mainly before 2020), natural gas by 48%, nuclear by 66% and renewables by 77%. Energy-related $CO_2$ emissions rise by 20%, reaching 37.2 Gt.
- Emerging economies account for more than 90% of global net energy demand growth, but this comes from multiple and sometimes unexpected sources. While Asian energy demand growth is led by China this decade, it shifts towards India and, to a lesser extent, Southeast Asia after 2025. The Middle East emerges as a major energy consumer, with its gas demand growing by more than the entire OECD: the Middle East is the second-largest gas consumer by 2020 and third-largest oil consumer by 2030, redefining its role in global energy markets.
- Electricity demand grows by more than any other final form of energy. Although its share declines, coal continues to be the largest source of electricity generation and coal-gas price dynamics remain important for regional trends. Nearly half of the net increase in electricity generation comes from renewables and their share of the total reaches more than 30% by 2035. Different natural gas and electricity prices across regions continue to have implications for relative industrial competiveness.
- World oil demand grows from 87 mb/d in 2011 to 101 mb/d in 2035, with transport and petrochemicals being key drivers. One-third of the net global growth fuels Asia's road freight. The refining industry faces huge structural challenges: the composition of feedstocks changes, while oil product demand shifts towards Asia and the Middle East, and towards diesel, naphtha and kerosene. Global refining capacity grows by 13 mb/d to 2035, but some regions risk being left with substantial idle capacity.
- Non-OPEC supply plays the major role in meeting net oil demand growth this decade, but OPEC plays a far greater role after 2020. The United States is the world's largest oil producer from 2015 to the early 2030s; light tight oil and efficiency policies reduce rapidly its reliance on imports. Brazil becomes a major oil exporter, delivering one-third of global supply growth to 2035. China is about to become the largest oil importer and becomes the largest oil consumer around 2030. The European Union stays the largest gas importer, but demand returns to 2010 levels only as 2035 approaches.
- Despite some signs of reform, fossil-fuel subsidies increased to $544 billion in 2012. Subsidies to renewables increased by 11% to reach $101 billion. Nearly 1.3 billion people did not have access to electricity in 2011 and more than 2.6 billion relied on the traditional use of biomass for cooking. More than 95% of these people are in Asia or sub-Saharan Africa, and they are mainly in rural areas.

## Overview of energy trends by scenario

Many of the long-held tenets of the energy sector are being rewritten. Major importers are becoming exporters, large exporters are becoming large consumers and previously small consumers are becoming the dominant source of global demand. These changes emerge as the energy sector acts and reacts to broader global trends, such as shifts in economic growth, demographic change, industrialisation, electrification, efforts at decarbonisation, technological breakthroughs and divergent regional energy prices. The energy sector itself is innovating at a rapid pace: unlocking unconventional oil and gas supplies, enhancing supply flexibility with liquefied natural gas (LNG), integrating larger shares of variable renewable supply into the power sector and increasing energy efficiency. Our understanding of the energy sector must therefore evolve if we are to take the best policy and investment decisions. This edition of the *World Energy Outlook (WEO-2013)* seeks to put the latest developments into perspective and explore their implications for global energy security, economic development and the environment.

*WEO-2013* takes 2011 to 2035 as its *Outlook* period and considers three scenarios based on differing policy assumptions (see Chapter 1); the results vary significantly (Box 2.1). The New Policies Scenario – our central scenario – takes account of existing policies and the anticipated impact of the cautious implementation of declared policy intentions. The Current Policies Scenario takes account only of policies enacted as of mid-2013, providing a baseline of how global energy markets would evolve if established trends continue unabated. The 450 Scenario illustrates an energy pathway compatible with a 50% chance of limiting the long-term increase in average global temperature to 2 degrees Celsius (°C).

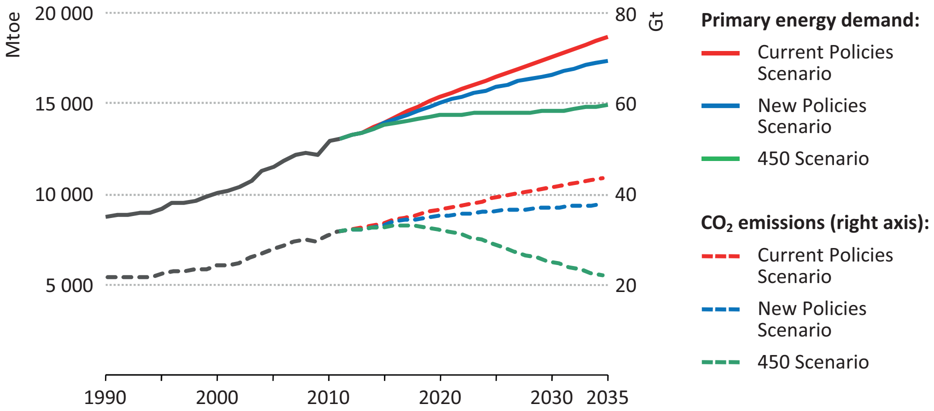
**Box 2.1 ▷ Building on a new base**

A reflection on the 2011 base year for *WEO-2013* and how it has changed from 2010 is useful before examining the key findings from the projections. Total primary energy demand increased by around 1.4% in 2011, compared with a robust 5.6% increase the year before (a year of economic rebound). Within this global trend, demand declined in Japan by 7.5%, in the European Union by around 3.5% and in the United States by just over 1% (although US coal demand was down nearly 5%). The exact drivers were country-specific, but a weak global economy, the repercussions of the Fukushima Daiichi nuclear accident in Japan, high fuel costs (in some cases), efforts to improve efficiency and the weather were among them. In contrast, primary energy demand increased by 8% in China, nearly 4% in Korea, more than 3% in Russia and almost 3% in India. Global coal demand grew by 5% in 2011 and accounted for more than 95% of the net growth in total energy demand. Key contributors were China (10% up), ASEAN[1] countries (7% higher across the region as a whole) and India (5% up). Global oil demand declined slightly while gas demand increased. Nuclear power declined globally by more than 6%, compared with a year earlier, while renewables continued to grow strongly.

1. The Association of Southeast Asian Nations (ASEAN) countries are Brunei Darussalam, Cambodia, Indonesia, Lao PDR, Malaysia, Myanmar, Philippines, Singapore, Thailand and Vietnam.

A growing global population and expanding economy will continue to push primary energy demand higher, but government policies will play an important role in dictating the pace (Figure 2.1). In the New Policies Scenario, global primary energy demand increases by one-third between 2011 and 2035, reaching around 17 400 million tonnes of oil equivalent (Mtoe). Demand rises more quickly in the Current Policies Scenario, ending nearly 45% higher than 2011, equivalent to adding the combined energy demand of the world's three largest consumers today (China, the United States and India). In both cases, energy demand grows most rapidly in this decade and moderates after 2020. Energy demand grows much more slowly in the 450 Scenario, increasing by only 14% over the *Outlook* period, and just 0.3% per year after 2020, which, given historical rates of global energy growth, would represent a massive and extremely challenging change in trajectory. The non-OECD share of global energy demand has increased from 45% in 2000 to 57% in 2011. This trend continues, reaching around 60% in 2020 and around two-thirds in 2035 in each scenario. Compared with *WEO-2012*, global energy demand in 2035 is 0.2% lower in the Current Policies Scenario, 1.1% higher in the New Policies Scenario and 0.8% higher in the 450 Scenario.

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




Note: Mtoe = Million tonnes of oil equivalent; Gt = gigatonnes.

Fossil fuels account for 82% of primary energy demand in 2011, but the share in 2035 declines in all scenarios: to 76% in the New Policies Scenario, 80% in the Current Policies Scenario and 64% in the 450 Scenario, showing that, even in a 2 °C climate scenario, the transition away from fossil fuels is likely to take considerable time to achieve (Table 2.1). The future trends differ markedly by fuel. Demand for natural gas grows in all scenarios and, in absolute terms, increases more than all other fuels in the New Policies Scenario. Its relative abundance, flexibility as a fuel and lower emissions than other fossil fuels all contribute to its relatively bright outlook. In contrast, the demand for coal swings from seeing the largest increase in demand (44%) in the Current Policies Scenario to the largest decrease (33%) in the 450 Scenario, reflecting the considerable range of uncertainty resulting from different policy paths. In the Current Policies Scenario, coal overtakes oil in the early 2020s as the largest fuel in the energy mix, while in the 450 Scenario coal demand drops below that of natural gas in the mid-2020s. Oil also has mixed results across scenarios, influencing the speed at which new supply will need to be brought online (see Part C for a detailed Outlook for oil markets).

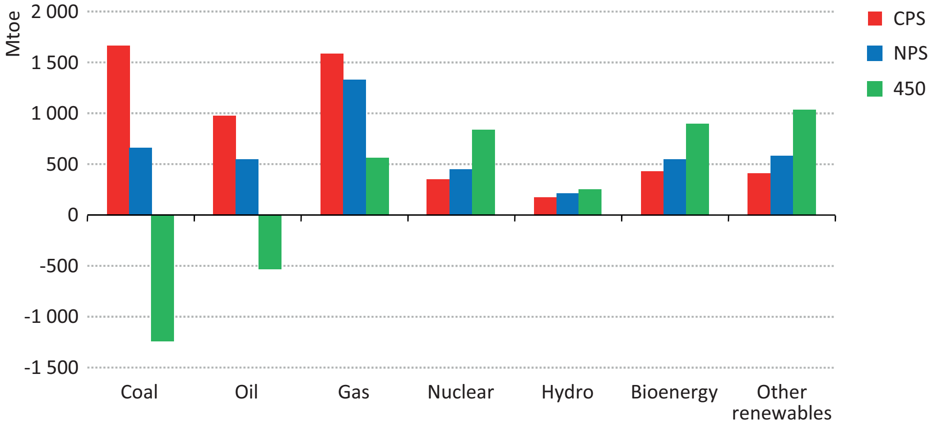
**Table 2.1 ▷ World primary energy demand and energy-related $CO_2$ emissions by scenario**

| | | | New Policies Scenario | | Current Policies Scenario | | 450 Scenario | |
|---|---|---|---|---|---|---|---|---|
| | 2000 | 2011 | 2020 | 2035 | 2020 | 2035 | 2020 | 2035 |
| Coal | 2 357 | 3 773 | 4 202 | 4 428 | 4 483 | 5 435 | 3 715 | 2 533 |
| Oil | 3 664 | 4 108 | 4 470 | 4 661 | 4 546 | 5 094 | 4 264 | 3 577 |
| Gas | 2 073 | 2 787 | 3 273 | 4 119 | 3 335 | 4 369 | 3 148 | 3 357 |
| Nuclear | 676 | 674 | 886 | 1 119 | 866 | 1 020 | 924 | 1 521 |
| Hydro | 225 | 300 | 392 | 501 | 379 | 471 | 401 | 550 |
| Bioenergy* | 1 016 | 1 300 | 1 493 | 1 847 | 1 472 | 1 729 | 1 522 | 2 205 |
| Other renewables | 60 | 127 | 309 | 711 | 278 | 528 | 342 | 1 164 |
| **Total (Mtoe)** | **10 071** | **13 070** | **15 025** | **17 387** | **15 359** | **18 646** | **14 316** | **14 908** |
| *Fossil fuel share* | *80%* | *82%* | *80%* | *76%* | *80%* | *80%* | *78%* | *64%* |
| *Non-OECD share*** | *45%* | *57%* | *61%* | *66%* | *61%* | *66%* | *60%* | *64%* |
| **$CO_2$ emissions (Gt)** | **23.7** | **31.2** | **34.6** | **37.2** | **36.1** | **43.1** | **31.7** | **21.6** |

* Includes traditional and modern biomass uses. ** Excludes international bunkers.

While constituting a relatively small share of the energy mix today (13% in 2011), global demand for renewable energy increases strongly to 2035 in all scenarios, by around 75% in the New Policies Scenario, nearly 60% in the Current Policies Scenario and more than 125% in the 450 Scenario. Policies already implemented, including subsidies, have given a boost to renewables and those adopted but yet to be implemented give a further push in the New Policies Scenario; but additional policies, often targeted at objectives such as energy security or tackling environmental concerns, would see the penetration of renewables increase substantially in the 450 Scenario. The outlook for hydropower varies little across the scenarios, reflecting the extent to which it is driven by the intentions and technically exploitable resources of a small number of countries, such as China and Brazil (Figure 2.2). The main difference between scenarios occurs in the uptake of bioenergy and other renewables, such as wind and solar which, while cost competitive in some countries, require continued government support in a number of cases in order to stimulate increased adoption. Taking into account nuclear power, which increases in all scenarios, low-carbon energy meets less than one-quarter of the growth in primary energy demand in the Current Policies Scenario, around 40% of the growth in the New Policies Scenario and more than 80% of the increase (of those energy sources whose demand rises) in the 450 Scenario.

**Figure 2.2 ▷ Change in world primary energy demand by scenario, 2011-2035**




Note: CPS = Current Policies Scenario; NPS = New Policies Scenario; 450 = 450 Scenario.

There is a growing disconnect between the greenhouse-gas emissions trajectory that the world is on and one that is consistent with the 2 °C climate goal. The energy sector accounts for more than two-thirds of global greenhouse-gas emissions (IEA, 2013a) and, in 2012, we estimate that energy-related carbon dioxide ($CO_2$) emissions increased by 1.2% to 31.5 gigatonnes (Gt). The scenarios have a significantly different impact on the level of future emissions. By 2035, global energy-related $CO_2$ emissions are projected to increase to 37.2 Gt in the New Policies Scenario and 43.1 Gt in the Current Policies Scenario, but they decrease to 21.6 Gt in the 450 Scenario.[2] In the absence of additional policies, as in the Current Policies Scenario, $CO_2$ emissions would be twice the level in the 450 Scenario in 2035, while the cautious implementation of announced policies, as in the New Policies Scenario, achieves nearly 30% of the cumulative savings needed to be on a trajectory consistent with limiting the average global temperature rise to 2 °C.

## Energy trends in the New Policies Scenario

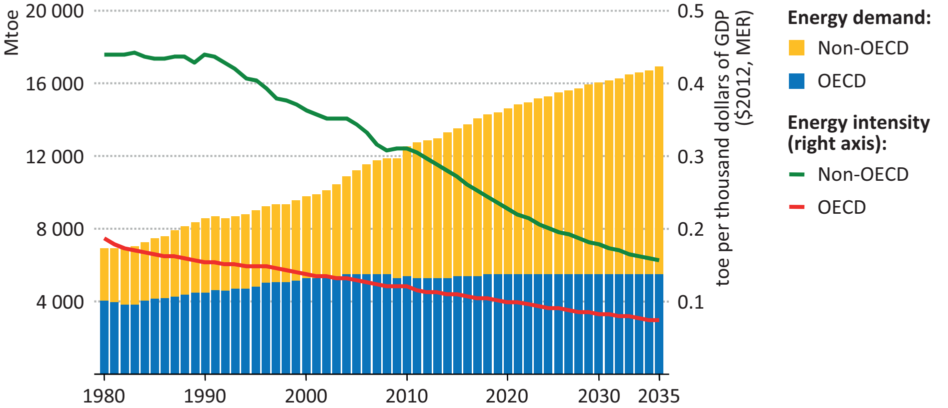
### *Energy demand*

In the New Policies Scenario, global energy demand grows by 1.6% per year on average to 2020 and then gradually slows to average 1% per year thereafter, reaching around 17 400 Mtoe in 2035 (Figure 2.3). Associated with this 33% increase in energy demand over the projection period, the global population grows by around one-quarter and the global economy more than doubles. Energy demand growth slows primarily as a result of a gradual slowdown in economic growth in certain countries, particularly the largest rapidly industrialising developing economies, and as recently announced energy policies

2. See the *WEO* special report *Redrawing the Energy-Climate Map* (IEA, 2013a) and the Spotlight in this chapter for more on the pragmatic and economic actions the energy sector can take to keep open the path to a 2 °C climate trajectory.

(targeted at increasing energy security, improving efficiency and reducing pollution) are implemented and have a greater effect over time. Despite these actions, global energy demand is 190 Mtoe higher in 2035 than projected last year. In the OECD, a comparison with *WEO-2012* shows demand in 2035 to be slightly lower across all fuels, mainly as a result of the continuing economic woes in many countries. In contrast, non-OECD energy demand is generally higher, the biggest change being higher coal demand in 2035, mainly due to an upward revision of coal used as petrochemical feedstock in China (see Chapter 15).

**Figure 2.3 ▷ Primary energy demand and energy intensity in the New Policies Scenario**




Note: toe = tonne of oil equivalent; MER = market exchange rate.

A renewed focus on energy efficiency, at a time of relatively high energy prices, has accelerated the previously slow rate of improvement in global energy intensity (see Chapter 7).[3] From 2000 to 2010, the amount of energy used to produce a unit of gross domestic product (GDP) declined by 0.4% per year on average. But there has been a significant improvement since 2010 and, in 2012, the amount of energy used to produce a unit of GDP declined by 1.5%. This has been driven by high energy prices inducing energy conservation, renewed government-led action in support of energy efficiency and fuel switching. The long-term improvement in global energy intensity is expected to continue through the projection period – energy intensity is down by more than one-third in 2035. Energy efficiency policies, a primary contributor to energy intensity improvements in the New Policies Scenario, deliver global savings of 910 Mtoe in 2035, compared with the Current Policies Scenario, a level equivalent to slightly more than half the current energy use of the European Union. In cumulative terms, these efficiency-related primary energy savings are more than 9 200 Mtoe over the projection period. China sees the biggest efficiency gains in the New Policies Scenario (relative to the Current Policies Scenario),

3. Energy intensity is often used as a proxy measure – albeit an imperfect one – for energy efficiency. It is calculated as primary energy demand per dollar of GDP at market exchange rate.

as policies, such as those in its 12th Five-Year Plan, deliver important improvements. The United States also makes significant gains as a result of its energy efficiency policies. In 2035, industry accounts for 37% of total efficiency-related energy savings globally and buildings for 26%. In both sectors, the bulk of the savings are made in the use of electricity, led by efficiency improvements in electric motor systems, stricter standards for appliances and more efficient lighting. In the transport sector, improved fuel-economy standards lead to oil savings of around 5 million barrels per day (mb/d) by 2035. Improvements in the efficiency of fossil fuel-fired power plants account for most of the remainder.



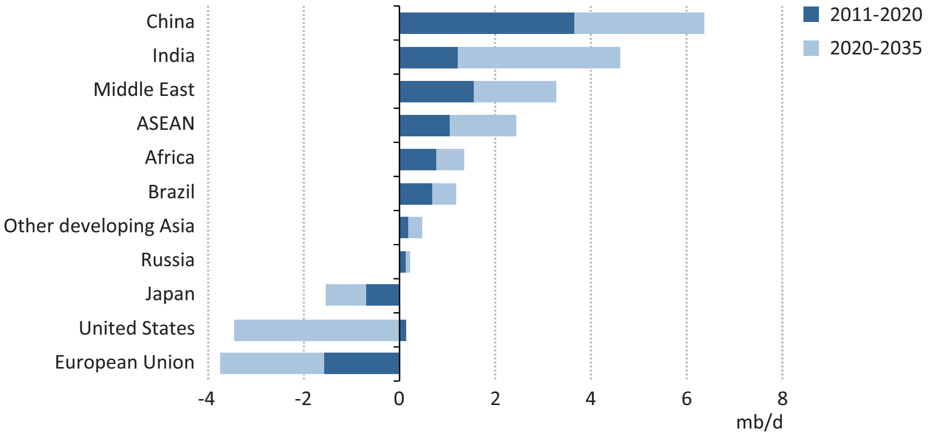
The global average level of energy demand per capita increases marginally in the New Policies Scenario, from 1.9 tonnes of oil equivalent (toe) in 2011 to 2.0 toe in 2035. The large gap in energy demand per capita between OECD and non-OECD countries narrows over the projection period, but remains significant: in 2035, the OECD average is more than two-and-a-half times the non-OECD average. Comparisons at the extremes are even starker, with average per-capita energy demand in Africa being one-tenth or less of the levels in countries such as Canada, Russia and the United States in 2035.

### *Outlook by fuel*

Global demand for oil increases from 86.7 mb/d in 2011 to reach 101.4 mb/d in 2035. The average pace of demand growth slows over the period, from around 1.1% per year to 2020 to just 0.4% per year thereafter. Oil continues to be the largest single component of the primary energy mix, but its share declines from 31% to 27%. While global oil demand grows, the overall change is the net result of decreasing demand in many OECD markets and increasing demand in many non-OECD markets, particularly in Asia (where markets often lack strong fuel-economy standards for vehicles) and the Middle East (where fossil-fuel subsidies persist) (Figure 2.4). The combination of rapidly increasing oil demand in China and decreasing demand in the United States (after 2020), results in China overtaking the United States as the world's largest oil consumer around 2030. Total oil demand growth in developing Asia is 13.9 mb/d to 2035, with India becoming the largest single source of growth after 2020. Another pivotal development is the emergence of the Middle East as a major energy consumer, which, in the case of oil, results in its demand increasing by half to 2035 (reaching 9.9 mb/d), surpassing oil demand in the European Union before 2030.

Oil demand is concentrated increasingly in the transport sector, which accounts for nearly 60% (59 mb/d) of global oil demand in 2035. Fuel for road freight in Asia alone accounts, in energy terms, for one-third of the net global growth in oil demand over the *Outlook* period. Oil demand from road freight grows faster than that for passenger vehicles, increasing the weight of diesel in the overall road-transport fuel mix, which reaches 21 mb/d in 2035, getting close to the levels for gasoline (see Chapter 15). Non-energy use – fuels used for feedstocks and non-energy products, such as asphalt, bitumen and lubricants – grows to 24 mb/d globally in 2035, about 70% of which is petrochemicals feedstocks. Global oil demand in industry remains broadly flat in the New Policies Scenario (around 6.5 mb/d), while its use in power generation halves and in buildings it falls by around 10%.

**Figure 2.4 ▷ Change in oil demand in selected regions in the New Policies Scenario**



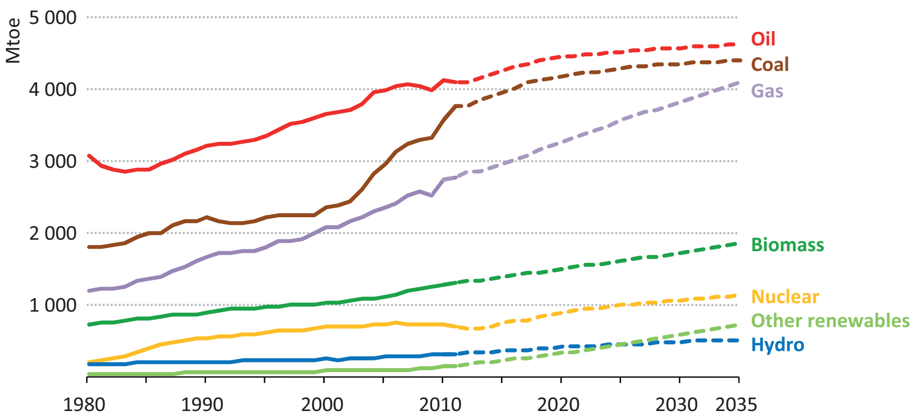

Very strong growth in coal use over the last decade has resulted in the gap between primary energy demand for coal and oil narrowing significantly (Figure 2.5). In the New Policies Scenario, two-thirds of the projected growth in coal demand occurs before 2020, demand thereafter rising more gradually, to reach around 6 300 million tonnes of coal equivalent (Mtce) in 2035 (see Chapter 4). Nearly three-quarters of this increase comes from the power sector. Coal continues to be the largest source of fuel for power generation, but its share declines from 47% in 2011 to 39% in 2035. China is by far the world's largest coal producer and consumer and (as of 2012) the largest coal importer as well, having overtaken Japan. The growth in coal demand in China through to 2020 exceeds the growth in the rest of the world combined. However, this comparison masks a slowdown in coal demand growth in China that culminates in demand reaching a plateau before 2030. The scale of China's coal use means that variations in its demand for imports could have a big impact on the global picture. India becomes both the second-largest coal consumer – surpassing the United States – and the largest importer by 2025.

Coal demand, similar to oil, declines in most OECD countries over the *Outlook* period, largely as a result of policies to reduce energy-related $CO_2$ emissions from the power sector. Coal use in the United States declines by 14%, while, despite price dynamics currently supporting coal use, demand in the European Union falls by half by 2035. Industry (including coking ovens and blast furnaces) dominates coal consumption in end-use sectors and accounts for around one-quarter of global demand over the *Outlook* period, with iron and steel making up about half of this. Its use in industry increases by around 1.6% per year this decade, but then starts to decline. Global coal demand in buildings[4] starts to decline this decade, while coal for non-energy use (such as petrochemical feedstock) becomes increasingly material, nearly tripling and overtaking use in buildings before 2030.

4. 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.

In the New Policies Scenario, the absolute growth in primary demand for natural gas outpaces that of any other individual fuel (see Chapter 3), and increases by more than the growth in demand for oil and coal combined from 2011 to 2035. Demand grows strongly throughout the *Outlook* period, and ends up nearly 50% higher, at 5 trillion cubic metres (tcm). Despite this strong growth, demand for natural gas remains below that for both oil and coal in 2035. Regional market dynamics continue to be important, with gas prices reflecting differing gas supply and demand fundamentals, the nature of prevailing coal-to-gas competition (see Chapter 5) and the different contract structures adopted. In the United States, gas demand increases relatively slowly over the period – by 13% (over 90 billion cubic metres [bcm]) – but it continues to be the world's largest gas market in 2035. Demand in the European Union is also 13% higher in 2035, leaving it around 65 bcm (10%) lower than projected in *WEO-2012.* This is, in part, due to a lower starting point, but also to a combination of factors that include more modest economic growth, increased efficiency in buildings and the faster growth of renewables in power generation.

**Figure 2.5 ▻ World primary energy demand by fuel in the New Policies Scenario**




Non-OECD countries account for more than 80% of global gas demand growth over the period to 2035. Demand for gas in developing Asia grows by around 680 bcm, equivalent to the total amount of gas traded inter-regionally today. Demand grows quickly in China (nearly 400 bcm), but also briskly in India (over 110 bcm), Indonesia (40 bcm) and other parts of the region. In absolute terms, demand for gas in the Middle East increases by more than the growth of the entire OECD – around 300 bcm – between 2011 and 2035, driven by new power generation (where demand for gas nearly doubles to reach 275 bcm), desalination and higher industrial activity. Often thought of primarily as an energy exporter, the Middle East increases its own natural gas use so rapidly that it overtakes the European Union before 2020 and consumes 26% more than the European Union by 2035. Russia, the world's second-largest gas consumer, sees demand grow slowly (0.6% per year) as improved efficiency and a move towards more market-based pricing help restrain demand growth. Gas demand in Latin America increases by around 85%, led by a 60 bcm increase in Brazil as a result of the increased availability of domestic supplies (see Chapter 10).

In the New Policies Scenario, power generation continues to be the largest source of gas demand, accounting for around 40% of global demand over the period. Around one-quarter of the net capacity additions in the power sector between 2011 and 2035 are fuelled by natural gas (over 1 000 gigawatts). Of the end-use sectors, industry sees the largest growth in gas demand in absolute terms (around 335 bcm). Compared with *WEO-2012*, gas use in industry in the United States is slightly higher in the first half of the projection period, but around the same level in 2035. This picture is subject to uncertainty, as several firms in energy-intensive industries have plans to relocate to North America to benefit from low gas prices (see Chapter 8). In the European Union, industrial demand for gas declines by 10%, as a result of improvements in efficiency and the continuation of a trend away from heavy industry to more light industry. China's gas demand in industry increases by 14% per year to 2020 and reaches nearly 120 bcm in 2035. Middle East demand for gas in industry overtakes that in the United States around 2030 and is around one-fifth higher in 2035 (reaching 150 bcm); this is despite its economy being only around one-fifth the size of the US economy at that time (in 2012 dollars at market exchange rates). Global gas demand in the buildings sector grows by 37%, driven by increased demand for space and water heating, to reach around 985 bcm in 2035. Natural gas use in transport doubles from 112 bcm in 2011 to 225 bcm in 2035, with a particular focus on use in heavy-duty vehicles and fleet vehicles, such as buses and taxis.

Nuclear power generation increases by two-thirds in the New Policies Scenario, reaching 4 300 terawatt-hours (TWh) in 2035. Demand is driven heavily by expansion in just a few countries: China accounts for around half of the global increase; Korea experiences the next largest increase over the projection period (the only OECD country to see appreciable growth), followed by India and Russia. Overall, non-OECD economies see their share of global demand for nuclear power jump from less than 20% to nearly 45% in 2035. While prospects for nuclear power at the global level are now less uncertain than they were two years ago, there are still key issues that remain unclear. These include the possibility of further changes in government policy, implications of the ongoing safety upgrades for plant economics and public confidence, and the impact of increased competition from shale gas.[5]

Global demand for energy from renewable sources grows by nearly 80% in the New Policies Scenario (see Chapter 6). This masks differences in the fortunes of different renewable products. Demand for traditional forms of bioenergy declines, while demand for modern renewable energy — including hydropower, wind, solar, geothermal, marine and bioenergy — rises almost two-and-a-half times from 2011 to 2035. Government policies and incentives, higher fossil fuel prices and technology-driven cost reductions all help to increase the attractiveness of renewable technologies, especially in the power sector. OECD countries collectively account for 40% of the global increase in the use of renewables, led by the United States and Europe, while China accounts for 16%. Renewables account for nearly half of the net increase in global electricity generation and see their share of the generation mix increase from one-fifth in 2011 to closer to one-third in 2035. They are

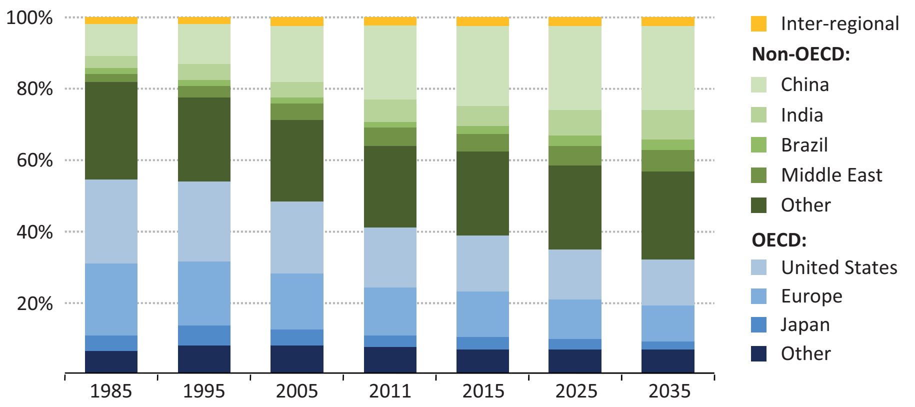
5. The 2014 edition of the *World Energy Outlook* will include an in-depth focus on nuclear power.

projected to become the second-largest source of electricity before 2015 and approach coal as the primary source by 2035. China (mainly before 2020), India (mainly after 2020), Brazil and Africa see noticeable increases in hydropower. China, the European Union and the United States see the largest increases in electricity from wind and, by 2035, around 70% of the world's wind power generation capacity is expected to be in these three regions: 30% in China, 25% in the European Union and 14% in the United States. Prior to 2020, solar capacity additions are concentrated in China, the European Union, Japan and the United States. After 2020, solar capacity also increases rapidly in India and the Middle East. Global demand for biofuels increases from 1.3 million barrels of oil equivalent per day (mboe/d) in 2011 to 4.1 mboe/d in 2035. The share of biofuels in energy demand for road transport goes from 3% to 8%. The largest increases are seen in the United States, Brazil, European Union and China (but from a lower base).

### *Regional trends*

The global energy map continues to be transformed, with the weight of energy demand moving from OECD countries towards non-OECD countries (Figure 2.6). Non-OECD countries account for more than 90% of primary energy demand growth in the New Policies Scenario: more rapid population and economic growth, and increasing income, generates more demand for modern energy services. In 2004, the two groupings used about the same amount of energy but, by 2035, non-OECD demand is projected to be more than double that of OECD countries.

**Figure 2.6 ▷ Share of world primary energy demand by region**




In the New Policies Scenario, primary energy demand in the United States – the world's second-largest energy consumer – increases to 2020 and then declines slightly to 2035. Over the *Outlook* period as a whole, US primary energy demand grows by around 2%. Oil demand in the United States in 2035 is around 20% lower than 2011 and only two-thirds of its historical peak in 2005. Demand for oil plateaus before 2020, at a level not much higher than today and, from that point, declines by around 3.7 mb/d to reach 14 mb/d in 2035. Fuel efficiency standards play a major role in reducing gasoline demand, combined with increasing use of alternative fuels in transport, and there is a continuing decline of oil use in most other sectors. Coal demand declines by 14% over the period, mainly as a result of policies to encourage a move towards other forms of power generation and a reduction in use in industry. Helped by favourable prices and policies, natural gas demand increases by more than 90 bcm (13%) through to 2035, with power generation (60% of the increase), buildings and transport being the key growth sectors. Electricity generation from renewables more than doubles, and accounts for around 23% of total generation in 2035. Supported by production tax credits, electricity generated from wind increases by 5% per year on average, and overtakes hydropower to become the largest source of renewables-based generation around the mid-2020s. Biofuels demand in the United States increases from less than 0.7 mboe/d in 2011 to 1.5 mboe/d in 2035, at the expense of oil products. Overall, shifts in energy demand and domestic supply (see energy supply section) push the United States to the brink of being energy self-sufficient in net terms in 2035: exports of coal and gas almost completely offsetting (in energy equivalent terms) the declining net imports of oil.

Primary energy demand in the European Union declines by around 7% between 2011 and 2035. Demand for oil drops by one-third (3.7 mb/d). Gasoline and diesel each see a reduction of around 1 mb/d, as strict fuel-economy standards result in reduced demand in transport and the use of oil products in the buildings sector declines. Coal consumption is half today's level by 2035, falling by more than 200 Mtce, almost all of which is steam and brown coal use in the power sector. It takes around two decades for natural gas demand to get back to 2010 levels, with increases in the power sector and in buildings (where oil and coal use falls), but a decline in industry. Renewables increase their share of electricity generation from 21% in 2011 to 44% in 2035, backed by renewables targets and ongoing support in the form of subsidies. Generation from wind grows particularly strongly and it becomes the largest source of renewables-based generation around 2020.

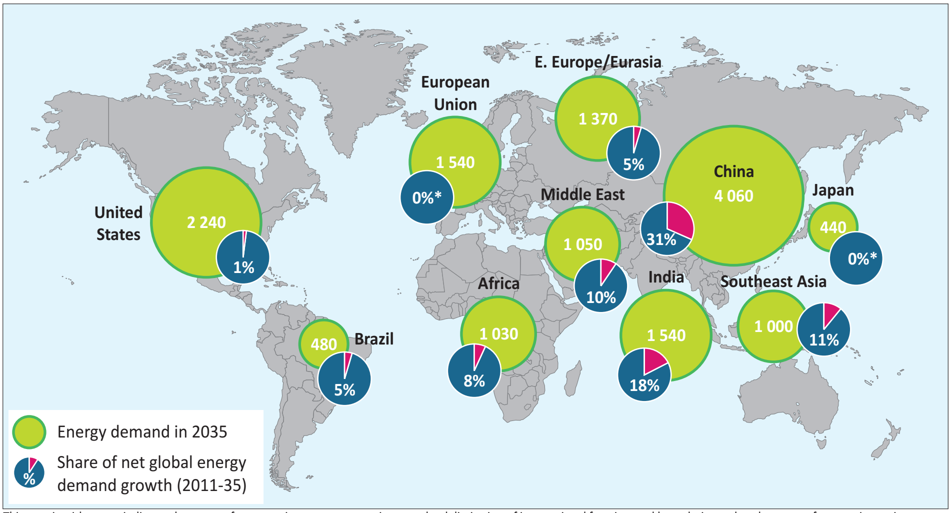
Japan sees primary energy demand decline by 4% over the projection period, with a reduction in energy use in transport and industry outweighing a slight increase in buildings. Oil consumption declines by 36%, to less than 3 mb/d by 2035. Gas demand increases in end-uses, mainly buildings and industry. Electricity generation from fossil fuels declines by around 110 TWh (13%) over the projection period, but this masks a significant decline in oil, a smaller decline in coal, and an increase in gas. Renewables-based generation increases by 210 TWh, accounting for 28% of total generation in 2035 (solar and wind growing strongly). While our projections show nuclear power providing 14% of electricity generation in 2035, this is an area of particular uncertainty. Japan is currently working on a new energy plan to be released in late-2013 and the way the future role of the Japanese nuclear industry is shaped will have major implications for the future of the rest of the power sector as well.

In the New Policies Scenario, developing Asia accounts for 63% of global energy demand growth from 2011 to 2035. China, only recently established as the world's largest energy consumer, is projected to consume in 2035 about 80% more energy than the United States (the next largest consumer) (Figure 2.7). China's energy demand per capita increases by

40% over the *Outlook* period (to reach 2.8 toe/capita), accelerating away from the global average and getting close to the level of the European Union by 2035. In our projections, China registers the largest energy demand growth in every major sector to 2035. Looking at growth by fuel is just as unambiguous, with China having a larger increase than any country in demand for oil, gas, nuclear, hydro, wind and solar. But the pace of energy demand growth does slow: growth this decade will be slower than the last, and in the 2020s growth will be less than half the level of the current decade.



**Figure 2.7 ▷ Primary energy demand in selected regions and the share of global growth in the New Policies Scenario** (Mtoe)



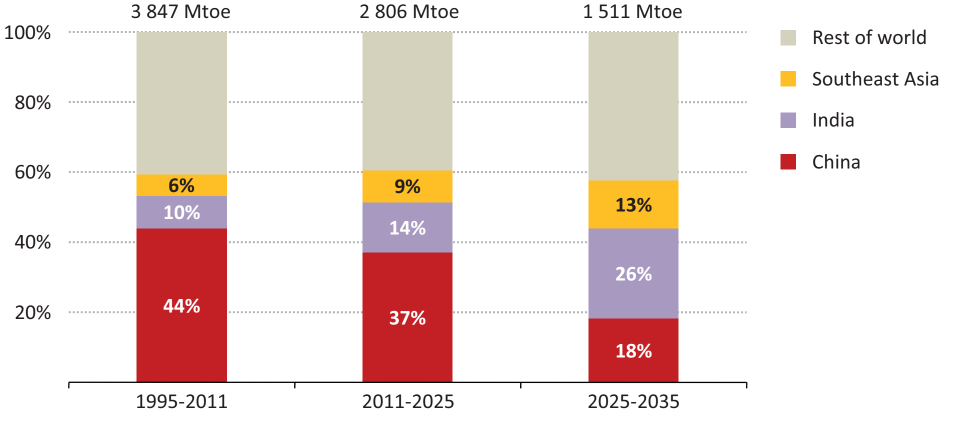

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

* These regions experience a decline in primary energy demand in 2035 relative to 2011.

China is about to become the world's largest oil importer and becomes the world's largest oil consumer around 2030 – reaching 15.1 mb/d in 2035. China's road-transport fleet becomes the largest consumer of oil products of any fleet in the world around 2030 and, by 2035, consumes 7.9 mb/d. Policy actions to curb local pollution and meet energy security goals help to continue the strong growth in gas and renewables and are an important factor in the slowdown in coal demand growth that is already occurring in China. The exact pace of this slowdown, and its impact on coal imports, continues to be the biggest source of uncertainty for global coal markets. An increase in the national target for solar photovoltaics (PV) underpins a significant upward revision from *WEO-2012* – with capacity reaching 35 gigawatts (GW) in 2015 and nearly 160 GW in 2035.

China accounts for nearly 40% of world energy demand growth from 2011 to 2025, dominating both the global and regional picture (Figure 2.8). After 2025, the focus of demand growth shifts within developing Asia towards India and, to a lesser extent, Southeast Asia. In India, total primary energy demand more than doubles over the *Outlook* period; it all but matches that of the European Union in 2035, but on a per-capita basis it is still only one-third of that level. India is projected to see the largest increase in coal demand globally, its consumption doubling to reach around 970 Mtce in 2035. Oil demand in India reaches more than 8 mb/d in 2035, with road transport taking the largest share (a combination of growing vehicle ownership and relatively low fuel efficiency levels), but residential demand for liquefied petroleum gas (LPG) and kerosene also accounts collectively for nearly 1 mb/d. In our projections, India meets the targets of its Solar Mission initiative (22 GW of capacity by 2022) and, assuming production costs continue to fall, is expected to have a relatively large solar market by the 2020s. India increases its solar capacity by about 75 GW between 2020 and 2035, second only to China and more than twice the increase in the European Union.

**Figure 2.8 ▷ Share of the growth in world primary energy demand by region in the New Policies Scenario**




The importance of the Middle East as a centre of energy demand grows significantly (Table 2.2). Total energy demand in the Middle East overtakes that of Russia around 2017 and is nearly 70% of the level of demand in the European Union in 2035. Oil demand in the Middle East grows to 10 mb/d in 2035, making it the world's third-largest oil consumer (after China and the United States). Gas consumption eclipses that of the European Union by 2020 and reaches more than 700 bcm by 2035 – second only to the United States. Gas demand in the power sector nearly doubles over the *Outlook* period. The share of renewables in electricity generation increases from around 2.5% in 2011 to 13% in 2035. Energy demand for petrochemical feedstocks overtakes the level in the United States before 2030, the Middle East expanding its petrochemical production substantially in 2035, consuming 2.2 mb/d of oil and 72 bcm of gas as feedstock. By 2035, industry in the Middle East consumes 150 bcm of natural gas – more than industry in China or the United States, where other fuels continue to play a more significant role.

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



| | 1990 | 2000 | 2011 | 2020 | 2030 | 2035 | 2011-2035* |
|---|---|---|---|---|---|---|---|
| **OECD** | **4 522** | **5 292** | **5 304** | **5 486** | **5 457** | **5 465** | **0.1%** |
| Americas | 2 260 | 2 696 | 2 663 | 2 811 | 2 826 | 2 850 | 0.3% |
| United States | 1 915 | 2 270 | 2 189 | 2 281 | 2 246 | 2 242 | 0.1% |
| Europe | 1 630 | 1 765 | 1 778 | 1 763 | 1 719 | 1 709 | -0.2% |
| Asia Oceania | 631 | 832 | 863 | 912 | 912 | 906 | 0.2% |
| Japan | 439 | 519 | 461 | 470 | 450 | 443 | -0.2% |
| **Non-OECD** | **4 047** | **4 507** | **7 406** | **9 136** | **10 709** | **11 435** | **1.8%** |
| E. Europe/Eurasia | 1 539 | 1 006 | 1 159 | 1 228 | 1 318 | 1 373 | 0.7% |
| Russia | 880 | 620 | 718 | 755 | 806 | 841 | 0.7% |
| Asia | 1 578 | 2 220 | 4 324 | 5 548 | 6 584 | 7 045 | 2.1% |
| China | 879 | 1 175 | 2 743 | 3 519 | 3 945 | 4 060 | 1.6% |
| India | 317 | 457 | 750 | 971 | 1 336 | 1 539 | 3.0% |
| Southeast Asia | 223 | 373 | 549 | 718 | 897 | 1 004 | 2.5% |
| Middle East | 212 | 358 | 640 | 796 | 970 | 1 051 | 2.1% |
| Africa | 388 | 494 | 698 | 836 | 962 | 1 026 | 1.6% |
| Latin America | 331 | 429 | 586 | 729 | 876 | 941 | 2.0% |
| Brazil | 138 | 184 | 267 | 352 | 441 | 480 | 2.5% |
| **World**** | **8 769** | **10 071** | **13 070** | **15 025** | **16 623** | **17 387** | **1.2%** |
| European Union | 1 642 | 1 691 | 1 659 | 1 614 | 1 556 | 1 541 | -0.3% |

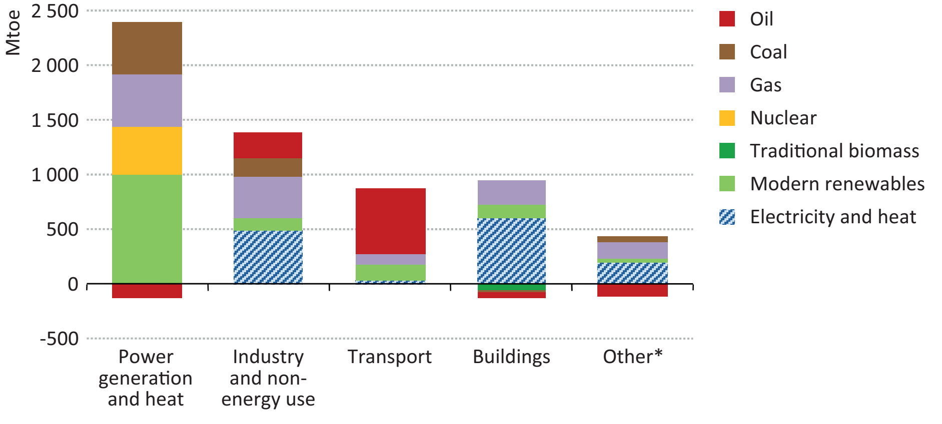
* Compound average annual growth rate. ** World includes international marine and aviation bunkers (not included in regional totals).

Economic growth and a burgeoning middle class see energy demand in Brazil increase by about 80%, underlining its position as the dominant consumer in Latin America (see Part B for an in-depth analysis of Brazil). Renewables continue to meet a large part of total demand, with hydropower at the core of electricity supply and supply from bioenergy and wind increasing. Biomass also plays a significant role in industry in Brazil, while demand for biofuels in transport reaches 0.8 mboe/d in 2035, helping to slow oil demand growth.

### *Sectoral trends*

In the New Policies Scenario, over half of the projected increase in global primary energy demand comes from the power sector – the result of continuing electrification of the world economy (Figure 2.9). Electricity demand expands most in buildings (in absolute terms), as a result of increased ownership of appliances and cooling needs in residences coupled with growing demand in the services sector (such as shops, offices, hotels and hospitals). The global average efficiency of fossil fuel conversion in power plants improves by about 15%, but demand for energy inputs to generation still increases by 45%. Carbon capture and storage (CCS) technology appears well-suited to resolving at least some of the tension between rapidly increasing electricity demand, readily available existing fossil fuel resources (and related infrastructure), and the need to limit $CO_2$ emissions and local pollution, yet many significant challenges have still to be overcome. They include the need to integrate component technologies effectively into large-scale projects, identify viable storage sites and put the necessary financial incentives in place.[6] At present, the outlook for CCS does not look bright and our projections show only 67 GW of CCS capacity in the power sector in 2035, around 1% of global fossil-fuelled power generation capacity. The CCS capacity that does exist in 2035 is located mostly in the United States, China and the European Union.

**Figure 2.9 ▷ Change in energy demand by sector and fuel in the New Policies Scenario, 2011-2035**




* Includes other energy sector and agriculture.

Demand grows quickly – 1.7% per year – for those fuels that are used as a raw material for other products, mostly in the form of petrochemical feedstocks. The Middle East sees a significant increase in demand to 2035, with the availability of relatively cheap feedstocks underlying a doubling of its petrochemical capacity over the projection period. Emerging petrochemical producers in Asia, particularly in China, Southeast Asia and India, also see substantially higher oil feedstock consumption, driven by a rapidly increasing demand for plastics. Globally, industrial energy use expands at 1.4% per year. China accounts for almost half of the growth to 2020, but its demand levels off thereafter, when India, Southeast Asia and the Middle East account for much of the increase. Among the OECD regions, only North America sees any notable increase in industrial energy use, thanks in part to the boost to competitiveness provided by relatively low electricity and gas prices (see Chapter 8). In aggregate, OECD industrial energy demand grows modestly to 2020 and then levels-off. Electricity and gas account for more than two-thirds of the demand increase from non-energy intensive industries in the OECD. Despite the growth in energy demand for such industries, their share of total industrial energy demand grows only slightly.

6. For more on CCS, see the IEA's *Technology Roadmap: Carbon Capture and Storage* (IEA, 2013b).

Global energy demand in transport grows at an average rate of 1.3% per year over the projection period – a significantly lower rate of growth than seen in recent decades. All of the net growth comes from non-OECD regions, notably developing Asia; demand declines in the OECD, where efficiency gains more than outweigh a modest expansion of the vehicle fleet. Although the number of cars and trucks on the world's roads will roughly double between 2011 and 2035, advances in automotive technology lead to major improvements in average vehicle fuel economy. Globally, demand for diesel in road transport increases by 6.4 mb/d from 2011 to 2035, compared with a 2.1 mb/d increase in demand for gasoline (see Chapter 15). Oil-based fuels continue to dominate transport energy demand, though biofuels, and, to a much lesser extent, electricity for plug-in hybrid and electric vehicles account for a rising share of road-transport fuel demand. The use of natural gas in liquefied or compressed form grows rapidly, but from a small base (reaching 5.6% of total energy demand in transport in 2035 and 4.8% in road transport). United States and China lead the contribution to growth, with low natural gas prices in the United States expected to push gas use in heavy trucks. However, while the technology is well-proven, the market remains small or non-existent in most countries, because of the obstacles to its adoption as a road fuel, for example, the lack of widespread refuelling infrastructure. Aviation and shipping become more fuel-efficient, offsetting to a large degree the effect on fuel demand of the projected rise in demand for air travel and maritime freight.

In the buildings sector, energy use grows at an average rate of 1% per year on average across the *Outlook* period, with nearly 75% of the growth coming from non-OECD countries. Households account for almost 60% of the increase in energy demand. Close to 1.8 billion new urban citizens (mainly in developing countries) push up residential demand, mostly in the form of electricity, because of strong growth in the use of appliances, space cooling and lighting. While the size of the world's rural population remains stable (in absolute terms), and policies encourage a shift to more efficient cookstoves, this only helps to limit growth in the use of biomass for cooking over the projection period.

## *Energy supply*

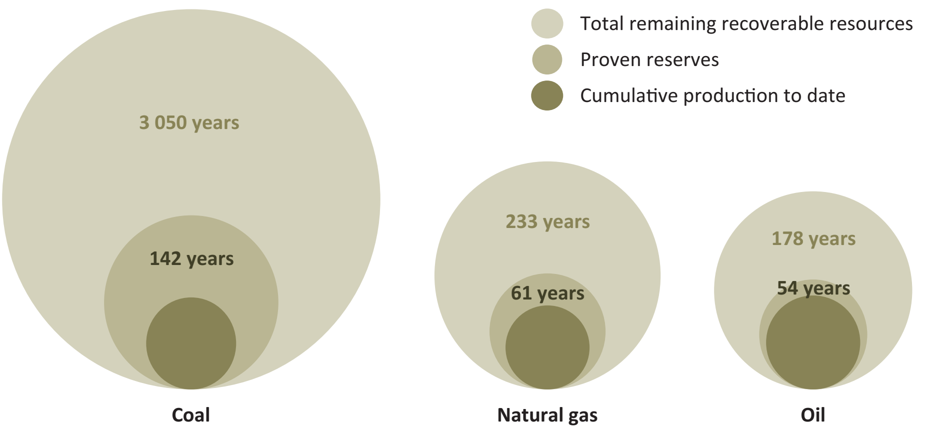
### *Energy resources*

The energy resources remaining in the world will not constrain the projected growth in energy demand to 2035 and well beyond. However, the scale of investment required to exploit them is huge and there are many factors that will determine the exact pace at which differing energy resources will be developed, such as uncertainty around the economic outlook, the investment climate and availability of financing, prevailing geopolitics, energy and climate change policies, depletion policies in key producing regions, advances in technology and changes to legal, fiscal and regulatory regimes.[7]

7. A *WEO* special report analysing the investment and financing needs of the world's energy infrastructure will be published in mid-2014.

High oil prices in recent years have supported an increase in total proven oil reserves, which are now estimated to be around 1 700 billion barrels, equivalent to 54 years of current production (Figure 2.10). Remaining recoverable resources are much larger: around 2 670 billion barrels of conventional oil, 1 880 billion barrels of extra-heavy oil and bitumen, 1 070 billion barrels of kerogen oil and 345 billion barrels of light tight oil (LTO) (see Chapter 13). Nearly 60% of remaining recoverable oil reserves are located onshore, 37% are offshore (of which, more than one-third are in deepwater) and the remainder are in the Arctic. Estimates of remaining recoverable resources of oil continue to increase as new technologies, such as multi-stage hydraulic fracturing, unlock types of resources (such as LTO) that were not considered recoverable only a few years ago. Enhanced oil recovery (EOR) technologies are currently estimated to have the potential to unlock another 300 billion barrels from conventional reservoirs (not included in our resource estimates) by increasing recovery rates, but realising the full potential of EOR may be hampered in practice by the complexity of EOR projects and shortage of the necessary skills in the industry.

**Figure 2.10 ▷ Fossil energy resources by type**




Notes: All bubbles are expressed as a number of years of production based on estimated production in 2013. The size of the bubble for total remaining recoverable resources of coal is illustrative and is not proportional to the others. The figure specifies the status of reserves for coal as of end-2011, and gas and oil as of end-2012. Sources: BGR (2012); O&GJ (2012); USGS (2000, 2012a and 2012b); IEA estimates and analysis.

There are abundant proven reserves of coal – bigger than those for oil and gas combined in energy terms. These proven reserves increased by more than 3% in 2011 to reach an estimated 1 040 billion tonnes (BGR, 2012), equal to 142 years of production at current rates (see Chapter 4). Total remaining recoverable resources of coal are more than twenty times the size of proven reserves and could support current production levels for much longer. Both coal reserves and resources are distributed relatively widely. Reserve levels are obviously far larger than needed to meet projected demand to 2035 and well in excess of the maximum which could be consumed without overshooting a 2 °C climate target (unless the $CO_2$ emissions are mitigated, such as by being captured and stored).

Proven resources of natural gas (both conventional and unconventional) are estimated to be 211 tcm, enough to sustain current levels of production for 61 years. Remaining recoverable resources are assessed to be 810 tcm and are equivalent to 233 years of production at current rates (see Chapter 3). This assessment takes into account the latest estimate of shale gas resources from the US Energy Information Administration, which, mainly because it has broader coverage, is 10% higher than previously (US EIA, 2013).



There are very large renewable energy resources – including bioenergy, hydro, geothermal, wind, solar and marine energy – which, if all harnessed, could meet projected energy demand many times over. These resources are also very well spread geographically, relative to other energy resources. However, in a number of cases, the cost of exploiting them on a large scale is currently prohibitive, even with government support. The potential for renewables production on an economically sound basis depends on how fast production costs can be reduced: such cost reductions are already happening rapidly (see Chapter 6). Similarly, resources of uranium – the raw material for nuclear fuel – are more than adequate to supply the projected growth in nuclear power capacity through to 2035 and well beyond. Uranium resources expanded by 12.5% between the start of 2008 and 2011 and are sufficient for over 100 years of supply, based on current requirements (NEA/IAEA, 2012).

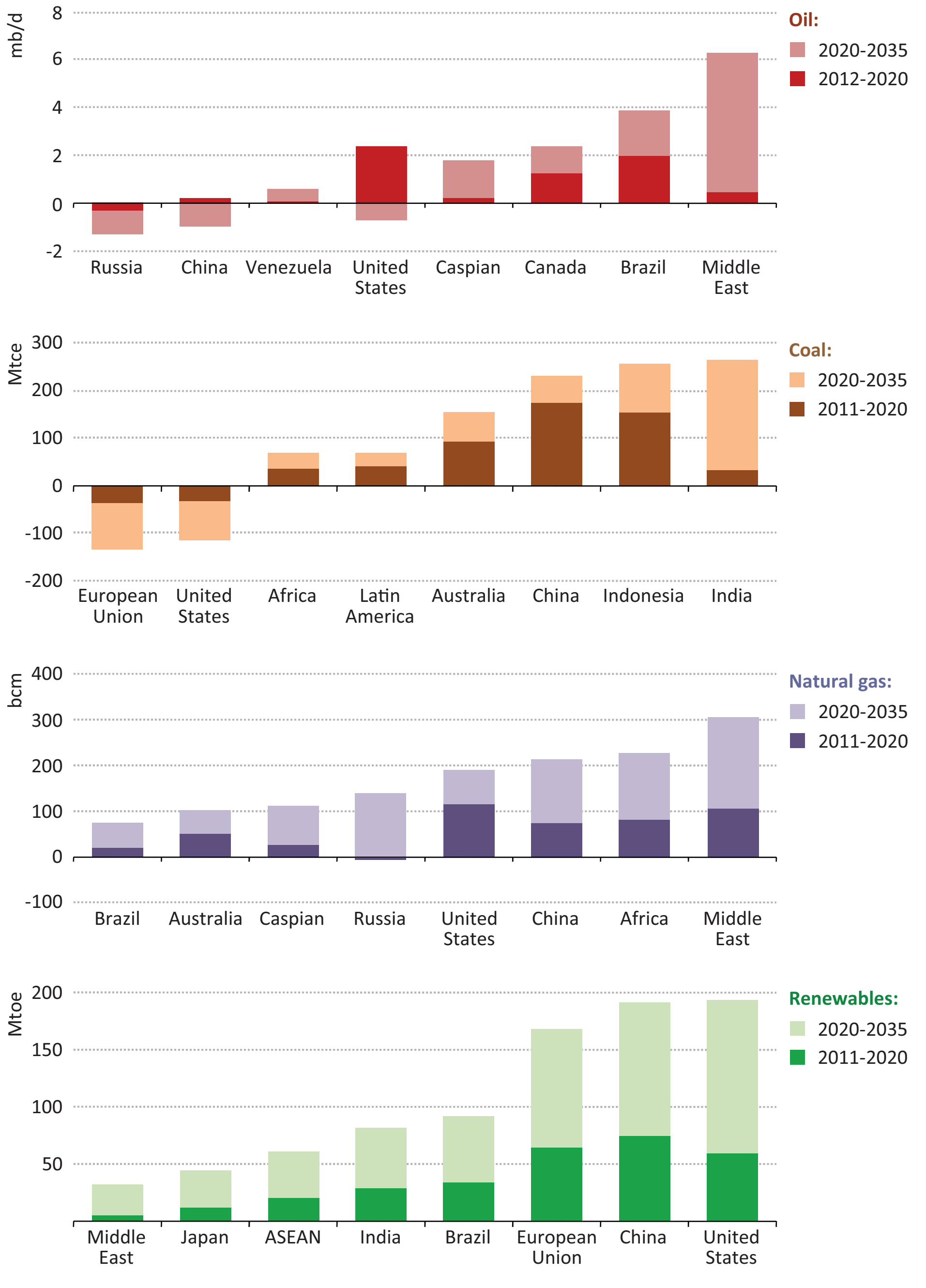
### *Production outlook*

In the New Policies Scenario, total oil production[8] increases by 11 mb/d from 2012 to reach 98 mb/d in 2035 (see Chapter 14). Production of crude oil declines by 4 mb/d over the *Outlook* period and its share of total oil production declines from around 80% to two-thirds. In contrast, production of natural gas liquids (NGLs) increases by 5 mb/d, with its availability being driven by growth in gas production. Unconventional oil production triples to reach 15 mb/d in 2035 and, while it remains concentrated in North America, world LTO production reaches nearly 6 mb/d by the late 2020s and remains around 5.6 mb/d in 2035.

Over the next decade, much of the net increase in global oil demand is met by non-OPEC supply, particularly LTO in North America (mainly the United States), Canadian oil sands and deepwater pre-salt oil in Brazil (Figure 2.11). The United States becomes the largest oil producer in the world (crude plus NGLs) in 2015 and retains this status until the beginning of the 2030s. Brazil alone delivers more than one-third of the net global growth in oil production – growing by more than double the increase in the United States – and becomes a net exporter around 2015 (see Chapter 11). Oil production falls in several regions, with Russia, the European Union and China seeing the biggest declines. From around the mid-2020s, OPEC oil production growth (mainly from the Middle East) meets all of the global growth in demand, as non-OPEC production starts to decline gradually. Over the projection period, Iraq is by far the biggest contributor to OPEC production growth, accounting for two-thirds of the total (although Saudi Arabia remains the largest producer). OPEC's share of global production declines slightly by 2020 (from 43% to 41%), before then increasing to reach 46% in 2035.

8. Total oil "supply" denotes production of conventional and unconventional oil and NGLs plus processing gains (oil supply reaches 101.4 mb/d in 2035), while oil "production" (discussed here) excludes processing gains. Processing gains are the volume increase in supply that occurs during crude oil refining.

**Figure 2.11** ▷ **Change in production by fuel in selected regions in the New Policies Scenario**




Note: The change in production through to 2035 is the summation of the two periods shown in the figure.

The global refinery sector is facing huge challenges: the changing composition of feedstocks, changing product demand and the geographical shift of demand away from OECD countries and towards Asia and the Middle East (see Chapter 16). There is both a growing share in overall supply of extra-heavy oil, which requires more complex technology to process, and of NGLs, biofuels and coal/gas-to-liquids, many of which bypass refineries completely. Rising demand for middle distillates, particularly diesel, pushes refiners to enhance yields for these products. Overall, global demand for refined products grows by 10 mb/d through to 2035, much less than the anticipated growth in overall liquids demand (16.8 mb/d, including biofuels) and less than net refinery capacity additions (13.1 mb/d).



In the New Policies Scenario, global coal production increases by 15% from 2011 to more than 6 300 Mtce in 2035. Production in the European Union declines by nearly 60% over the *Outlook* period, responding to lower regional demand, reduced production subsidies in some countries and cost escalation. Coal supply in the United States starts to decline gradually before 2020 and is around 15% lower in 2035. Australia sees strong production growth to 2020 and a more gradual increase thereafter. China's production increases by 9% and it remains the biggest coal producer over the period, accounting for around 45% of global production in 2035. However, production peaks before 2030 and then declines marginally. The absolute growth in coal production in India is the largest of any country over the projection period, helping to meet domestic demand for power generation. The majority of the increase occurs after 2020, when it accounts for more than 70% of global coal production growth. Indonesia achieves a more than 80% increase in coal production, both to meet domestic demand and for export. It overtakes Australia to become the fourth-largest coal producer on an energy equivalent basis.

World natural gas production grows by 47% to 5 tcm in 2035, with unconventional gas, LNG and evolving contractual structures all playing a role in the emergence of new players and an increasingly diverse trade picture. China sees the largest growth in gas production (nearly 215 bcm), two-thirds of this growth coming after 2020. It becomes the world's third-largest gas producer before 2025 (overtaking Qatar) and the second-largest producer of unconventional gas (after the United States) before 2030. Projections for Russian gas production are lower than in *WEO-2012*, not as a result of supply constraints, but mainly due to modest growth in domestic demand and weak European import needs this decade. Despite this, Russia's gas output rises by around 135 bcm to 2035 (all after 2020), much of which goes to meet Asian demand. Turkmenistan sees production double and its exports to China grow as the capacity of the Central-Asia pipeline is increased.

Currently an importer of both pipeline gas and LNG, Brazil increases gas production by 7% per year on average, to reach more than 90 bcm. The majority of this gas is associated gas from oil production. It supports both a move to increasing gas use in power generation, industry and buildings, and the attainment of self-sufficiency later in the projection period (see Chapter 12). Elsewhere in Latin America, an assumed improvement in Argentina's investment climate facilitates a revival in gas production, led by shale gas. The Middle East has more conventional gas resources than any other region and sees its production increase by more than 300 bcm in the New Policies Scenario. Qatar, Iraq, Iran, Saudi Arabia and the United Arab Emirates all achieve significant increases in production by 2035, but much of the gas goes toward meeting demand within the region.

Unconventional gas is expected to account for nearly half of the global growth in production over the *Outlook* period. However, the prospects for unconventional gas are particularly uncertain, given the need to allay public concerns about the environmental and social implications and as-yet limited knowledge about the resource base in many parts of the world. As of 2012, the United States is the world's largest gas producer (boosted by expanding supply of shale gas) and is expected to remain so through to 2035. Globally, production of unconventional gas continues to grow, reaching more than 830 bcm by 2020 and more than 1 300 bcm in 2035 – more than one-quarter of total gas production at that time. North America leads the way, still accounting for more than half of global unconventional gas production in 2035, but the revolution spreads after 2020 and more than two-thirds of the supply growth over the projection period as a whole occurs elsewhere (mainly China, Australia, India and Argentina).

Energy supply from renewables grows faster than any other source of energy, with two-thirds of the growth coming after 2020. Most of the increase is supplied in the form of electricity, with wind and hydropower making the largest contribution. In total, renewables-based generation expands by more than two-and-a-half times by 2035. The supply of bioenergy increases by over 40% over the *Outlook* period, with about half of the increase going to power generation and much of the rest to the production of biofuels (liquid road transport fuels). Biofuels production grows from 1.3 mboe/d in 2012 to 4.1 mboe/d in 2035, with most of the increase coming from the United States and Brazil. While production in the United States and the European Union is intended to meet domestic demand, Brazil is one of the few countries to develop production capacity to serve other markets – Brazil's net exports account for about 40% of global biofuels trade in 2035. China and India see production increase after 2020, but remain relatively small compared with the United States and Brazil.

## *Inter-regional energy trade*

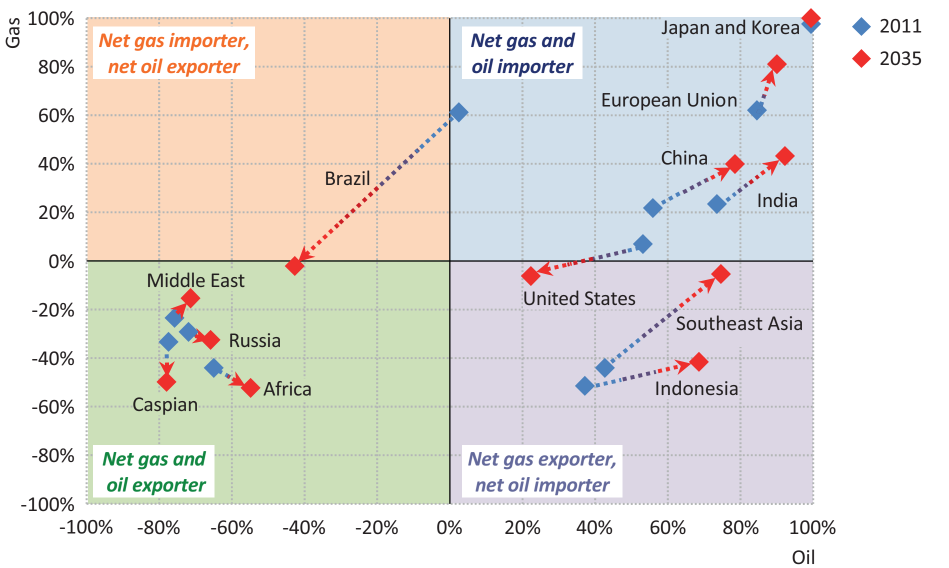
The changes happening in the global energy system become strikingly evident when examining the projected future trends in inter-regional energy trade.[9] Energy trade increases for all fossil fuels and for biofuels in the New Policies Scenario, with differing, but profound, energy security and competitiveness implications across regions. Oil remains the most heavily traded fuel, with trade increasing by around 5 mb/d to nearly 50 mb/d in 2035. Overall, OECD net oil imports more than halve (to around 10 mb/d) and their share of total inter-regional trade declines from around 50% to only 20% in 2035. Light tight oil (mainly through to 2020) and energy efficiency (mainly after 2020) combine to reduce US oil imports to around 3 mb/d in 2035. The added factor of production from Canadian oil sands means that, collectively, the United States and Canada become self-sufficient in oil

9. Analysis is based on net energy trade between *WEO* regions.

before 2030. Combined, the two countries actually become energy self-sufficient in net terms much sooner – around 2020.[10] Imports into Europe also decline, but at a slower pace, and due to reduced demand.

By contrast, Asia becomes the global centre of inter-regional crude oil trade – accounting for 63% of the world total in 2035.[11] China is about to become the world's largest oil importer, overtaking the United States, and goes on to surpass the oil imports of the European Union by 2020. By 2035, China's oil imports reach 12.2 mb/d, getting close to the peak historical level of imports into the United States. India's oil imports are larger than those of Japan by 2020 and exceed those of the European Union by 2035: its import dependence increases to more than 90%. Brazil undergoes a pivotal shift, becoming a net oil exporter around 2015 and going on to export around 2.6 mb/d in 2035 (Figure 2.12). By 2035, Southeast Asia will import around 60% more oil than the United States (over 5 mb/d). Exports from the Middle East are slightly lower than today in 2020, but then increase to reach 24.6 mb/d in 2035. The share of Middle East production which is exported declines slightly, as domestic consumption increases more quickly than production. Russian oil exports decline to 6.2 mb/d, as new production fails to keep pace with the decline in mature fields.

**Figure 2.12 ▷ Net oil and gas import/export shares in selected regions in the New Policies Scenario**




Notes: Import shares for each fuel are calculated as net imports divided by primary demand. Export shares are calculated as net exports divided by production. A negative number indicates net exports. Southeast Asia, *i.e.* the ASEAN region, includes Indonesia.

10. Calculated on an energy-equivalent basis.

11. Developing Asia, Japan and Korea, collectively.

Coal trade goes from 900 Mtce in 2011 to 1 260 Mtce in 2035, with most of the growth happening before 2020. As a share of total coal supply, trade increases from 16% in 2011 to 20% in 2035. China continues to be the dominant coal importer for the remainder of this decade, with its imports increasing substantially to 2020, before then starting to decline. India overtakes China soon after 2020 as the world's largest coal importer. Despite its domestic resources, India's coal imports more than triple over the *Outlook* period, reaching 350 Mtce in 2035 – more than one-quarter of global trade. Indonesia expands its coal exports by more than 50%, mainly in this decade, and Australian exports also grow by around half. The United States remains a significant net coal exporter throughout the period to 2035. Coal imports decline significantly in the European Union, Korea and Japan.

Inter-regional natural gas trade increases by 2% per year, to reach nearly 1.1 tcm in 2035. LNG accounts for nearly 60% of the increase in trade and, in combination with new sources of supply (conventional and unconventional) and evolving contractual structures, boosts the flexibility of global gas supply. In general, existing gas importers become more import-dependent (the European Union, China, India), but there are notable exceptions, such as the United States and Brazil. The United States moves to become a net exporter of gas in 2017 and is projected to export, in net terms, around 50 bcm in 2035 as a result of new LNG export facilities coming online.[12] Like trade in oil, gas trade will also see its focus shift to Asian markets, where the number of importing countries will increase. In addition, higher prices make Asia an attractive destination for many LNG cargoes. In many parts of the Middle East, there is a clear strategy to regard gas as a prime component of domestic supply and, in 2035, only 15% of Middle East gas production is exported. Exports from Africa are projected to increase by 135 bcm, as new production in East Africa supplements supplies from other parts of the continent. Gas exports from the Caspian region are projected to more than double and to go both east and west. LNG exports from Australia are projected to reach around 100 bcm in 2035, while Russian exports increase by more than 65 bcm and it remains the world's largest gas exporter through to 2035.

Regional gas price dynamics and evolving price mechanisms are important for gas markets over the *Outlook* period. In the New Policies Scenario, significant spreads between regional gas prices persist through to 2035, albeit with a limited degree of convergence (see Chapter 1). Such differences in regional gas prices (together with electricity price differences) can affect the competitiveness of energy-intensive industries, such as chemicals, oil refining, iron and steel and others. In the New Policies Scenario, strong growth in demand for energy-intensive goods in many developing countries supports a swift rise in their production (and export expansion). Relative energy costs play a more decisive role elsewhere, particularly among OECD countries: natural gas and industrial electricity prices in the United States remain around half the level of the European Union and Japan in 2035. While the United States sees a slight increase in its share of global exports of energy-intensives goods, the European Union and Japan both see a strong decline in their export shares a combined loss of around one-third of their current shares (see Chapter 8).

12. These net figures include Canadian exports by pipeline to the United States and US pipeline exports to Mexico.

Chapter 3 also explores a case in which several factors combine to drive a much stronger convergence in regional gas prices towards a more global gas price (after allowing for liquefaction and transport costs between regions). This case envisages increased linkages between regional markets and prices generally becoming more responsive to prevailing market conditions. In this Gas Price Convergence Case, global demand for gas is 107 bcm higher in 2035 than the New Policies Scenario, with lower prices stimulating demand in the European Union, Japan, China and other countries in Asia. Global gas trade is 5% higher in 2035, while gas import bills are lower in major gas-importing regions, most notably China and the European Union.



Global trade in biofuels increases from 0.2 mboe/d in 2012 to 0.7 mboe/d in 2035. The United States remains the world's largest producer, but becomes a net importer early in the projection period (albeit with relatively large imports and exports). Brazil is the main supplier to the international market during the *Outlook* period and exports around 0.2 mboe/d by 2035 (see Chapter 12), a significant portion of which goes to Europe.

### *Implications for energy-related $CO_2$ emissions*

It is extremely likely that human influence has been the dominant cause of climate change since the mid-20th century, and very likely that it has contributed to observed global scale changes in the frequency and intensity of daily temperature extremes, according to the Intergovernmental Panel on Climate Change (IPCC, 2013). As the source of more than two-thirds of global greenhouse-gas emissions, the energy sector is crucial to tackling climate change. Global energy-related $CO_2$ emissions in 2012 are estimated to be 31.5 Gt, a 1.2% increase over 2011. Over the past several decades, trends in emissions have followed those of the global economy closely, but they have shown increasing signs of divergence in more recent times: one-quarter less $CO_2$ is emitted today per unit of economic output than in 1990 (in PPP terms). The New Policies Scenario incorporates continued support for renewables and efficiency, an expansion of carbon pricing and a partial removal of fossil-fuel subsidies. Even after taking these factors into account, energy-related $CO_2$ emissions increase by nearly 20%, to 37.2 Gt, in 2035. Nonetheless, there is an acceleration in the divergence between emissions and economic growth, so that expanding the economy by one unit of GDP in 2035 emits nearly 50% less $CO_2$ than similar economic expansion today.

The New Policies Scenario points to an increase in the greenhouse-gas concentration in the atmosphere, from 444 parts per million (ppm) in 2010 to over 700 ppm by 2100.[13] This would correspond to an increase in the long-term global average temperature of 3.6 °C, compared with pre-industrial levels (an increase of 2.8 °C from today, adding to the 0.8 °C that has already occurred). By 2020, the level of emissions expected in the New Policies Scenario is already 3 Gt higher than under a trajectory compatible with limiting temperature increase to 2 °C, though additional corrective action is still possible (Spotlight).

13. While the concentration of greenhouse gases measured under the Kyoto Protocol was 444 ppm $CO_2$-eq in 2010, the concentration of all greenhouse gases, including cooling aerosols, was 403 ppm $CO_2$-eq (EEA, 2013).

**SPOTLIGHT**

## Redrawing the energy-climate map

Policies currently under discussion are insufficient to limit the long-term global temperature increase to 2 °C, the target governments agreed at the United Nations Framework Convention on Climate Change Conference of the Parties in Cancun, Mexico in 2010. The 450 Scenario demonstrates that reaching this target remains technically feasible, but intensive action prior to 2020, the year in which a new international climate agreement is due to come into force, is essential. The *WEO* special report *Redrawing the Energy-Climate Map*, published in June 2013, proposes a set of four fully economic policy measures that would, if implemented promptly, cut 80% of the excess emissions in 2020 relative to the 2 °C target (IEA, 2013a).

The four policy measures it set out in the 4-for-2 °C Scenario entail no net economic cost and would steer the world onto an emissions path that would keep the door open to achieving the 2 °C target. The policies were selected on the basis that they can deliver significant reductions in energy sector emissions by 2020 (as a bridge to further action), rely only on existing technologies, have already been proven in several countries, and their implementation (as a package) would not harm economic growth in any region. The four policies are:

- Adopting specific energy efficiency measures (49% of the emissions savings).
- Limiting the construction and use of the least-efficient coal-fired power plants (21%).
- Minimising methane ($CH_4$) emissions from upstream oil and gas production (18%).
- Accelerating the (partial) phase-out of subsidies to fossil-fuel consumption (12%).

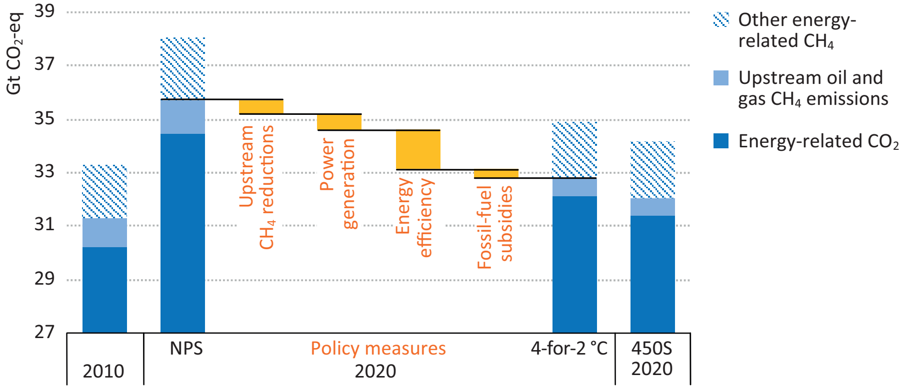
Targeted energy efficiency measures would reduce global energy-related emissions by 1.5 Gt in 2020 (Figure 2.13). These policies include imposing new or higher energy performance standards in many fields: in buildings, for lighting, new appliances and new heating and cooling equipment; in industry, for motor systems; and, in transport, for road vehicles. Around 60% of the global savings in emissions are obtained in the buildings sector.

Ensuring that new subcritical coal-fired plants are no longer built and limiting the use of the least efficient existing ones would reduce $CO_2$ emissions by 640 Mt in 2020 and also help curb local air pollution. Globally, the use of such plants would be one-quarter lower than would otherwise be expected in 2020. The largest emissions savings occur in China, the United States and India, all of which have a large number of coal plants.

Methane ($CH_4$) releases into the atmosphere from the upstream oil and gas industry would be almost halved in 2020, compared with the levels otherwise expected. Around 1.1 Gt carbon-dioxide equivalent ($CO_2$-eq) of methane, a potent greenhouse gas, was released in 2010 by the upstream oil and gas industry. Reducing such releases into the atmosphere represents an effective complementary strategy to the reduction of $CO_2$ emissions. The necessary technologies are readily available, at relatively low cost, and measures in this field are being adopted in some countries, such as new performance standards in the United States.

Accelerated action towards a partial phase-out of fossil-fuel subsidies would reduce $CO_2$ emissions by 360 Mt in 2020. Globally, fossil-fuel subsidies amounted to $544 billion in 2012, more than five times the level of support to renewables.

**Figure 2.13 ▷ Change in world energy-related $CO_2$ emissions by policy measure in the 4-for-2 °C Scenario**




Note: NPS = New Policies Scenario; 450S = 450 Scenario. Source: IEA (2013a).

Initiatives and announcements since the publication of this *WEO* special report suggest that policymakers are giving close attention to these four policy areas. The United States and China have signed an agreement to co-operate in combating climate change, including by raising efficiency in the transport and power sectors. The US President's Climate Action Plan includes strong action across these policy areas. The Major Economies Forum has a new initiative to improve the efficiency of buildings. The investor community is moving towards more ambitious investment in low-carbon assets, while the World Bank will now provide finance to greenfield coal power projects only in rare circumstances. Other multilateral investment banks are also considering adopting this position.

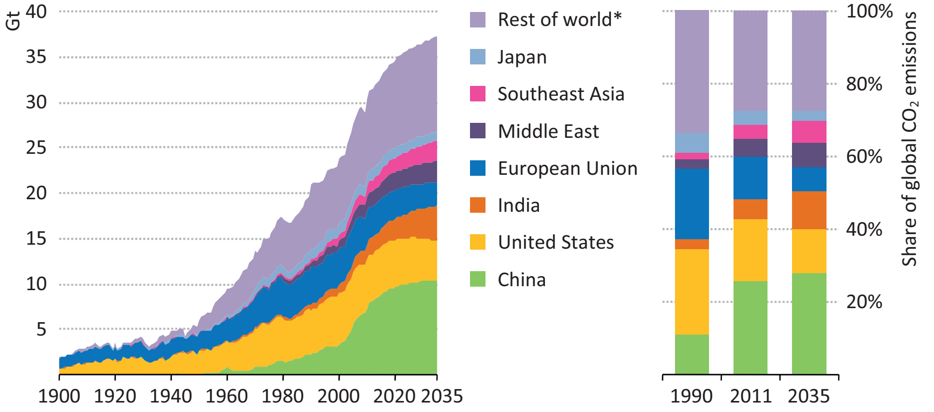
The very long lifetime of some greenhouse-gases means that their cumulative build-up in the atmosphere is an important consideration. The IPCC concludes that the world has a maximum global $CO_2$ emissions budget of 1 133 Gt from 2012 onwards if it is to keep to a 50% chance of limiting the long-term average increase in global temperature to no more than 2 °C (IPCC, 2013).[14] Based on this estimate and the New Policies Scenario, 74% of the available $CO_2$ emissions budget will be consumed by the energy sector alone by 2035. If

14. This IPCC estimate takes account of radiative forcing from other sources.

unabated, the potential $CO_2$ emissions from consuming all fossil fuel reserves (as of 2012) would amount to 2 860 Gt – two-and-a-half times the IPCC's estimate of the maximum global $CO_2$ emissions budget. This is before factoring in remaining recoverable fossil fuel resources (which are much larger than proven reserves) or non-energy related $CO_2$ emissions, such as deforestation. Such analysis puts into sharp focus the need to increase the adoption of technologies such as CCS rapidly and at scale if the world is to balance use of its fossil fuel resources with meeting its environmental objectives.

The geographical distribution of energy-related $CO_2$ emissions is set to change significantly between now and 2035. All of the growth occurs in developing countries, as emissions across the OECD declines by 16%, to 10.2 Gt in 2035, due to saturation of energy demand and the affects of policies promoting energy efficiency and decarbonisation of the fuel mix. China is expected to remain the largest emitter throughout the projection period. Chinese emissions are 60% larger than those of the United States in 2012, but will be more than twice the size of the United States by 2035 (Figure 2.14). Emissions in India are expected to overtake those of the European Union in the mid-2020s and get closer to the levels of the United States in 2035. By the end of the projection period, emissions from both Southeast Asia and the Middle East will be at a similar level to those of the European Union.

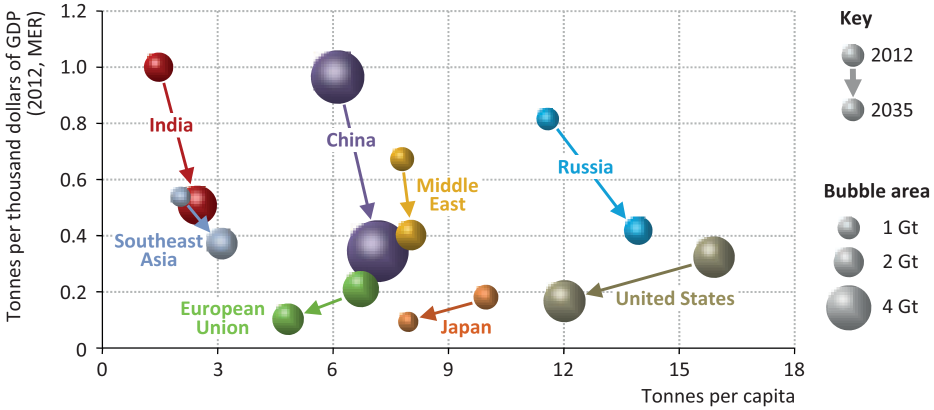
**Figure 2.14 ▷ Energy-related $CO_2$ emissions by region in the New Policies Scenario**




* Rest of world includes international bunkers.

$CO_2$ emissions per capita decline slightly on a global basis, to 4.3 tonnes per capita, in 2035. On average, OECD countries see their $CO_2$ emissions per capita decline by nearly one-quarter. Per-capita emissions in the United States drop significantly, but remain nearly three times the world average in 2035; those of Japan decline to 7.8 tonnes/capita and the average level of the European Union falls to 4.9 tonnes/capita (Figure 2.15). Some developing economies experience rapid increases in per-capita emissions: China converges to the OECD average in 2035, while the Middle East overtakes the OECD average. In Southeast Asia and India, per-capita emissions remain below the world average, despite an increasing trend over the projection period.

**Figure 2.15** ▷ **Energy-related $CO_2$ emissions per capita and $CO_2$ intensity in selected regions in the New Policies Scenario**






Emissions from coal remain the largest source of energy-related $CO_2$ emissions throughout the period, but they stabilise in 2025 at around 15.7 Gt. More than 45% of the growth in global emissions from 2012 to 2035 is expected to come from natural gas, despite its lower level of emissions per unit of energy. By 2035, natural gas combustion releases over 9.1 Gt of $CO_2$, while oil combustion accounts for 12.5 Gt. Emissions are expected to rise in all sectors over the *Outlook* period, with the largest increase in the power sector (2.1 Gt), driven by increasing electricity demand in developing countries, mostly in buildings. The power sector in China alone adds 1.3 Gt through to 2035, even though the share of non-fossil generation expands from 22% in 2012 to 38% in 2035. Global $CO_2$ emissions from the transport sector expand by 2.0 Gt, with developing Asia accounting for nearly three-quarters of this growth. Expanding demand for mobility, often coupled with subsidised prices and weak or non-existent fuel-economy standards, explains this growth.

## Topics in focus

This section presents new data and analysis on three topics that have an important bearing on the *Outlook* for the global energy system. The ten members of the Association of Southeast Asian Nations (ASEAN) are, together with China and India, shifting the centre of gravity of the global energy system toward Asia. We examine in greater detail the current energy situation in Southeast Asia and the important trends influencing its energy outlook to 2035. *WEO-2013* also continues its coverage of the need to increase modern energy access to the huge number of people in the world currently without it, and the imperative to phase out inefficient fossil-fuel subsidies that serve to distort energy markets. Here we present our latest data and analysis, as well as covering key developments over the last year and, in the case of energy access, our projections for the future.

## *Energy trends in Southeast Asia*[15]

### *The situation today*

Since 1990, Southeast Asia's energy demand has expanded two-and-a-half times. By 2011, it had reached 550 Mtoe, or around three-quarters of that of India. Considerable further growth in demand can be expected in the region, especially considering that the per-capita energy use by its 600 million inhabitants is low, at just half of the global average, and the region's strong long-term economic growth prospects. However, the countries of Southeast Asia are extremely diverse, with vast differences in their scale and pattern of energy use and their energy resource endowments (Figure 2.16). Indonesia, the largest energy user in the region, with 36% of overall demand, consumes 66% more energy than Thailand (the second-largest user) and over 50 times more energy than Brunei Darussalam (which has the lowest consumption and a much smaller population). Compared with some of its neighbours, Southeast Asia is richly endowed with fossil and renewable energy resources, though they are distributed unevenly across the region and often located far from demand centres. Currently, the region is an exporter in net energy-equivalent terms, as exports of coal (220 Mtce), natural gas (62 bcm) and biofuels more than offset net imports of oil (1.9 mb/d). Indonesia is by far the dominant producer, having greatly increased its coal output and exports in the last decade.

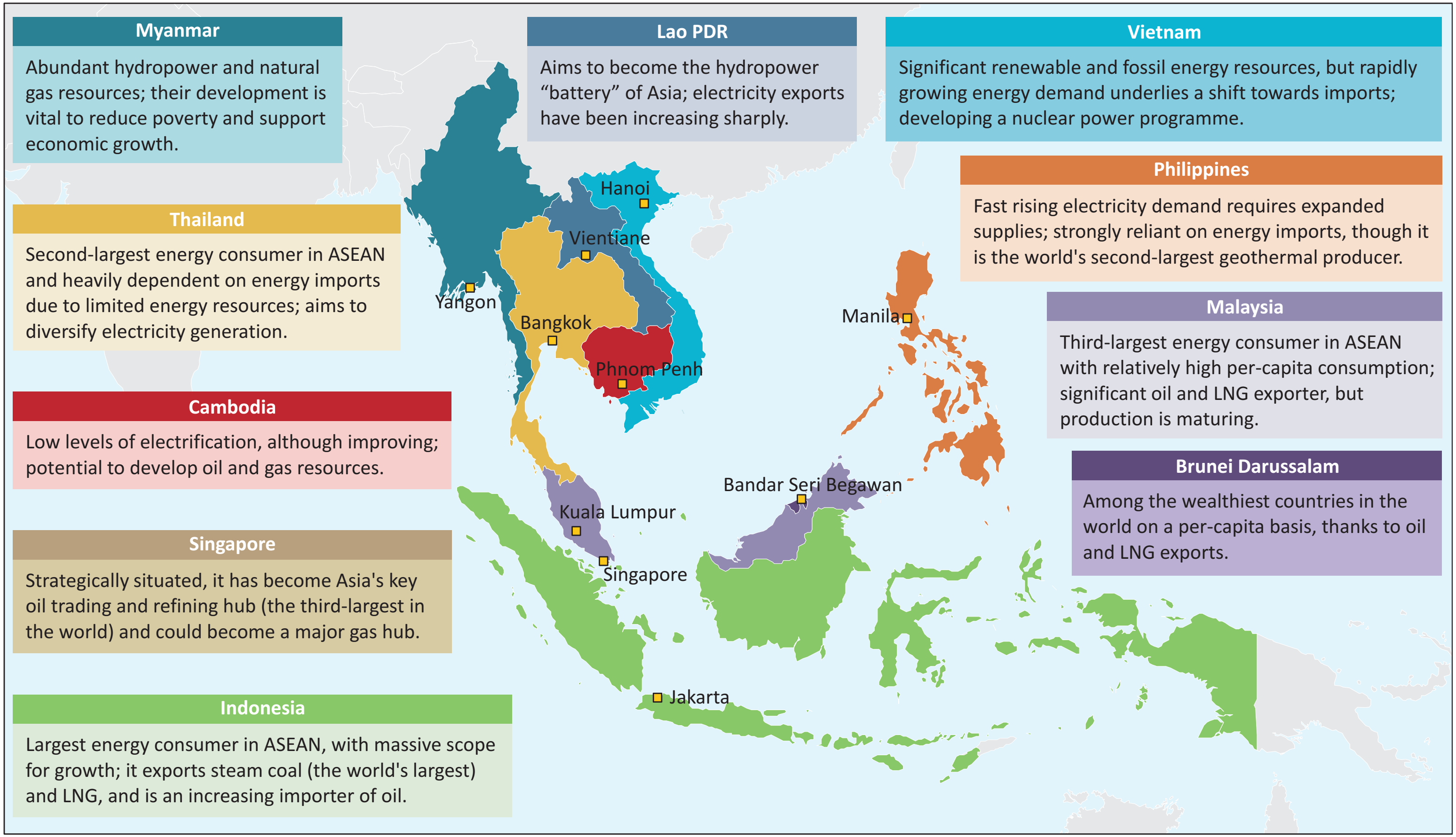
Phasing out fossil-fuel subsidies and providing access to modern energy services remain unfinished business in Southeast Asia. Fossil-fuel subsidies amounted to $51 billion in the region in 2012. Despite recent reform efforts, notably in Indonesia, Malaysia and Thailand, subsidies remain a significant factor distorting energy markets. They encourage wasteful energy consumption, burden government budgets and deter investment in energy infrastructure and efficient technologies (see final section of this chapter). With one-fifth of the population in the region still lacking access to electricity and almost half still relying on the traditional use of biomass for cooking, much remains to be done to achieve universal access to modern energy. In Indonesia, for example, electricity demand was lower than Norway's until the mid-2000s, yet its population is some 50 times greater.

### *Meeting future needs*

In the New Policies Scenario, Southeast Asia's energy demand increases by over 80% between 2011 and 2035, a rise equivalent to current demand in Japan. This supports a near tripling of the region's economic activity and a population increase of almost one-quarter. Oil demand rises from 4.4 mb/d today to 6.8 mb/d in 2035, almost one-fifth of projected world growth. After having grown at 10% per year, on average, since 1990, coal demand triples over the period to 2035, accounting for nearly 30% of global growth in coal use. Natural gas demand increases by around 80% to 250 bcm. The share of renewables in the primary energy mix falls, even with rapidly increasing use of modern renewables – such as geothermal, hydropower and wind – and relatively stable use of traditional biomass for cooking.

15. This section summarises the findings of a *WEO* special report presented at the 7th East Asia Summit Energy Ministers Meeting in Bali on 26 September 2013.

**Figure 2.16 ▷ Energy in Southeast Asia**




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.

The power sector is fundamental to the energy outlook for Southeast Asia and, within it, coal emerges as the fuel of choice. Electricity generation between 2011 and 2035 increases by more than the current power output of India. Coal's relative abundance and affordability in the region boosts its share of electricity generation from less than one-third today to almost half in 2035, at the expense of natural gas and oil. This shift is already underway: some three-quarters of the thermal capacity now under construction is coal-fired. Deploying only more efficient coal-fired power plants should be a major priority in the region – the average efficiency is currently just 34%, owing to the almost exclusive use of subcritical technologies. If the region's coal-fired power plants were as efficient as those in Japan today, their fuel use would be one-fifth lower, and $CO_2$ emissions and local air pollution be substaintially reduced.

Southeast Asia faces sharply increasing reliance on oil imports, which will impose high costs and leave the region more vulnerable to potential disruptions. Decline in mature fields and the absence of large new prospects lead oil production across the region to fall by almost one-third in the period to 2035. As a result, Southeast Asia becomes the world's fourth-largest oil importer, behind China, India and the European Union. Its oil import dependency almost doubles, to 75%, as net imports rise from 1.9 mb/d to just over 5 mb/d. The region's spending on net oil imports triples to almost $240 billion in 2035, equivalent to almost 4% of GDP. Spending in Thailand and Indonesia on net oil imports triples to nearly $70 billion each in 2035.

There will be a reduced surplus of natural gas and coal from the region for export, as production is increasingly dedicated to domestic markets. Despite increasing gas production, Southeast Asia's net gas exports, which come mainly from Indonesia, Malaysia, Myanmar and Brunei Darussalam, are projected to be cut from 62 bcm to 14 bcm in the period to 2035. The region's net coal exports also decline after 2020, as regional demand outpaces growth in indigenous production, though Indonesia's coal production rises by more than 80%, to 550 Mtce in 2035 and it remains one of the world's biggest coal producers and, by a very large margin, the top exporter of steam coal.

Developing policies to attract investment will be vital for enhancing energy security, affordability and sustainability. Around $1.7 trillion of cumulative investment in energy-supply infrastructure to 2035 is required in the region, with almost 60% of the total in the power sector. Mobilising this will be challenging unless action is taken to eliminate existing barriers, which include subsidised energy prices, under-developed energy transport networks, and instability and inconsistency in the application of energy-related policies.

While Southeast Asia has made some gains in energy efficiency, almost three-quarters of the full economic potential is set to remain untapped in 2035. Removing barriers to energy efficiency deployment would, accordingly, deliver major energy savings, as demonstrated in the Efficient ASEAN Scenario of the *WEO* special report *Southeast Asia Energy Outlook*, which provides for the uptake of energy efficiency opportunities that are both economically viable and have acceptable payback periods (IEA, 2013c). Compared with the New Policies Scenario, energy demand is cut by almost 15% in 2035, an absolute amount that exceeds

Thailand's current energy demand. Lower electricity demand and the use of more efficient power plants reduce coal demand by 25%. More efficient industrial equipment, stringent vehicle fuel-economy standards and the quicker phase-out of fossil-fuel subsidies drive demand reductions in oil (10%) and gas (11%). The region's net oil imports are cut by around 700 kb/d in 2035, a level comparable to Malaysia's current production, cutting oil-import bills by $30 billion. By the end of the period, net exports of natural gas are three times higher than in the New Policies Scenario (reaching 42 bcm) and of coal 50% higher (reaching 320 Mtce).

Unlocking Southeast Asia's energy efficiency potential requires government action to address a wide spectrum of barriers. The measures to be adopted will vary by country and by sector, but priority areas include vehicle fuel-economy standards, more stringent building codes and energy performance standards for a wider range of appliances and products. Improving administrative expertise and energy data collection are essential pre-requisites to developing effective energy efficiency policies and their implementation. Realistic and measurable efficiency targets are needed, along with selective measures to achieve them and mechanisms to monitor progress and make adjustments as required. Energy efficiency investments need to be made more affordable, both by eliminating market distortions and by increasing the availability of financing and incentives. Carefully constructed packages could supply financial support to those who need it most, drawing on funds released by the progressive elimination of consumer subsidies.

### *Modern energy for all*[16]

There is growing recognition that modern energy is crucial to achieving a range of social and economic goals relating to poverty, health, education, equality and environmental sustainability, and this recognition is reflected in a number of new initiatives. A United Nations High Level Panel of Eminent Persons has recommended that universal access to modern energy services be included in the Post-2015 Development Agenda. The United States has launched a Power Africa initiative, aimed at doubling electricity access in sub-Saharan Africa over five years. At the time of writing, 77 developing countries have signed up to the UN Sustainable Energy for All (SE4All) initiative, including many of those with the largest populations lacking access to modern energy. Many businesses, aid organisations and non-governmental organisations have also joined the SE4All initiative.

Alongside this increase in political focus, the last year has seen new analysis which increases our understanding of energy access. The first major analytical report produced under the SE4All initiative, *Global Tracking Framework*, which was led by the IEA and the World Bank, defines the starting point against which progress can be measured and the scale of the challenge understood (IEA and World Bank, 2013). In addition, new research finds that

16. In this analysis, we define access to modern energy services as household access to electricity and clean cooking facilities. It is recognised that this excludes some important categories, such as access to energy for productive use, for community services and for heating. While this is an imperfect situation, such categories are often excluded from quantitative analysis of energy access due to the lack of comprehensive, reliable data. See *WEO-2012* and our energy access methodology for a fuller discussion of these issues, both available at *www.worldenergyoutlook.org/energydevelopment*.

there are 3.5 million premature deaths each year as a result of household air pollution from using solid fuels (rising to 4 million, if the contribution of household air pollution to outdoor air pollution is included). This figure is much higher than previous estimates, primarily due to the inclusion of new diseases, such as cardiovascular disease and lung cancer (Lim, *et al.,* 2012).

### *Current status of energy access*

Modern energy for all is far from being achieved. We estimate that nearly 1.3 billion people, or 18% of the world population, did not have access to electricity in 2011 – 9 million fewer than in the previous year (Table 2.3).[17] The global improvement since last year is modest, while the picture for some countries has worsened. Sub-Saharan Africa and developing Asia account collectively for more than 95% of the global total. The population without access to electricity in sub-Saharan Africa is now almost equal to that of developing Asia and, if current trends continue, will overtake it in the near future.[18] Since 2000, around two-thirds of the people gaining access to electricity have been in urban areas and the population without electricity access has become more concentrated in rural areas.

At a country level, the latest estimates confirm the progress that China and Brazil have made over many years in increasing access to electricity and that they are now getting close to the goal of universal electrification. In Asia, the latest estimates reveal improvements in electricity access in Bangladesh, Indonesia and Sri Lanka. India remains the country with the largest population without electricity access at 306 million people.[19] Experience in Pakistan serves to highlight a different element of the energy access challenge, that of achieving reliability of supply, as fuel shortages have jeopardised electricity supply there and resulted in prolonged load-shedding (Box 2.2). In Africa, the latest estimates reveal improvements in South Africa, Ghana, Cameroon and Mozambique, all of which have explicit plans in place to boost electricity access. The Power Africa initiative is supporting these efforts, with the US government having committed more than $7 billion, through a combination of loans, guarantees, credit enhancements and technical assistance. Private companies have agreed to put up an additional $9 billion (US Government, 2013). Partner countries already include Ethiopia, Ghana, Kenya, Liberia, Nigeria and Tanzania; around 40% of those without access to electricity in sub-Saharan Africa live in these countries. In Latin America, the overall level of access to electricity is high, but some countries still have relatively low electrification rates, such as Honduras (83%), Guatemala (82%) and, particularly, Haiti (28%).

17. Our estimates are based on 2011 data where available or an estimate based on latest available data.

18. *WEO-2014* will include a special focus on energy developments in Africa.

19. Our estimates for India are based on the latest National Sample Survey and are in line with those published in India's 12th Five-Year Plan (Planning Commission of India, 2013). However, the Five-Year Plan also notes that the 2011 Census of India reports a 67.2% national electrification rate, which is lower than the latest National Sample Survey. Applying the rate reported in the Census results in the estimated number of people in India without access to electricity increasing to around 410 million in 2011, which would change our global estimate to around 1.4 billion. India's 12th Five-Year Plan notes this difference in estimates, stating that it is possibly due to differences in questionnaire design and that it needs to be looked into further.

**Table 2.3 ▷ Number of people without access to modern energy services by region, 2011** (million)[20]



| | Without access to electricity | | Traditional use of biomass for cooking* | |
|---|---|---|---|---|
| | Population | Share of population | Population | Share of population |
| **Developing countries** | **1 257** | **23%** | **2 642** | **49%** |
| Africa | 600 | 57% | 696 | 67% |
| Sub-Saharan Africa | 599 | 68% | 695 | 79% |
| Nigeria | 84 | 52% | 122 | 75% |
| South Africa | 8 | 15% | 6 | 13% |
| North Africa | 1 | 1% | 1 | 1% |
| Developing Asia | 615 | 17% | 1 869 | 51% |
| India** | 306 | 25% | 818 | 66% |
| Pakistan | 55 | 31% | 112 | 63% |
| Indonesia | 66 | 27% | 103 | 42% |
| China | 3 | 0% | 446 | 33% |
| Latin America | 24 | 5% | 68 | 15% |
| Brazil | 1 | 1% | 12 | 6% |
| Middle East | 19 | 9% | 9 | 4% |
| **World*** ** | **1 258** | **18%** | **2 642** | **38%** |

* Based on World Health Organization (WHO) and IEA databases. ** Since *WEO-2012*, population numbers for India have undergone a significant upward revision (See Chapter 1 for population assumptions), meaning that, while the electrification and clean cooking access rates have not changed, the number of people estimated to be without access has significantly increased. See also footnote 19. *** Includes OECD countries and Eastern Europe/Eurasia.

We estimate that more than 2.6 billion people, or 38% of the global population, relied on the traditional use of biomass for cooking in 2011 – 54 million more people than in the previous year.[21] This deteriorating situation is primarily due to population growth outpacing improvements in the provision of clean cooking facilities. The estimates reveal a worsening situation in sub-Saharan countries such as Nigeria, Uganda, Kenya and Tanzania. Developing Asia accounts for more than 70% of the global total and includes seven of the ten largest populations without access to modern cooking facilities. In India, 818 million people, or around two-thirds of the population, rely on traditional biomass – almost twice as many as in China, which is ranked second. In China, the predominance of coal for cooking has decreased over the last decade, but around one-third of the population still relies on traditional biomass. While the number of people relying on biomass is larger in developing Asia than in sub-Saharan Africa, the share of the population is lower: 50% in developing Asia, compared with 80% in sub-Saharan Africa.

20. For a complete country-by-country breakdown, the IEA *World Energy Outlook* electricity access database can be accessed at *www.worldenergyoutlook.org/resources/energydevelopment*.

21. This chapter focuses on the traditional use of biomass for cooking, but there are also 200-300 million people (not included in Table 2.3) that rely on coal for cooking and heating purposes, which can potentially have serious health implications when used in primitive stoves. These people are mainly in China, but there are also significant numbers in Liberia, Democratic People's Republic of Korea and Paraguay.

**Box 2.2 ▷ Fuel shortages in Pakistan**

Pakistan faces economic and energy challenges that intersect most clearly in relation to electricity supply. Around 55 million people – more than 30% of the population – do not have access to electricity. Of those that do have electricity, the quality of supply they receive can be a major source of frustration. While Pakistan has 23 GW of installed power generation capacity, the cost of fuel has proved to be a significant financial burden to generators, relative to the price they can charge for power, resulting in shortages and power cuts. The share of oil in the generation mix is relatively high and the doubling of electricity tariffs since 2008 has not been sufficient to compensate for rising fuel costs. The problem is made worse by a long legacy of unpaid energy bills and distribution losses (often due to theft). State-owned power companies have faced large losses and accumulated debt that government subsidies are unable to cover fully. This has resulted in power companies being unable to buy sufficient fuel, which, in turn, has prompted extensive load shedding – up to 12 hours per day in urban areas and 20 hours per day in rural areas (NEPRA, 2012). Such prolonged power shortages have a major impact on Pakistan's economy, cutting GDP growth by an estimated 2% (ADB, 2013).

The Asian Development Bank is supporting government efforts to increase power generation capacity, improve transmission and distribution, and deliver renewable energy projects. Pakistan has also recently agreed funding support from the government of Saudi Arabia to complete a 1 GW hydro project (Arab News, 2013) and, in September 2013, reached agreement with the International Monetary Fund on a $6.7 billion loan, linked to energy sector reforms. In mid-2013, the government also took steps to help clear the debt of independent power producers. In the longer term, the power sector will need to be restructured, including the introduction of tariffs that fully reflect underlying costs and better revenue collection and enforcement. Such reforms can be easier to implement as the quality of service improves.

Several countries are taking action to expand access to clean cooking facilities. Indonesia has set a highly ambitious target of enabling 85% of households to use LPG or natural gas for cooking by 2015. The kerosene-to-LPG conversion programme implemented in 2007 has successfully decreased the use of kerosene, a relatively polluting fuel, but the shift from biomass to gas remains a challenge. While subsidies to LPG represent an important cost of transition to clean fuels in Indonesia, they represent a net saving in cases where households are switching from kerosene, which receives higher subsidies. In Africa, Ghana's government has committed to the very ambitious goal of bringing LPG to half the number of households, more than doubling the current level. Nigeria, Africa's most populous country, has set a national goal of helping 10 million households (around one-third of the total) to switch to clean cooking facilities by 2021; Nigerian households currently rely heavily on traditional biomass for cooking despite the country's abundant fossil fuel resources. International efforts are also being stepped up. The Global Alliance for Clean Cookstoves plans to promote the adoption of clean cookstoves and fuels to 100 million households by 2020 (GACC, 2012). It has prioritised action in six countries: Bangladesh, China, Ghana, Kenya, Nigeria and Uganda. While relatively small in scale, some other new clean cookstove projects are noteworthy because of the involvement of multinationals and the commitments made to manufacture clean cookstoves in Africa, bringing economic, as well as health, benefits. Examples include partnerships between the firm Philips and the Industrial Development Corporation of South Africa, and between the firms General Electric, Burn Manufacturing, and the US Overseas Private Investment Corporation. Such developments are encouraging, but evaluation is needed of their success in increasing adoption and changing behaviour (and, ultimately, improving health).



### *Outlook for energy access in the New Policies Scenario*

In the New Policies Scenario, the number of people without access to electricity is projected to decline by more than one-fifth to around 970 million in 2030, or 12% of the global population (Table 2.4).[22] Around 1.7 billion people are expected to gain access over the period to 2030 but, in many cases, these gains are offset by population growth (increases by 1.4 billion to 2030). While there is an improving global picture, the regional trends are very diverse. Developing Asia sees the number of people without access to electricity decline by around 290 million between 2011 and 2030. China is expected to achieve universal access within the next few years. India sees a significant improvement: its electrification rate rises from 75% today to around 90%, but the country still has, in 2030, the largest number without access to electricity in any single country.

**Table 2.4 ▷ Number of people without access to modern energy services by region in the New Policies Scenario, 2011 and 2030** (million)

| | Without access to electricity | | Without access to clean cooking facilities | |
|---|---|---|---|---|
| | **2011** | **2030** | **2011** | **2030** |
| **Developing countries** | **1 257** | **969** | **2 642** | **2 524** |
| Africa | 600 | 645 | 696 | 881 |
| Sub-Saharan Africa | 599 | 645 | 695 | 879 |
| Developing Asia | 615 | 324 | 1 869 | 1 582 |
| China | 3 | 0 | 446 | 241 |
| India | 306 | 147 | 818 | 730 |
| Latin America | 24 | 0 | 68 | 53 |
| Middle East | 19 | 0 | 9 | 8 |
| **World** | **1 258** | **969** | **2 642** | **2 524** |

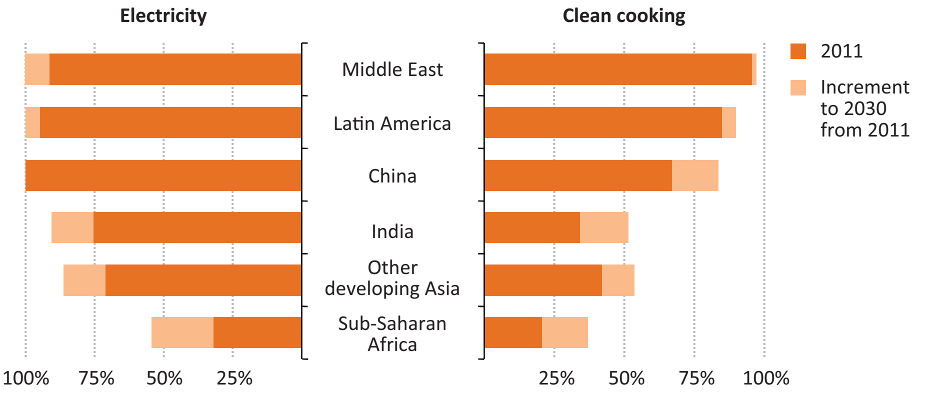
In sub-Saharan Africa, the number of people without access to electricity in 2030 is projected to reach 645 million, 8% more than in 2011. It is the only region where the number of people without access to electricity deteriorates over the *Outlook* period, resulting in sub-Saharan Africa's share of the global total increasing from less than half in 2011 to two-thirds in 2030. Developments in sub-Saharan Africa are not uniform across the

22. While the *Outlook* period for *WEO-2013* is 2011 to 2035, analysis in this section is based on the period 2011 to 2030, so as to be consistent with the timeframe of the SE4All initiative.

projection period, with the rise in the numbers lacking access levelling off in the 2020s and a decline beginning just before 2030. Brazil is projected to achieve universal access in the next few years – the aim of its "Luz para Todos" (Light for All) programme (see the Brazil Energy Outlook in Part B) – while the rest of Latin America is projected to achieve universal access around 2020.

The number of people relying on the traditional use of biomass for cooking is projected to drop slightly, to just over 2.5 billion in 2030 – around 30% of the global population at that time. Economic growth, urbanisation and clean cooking programmes all help improve the situation in developing Asia, where the number of people without clean cooking facilities declines by around 290 million. Despite this, India still has around 730 million people without clean cooking facilities in 2030, equivalent to half of the population (Figure 2.17). While the overall picture has improved slightly compared with *WEO-2012*, our projections continue to show a worsening situation in sub-Saharan Africa, where nearly 880 million people (63% of the population), do not have access to clean cooking facilities in 2030.

**Figure 2.17 ▷ Shares of population with access to electricity and clean cooking facilities by region in the New Policies Scenario**




### *Energy for All Case*

A trajectory consistent with achieving universal access to electricity and clean cooking facilities by 2030 has been drawn up in the Energy for All Case. To arrive at the required trajectory, in the case of electricity, we assess the required combination of on-grid, mini-grid (such as village or district level generation) and isolated off-grid solutions (such as solar PV) in each region, taking account of regional costs and consumer density in determining a regional cost per megawatt-hour (MWh). When delivered through an established grid, the cost per MWh is cheaper than other solutions, but extending the grid to remote areas can be very expensive and incur high transmission losses.[23] In developing Asia, around

23. We assume that grid extension is the most suitable option for all urban zones and around 30% of rural areas, but not in more remote rural areas. The remaining rural areas are connected either with mini-grids (65% of this share) or small, stand-alone off-grid solutions (the remaining 35%), which have no transmission and distribution costs.

three-quarters of people gaining access are connected to the main grid or to mini-grid systems. In sub-Saharan Africa, more people gain access through off-grid solutions, as a larger proportion of the population lacking access live in rural areas. In the case of clean cooking facilities, access is also assumed to be achieved through different technologies: one of the most common options is LPG stoves, adopted by 7 million households per year on average in developing Asia and 5 million households per year in sub-Saharan Africa over the projection period.



Universal access to modern energy has only a small impact on global energy demand and related $CO_2$ emissions. The additional energy demand for electricity generation is around 120 Mtoe, pushing total primary energy demand up by less than 1% relative to the New Policies Scenario in 2030; but only around 35% of the additional generation comes from fossil fuels, with the remainder coming from renewables. For cooking, an additional 0.82 mb/d of LPG is required in 2030. The additional $CO_2$ emissions in the Energy for All Case are negligible, 260 Mt higher in 2030, and only 0.7% higher than in the New Policies Scenario. This small increase in $CO_2$ emissions is attributable to the low level of energy per capita expected to be consumed by the people gaining modern energy access and to the relatively high proportion of renewable solutions adopted. The total impact on greenhouse-gas emissions of achieving universal access to clean cooking facilities needs to be treated with caution, but it is widely accepted that advanced cookstoves, more efficient than traditional biomass stoves, would reduce emissions.

## *Energy subsidies*

### *Estimated costs*

Subsidies to fossil fuels distort energy markets in many countries, pushing up energy use and emissions, and engendering large economic costs (Box 2.3). Fossil-fuel consumption subsidies worldwide are estimated to have totalled $544 billion in 2012. This finding is based on a survey that identified 40 countries that set energy prices below reference prices, which we define as the full cost of supply based on international benchmarks.[24] The estimates cover subsidies to fossil fuels consumed by end-users and subsidies to fossil-fuel inputs to electric power generation, but do not cover subsidies to petrochemical feedstocks. Unlike oil, gas and coal, electricity is not extensively traded over national borders, so subsidy estimates are based on the difference between end-user prices and the cost of electricity production, transmission and distribution. Countries that subsidise fossil fuels fall into two broad groups: those that import energy at world prices and then sell it domestically at lower regulated prices; and those that are net exporters of energy — and therefore do not import energy at world prices — but price it domestically at below the reference prices.

24. Some authorities regard the use of international benchmark prices to calculate reference prices as inappropriate. In particular, some are of the opinion that reference prices should be based on actual production costs, particularly when estimating subsidies in energy resource-rich countries, rather than prices on international markets as applied within this analysis.

### Box 2.3 ▷ Smuggling as a possible driver of fossil-fuel subsidy reform

The prevalence of fossil-fuel subsidies in many parts of the world is making fuel smuggling a serious problem by providing an incentive to sell subsidised products from one country in neighbouring countries where prices are higher. While the smugglers make big financial gains, there is a high financial cost to the subsidising country (with no national benefit), and probably substantial financial costs to the recipient country, by way of forgone taxes and excise duties, due to reduced legitimate sales.

A good example is Iran. Although subsidy reforms in 2010 reduced the incentive to smuggle gasoline and diesel to neighbouring countries, a sharp devaluation of its currency against the US dollar in 2013 (which was not matched by an adjustment in local prices) has increased it again. It is estimated that around 10 million litres of fuel, or more than 60 000 barrels, are currently being smuggled out of the country each day, mainly into Pakistan. It is potentially a very lucrative activity, as diesel still sells for as little as $0.12 per litre in Iran, compared with $1.20 per litre in Pakistan.

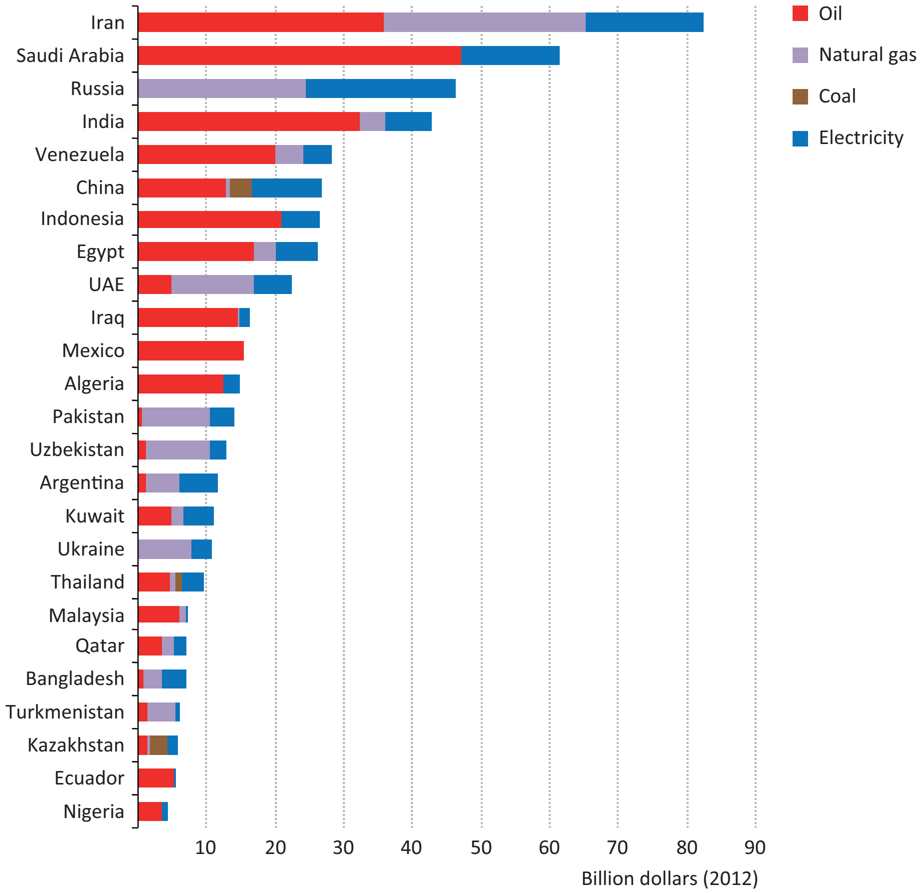
In Southeast Asia, the geographical proximity of countries with major retail price disparities has meant that fuel smuggling has long been a major problem. It often involves the use of small oil tankers or fishing boats that either bypass normal customs routes altogether or falsely declare their load as products that are exempt from excise duties. Gasoline in Indonesia, for example, was until recently around 60% cheaper than in a number of its neighbouring countries. Subsidies in Malaysia have reduced refined product prices to well below the regional average. In the Philippines, which has been the recipient of a lot of smuggled fuel, the government estimates that its tax revenues are being reduced by around $1 billion per year as a result of illegitimate purchases.

Many countries are taking steps to stamp out fuel smuggling. Saudi Arabia, for example, has increased inspections of vehicles leaving its borders to check that they have only enough fuel to get to the nearest re-fuelling station on the other side. The Philippines has also recently stepped up coastal patrols, in this case to stop smuggled fuel from getting into the country. But history has shown that efforts to curtail smuggling absorb scarce administrative resources and are rarely completely successful. While better border control may be a necessary option for countries that are the recipients of smuggled fuels, a much more effective strategy would be for the originating countries to remove the subsidies, as that would eliminate the incentive to smuggle the fuels.

The value of fossil-fuel subsidies increased in 2012 compared with 2011, as moderately higher international prices and increased consumption of subsidised fuels offset considerable progress in reining in subsidies in some countries. Oil products were the most heavily subsidised fuels in 2012 and cost $277 billion, or 51% of the total. Subsidies to natural gas and coal consumed by end-users amounted to $124 billion and $7 billion respectively. Subsidies to electricity stood at $135 billion. Almost all consumption subsidies are in non-OECD countries, while production subsidies, typically intended to expand domestic supply, are a much more common form of subsidy in OECD countries than consumption subsidies (OECD/IEA, 2013) (Figure 2.18). Consumption subsidies remain most prevalent in net energy-exporting countries: they accounted for around 75% of the global total in 2012.



**Figure 2.18** ▷ **Economic value of fossil-fuel consumption subsidies by fuel for top 25 countries, 2012**




Subsidies to renewable energy are aimed chiefly at improving the competitiveness of renewables *vis-à-vis* conventional alternatives. Our latest estimates show that renewables subsidies increased by 11% to reach $101 billion in 2012, primarily due to the increase in solar PV capacity, but that they continue to be less than one-fifth of the level of fossil-fuel consumption subsidies (see Chapter 6). While some renewable energy technologies, such as hydropower and geothermal, have long been economic in many locations, others, such as wind (particularly offshore) and solar, require financial support to foster their deployment in most countries. Significant growth in renewables is projected in the New

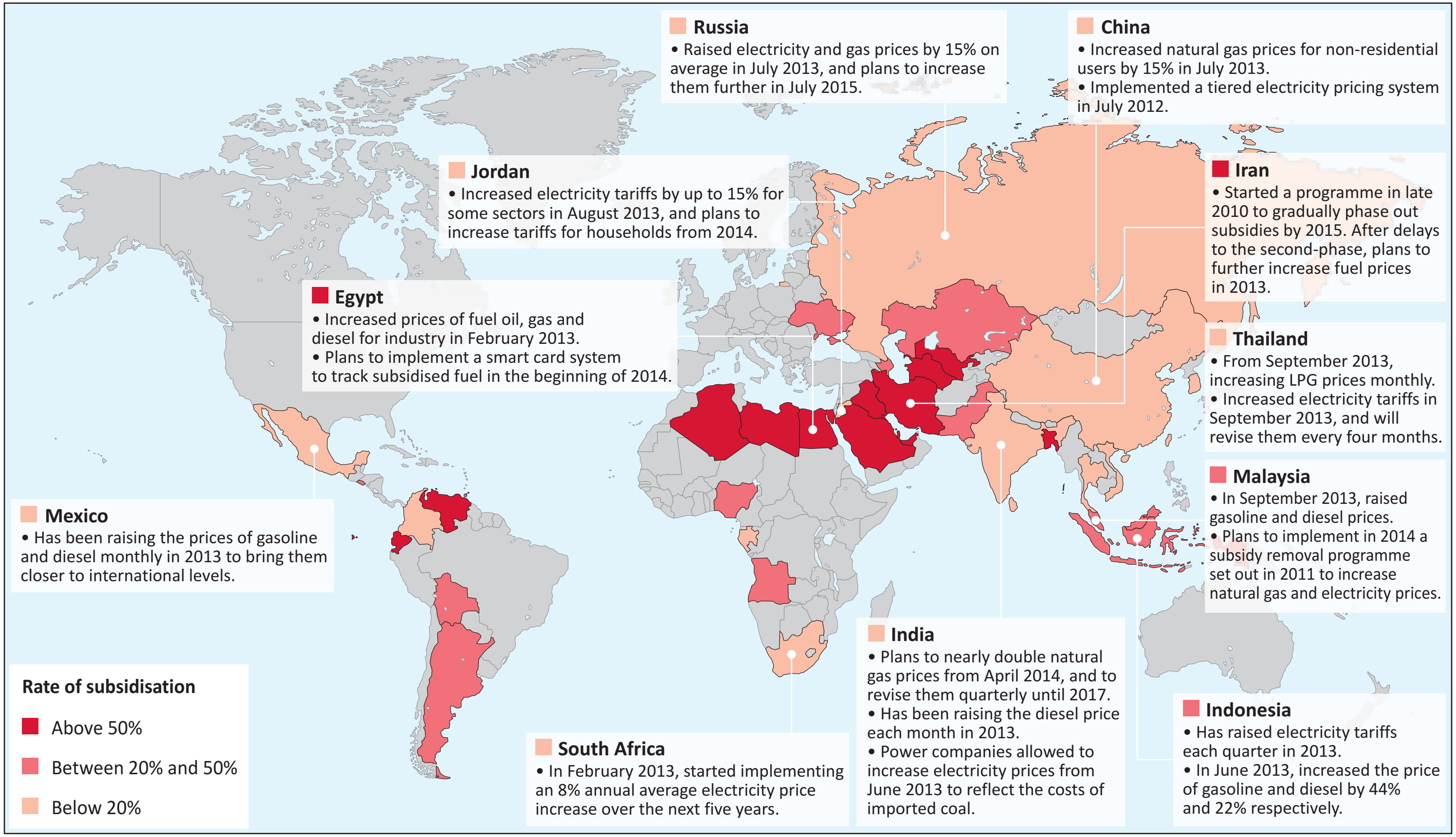
Policies Scenario, mainly driven by subsidies, which are projected to continue to rise to around $220 billion in 2035, although they start declining before then in some regions as different technologies become competitive. Support schemes for renewable energy need to be carefully designed (and sometimes re-designed) if they are to achieve their objective in the most cost-effective way.

### *Update on fossil-fuel subsidy reform*

A number of major reforms to reduce or phase out fossil-fuel subsidies have been announced since last year's *Outlook*, significantly adding to the momentum that has been building up over recent years. Barring a major increase in international energy prices or in consumption, these reforms – if they prove durable – will lead to a reduction in the economic cost of fossil-fuel subsidies and the associated environmental damage. Economic factors have become the dominant driver of moves to reform fossil-fuel subsidies as rising consumption and persistently high energy prices have made them an unsustainable financial burden in many instances (Figure 2.19). For example, Indonesia increased the prices of gasoline by 44% and diesel by 22% in June 2013 in order to reduce the strain on the state budget. The last time fuel prices were raised in Indonesia was in 2009 and since then the cost of subsidies has risen in line with the country's mounting dependence on imported oil and a boom in vehicle ownership in the fast-growing economy. The reforms, which were accompanied by cash hand-outs to poor households, have proved successful. Although providing blanket subsidies to an entire population is an extremely inefficient way to make energy affordable for the poor, if the subsidies are to be removed, it is often important to provide targeted welfare assistance to avoid restricting access to modern energy services.

Other particularly notable reforms to energy pricing were made by India and China during the year. India has started increasing diesel prices on a monthly basis (with the eventual goal of eliminating subsidies entirely) following reforms to gasoline pricing that were introduced in 2010. India has also announced that power stations that need to buy imported coal due to local supply shortfalls will be able to pass on the extra costs to their customers. Under the old system, tariffs could not be increased to reflect fuel prices, sometimes leaving generators with little incentive to increase generation to meet peak demand and so contributing to frequent blackouts and rolling outages. India has also announced that prices of domestically produced natural gas will be adjusted on a quarterly basis from April 2014, to match the average of the prices of the LNG it imports and of gas on other major international markets. This is expected to result in a doubling of domestic gas prices. In a similar move, China increased natural gas prices by 15% for non-residential users, which make-up around 80% of total demand. In both countries, the reforms increase the incentive to produce gas domestically and make it more economic to import gas, helping to meet targets to increase the share of gas in the energy mix. In Russia, a shift towards market-based pricing in recent years has seen a narrowing of the gap between domestic gas and electricity prices and comparable international levels.

**Figure 2.19** ▷ **Rates of fossil-fuel consumption subsidies in 2012 and recent developments in selected countries**




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.

Multilateral co-operation to support fossil-fuel subsidy reform has also continued to build throughout 2013. Four years have now passed since leaders of the G-20 and Asia-Pacific Economic Cooperation forum (APEC) committed to "phase out inefficient fossil-fuel subsidies that encourage wasteful consumption".[25] Much remains to be done to fulfil these commitments, but many countries introduced reforms aimed at reducing subsidies, while G-20 countries have begun undertaking voluntary peer reviews of each other's subsidies and reform efforts. In a more recent initiative, a high-level panel reporting to the United Nations Secretary General has recommended that a goal of achieving sustainable energy be included in the post-2015 Development Agenda, which will succeed the Millennium Development Goals, and that this objective should encompass the phasing out of fossil-fuel subsidies.

25. Since the G-20 Pittsburgh Summit in 2009 committed to "rationalize and phase out over the medium term inefficient fossil fuel subsidies that encourage wasteful consumption", the IEA along with several other international organisations has been providing the group with ongoing analysis aimed at supporting the implementation of their commitment.

# Natural gas market outlook

## What price is right?

### Highlights

- Although current market conditions vary markedly across the world, the overall outlook for natural gas is bright: consumption in 2035 is higher than in 2012 in all three scenarios. In the New Policies Scenario, gas use rises by 1.6% per year on average to reach almost 5 tcm in 2035; 82% of this increase is concentrated in non-OECD countries, where demand rises by around 1.3 tcm.

- The biggest absolute increases in demand are in China, the Middle East (where gas use overtakes that of the European Union before 2020) and North America. Outside Japan, Korea and parts of ASEAN, gas has played a relatively small role in the Asia-Pacific energy picture to date. It gains ground quickly, notably in China, where gas use quadruples by 2035, driven by policies to diversify the energy mix and, where it replaces coal, to reduce air pollution. In the European Union, an unfavourable blend of prices for gas, coal and $CO_2$ and a rising share of renewables in the power sector mean that demand struggles to return to 2010 levels before 2035.

- New sources of gas, both conventional and unconventional, bring additional diversity to global supply over the *Outlook* period. New contributors to conventional output growth include Iraq, East Africa, Brazil and the eastern Mediterranean, supplementing increases from established suppliers in Russia, the Caspian, North and West Africa and the Middle East. Unconventional gas accounts for almost half of the growth in global output and its development spreads well beyond North America, notably after 2020, making China and Australia major contributors to global production growth.

- Changes in the cast of major LNG suppliers create new linkages between regional gas markets, notably between those of North America and the Asia-Pacific, narrowing to a degree the wide regional gas price differentials that exist today. LNG exports from the United States factor strongly in putting additional pressure on traditional oil-indexed mechanisms for pricing gas and in loosening the current rigidity of LNG contracting structures, although various market and institutional barriers continue to put a brake on global gas market integration.

- We examine a Gas Price Convergence Case in which convergence between different regional gas prices is more rapid than in the New Policies Scenario, underpinned by the assumption of higher LNG volumes from North America, faster changes to gas markets and pricing mechanisms in the Asia-Pacific region, and an easing of costs for liquefaction and LNG shipping. In this case, lower prices result in higher global gas demand (by 107 bcm in 2035) and reduced import bills. Prices remain sufficiently attractive to bring forward additional production from a range of suppliers.

## Global overview

Whatever the policy landscape for the next quarter of a century, natural gas is set to grow in importance globally thanks to its widespread availability, competitive supply costs and environmental advantages over the other fossil fuels. Since the turn of the century, global gas use has expanded on average by 2.7% per year – faster than oil and nuclear power, but more slowly than coal and renewables. The share of gas in the world energy mix continues to rise, with unconventional gas playing an increasingly significant role in meeting growing gas demand. Yet behind this upbeat global outlook for gas, there are marked variations by region – with gas use in Europe, in particular, facing a more difficult future. These regional disparities are caused by differences in the dynamics of inter-fuel competition and specific economic and policy conditions.

**Table 3.1 ▷ Natural gas demand and production by region and scenario** (bcm)

| | | | | New Policies | | Current Policies | | 450 Scenario | |
|---|---|---|---|---|---|---|---|---|---|
| | | 1990 | 2011 | 2020 | 2035 | 2020 | 2035 | 2020 | 2035 |
| OECD | Demand | 1 036 | 1 597 | 1 707 | 1 885 | 1 741 | 1 999 | 1 654 | 1 493 |
| | Production | 881 | 1 195 | 1 358 | 1 483 | 1 377 | 1 585 | 1 334 | 1 237 |
| Non-OECD | Demand | 1 003 | 1 773 | 2 249 | 3 086 | 2 291 | 3 279 | 2 149 | 2 554 |
| | Production | 1 178 | 2 188 | 2 599 | 3 492 | 2 655 | 3 693 | 2 472 | 2 817 |
| **World*** | **Demand** | **2 039** | **3 370** | **3 957** | **4 976** | **4 032** | **5 278** | **3 806** | **4 054** |
| *Share of non-OECD* | *Demand* | *49%* | *53%* | *57%* | *62%* | *57%* | *62%* | *56%* | *63%* |
| | *Production* | *57%* | *65%* | *66%* | *70%* | *66%* | *70%* | *65%* | *69%* |

* For 1990 and 2011, the world numbers shown correspond to demand. For the projections, demand and production are always the same, as stock changes are assumed to be zero. The world numbers include gas use as an international marine fuel. Note: bcm = billion cubic metres.

In the New Policies Scenario, the share of gas in the global energy mix reaches 24% in 2035, up from 21% in 2011 (almost catching up with coal in the process), but the pace of annual gas demand growth, which averages 1.6% per year, declines progressively through the projection period. In the Current Policies Scenario, demand grows faster – at 1.9% per year – as no new policies are introduced to rein in demand for either gas or electricity, resulting in stronger demand for gas to generate power. In the 450 Scenario, demand grows by only 0.8% per year, levelling off in the late 2020s, with consumption in the power sector especially subdued. Regardless of the scenario, future gas demand growth is led by non-OECD countries. Their share of global demand already overtook that of the OECD in 2007 and reaches 62% in 2035 (up from 53% in 2011) (Table 3.1).

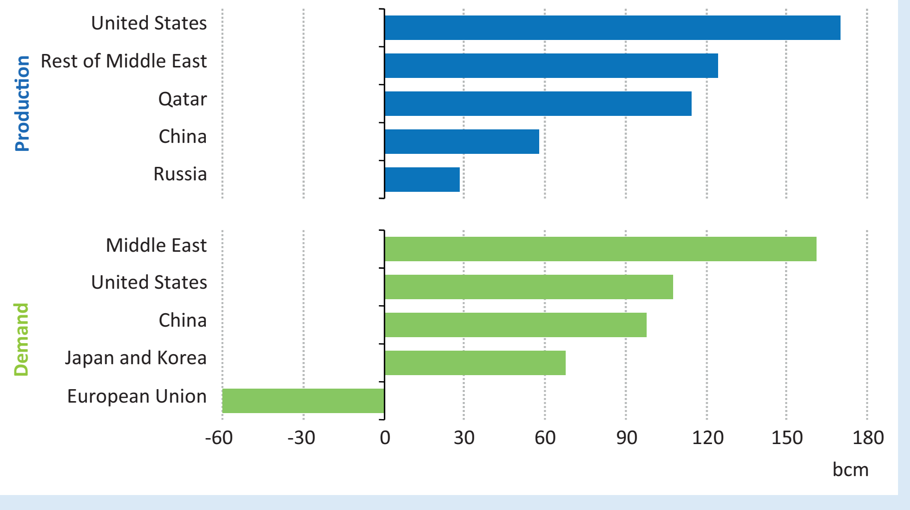
Non-OECD countries also account for the bulk of the growth in gas production across the three scenarios. In the OECD, production in North America and Australia grows briskly, with both regions becoming major gas exporters; but production falls in Europe. Unconventional gas grows strongly in all scenarios, accounting for 27% of total production in 2035, compared with 17% in 2011. New sources of conventional production also emerge, notably in Iraq, East Africa and the deepwater eastern Mediterranean. This diversity of supply sources and of supply routes can be expected to contribute to an environment of growing confidence in the adequacy and reliability of gas supply.

**Box 3.1 ▷ Wide variety in regional starting points for the gas outlook**

3

The last year has seen extreme divergence in market conditions across the major regional markets (trends since 2005 for selected countries and regions are shown in Figure 3.1). The gas market in North America remains characterised by ample supply of natural gas and low prices, which have permitted gas to gain market share in the power sector at the expense of coal. Despite much higher prices, there has also been strong growth in gas consumption across much of Asia. In China, which in 2011 became the third-largest individual gas market in the world after the United States and Russia, demand has been driven primarily by policy interventions, while gas demand in Japan has been boosted by the need to replace lost power generation due to the shutdown of the nuclear fleet following the events at Fukushima Daiichi. In the Middle East, rapid consumption growth has been stimulated in many instances by low prices that do not reflect the international value of the gas. Production has also risen substantially in the Middle East region as whole, but, outside Qatar, it has often struggled to keep up with demand. By contrast, conditions in Europe have remained difficult with gas use declining by a further 2% in 2012, as economic conditions depressed overall energy demand, and increased renewables supply and cheaper coal-fired generation (aided by depressed $CO_2$ prices) backed out gas in the power sector.

**Figure 3.1 ▷ Natural gas demand and production growth in selected regions, 2005-2012**

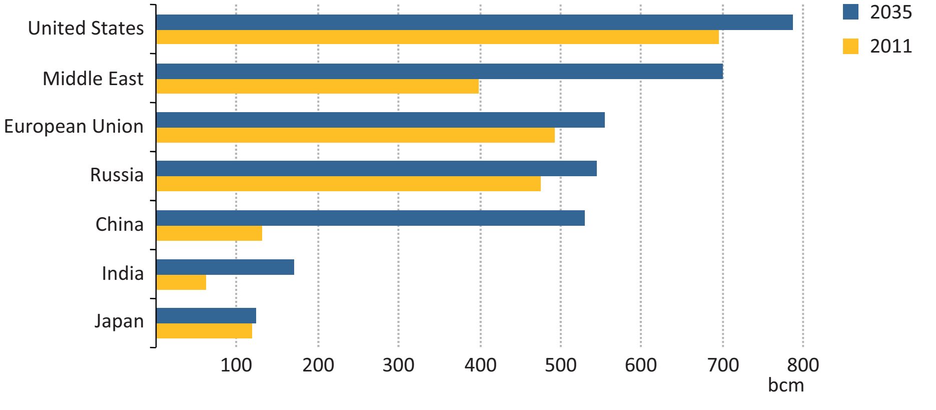


# Demand

## *Regional trends*

In the New Policies Scenario (on which this analysis concentrates), the fastest-growing gas markets in the world are all outside the OECD. Non-OECD countries account for more than three-quarters of global primary demand growth over the period to 2035, with the biggest increases in absolute terms occurring in China and the Middle East. Consumption increases but rates of growth are smaller in the three main OECD regions, because of saturation effects and strong penetration of renewables in the power sector in Europe. Nonetheless, these OECD markets remain comparatively large. For example, demand in the United States, which remains the world's single largest gas consuming country, is 50% higher than Chinese demand in 2035.

**Figure 3.2 ▷ Natural gas demand in selected regions in the New Policies Scenario**




Despite relatively low gas prices, the maturity of the United States and Canada as gas markets limits the scope for rapid growth in North American natural gas demand, even though price differentials with other fuels do create incentives to expand gas use into new areas, such as transport. For the region as a whole (including Mexico, where growth is faster), gas demand rises from 864 billion cubic metre (bcm) in 2011 to 1 036 bcm in 2035. The main driver for this increase is electricity generation. Whereas the short-term rise in gas use is largely due to switching from coal to gas in existing plants (for which 2012 may have represented a high-water mark), the longer-term trend depends more on what type of new capacity is built: we see gas as the preferred fuel for new thermal generation, as environmental restrictions limit the scope for building new coal plants. Outside the power sector, the transport sector sees a rapid rate of increase in demand, though it still accounts for only a relatively small share of total gas use in 2035, as it starts from a very low base. (The prospects for natural gas use in transport are discussed in Chapter 15).

## Table 3.2 ▷ Natural gas demand by region in the New Policies Scenario (bcm)

| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011-2035 | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | Delta | CAAGR* |
| **OECD** | **1 036** | **1 597** | **1 707** | **1 778** | **1 827** | **1 885** | **289** | **0.7%** |
| Americas | 628 | 869 | 957 | 988 | 1 016 | 1 044 | 175 | 0.8% |
| United States | 533 | 696 | 749 | 769 | 781 | 789 | 93 | 0.5% |
| Europe | 325 | 525 | 537 | 568 | 584 | 605 | 80 | 0.6% |
| Asia Oceania | 82 | 202 | 214 | 222 | 227 | 236 | 34 | 0.6% |
| Japan | 57 | 120 | 119 | 123 | 122 | 124 | 3 | 0.1% |
| **Non-OECD** | **1 003** | **1 773** | **2 249** | **2 541** | **2 815** | **3 086** | **1 313** | **2.3%** |
| E. Europe/Eurasia | 738 | 703 | 732 | 756 | 785 | 817 | 114 | 0.6% |
| Caspian | 100 | 117 | 127 | 134 | 139 | 144 | 27 | 0.9% |
| Russia | 447 | 476 | 493 | 504 | 523 | 544 | 68 | 0.6% |
| Asia | 84 | 410 | 669 | 816 | 949 | 1 088 | 678 | 4.2% |
| China | 15 | 132 | 307 | 396 | 470 | 529 | 397 | 6.0% |
| India | 13 | 61 | 87 | 114 | 140 | 172 | 111 | 4.4% |
| Middle East | 87 | 399 | 504 | 577 | 645 | 700 | 301 | 2.4% |
| Africa | 35 | 111 | 153 | 170 | 187 | 204 | 93 | 2.6% |
| Latin America | 60 | 149 | 190 | 221 | 248 | 277 | 128 | 2.6% |
| Brazil | 4 | 27 | 45 | 61 | 75 | 90 | 63 | 5.2% |
| **World**** | **2 039** | **3 370** | **3 957** | **4 322** | **4 646** | **4 976** | **1 606** | **1.6%** |
| European Union | 371 | 492 | 494 | 523 | 537 | 554 | 62 | 0.5% |

* Compound average annual growth rate. ** The world numbers include gas use as an international marine fuel.

The outlook for gas demand in Europe remains subdued. Demand in OECD Europe fell to 514 bcm in 2012 – the second consecutive year of decline and down 10% from 2010 – and is now back to the level of 2003. The situation is similar within the European Union. The weak economic environment and high gas prices are the main causes, but a combination of low coal prices, rock-bottom prices for carbon-dioxide ($CO_2$) and the big expansion in renewables-based capacity, plus efficiency and energy saving measures, have also played their part. In the New Policies Scenario, demand in OECD Europe recovers only very slowly, returning to 2010 levels only around 2025 before reaching just over 600 bcm in 2035.

The power sector holds the key to gas demand in Europe and the prospects in this area depend on the relationship between gas, coal and carbon prices (see Chapter 5, Box 5.1 for analysis of coal-to-gas switching in the power sector). A gradual re-balancing in relative prices favours gas, notably because the extremely low carbon prices in Europe seen in recent years are not expected to persist: we assume that they will rise from the current level of around $6 per tonne (in mid-2013) to $20/tonne by 2020 and $40/tonne by 2035. In addition, a number of coal plants are expected to close in Europe as a result of new air-quality legislation at European level. Europe's nuclear capacity is also expected to tail off as, in aggregate, more plants are de-commissioned than built. These factors help to keep gas use in absolute terms on a rising trend in the New Policies Scenario. But there are still significant questions about European gas demand prospects, not least of which is the uncertainty over the business case for new conventional capacity in a power market characterised by a rising share of renewables (see Chapter 6). The European energy policy targets for 2030 could also herald a new effort on energy efficiency and $CO_2$ emissions reductions, both of which could squeeze gas demand further.[1]

In Japan, energy policies are a key uncertainty for the outlook for gas demand. In particular, the future role of nuclear power remains unclear at the time of writing. The projections of the New Policies Scenario assume greater emphasis in Japan on energy efficiency and renewables, but with gas nonetheless continuing to play an important role, particularly in meeting peak demand. Gas demand is projected to stabilise at around 120-125 bcm per year. In the short term, unavoidable reliance on expensive liquefied natural gas (LNG) purchases to compensate for the shortfall in nuclear output has added to Japanese import bills, strengthening the dissatisfaction within Japan about the high oil-indexed prices that currently form the basis for gas trade in the Asia-Pacific region.

Russia, the world's second-largest gas consumer, faces considerable uncertainty over domestic demand, relating primarily to the rate and direction of price reform and the speed at which it's ageing, highly inefficient energy-consuming capital stock will be replaced. The potential for efficiency gains is enormous and this is realised, in part, in the New Policies Scenario: Russian demand grows only slowly, from 476 bcm in 2011 to around 545 bcm by 2035, with gas demand in the power sector flat (at around 285 bcm), even though generation from gas-fired power plants increases by one-quarter (140 terawatt-hours [TWh]). The modest growth in other sectors is driven by an expanding economy and the expectation of expanded average residential space per capita. A more rapid shift towards market-based pricing for industrial and residential users and greater attention to energy efficiency policies could easily bring Russian gas demand to a flat or declining trajectory. Price changes are also expected to curb demand in some neighbouring markets. In Ukraine, for example, higher prices for imported gas have dampened domestic demand (which fell by 8% in 2012) and created stronger incentives to develop the country's indigenous gas resources, including unconventional resources.

In the New Policies Scenario, China sees by far the largest increase in gas demand in any single country, reaching 530 bcm in 2035. As in almost all other regions, electricity generation is the main source of additional demand: the widely shared concerns about air quality and local pollutants among China's rapidly expanding urban population make a forceful case for gas, rather than coal, as the preferred fuel for powering the country's cities. More than 60 gigawatts (GW) of gas-fired capacity is due to be online by the end of the current five-year plan in 2015; around 50 bcm of gas demand can be expected from this source alone.

1. The role of gas as back-up for variable renewable power sources implies a significant volume of gas-fired capacity to be available, but it does not require this capacity to operate for many hours in the year. Thus, in the 450 Scenario, the European Union requires 280 GW of gas-fired power in 2035, but this generates only 370 TWh at 15% capacity utilisation, compared with 800 TWh at almost 30% utilisation in the New Policies Scenario; the difference in gas demand between the two scenarios is around 75 bcm.

Over the projection period as a whole, gas use in the power sector is projected to increase six-fold, to around 160 bcm, driven by environmental policies (including the introduction of carbon pricing from 2020). Road transport represents another area of nascent, but potentially rapid growth; consumption of around 10 bcm in 2011 is set to triple over the projection period, driven by air quality and energy security concerns.



In India, gas consumption is expected to remain constrained in the short to medium term by low availability of domestic gas production and the high cost of imported LNG. However, consumption picks up again in the latter part of the decade, as the supply situation improves, with the power sector leading the way and accounting for almost half of total gas use by 2035 (80 bcm out of a total of 170 bcm). Consumption in the transport sector also increases strongly, to reach 18 bcm: India is already one of the global pace-setters for natural gas vehicles.

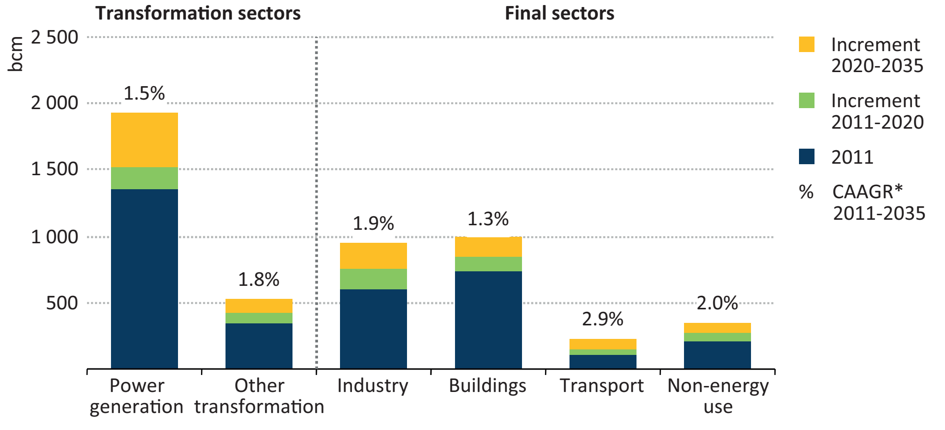
Outside Asia, the Middle East sees the biggest increase in gas demand in absolute terms – around 300 bcm – between 2011 and 2035, driven by new power generation, water desalination and petrochemical projects. Gas has become a popular fuel across the region, particularly because it has usually been available at low cost as a by-product of oil production (and because it provides an alternative to oil consumption, freeing up the more valuable product for export). However, this has led to imbalances in some markets, with gas output lagging behind fast-growing demand, stimulated by low domestic gas prices which do not reflect the international value of the gas. Kuwait and the UAE now have to import gas, as peak seasonal demand has outstripped production. Some governments are, therefore, reviewing their pricing policy towards gas and electricity, in an attempt to rein in demand, restrict imports (in some cases) and encourage supply. Oman, for example, has announced that it will raise industrial gas prices to the equivalent of $3 per million British thermal units (MBtu) by 2015 (though this is still below the international market level).

Despite the region's large and growing resource base, the prospects for domestic gas demand in Africa are constrained by low incomes and difficulties in expanding upstream and transport infrastructure. Export projects are generally more viable, particularly LNG plants fed with associated gas which would otherwise have little value (and which is, in some cases, flared). Liquefied petroleum gas (LPG), derived from natural gas liquids, is expected to play an important role in improving access to energy. African gas demand is projected to rise more than 80% over the period to 2035 in the New Policies Scenario, reaching 200 bcm. In Latin America, half of the projected 130 bcm growth in annual gas demand between 2011 and 2035 comes from Brazil, driven by the increased availability of domestic supplies (see Chapter 10).

### *Sectoral trends*

The power sector remains the main driver of increased gas demand worldwide in the New Policies Scenario, though consumption trends are highly sensitive to competitive pressures from other fuels, notably coal and renewables, and to the impact of government policies. Outside major gas-producing countries and regions (including North America), coal is generally less expensive than gas as a fuel for generating electricity (especially in the absence of a price for $CO_2$) in both existing and new plants. But gas use for power nonetheless continues to expand, albeit at varying rates by region, as it has a number of advantages that make it attractive to investors and policymakers alike. These include high technical efficiency and flexibility (making it suitable for complementing variable renewables), the relative ease and speed of construction and its low carbon and other emissions characteristics, compared with coal and oil. Moreover, the up-front capital expenditures tend to be lower for gas than coal plants. In the New Policies Scenario, gas use for power grows by around 42% and electricity generation remains the leading gas-consuming sector (Figure 3.3). The increase is especially marked in the Middle East (where it doubles) and China (where it expands six-fold), and India (where it more than triples).

**Figure 3.3 ▷ World natural gas demand by sector in the New Policies Scenario**




* Compound average annual growth rate.

Globally, gas use in the energy sector itself, mainly for oil and gas extraction, LNG liquefaction and conversion from gas-to-liquids (GTL), together with its use as chemical feedstock expands by more than half, or around 300 bcm. Most of the increase in feedstock use is directed towards the production of ammonia, the most important base product for fertilisers, and of methanol, which is used to produce a variety of products, mainly in the chemicals industry. Outside the power and energy sectors, gas use in industry grows the most in volume terms over the period to 2035 (by 340 bcm), with most of the increase occurring before 2025. One-third of the growth to 2035 comes from China, with demand growing particularly rapidly (by 14% per year on average) to 2020. Gas demand in the buildings sector (residential and commercial use) grows in OECD countries (by 0.7% per year), but saturation effects limit the potential for more gas use; the increase comes as most of the remaining demand for oil is squeezed out of this sector and space heating demand increases modestly. In non-OECD countries, gas consumption in the buildings sector grows by 75%. In this sector, too, it is China that dominates the picture, accounting for almost half of the total non-OECD increase; urbanisation and rising incomes, which boost demand for water heating, cooking and space heating, are the main drivers.

The fastest projected rate of growth in gas use (though the smallest sectoral increase in absolute terms) is in the transport sector, with most of the increase coming from road vehicles (see also Chapter 15). The technologies are well-proven and the number of natural gas vehicles (NGVs) increased from about 1.3 million in 2000 to an estimated 13.7 million in 2012. But these numbers pale in comparison with the number of vehicles that run on liquid fuels – more than 1 billion. Two-thirds of NGVs on the road today are in non-OECD countries, mostly in Asia and Latin America; within the OECD, only Italy and Korea have sizeable numbers of NGVs.



In the New Policies Scenario, overall transport demand for gas (including the use of gas for pipelines) doubles to 225 bcm in 2035, an average increase of almost 3% per year, with most of the increase coming from road transport in countries that currently have small natural gas-fuelled vehicle fleets. Natural gas accounts for around 5.6% of total transport energy demand in 2035 (up from 3.8% today), and 4.8% of road transport demand (up from 1.8%). China is again the leading contributor to this growth, with gas use in the road-transport sector rising from around 11 bcm in 2011 to 35 bcm by 2035. In the United States, continued low natural gas prices, relative to oil, are also expected to push up gas use (mainly LNG) in heavy trucks, with road-transport demand rising rapidly post-2020 to more than 25 bcm by 2035. There is also potential for gas to be used in the form of LNG as marine bunker fuel in ships (other than in LNG carriers where it is already used), replacing heavy fuel oil, though given the uncertainties in this area (as with any emerging energy application) for the moment we project use of only around 5 bcm in 2035.

## Production

### *Resources and reserves*

The world's remaining resources of natural gas are more than sufficient to meet any conceivable level of gas demand for the next several decades. Proven reserves of gas stood at 187 trillion cubic metres (tcm) at the end of 2012 (BP, 2013). This is marginally lower than the estimate one year earlier, as production in 2012 outstripped reserve additions from new discoveries and reassessments of reserves in previously discovered fields. Reserves increased sharply in 2011.

Proven reserves are a very narrow indicator of the size of the resource base. Our modelling of gas production is based primarily on estimates of technically recoverable resources, which are much larger and which have been increasing over time.[2] At the end of 2012, total remaining technically recoverable resources of gas stood at 810 tcm, *i.e.* more than four times larger than proven reserves and equivalent to around 235 years of production at current rates (Table 3.3). Our latest figures take into account the new global assessment of shale gas resources from the US Energy Information Administration (US EIA, 2013), which shows an increase of nearly 10% over the estimate in their 2011 report, mainly because the latest study covers more geological formations in a larger number of countries. Cumulative

2. See Chapter 13 for definitions of the different categories of hydrocarbon resources.

gas production to date amounts to some 109 tcm, meaning that around 12% of ultimately recoverable resources have been produced. In the New Policies Scenario, an additional 100 tcm is projected to be produced, implying that more than three-quarters of ultimately recoverable resources would still remain to be recovered as of 2035. In practice, further upward revisions to resource estimates are likely as our understanding of the resource base – notably for unconventional gas – improves.

**Table 3.3 ▷ Remaining technically recoverable natural gas resources by type and region, end-2012** (tcm)

| | Conventional | Unconventional | | | | Total |
|---|---|---|---|---|---|---|
| | | Tight gas | Shale gas | Coalbed methane | Sub-total | |
| E. Europe/Eurasia | 143 | 11 | 15 | 20 | 46 | 190 |
| Middle East | 124 | 9 | 4 | - | 13 | 137 |
| Asia-Pacific | 44 | 21 | 53 | 21 | 95 | 138 |
| OECD Americas | 46 | 11 | 48 | 7 | 66 | 112 |
| Africa | 52 | 10 | 39 | 0 | 49 | 101 |
| Latin America | 32 | 15 | 40 | - | 55 | 86 |
| OECD Europe | 26 | 4 | 13 | 2 | 19 | 46 |
| **World** | **468** | **81** | **212** | **50** | **343** | **810** |

Notes: Remaining resources comprise known reserves, reserves growth and undiscovered resources. Unconventional gas resources in regions that are richly endowed with conventional gas, such as Eurasia or the Middle East, are often poorly known and could be much larger. Sources: BGR (2012); US EIA (2013); USGS (2000); USGS (2012a and 2012b); IEA databases and analysis.

## *Production trends*

In the New Policies Scenario, natural gas production increases in every region of the world between 2011 and 2035 with the exception of Europe, where robust production from Norway is not enough to offset the decline of maturing fields in other parts of the North Sea and onshore Netherlands. Conventional gas as a whole contributes 52% of the increase in supply, with the rest coming from unconventional sources (covered in more detail in the next section). China, the United States, Russia and Australia are the countries with the biggest increases in gas output (Table 3.4).

In North America, rising production of unconventional gas more than offsets a decline in conventional gas output and its share of the region's gas production increases to 70% by 2035. Total gas output in the United States increases by around 190 bcm, reaching nearly 840 bcm in 2035, the country remaining the top gas producer globally throughout the projection period. Canadian production is also expected to grow, though more slowly than in the United States, with unconventional gas similarly offsetting a decline in conventional gas output. Mexican production reaches 80 bcm, with both conventional and unconventional gas contributing to a 30 bcm increase in output.

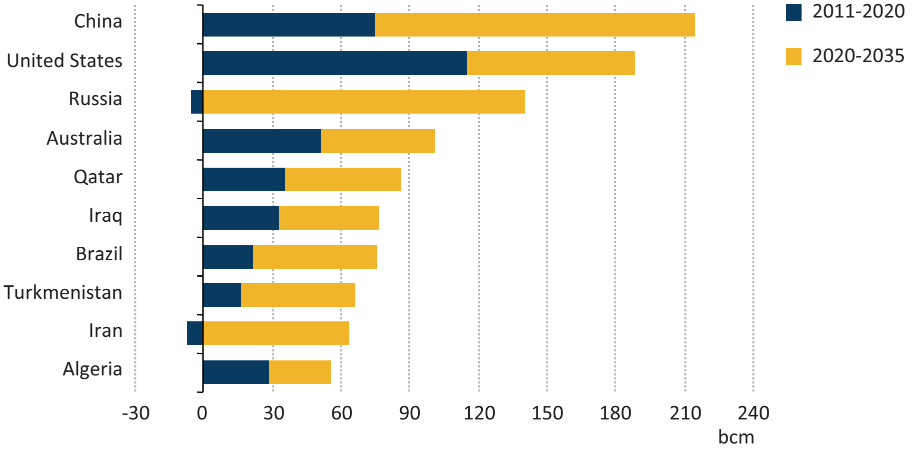
**Table 3.4 ▷ Natural gas production by region in the New Policies Scenario** (bcm)

| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011-2035 Delta | 2011-2035 CAAGR* |
|---|---|---|---|---|---|---|---|---|
| **OECD** | **881** | **1 195** | **1 358** | **1 403** | **1 430** | **1 483** | **288** | **0.9%** |
| Americas | 643 | 859 | 1 000 | 1 041 | 1 063 | 1 114 | 255 | 1.1% |
| Canada | 109 | 160 | 184 | 189 | 186 | 194 | 34 | 0.8% |
| Mexico | 26 | 49 | 50 | 58 | 68 | 81 | 32 | 2.1% |
| United States | 507 | 649 | 764 | 792 | 807 | 837 | 188 | 1.1% |
| Europe | 211 | 277 | 249 | 237 | 225 | 215 | -62 | -1.1% |
| Norway | 28 | 101 | 121 | 118 | 115 | 111 | 10 | 0.4% |
| Asia Oceania | 28 | 59 | 109 | 125 | 143 | 155 | 95 | 4.1% |
| Australia | 20 | 51 | 103 | 120 | 139 | 152 | 101 | 4.6% |
| **Non-OECD** | **1 178** | **2 188** | **2 599** | **2 919** | **3 216** | **3 492** | **1 304** | **2.0%** |
| E. Europe/Eurasia | 831 | 882 | 911 | 986 | 1 094 | 1 164 | 282 | 1.2% |
| Azerbaijan | 10 | 16 | 23 | 33 | 43 | 47 | 30 | 4.5% |
| Russia | 629 | 673 | 667 | 692 | 757 | 808 | 135 | 0.8% |
| Turkmenistan | 85 | 67 | 83 | 100 | 117 | 132 | 66 | 2.9% |
| Asia | 130 | 419 | 566 | 625 | 694 | 769 | 350 | 2.6% |
| China | 15 | 103 | 178 | 218 | 266 | 317 | 214 | 4.8% |
| India | 13 | 46 | 62 | 73 | 85 | 98 | 52 | 3.2% |
| Indonesia | 48 | 81 | 108 | 118 | 129 | 139 | 57 | 2.3% |
| Middle East | 92 | 519 | 624 | 720 | 766 | 823 | 304 | 1.9% |
| Iran | 23 | 150 | 143 | 165 | 180 | 207 | 56 | 1.3% |
| Iraq | 4 | 6 | 39 | 71 | 79 | 83 | 77 | 11.5% |
| Qatar | 6 | 151 | 187 | 214 | 227 | 237 | 86 | 1.9% |
| Saudi Arabia | 26 | 86 | 112 | 121 | 128 | 136 | 50 | 1.9% |
| UAE | 20 | 52 | 58 | 61 | 62 | 65 | 13 | 0.9% |
| Africa | 64 | 200 | 280 | 333 | 378 | 428 | 228 | 3.2% |
| Algeria | 43 | 77 | 106 | 115 | 123 | 132 | 55 | 2.3% |
| Libya | 6 | 8 | 17 | 21 | 24 | 30 | 22 | 5.7% |
| Nigeria | 4 | 36 | 42 | 55 | 70 | 83 | 47 | 3.6% |
| Latin America | 60 | 168 | 218 | 255 | 285 | 308 | 140 | 2.6% |
| Argentina | 20 | 42 | 49 | 65 | 80 | 91 | 49 | 3.3% |
| Brazil | 4 | 17 | 38 | 60 | 78 | 92 | 76 | 7.4% |
| Venezuela | 22 | 25 | 36 | 43 | 52 | 63 | 38 | 3.9% |
| **World** | **2 059** | **3 384** | **3 957** | **4 322** | **4 646** | **4 976** | **1 592** | **1.6%** |
| European Union | 213 | 185 | 135 | 122 | 114 | 104 | -80 | -2.3% |

* Compound average annual growth rate.

Norway remains the largest gas producer in Europe: with a portfolio of large projects in the Arctic Barents Sea, it is able to sustain its production at current levels throughout the projection period. Elsewhere in Europe, though, the outlook for conventional gas production is one of continued decline, mitigated, in part only, by a modest rise in unconventional output. The decline in United Kingdom production of conventional gas has been particularly steep, although this is now levelling off into an extended late-life production tail. On the other side of the North Sea, the giant Groningen field in the Netherlands is expected to come off plateau and decline after 2020.

**Figure 3.4 ▷ Change in annual natural gas production in selected countries in the New Policies Scenario**




Australia's gas production growth is linked directly to plans to expand exports, which, if realised in full, would see the nation rival Qatar as the world's largest LNG exporter by 2020. More than two-thirds of current global investment in LNG is in Australia, where there are already three LNG export projects operating and a further seven under construction. Of the facilities under construction, three in Queensland are based on coalbed methane (the first LNG projects of this kind), while one uses floating LNG technology.[3] However, cost increases have been announced in several of the projects that are underway, with the biggest overruns occurring in the Gorgon and the Australia Pacific projects (the unprecedented appreciation of the Australian dollar has been a major contributing factor). Such increases threaten to hold back plans for additional export projects – especially as there are large investment needs elsewhere in the mining and energy sector. Commitments to new resource developments in Australia have slowed markedly over the last year or so, and the prospects for another round of major Australian LNG projects will depend heavily on how costs evolve, on the deployment of new, potentially less costly technologies, such as floating LNG, and on competition from other regions, notably North America. We project production to rise to 150 bcm by 2035, at a slightly slower pace than in last year's *Outlook*.

3. Floating LNG technology uses a purpose-built barge to produce LNG from offshore gas. There would otherwise be technical problems or high capital costs to bring gas to land for liquefaction.

In the Caspian region, the biggest increase in gas output is projected to come from Turkmenistan, where production doubles by 2035, reaching 130 bcm. Exports to China from Turkmenistan increased to 20 bcm in 2012 and the progressive rise in capacity of the Central-Asia China pipeline, to a planned 65 bcm per year, is the main spur for output growth. The Galkynysh field – the second-largest gas field in the world, which began production in mid-2013 – is the main source of incremental output. The increased capacity in the export pipeline from Turkmenistan to China also stimulates upstream developments that can tap in along the pipeline route in Kazakhstan, Uzbekistan and potentially also Tajikistan. With exports to Russia likely to remain limited, the possibilities for additional output growth for Turkmenistan rest on opening up routes to new markets. All of the options are subject to serious political obstacles, but the best long-term match appears to be with growing gas demand in India and Pakistan. If the direct overland route to South Asia via Afghanistan proves impossible, then an alternative (no less fraught with political uncertainties) would be for Turkmenistan to increase export to Iran, thereby freeing up Iranian gas for export along the proposed Iran-Pakistan route.



Russia's gas production is projected to increase by around 135 bcm to over 800 bcm in 2035, with all of the growth coming after 2020, resting mainly on rising exports. There is no current shortage of supply options in Russia: Gazprom is in a position to increase output, notably from the Yamal peninsula, while other companies – already responsible in 2012 for one-quarter of Russian output – have both the capability and ambition to increase production from smaller onshore fields. The supply outlook is limited over the current decade rather by modest growth in domestic demand and weak European import needs, and, to a larger degree, by constraints on how quickly Russia can secure a significant position in Asia-Pacific markets. The prospect of continuing weak demand in Europe in the next few years appears to have convinced the Russian government to make a serious effort to expand exports to Asia. But neither the economics nor the politics of eastern gas exports are simple; while gas resources in eastern Siberia and the Russian far east are ample, they are remote and – with the exception of the Sakhalin developments – largely untouched. A feature of recent Russian production is the way in which companies are targeting "wet" gas, *i.e.* gas deposits with a large share of natural gas liquids (NGLs), in order to improve the economics of upstream projects (Box 3.2).

The production outlook in China, which sees output triple to almost 320 bcm from 103 bcm in 2011, will depend on progress with unconventional gas and also on the widespread and timely implementation of reforms in the pricing of wholesale gas, announced by the Chinese government late in 2011. The reforms are designed primarily to encourage upstream investment, but also to stimulate import infrastructure development. While trials have been implemented in two regions, extension of the scheme nationally is proceeding only gradually.

ASEAN as a whole is poised for a significant expansion in its gas production, drawing on a large resource base and growing demand (and high prices) for LNG in the Asia-Pacific market.[4] Output rises from 203 bcm in 2011 to 265 bcm in 2035. Indonesia, the largest producer, sees output rise to 140 bcm, from 81 bcm in 2011. In the absence of extensive inter-regional pipeline networks, gas resources located far from national demand centres are likely to be developed as LNG export projects, while those located nearby go to meet domestic demand. However, many individual countries within the region will have to turn increasingly to energy imports to satisfy domestic demand growth, incurring higher energy import bills. Major gas producers, such as Indonesia and Malaysia, will face difficulty in allocating supply between domestic demand and exports that provide an important source of government revenue.

### Box 3.2 ▷ Natural gas liquids and upstream gas investment

NGLs are liquids produced within a natural gas stream, separated from the gas flow either at the well site (field condensate) or at gas processing plants[5]. The boost that they provide to upstream gas economics is not a new phenomenon. Gas production in Qatar, for example, has long been driven by the condensate and liquids output, which essentially covers all upstream costs. It is also well-documented how producers in the United States have been targeting wet-gas plays, where the value of the liquids provides them with economic returns even at very low gas prices. This has allowed natural gas prices to remain lower for longer than many had assumed, an effect that is likely to continue, at least until the most liquids-rich gas plays start to deplete.

Russia has long been an outlier in global NGLs production, with a relatively small content of NGLs in gas production to date. The reason for this is that most of the gas produced from the most accessible, uppermost layers of the huge western Siberian fields, the traditional mainstays of Russian production, has been very dry. But this is changing. The attraction of NGLs among Russian gas players is amplified by relatively favourable tax treatment and by the opportunities for export (in contrast to natural gas, where Gazprom retains, for the moment, an export monopoly). Novatek has been among the leading companies in Russia to invest in gas processing facilities and to target NGLs; these liquids accounted for less than 10% of production in energy terms in 2012, but around 30% of company revenues. Gazprom has also been increasing its interest in NGL production, helping to offset the drop in demand (and price concessions) for its gas in Europe by producing from deeper, wetter, layers at its mainstay gas fields in western Siberia. Over the projection period, we anticipate that Russia sees a gradual growth in the share of NGLs in its produced gas, moving it into line with the situation in many other countries where NGLs make a major contribution to the economics of upstream gas projects.

4. The prospects for ASEAN energy markets are discussed in detail in *Southeast Asia Energy Outlook*: *World Energy Outlook Special Report* released in October 2013 (IEA, 2013a).

5. In our projections, NGLs are included as oil production.

The Middle East is endowed with more conventional gas resources than any other region except for Eastern Europe/Eurasia, but getting the gas to market is proving extremely difficult, in part because low regulated prices often discourage investment. The projected increase in the region's gas production – 305 bcm, or just under 2% per year, between 2011 and 2035, while substantial, represents growth at a slower rate than in Africa or Asia. Qatar is expected to remain the leading contributor to production growth in the region over the projection period, though the recent breakneck expansion in production capacity – most of which serves LNG plants – slows in the near term as the current wave of development projects comes to an end. Qatari gas production is projected to reach a plateau of about 180 bcm by 2015, but a further increase later in the *Outlook* period to around 240 bcm in 2035, is projected on the assumptions that the moratorium on development of the North Field – part of the world's largest single gas field, which straddles the border with Iran (where it is called South Pars) – is lifted and that the government authorises new LNG and GTL projects. With an increasing number of LNG producers entering the market in the next decade, Qatar's share of the global LNG market is set to fall in the medium term.

Production in Saudi Arabia is set to rise in the next few years, with the commissioning of the 30 bcm per year Karan field alleviating acute gas shortages in power generation and petrochemicals. But we project only modest increases in output thereafter, with total gas production reaching 135 bcm in 2035. The low fixed wholesale gas price of $0.75/MBtu discourages upstream investment. Moreover, the results of recent drilling by international companies in the Rub al-Khali region have not yielded commercial finds. Gas output in Iraq is projected to increase substantially to over 80 bcm, an absolute increase almost as big as that of Qatar, which stems mainly from increased associated gas production and reduced gas flaring in the south. Prospects for Iranian production remain clouded by uncertainty over the application of international sanctions. Development of South Pars has boosted the country's overall gas production to around 150 bcm, but further major expansions are expected to be delayed until after 2020, when – with political constraints by then assumed to be relaxed – Iran's huge remaining resource base starts to translate into growing output.

Gas production in Africa more than doubles over the *Outlook* period, to almost 430 bcm, based on increases from the emerging producers in East Africa, as well as Algeria, Nigeria and Libya. LNG exports will be the main driver of production increases in sub-Saharan countries, especially in the period to 2020, as local demand will be insufficient to support the large investments needed to develop fields. In East Africa, LNG projects are planned in Mozambique, Tanzania and Kenya and we assume they add a combined export capacity of 40 bcm by 2035. Most planned developments across the region involve conventional gas, but interest in shale gas in North Africa, where resources are thought to be huge, is growing. Another new province set to appear on the gas production map is the eastern Mediterranean region, where Israel is taking the lead in developing recent offshore discoveries (Box 3.3).

In Latin America, domestic needs will drive most upstream developments in the coming decades. In Argentina, the region's largest producer, shale resources are expected to underpin a revival in gas production, which has been declining in recent years because of dwindling investment – mainly the result of low regulated prices. The potential for production growth is biggest in Brazil, which has discovered large resources of associated gas offshore and pockets of gas onshore (see Chapter 11). By contrast, production in Trinidad is set to decline over the longer term unless new discoveries are made or the regulatory framework changes.

**Box 3.3 ▷ Levant gas on the rise**

Large offshore gas discoveries in the eastern Mediterranean Sea can change the energy landscape of the whole region. A 2010 assessment by the US Geological Survey estimates that undiscovered gas resources in the Levant Basin could amount to 3.5 tcm – more than six times the region's current proven reserves. Thus far, the bulk of the discoveries made have been offshore Israel, including the two largest fields – Leviathan and Tamar. For Israel, heavily dependent on imported energy, the prospect of developing a large indigenous resource represents a major turn-around. Production from the Tamar field began in spring 2013 (a very quick development given that the field was discovered only in 2009), helping to compensate for declining output from existing fields.

The timing for development of the larger Leviathan field (with estimated recoverable resources of 0.5 tcm) and other areas of offshore potential depends on the balance that Israel chooses to strike between reserving gas for the domestic market (even though long-term domestic needs are uncertain) and sanctioning export projects. In the projections, production rises steadily from the current low base and approaches 20 bcm by 2035. This is well in excess of the volumes that could be consumed on the domestic market, implying a growing contribution from Israel to gas balances further afield. There are several export options: building domestic LNG infrastructure, or floating LNG facilities at the fields, would give Israel flexibility over export destinations; alternatively, the gas could be piped to Turkey, Jordan or even Egypt.

The offshore potential in the eastern Mediterranean is by no means confined to Israel and there are signs of increasing interest from major gas companies in the region's resources, following the trail set by the medium-size and independent companies in making the early discoveries. There are still numerous obstacles that may hinder further development of the Levant Basin's potential, including regional conflicts, territorial disputes as well as regulatory uncertainty. But, if politics allow, there is also a realistic prospect that gas from this area will soon be making its mark in parts of southeast Europe as well as the increasingly gas-thirsty markets of the Middle East.

## *Focus on unconventional gas*

### *Resources*

Unconventional gas will surely play an increasingly important role in future gas supply – not just in North America, the site of the overwhelming bulk of production today, but also in several other parts of the world (Table 3.3). Resources of unconventional gas (shale, tight gas and coalbed methane) are globally abundant (Figure 3.6). Indeed, the figures for shale gas that underpin the modelling have been revised upwards for many countries, based on the updated assessment of 137 shale formations in 41 countries (US EIA, 2013).[6] But there are numerous obstacles to developing these resources at anything like the scale seen in North America, so replicating that region's success will be neither easy nor quick. As other countries move down the path towards commercial exploitation of unconventional gas resources, growing awareness of these obstacles is injecting a new realism into discussions about the extent and timing of global prospects for unconventional gas.



**Box 3.4 ▹ High-Level Unconventional Gas Forum-towards global best practice**

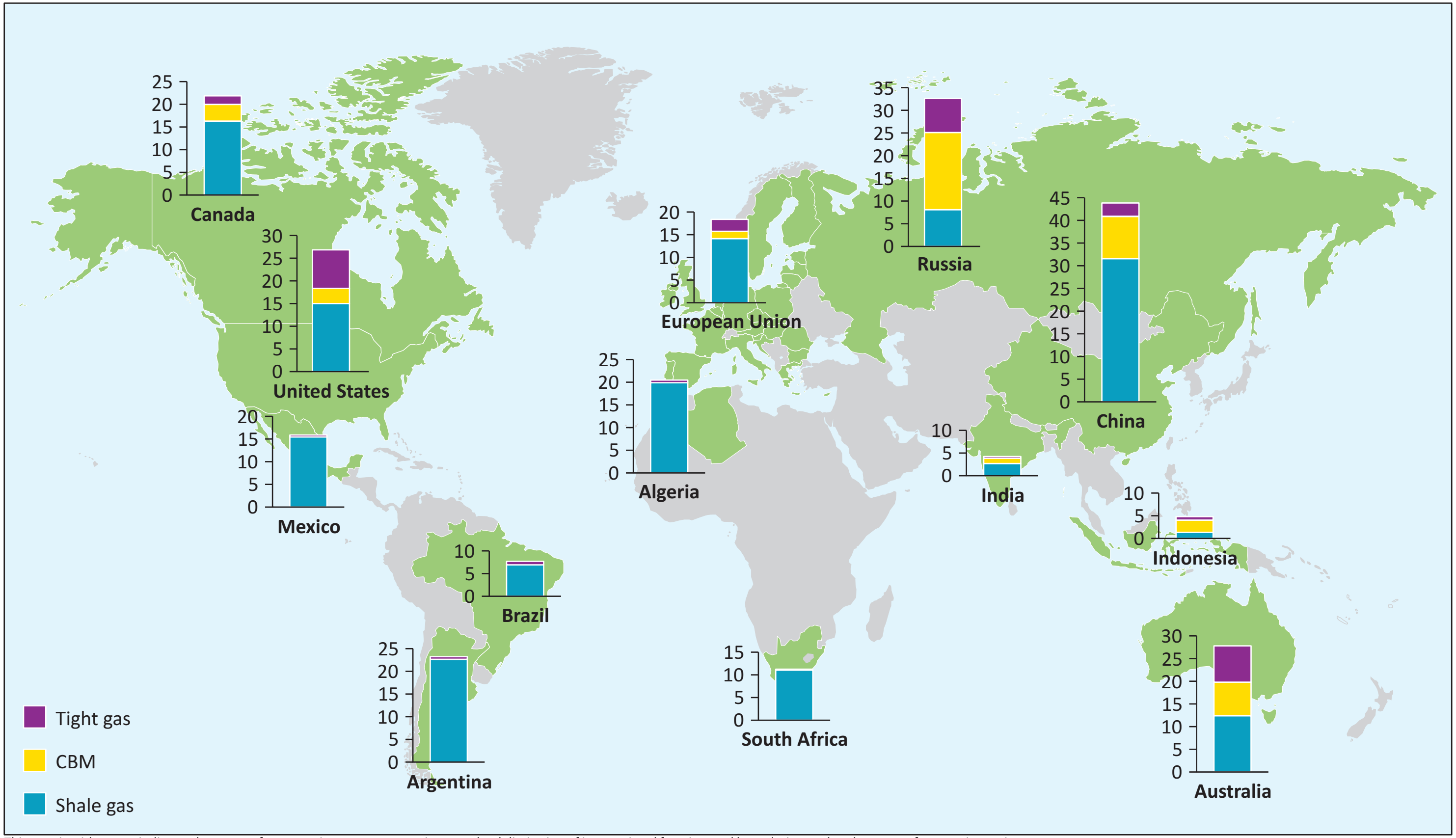
The IEA High-Level Unconventional Gas Forum was created in 2013 to enable governments, industry and other key stakeholders to share insights into best practices in operations, regulations and methods to stimulate the widespread and sustainable development of unconventional gas. The groundwork for the forum was laid by the release of several *WEO* reports on the subject of unconventional gas. *WEO-2009* highlighted the potentially major role that could be played by unconventional gas worldwide. In 2011, a *WEO* special report, *Are We Entering a Golden Age of Gas?*, analysed the global prospects for gas markets, and a subsequent one in 2012, *Golden Rules for a Golden Age of Gas,* looked specifically at unconventional gas, offering guidance for industry and policymakers on how to ensure that its production is conducted in a socially and environmentally acceptable way (IEA, 2011 and 2012).

The first meeting of the Forum was held in March 2013. It was attended by 130 representatives from governments, international organisations, industry, non-governmental organisations and investors from all corners of the globe, who shared their experiences regarding unconventional gas development, including how to deal with social, environmental and economic challenges. It was agreed that best practice regulation should be a particular focus of the Forum's work. The next meeting is planned to be held in the first half of 2014.

Differences in geological, regulatory and market conditions will dictate the nature and pace of development in each region. Production may be held back by several factors, including: unfavourable geology; concerns about the environmental impact of hydraulic fracturing, particularly water management and the risk of methane leaks to the atmosphere (the latter reducing the net climate benefits of using lower-carbon natural gas as a substitute for coal and oil); local opposition to the disruption caused by drilling (the likelihood of which is

6. The previous report, released in 2011, covered 69 shale formations in 32 countries.

**Figure 3.5** ▹ **Remaining unconventional gas resources in selected regions, end-2012** (tcm)




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.

heightened by systems of mineral rights ownership that, in contrast to much of the United States, do not give surface landowners a stake in the development); lack of access to resources and transportation infrastructure; absence of a local oil services industry; and unattractive investment options and regulatory framework. Many of these factors can be influenced directly or indirectly by policy. On the other hand, further advances in production technology could accelerate developments.

3

Global production of unconventional gas in 2011 is estimated to have been around 560 bcm. In the New Policies Scenario, it rises to 1 330 bcm in 2035, its share of total world gas production climbing from 17% to 27%.[7] The United States remains the leading unconventional gas producer, but several countries – notably China – emerge as important producers. Shale gas output rises most in absolute terms, but the output of coalbed methane quadruples (Table 3.5). Inevitably, the uncertainty surrounding these projections is especially acute, given the immaturity of the unconventional gas sector outside the United States. Since it is *WEO* practice not to assume radical technological breakthroughs (though technology learning over time is allowed for), the projections for unconventional gas output do not include production from methane hydrates (Box 3.5).

**Table 3.5 ▷ Global production of unconventional gas in the New Policies Scenario**

| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011-2035 | |
|---|---|---|---|---|---|---|---|
| | | | | | | Delta | CAAGR* |
| Shale gas | 232 | 402 | 513 | 627 | 745 | 513 | 5.0% |
| Coalbed methane | 78 | 148 | 202 | 261 | 315 | 237 | 6.0% |
| Tight gas | 250 | 281 | 285 | 276 | 269 | 18 | 0.3% |
| **Total** | **560** | **832** | **999** | **1 165** | **1 328** | **769** | **3.7%** |

* Compound average annual growth rate.

### *Production trends*

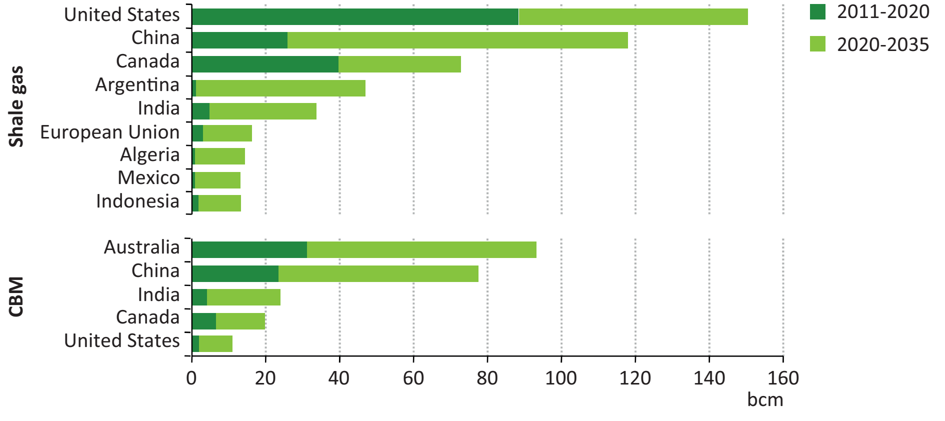
More than half of the growth in unconventional gas production over the period to 2020 is projected to come from the two main established producers, the United States and Canada, which accounted for 90% of total production in 2011. By 2020, their share in global unconventional production drops to 80%, as production in China and Australia starts to grow. After 2020, the picture becomes much more diverse (Figure 3.6).

The surge in the production of unconventional gas in the United States, especially shale gas, slowed somewhat in 2012, as very low gas prices led to fewer rigs drilling gas wells. Nonetheless, production of unconventional dry gas has remained high. There are a number

7. The demarcation between conventional and unconventional gas is not always clear cut, especially with respect to tight gas and conventional gas with reservoir stimulation. We classify tight gas as unconventional according to whether we consider that special production techniques, such as hydraulic fracturing, will be needed for its production. Coalbed methane and shale gas are categorised as unconventional gas in our definition.

of reasons for this, including the working off of a backlog of drilled but not completed wells, drilling for dry gas in low cost areas, such as the Marcellus shale, and the production of large volumes of dry gas a by-product of wells targeted at areas of liquids-rich gas, such as the Eagle Ford shale. We nonetheless assume that, over time, gas prices will move towards a range where production of drier gas is more profitable, *i.e.* within the range of $4.50-6/MBtu. At these levels, we judge that large volumes of shale gas can be produced, which is why North American gas prices plateau for a period around these levels before increasing again towards the end of the *Outlook* period. Total unconventional gas production in the United States continues to increase in the projections, reaching nearly 600 bcm in 2035. There is little sign that resource limitations kick in before the end of the projection period, in contrast to our current expectations for US production of light tight oil (see Chapter 14).

**Figure 3.6** ▷ **Growth in unconventional gas production by type in selected regions in the New Policies Scenario**




Any adverse change in the generally favourable regulatory and operating environment in the United States could have a material impact on the outlook for unconventional gas production. The likelihood of this is linked, in turn, to the way that the industry meets public concerns about the environmental impact of hydraulic fracturing and other contentious aspects of unconventional gas development. These are, in principle, manageable – as demonstrated by the IEA Golden Rules (IEA, 2012a) – but the industry will need to be vigilant. There are initiatives underway at the federal level that could influence this picture. The US Environmental Protection Agency, for example, is preparing an analysis of the impact of hydraulic fracturing on drinking water and ground water, which is due to be released for public comment in 2014. The US Department of Interior has proposed a strengthening of federal regulation of hydraulic fracturing on publicly owned land, in order to establish baseline environmental safeguards for these operations across all public and Indian lands. At the state level, the regulatory picture varies significantly, so it is difficult to draw nationwide conclusions. States have the authority to set regulations that apply to unconventional gas production as well as their degree of stringency, and have chosen different regulatory approaches, some opting for detailed regulation, others for more flexible performance standards and case-by-case permitting (Richardson, *et al.*, 2013). Where shale gas activity is underway, regulatory changes have tended to tighten the requirements related to well construction and protection of groundwater.[8] However, some states maintain or are considering outright prohibitions of certain activities: New York and New Jersey have temporarily banned hydraulic fracturing, pending additional research and data on environmental impacts.



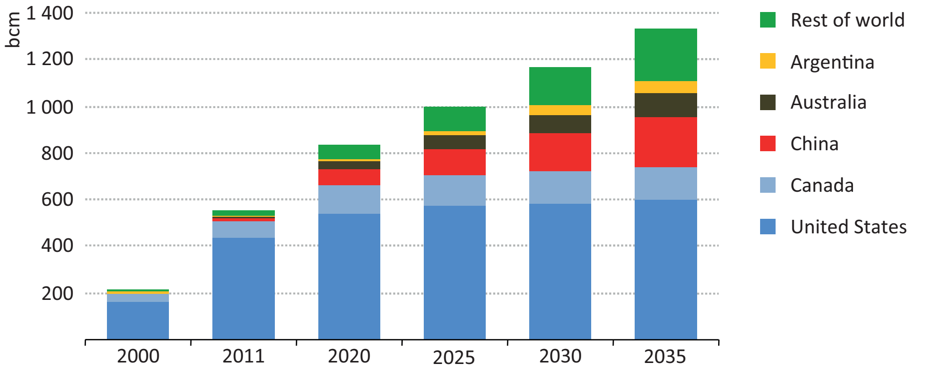
**Box 3.5 ▷ Are methane hydrates the next revolution-in-waiting?**

Methane hydrates are deposits of natural gas trapped together with water in a crystalline structure that forms at low temperatures and moderate pressures. They can be found either on the sea floor, in shallow sediments beneath the sea floor or underneath Arctic permafrost. Methane hydrates may offer a future means to further increase the supply of natural gas. Though quantitative estimates vary by several orders of magnitude, all agree that the resources in place are extremely large, with even the lower estimates giving resources larger than all other natural gas resources combined. Many estimates fall between 1 000 and 5 000 tcm, or between 300 and 1 500 years of production at current rates. The US Geological Survey estimates that gas hydrates worldwide are between 10 to 100 times as plentiful as US shale gas reserves.

Producing gas from methane hydrates poses huge technological challenges and the relevant extraction technology is in its infancy. So far there have been only small-scale experimental production projects: the Japanese Nankai Trough project has just achieved small-scale production and the Malik project in Canada produced for about three months from one well. The longer-term role of methane hydrates will depend on climate change policies as well as technological advances, as meeting ambitious goals to reduce emissions would require a reduction in demand from all fossil fuels, certainly in the longer term. In addition, methane released to the atmosphere from any source is a potent greenhouse gas and great care has to be taken to minimise such releases – a point highlighted in *Redrawing the Energy Climate Map*: *World Energy Outlook Special Report* (IEA, 2013b). One aim of the Japanese research programme is to develop production technology that achieves controlled release of the methane from the ice into the production well, minimising the risk of the methane escaping into the atmosphere. For countries like Japan that continue to rely on expensive imported energy, methane hydrates may be an attractive energy supply option. The Japanese government aims to achieve commercial production in ten to fifteen years, *i.e.* by the mid- to late-2020s.

8. An example is the updated requirements related to well casing, cementing, drilling, control and completions that were passed by the Texas Railroad Commission and apply to all wells drilled in Texas from January 2014.

**Figure 3.7** ▷ **Unconventional gas production by selected country in the New Policies Scenario**




Canada's unconventional gas production is currently around 70 bcm, consisting of tight gas along with smaller volumes of shale gas and coalbed methane. Shale gas provides most of the increase that takes unconventional output to 140 bcm in 2035. Somewhat paradoxically, the boom in shale gas production in the United States has hindered the development of the unconventional gas sector in Canada, as the need for imports from Canada into the United States has slumped, driving down prices across the North American market and depressing incentives to invest in Canada. Nonetheless, there is potential for Canadian LNG exports and companies are now concentrating on exploration in oil and liquids-rich areas of British Columbia (including the Montney play) and Alberta (including the Duvernay and Cardium plays), and the northern part of the Bakken shale, which is predominately an oil play, which extends across the US border into Canada. There is a moratorium in place on hydraulic fracturing in Quebec (where companies had been hoping to develop the Utica shale), which could be extended to allow for further studies on the environmental impact.

Mexico is also set to become a significant producer of unconventional gas in the longer term, with output reaching almost 30 bcm by 2035 in the New Policies Scenario. Pemex, the national oil and gas company with a monopoly over all upstream developments, has launched a $200 million three-year programme to explore for shale gas in Mexico, starting with the extension into the north of the country of the Eagle Ford play, which is thought to hold close to half of the country's shale resources. But commercial production may be constrained by: water scarcity in some of the resource-rich areas; the absence of rights for companies other than Pemex to work in the upstream sector; the priority given by Pemex's investment in export revenue-generating oil projects; and the difficulty in keeping development costs at a level that allows competition with imported gas from the United States. Prospects though could brighten if proposals for reform of the country's oil and gas sectors were to bring new investment capital.

Europe is well-endowed with all three types of unconventional gas, but large-scale development must deal with geological conditions that are considered to be more difficult than those in North America, as well as public and political opposition in many countries to unconventional gas production, especially in Western Europe. It is for the moment unclear to what extent these social and environmental concerns will find reflection in a tightening of the regulatory framework at European level. In the New Policies Scenario, we take a generally cautious view of the prospects for production, which reaches 20 bcm by 2035 in the European Union. The largest share of this (8 bcm) comes from Poland, which has been seen as the most promising country for unconventional production. As of September 2013, more than 50 wells have been completed (and another 200 or so are planned by 2016). Thus far the results have not met the industry's initial expectations, although it is still early to make judgement on the scale or quality of exploitable resources (only seven horizontal wells have undergone multi-stage fracturing). The United Kingdom contributes 3 bcm of shale gas in 2035, its potential having been buoyed by a new resource assessment, released by the British Geological Survey in June 2013, which doubled the resource estimate for the country's main prospective area, the Bowland shale. Outside the European Union, unconventional production in Ukraine rises to levels similar to those of neighbouring Poland, but prospects are dampened by a generally difficult investment climate that has also held back development of Ukraine's conventional potential.



In Australia, coalbed methane has been the main focus of unconventional gas development and production is set to climb steeply with the completion of three LNG plants that are being built in Gladstone in Queensland, to be fed by natural gas from coal seams in the Surat Basin. In the projections, coalbed methane production in Australia rises from just 6 bcm in 2011 to almost 100 bcm by 2035. For this to be realised, operators will need to pay particular attention to water management: water is a particularly sensitive matter in Australia, given general water scarcity and the high reliance in some regions on ground and artesian water sources for agricultural and grazing activity. As in most federal systems, environmental regulation is mostly a state responsibility, with regulation focused on guaranteeing well integrity and management of the large quantities of formation water that must be removed prior to gas production. A warning shot for the industry was the decision in New South Wales in early 2013 to ban coalbed methane developments within two kilometres of residential areas or certain rural activities, causing at least one major development to be suspended in that state and exploration activities to be curtailed. Subsequently, in March 2013, the federal government indicated that federal approvals for new coalbed methane projects (and large coal mining developments) will be required where they significantly impact water resources.

In China, coalbed methane is already in commercial production, with 10 bcm marketed in 2011. But production is rising less rapidly than planned and the target of 30 bcm by 2015 that was set in the 12th Five-Year Plan is unlikely to be met; in our projections, coalbed methane production reaches 30 bcm only closer to 2020. The potential for shale gas production in China is much larger, but projects are still largely at the exploration stage. Two licensing rounds have been completed, mainly in the Sichuan region, with foreign companies allowed to participate as minority partners of a Chinese company. In at least two instances the foreign company is operator, with important implications for technology transfer. Shell and Hess have already signed production-sharing agreements. However, the anticipated increase in commercial production is unlikely to get China close to the official target of 6.5 bcm of shale gas production by 2015.

In the projections, China's shale gas production builds up relatively slowly until the latter part of this decade, but then accelerates as the industry starts to scale up its efforts, to reach almost 120 bcm per year by 2035. The increase is facilitated by gradual changes in gas pricing policy, which help to improve incentives for exploration and development of unconventional gas. The resource base could probably support a considerably higher level of production than we project, but production is expected to be held back by several factors. There are still significant questions over how favourable the geology is (for example, the gas-bearing formations are in most cases much deeper than in North America, making them potentially more costly to develop). Some of the most promising resources are also located in mountainous areas where access is difficult. Limited availability of water, particularly in the Tarim and Ordos Basins, and of pipeline and processing capacity could also hinder development.

In India, there is currently no unconventional production, but its value as a means to meet growing demand and reduce import dependence is gaining recognition. Shale gas appears to be the most promising prospect and the government is developing specific rules for the exploration and development of shale gas ahead of a planned auction of licenses for at least 100 blocks. The auction has been delayed while the environment ministry completes studies on the implications of hydraulic fracturing for both the availability and quality of water supplies. Land acquisition rights have also complicated matters: local protests have occurred over the use of farmland in West Bengal for shale gas drilling by the state-owned Oil and Natural Gas Corporation. For commercial production to proceed in the event of successful drilling, transport infrastructure will need to be built and the fiscal regime adapted. Prices have been too low to make shale gas production profitable, but a government decision in June 2013 to raise gas prices is expected to boost interest in drilling. The government also plans to introduce a scheme whereby the states would receive a 10% royalty on production, similar to the one already being used for country's coalbed methane. In the New Policies Scenario, commercial production of shale gas and coalbed methane starts towards the end of the current decade, with shale gas output rising to almost 35 bcm by 2035 and coalbed methane to 25 bcm.

Indonesia has also been pushing ahead with plans to develop its unconventional gas resources and, like India, is projected to produce both shale gas and coalbed methane from the 2020s, with combined output of around 20 bcm by 2035. Five companies have finished a joint study regarding shale gas potential in North Sumatra and around 70 proposals to drill exploration wells have been submitted for approval, following a first licensing round in the area. Licensing rounds for other prospective areas are planned in the coming months. The government expects commercial shale gas production to begin in 2018. Exploration activity is also underway for coalbed methane and dozens of production-sharing agreements have been signed. The regulatory regime for unconventional gas, including the sharing of competences between local and central government, is under development, with tax incentives planned to bring forward investment.

Algeria's interest in unconventional gas is noteworthy as it comes from a major conventional producer with significant remaining conventional resources looking to address the problem of declining output. Amendments to hydrocarbon legislation in 2013 introduced tax incentives for shale and tight gas development, but it remains to be seen whether these will be sufficient to bring projects to fruition, particularly in the light of concerns over security and the scarcity of water resources. In the New Policies Scenario, Algerian unconventional output (almost all of which is shale gas) gains momentum only towards the end of the projection period, reaching 15 bcm in 2035.



In the recent US EIA assessment, Argentina is ranked second in the world for shale gas resources (US EIA, 2013). The most promising play is Vaca Muerta in northern Patagonia. The geological prospects for production appear positive, but fiscal, contractual and political obstacles are expected to slow development in practice. Companies are expected to focus on oil and liquids-rich areas in preference to drier gas resources. One of the factors holding back investment in shale plays has been the low price offered for production. This was addressed with a government decision in February 2013 to triple the wellhead price for all types of gas to $7.50/MBtu. YPF – the newly nationalised leading producer in Argentina – has a $6.5 billion capital expenditure programme for gas that aims to boost overall production by 8% per year over 2013-2017, with about 60% of the incremental production coming from tight and shale gas. It has also announced partnerships with local and international companies to develop Argentina's resources, including a joint-venture agreement with Chevron to develop the Vaca Muerta field (though the deal is being contested by Repsol, the former owner of YPF). On the assumption that these deals bear fruit, shale and tight gas production reaches more than 50 bcm per year by 2035 in the New Policies Scenario in addition to almost 40 bcm from conventional resources.

## Trade, pricing and investment

### *Inter-regional trade*

Inter-regional gas trade has risen by 80% over the last two decades and we project that it continues to follow an upward path in the New Policies Scenario, expanding by some 400 bcm to reach 1 090 bcm in 2035 (Table 3.6).[9] This promises to be a very dynamic period for international trade in gas, with the rising importance or emergence of strong new market players, notably Australia, the United States, Canada and countries in East Africa, who provide a competitive challenge to established exporters such as Russia and Qatar. The period also sees a continued shift in the direction of international gas trade, away from the Atlantic basin (although Europe continues to be the largest single importing region) and towards the Asia-Pacific region, a shift that poses new dilemmas for Eurasian producers reliant on fixed pipeline infrastructure for access to market. And there are signs that the terms of international trade – particularly in the form of LNG – will become more

9. Inter-regional trade is trade between the major *WEO* regions; its rise has been interrupted twice in the last four years – the first time by the recession-induced fall in demand in 2009 and the second in 2012 because of continuing weak import demand in Europe and a decline in LNG supply.

sensitive to short-term market conditions, with innovative pricing and fewer destination clauses, bringing new connections between the different regional markets and changes in the way gas is priced around the world.

**Table 3.6 ▷ Net natural gas trade by region in the New Policies Scenario** (pipeline and LNG)

| | 2011 | | 2020 | | 2035 | |
|---|---|---|---|---|---|---|
| | Trade (bcm) | Share of demand or output (%)* | Trade (bcm) | Share of demand or output (%)* | Trade (bcm) | Share of demand or output (%)* |
| **OECD** | **-402** | **25%** | **-349** | **20%** | **-402** | **21%** |
| Americas | -11 | 1% | 43 | 4% | 69 | 6% |
| United States | -47 | 7% | 15 | 2% | 48 | 6% |
| Europe | -248 | 47% | -288 | 54% | -390 | 65% |
| Asia Oceania | -143 | 71% | -105 | 49% | -81 | 34% |
| Japan | -117 | 97% | -117 | 99% | -123 | 100% |
| **Non-OECD** | **415** | **19%** | **351** | **13%** | **407** | **12%** |
| E. Europe/Eurasia | 179 | 20% | 179 | 20% | 347 | 30% |
| Caspian | 58 | 33% | 76 | 37% | 143 | 50% |
| Russia | 197 | 29% | 174 | 26% | 263 | 33% |
| Asia | 9 | 2% | -103 | 15% | -319 | 29% |
| China | -29 | 22% | -130 | 42% | -212 | 40% |
| India | -14 | 24% | -25 | 29% | -74 | 43% |
| Middle East | 120 | 23% | 119 | 19% | 123 | 15% |
| Africa | 89 | 44% | 127 | 45% | 224 | 52% |
| Latin America | 19 | 11% | 29 | 13% | 32 | 10% |
| Brazil | -10 | 38% | -7 | 16% | 2 | 2% |
| **World**** | **685** | **20%** | **804** | **20%** | **1 092** | **22%** |
| European Union | -308 | 63% | -360 | 73% | -450 | 81% |

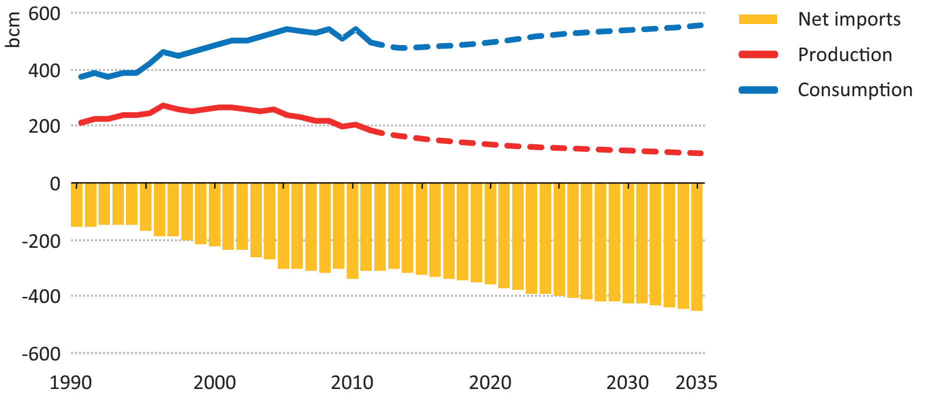
* Imports as a share of primary demand for importing countries; exports as a share of production (output) for exporting regions/countries. ** Total net exports for all *WEO* regions, not including trade within *WEO* regions. Notes: Positive numbers denote exports; negative numbers imports. The difference between OECD and non-OECD totals in 2011 is due to stock change and statistical discrepancies.

Despite a relatively modest increase in demand, Europe's need for imported gas grows more strongly over the projection period, as production falls back across the continent (Norway is the important exception). In the case of the European Union, the gas import requirement rises by some 140 bcm to reach 450 bcm by 2035 (Figure 3.8). Europe is well-placed to secure this supply from a variety of sources, including traditional suppliers such as Norway (which became the European Union's largest single supplier of gas in 2012), Russia and Algeria, as well as from the international LNG market. There are also newcomers looking to supply Europe by pipeline, notably Azerbaijan and, potentially, also Iraq, along the so-called "southern corridor" through Turkey and the rest of southeast Europe.

The Asia-Pacific region is the arena in which the most profound changes in global gas markets are set to play out over the coming decades, though the speed and extent of those changes is subject to a high degree of uncertainty. Outside Japan and Korea, which are already mature gas markets, this is a region with major potential, and good reasons, to increase gas consumption, especially in countries looking to diversify the energy mix and tackle the issues of air quality and local pollution related to coal combustion. Yet this is also the region paying the highest prices for internationally traded natural gas (and one that continues to do so throughout the projection period, in all scenarios), raising questions of affordability and whether policy objectives can outweigh economic factors in some areas.



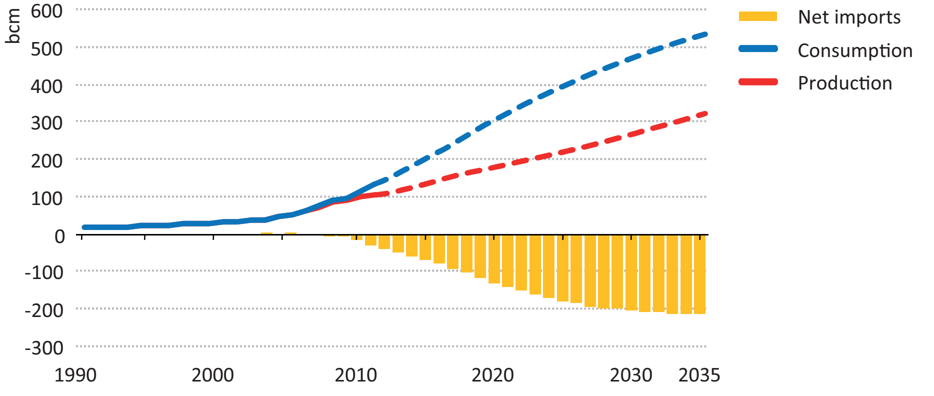
**Figure 3.8 ▷ European Union natural gas supply and demand balance in the New Policies Scenario**




Japan, Korea and Chinese Taipei, the traditional Asian importers of LNG, have already been joined as importers by China, India, Indonesia, Thailand and more recently Malaysia and Singapore. In the projections, the increase in gas imports goes to the emerging gas consumers. China leads the way, with an import requirement that exceeds 210 bcm by 2035 (Figure 3.9), followed by India (imports of 70 bcm by 2035). Over the same period, the net gas exports available from ASEAN as a whole shrink from just over 50 bcm to 15 bcm, while net demand for imported gas increases in other non-OECD Asian countries. The overall impact of these changes is to make the Asia-Pacific region the fulcrum of the international gas trade. Some of the gas in question is set to be delivered by pipeline to China, but LNG accounts for a larger share of the increase.

For pipeline exporters, the main developments are concentrated in Eurasia. For European markets, the consortium developing Phase II of Azerbaijan's Shah Deniz field made a long-awaited announcement about their route to market in 2013: after crossing Turkey through the proposed Trans-Anatolian Gas Pipeline (known as TANAP), Azerbaijan's exports will head through Greece, Albania and then on to southern Italy via the Trans-Adriatic Pipeline (or TAP), with a possible spur from Albania northwards to Montenegro, Bosnia and Herzegovina, and Croatia. Once the pipeline is built, around 2020, some 10 bcm per year of gas is set to flow to southern Europe with the possibility of later capacity expansion to 20 bcm. The prospective opening of the southern corridor over the *Outlook* period allows for an expansion of exports from Azerbaijan, whose production is projected to rise to 47 bcm in 2035 from 17 bcm today, and also, potentially, from other countries in the region, notably from Iraq. The volumes delivered along this corridor remain relatively small compared with European gas demand, but nonetheless promise to make a contribution to diversity and security of supply.

**Figure 3.9 ▹ China natural gas supply and demand balance in the New Policies Scenario**




The volume of Russian pipeline exports rises only modestly over the period to 2020, despite the possible addition of new export capacity in the form of the South Stream pipeline or additional North Stream pipelines. More rapid growth is assumed to be constrained by Russia's stance on pricing gas in Europe, where the defence of oil-indexed pricing clauses could come at the expense of market share. After 2020, however, Russian pipeline exports are expected to expand once again as its focus shifts to the east, with most of the growth coming from an assumed new link to China from Russia's east Siberian fields. China is also expected to draw increasing volumes of gas from Central Asia, where the existing pipeline link from Turkmenistan is assumed to expand to 60 bcm of capacity, and from Myanmar, with which a 12 bcm per year link was completed in 2013.

Of the overall increase in inter-regional gas trade of more than 400 bcm, pipelines carry just under half. The slightly larger share (210 bcm) is expected to come in the form of LNG. Whereas pipeline trade remains dominated by a few producers, primarily in Eurasia, the ranks of LNG exporters are set for a major re-shuffle. Among some of the existing exporters, there are already signs of rapidly increasing domestic demand limiting supply for export. This trend is most notable in the Middle East, where Qatar and Yemen may become the sole remaining LNG exporters by the early 2020s (although they may be joined later by Iraq and/or Iran).[10] Egypt and Trinidad and Tobago are among other current exporters which may have to cut back external commitments.

10. Oman's sales and purchase agreement for LNG exports expires by 2024 and may not be renewed because of booming local demand and insufficient gas supplies. The United Arab Emirates will need to decide whether to do likewise when the current contract to supply LNG to Japan from a plant in Abu Dhabi terminates in 2019; Abu Dhabi is already a net gas importer.

**Box 3.6 ▷ How great should expectations be for North American LNG?**

The emergence of North America as an LNG exporter is based in part on proposed greenfield projects in the United States and western Canada, but the first new projects in the United States are based rather on conversion of terminals that were originally intended to handle LNG imports. The construction of liquefaction facilities is expensive, but existing terminals have shipping and storage infrastructure already in place, reducing the overall cost and the time required to get projects operational. As of October 2013, four such projects have thus far received conditional approvals from the US Department of Energy allowing them to move ahead.[11] These include: Sabine Pass and Lake Charles projects in Louisiana; Freeport project in Texas; and the Cove Point project in Maryland, which will provide annual export capacity totalling some 65 bcm. Sabine Pass has also received the necessary supplementary approval from the US Federal Energy Regulatory Commission to construct the liquefaction facilities and is expected to begin operation in 2016.

As of October 2013, there are an additional 28 applications to export LNG from the United States at various stages of the approvals process, together providing for a theoretical addition of more than 250 bcm per year in export capacity. Only a fraction of these are expected to see the light of day, but a few are nonetheless advancing, with the Cameron project in Texas already having long-term export commitments in place with prospective buyers. The business model for US LNG export projects, at least for the initial projects, is distinctive by international standards. Instead of being supported by long-term contracts, with pricing linked to the oil price and exports dedicated to a single destination, they are based on the Henry Hub price, plus a liquefaction fee, and there are no destination restrictions. The tolling (liquefaction) fee is set by long-term contract. The net result is that this LNG is effectively free to seek the most advantageous international market. In most cases, this is expected to be in Asia.

In Canada, the focus for LNG export projects is largely on the west coast. Of the seven proposed projects in British Columbia, three have received export licenses and are at the stage of seeking environmental approvals: Shell's LNG Canada (with ultimate capacity of 32 bcm per year), Chevron's Kitimat LNG (13 bcm per year) and the much smaller Douglas Channel Energy Project. As greenfield projects, these are expected to take longer to become operational than the initial US projects; and the pricing arrangements are expected to be at least partially indexed to oil. The relative proximity of the west coast projects to Asian markets and the promise of supply diversity for consumers are likely to appeal to Asian buyers.

11. In the case of the United States, export approvals are required from the Department of Energy (DoE), a routine matter for applications to export to countries with which the United States has a free-trade agreement, but a more lengthy process – involving an assessment of the public interest – for export to other countries. Facility approvals are also required from the Federal Energy Regulatory Commission. Overall, the approval process can take at least two years and cost $100 million or more. At a federal level in Canada, all projects must be approved by the National Energy Board.

On the other hand, new LNG exporters are also set to emerge, while some existing ones expect to see their market shares rise. Worldwide, there are twelve LNG export plants under construction today with a combined capacity of around 130 bcm per year.[12] This new capacity is set to come into operation between 2015 and 2018, although the timetable is heavily contingent on what happens in Australia, where seven of the twelve terminals are located and where projects have seen cost escalations and delays.

After Australia, the next new tranche of LNG supply is set to come from North America (Box 3.6). With production outstripping domestic demand, by 2035 net exports from the United States reach almost 50 bcm and 45 bcm from Canada (pipeline and LNG), with net North American LNG exports as a whole reaching around 50 bcm by 2020 and 75 bcm by the end of the projection period.[13] These projections are highly sensitive to changes in the outlook for demand and production – relatively small shifts in either could have a large impact on the overall trade balance. There is potential upside to these figures (particularly those from the United States) that would have implications for other exporters around the world – a possibility that we examine in more detail below in a Gas Price Convergence Case.

The rise of LNG export from Australia and from North America is accompanied, in the projections, by new projects, based on offshore developments in East Africa, as well as by expansion of capacity among some existing LNG exporters, including Russia. The Russian expansion may take on added significance if, as seems possible, Rosneft and Novatek secure rights to export LNG directly to Asian markets, marking the first major breach in Gazprom's export monopoly. Over the projection period, higher assumed import prices into the Asia-Pacific region make this the destination of choice for most LNG exporters, with Europe assuming the role of balancing the market.

### *Pricing of internationally traded gas*

The way that gas is priced in international trade has undergone substantial changes in recent years. An initial switch, noticeable in the period from 2005 to 2008, reduced the share of gas sold under prices established by bilateral negotiation between large buyers and sellers (Figure 3.10); this was largely due to a switch in pricing policy for Russian gas exports to neighbouring countries (as in the disputed case of Russian exports to Ukraine, this was eventually replaced by pricing based on oil-price indexation).[14] But a second change has been the rising share of gas traded under prices set by gas-to-gas competition, *i.e.* prices determined by the interplay of gas supply and demand. In 2005, this share was around one-fifth; by 2012, it is estimated to have risen to 37%.

12. This is offset in part by the anticipated decommissioning of some 13 bcm per year of existing LNG capacity in Indonesia, Algeria and Alaska.

13. These net figures take into account Canadian exports by pipeline to the United States, and pipeline exports from the United States to Mexico.

14. Trade with prices set by bilateral negotiation is now largely confined to two routes; Russia to Belarus and Qatar to the United Arab Emirates.

**Figure 3.10** ▷ **Estimated shares of internationally traded gas by type of pricing mechanism**


Source: International Gas Union (2013).

The shift towards prices set by gas-to-gas competition has been concentrated in continental Europe. A combination of weak demand resulting from economic contraction, surplus take-or-pay obligations and the short-term availability, at competitive prices, of LNG no longer required in North America put the system of oil indexation in long-term supply contracts under substantial pressure. The result of negotiation and, occasionally, arbitration between European importers and their external suppliers has been a higher share of gas sold with reference to the prices at European gas trading hubs, lower base prices, as well as revisions to take-or-pay provisions. By most estimates, the share of gas sold under oil indexation has already fallen towards half of the gas sold in Europe, although the boundary between prices set by oil indexation and those established by gas-to-gas competition is not a precise one.[15] There are also marked regional variations, with oil-indexed gas dominant in the south of the continent, but – with a share of less than 30% – increasingly rare in the northwest.

In the Asia-Pacific region, there have been fewer signs of change to the pricing terms for the bulk of regional trade, which continues to be based overwhelmingly on oil-indexed long-term contracts (many with clauses restricting the potential for re-sale of the gas). The enduring role of this type of contract reflects a premium that buyers have been obliged to pay for security of supply, the ability of regulated utility buyers to pass the additional costs on to their customers and – by way of contrast to the conditions prevailing in Europe – the region's relatively tight gas markets, which meant that sellers could generally set the terms of sale.

15. In practice, oil, gas (and power) price indices can combine in a variety of ways to determine the level and movement of gas prices in long-term contracts. The International Gas Union (2013) puts the share of European gas imported under oil indexation at 60% in 2012, with the remainder set by gas-to-gas competition.

With the projections of robust gas demand and relatively high costs of supply, there would be strong underpinning to prices for gas imports to the Asia-Pacific region even under an alternative gas-to-gas system of price formation, but buyers in this region are nonetheless showing increasing interest in diversifying pricing away from oil indexation. The current situation has resulted in import prices for the region that are the highest in the world and many times higher than wholesale prices in the United States, undermining the ability of gas to compete with other fuels, burdening the region's economies with high import bills and raising concerns about industrial competitiveness (see Chapter 8).

Over the projection period, we anticipate continued momentum behind changes to the pricing of internationally traded gas, with greater reliance over time on mechanisms that reflect the supply-demand balance for gas itself, rather than the price of oil. In Europe, at least, the clear trend is towards more widespread adoption of hub-based pricing, more use of spot trading and shorter duration of long-term contracts. In the Asia-Pacific region, too, we expect alternatives to oil indexation to gain ground and the contracting structure to become more flexible, albeit at a slower pace.

Alongside the desire of gas buyers to seek more advantageous terms for their purchases, a catalyst for these changes is the increasing quantity of LNG that is set to be available without commitment to a specific destination, loosening the current rigidity of LNG contracting structures. As this LNG is free to seek the most advantageous sales price at any given moment, it has the potential to arbitrage price differences between markets, increasing the depth and liquidity of short-term LNG trade.[16] Such volumes are set to grow, not only from the United States, but also from other projects, notably in East Africa, where a part of the gas is set to be absorbed into the portfolios of major LNG marketers.[17] The destination of other volumes, from North America and East Africa, appear to be pre-ordained, in that they belong to large Asian buyers (Kogas, Mitsui, CNOOC) that can be expected to bring the gas to their home markets (Korea, Japan and China, respectively); but, in practice, they too have a diversified portfolio of purchases and so retain the possibility to arbitrage and swap where opportunities arise.

The result is to create new linkages between regional markets and new interactions between their pricing mechanisms. The speed at which change takes place is highly uncertain, depending on market circumstances (that may align in some periods to favour a faster shift, as has been the case in Europe since 2009) and the implementation of policies allowing for regional pricing signals to emerge. The latter include third-party access to infrastructure and re-gasification terminals, the development of competitive wholesale gas markets and independent regulation (IEA, 2013b).

16. Short-term LNG trade typically includes contracts with duration of up to four years.

17. Major LNG marketers such as ENI and BG have stakes in the East African gas projects, and would be ideally located to arbitrage between the Atlantic and Pacific basins, providing some competition with Qatar.

With some convergence in pricing mechanisms over the projection period, we expect to see some narrowing of the pricing boundaries within which global trade takes place, *i.e.* some convergence in gas price levels (see Chapter 1). However, there are limits to the emergence of a fully integrated global gas market in the New Policies Scenario; as the regional prices for this scenario show, differences in the various gas prices persist – notably for the price of Asia-Pacific imports – that are, arguably, above the costs of transporting gas (including liquefaction and regasification costs in the case of LNG) between regions (Box 3.7).

That regional markets remain segmented in the New Policies Scenario reflects strong forces of inertia within the existing system. An underlying reason is the high capital cost of gas infrastructure, which, in many markets, has fostered the use of long-term capacity reservation contracts as a means to reduce risks and lower the cost of capital.[18] These contracts have the accompanying effect of leaving little room for the spot transactions that are essential if a global price is to emerge. Seeking to change this situation runs into a chicken-and-egg problem: in regions without an efficient trading market, long-term oil-indexed contracts are a logical choice to get projects off the ground; but this has the effect of hindering the development of markets (perpetuating a lack of confidence among producers in the reliability of the price generated through trading markets). Around 80% of the LNG from the twelve projects under construction worldwide has already been contracted on a long-term basis and (with the exception of gas from the single US project among the twelve – Sabine Pass) all of this gas has been sold under contracts with oil indexation.

As described, LNG exports from the United States have the potential to change this situation, but, in the New Policies Scenario, the room for their expansion is constrained by prevailing market rigidities and the consideration that a potential second wave of US export projects, after the initial plants based on conversion of LNG import terminals, are greenfield developments that would face higher costs. As such, in the New Policies Scenario, these exports from the United States provide a welcome means for Asian buyers to diversify their import pricing structures and sources of supply, but not the basis for a more wide-ranging transformation of the pricing foundations of regional gas trade.

In considering the possibility of a far-reaching overhaul of pricing structures, it is worth factoring in the staunch resistance from other producers to a change in the way

18. Capital intensity does not preclude a business model based on sales to a spot market, if market efficiency reaches a critical level. As demonstrated in North America and in projects serving the UK market, deep and liquid gas markets can provide adequate security for large investments in new production or transportation capacity. The development of gas futures markets could also provide a mechanism to lower the risk associated with large-scale, long-term gas investments. In the case of LNG, due to their balance sheet and risk-taking ability, the major oil and gas companies can act as anchor consumers for at least a portion of a project and, instead of delivering to captive end-users with a destination clause, they take gas into their global portfolio, with the view of selling it in the most attractive market. Yemen LNG, for example, applied this model with Total as the lead shareholder and offtaker.

that their exports are priced. Algeria's Sonatrach and Russia's Gazprom are at the fore of this opposition (and the summit of the Gas Exporting Countries Forum in Russia in June 2013 committed to defending oil indexation). There are also the policy challenges associated with introducing a more competitive model for gas markets and supply in key Asian countries; this was a lengthy and complex process in North America and has been even more so in continental Europe (despite the spur provided by European Union law and competition policy). Although individual countries may choose to move quickly, the absence of authoritative supranational energy policy co-ordination in Asia gives reason to assume that this process for the region as a whole will be slow. All of these factors serve to put a brake on global gas market integration in the New Policies Scenario.

### *A Gas Price Convergence Case*

Nevertheless, given the increasing role of spot trading and rising interconnections between regional markets, it is reasonable to investigate the conditions under which convergence between regional pricing mechanisms and prices could be more pronounced than in the New Policies Scenario, and examine the potential implications for markets, gas demand and trade flows of such a development. We discuss these possibilities in an illustrative Gas Price Convergence Case, in which the different regional gas markets make a more rapid transition to the point at which they all respond to a single global price signal. At this point, differences in regional prices narrow to reflect only the cost of moving gas between them.

This case rests on three main conditions that differentiate it from the New Policies Scenario. The first is a larger volume of LNG export from North America (primarily from the United States), which exceeds 100 bcm by the latter part of the 2020s, more than double the volumes envisaged in the New Policies Scenario. The second condition is that new supply contracts, whether completely new or replacing expiring contracts, are hub-priced in Europe and, even if partly oil-indexed in Asia, not indexed to the traditional JCC mechanism (the average price of crude oil imports to Japan, or Japan Crude Cocktail). This development is accompanied, in the Asia-Pacific region, by an accelerated pace of regulatory change in the gas sector, so as to increase market liquidity and competition among suppliers, including more rapid progress with setting up regional trading hubs that facilitate the exchange of gas.[19] A third condition is some easing of costs of constructing liquefaction plants and of LNG shipping, in order to keep down the costs of moving gas between markets (Box 3.7).

19. Although there are moves to expand gas trading in Singapore and elsewhere in the region, China can play a special role in Asia-Pacific price formation, because it has meaningful potential for both domestic upstream and pipeline imports, as well as LNG imports. With a well functioning gas market based on third-party access to Petrochina's pipelines, the upstream value which would emerge in Inner Mongolia or Sichuan would be around $8-10/MBtu, which, even with all the geological and project management difficulties, would provide a powerful incentive for unconventional gas development. With a competitive domestic upstream, pipeline imports and several LNG terminals, China has the necessary conditions to create a liquid, diversified gas trading hub, possibly developing the current pilot project in Shanghai.

### Box 3.7 ▷ Price differentials between regions in a "global" gas market

Movement in the direction of a global gas market does not imply the emergence of a single global gas price, as is largely the case for oil. The key reason for this is the high cost of transporting (and storing) gas, related in turn to a much lower energy density than oil. Transforming natural gas into LNG solves the energy density problem, creating a commodity that can be moved more easily and flexibly between markets, but comes at the considerable price of constructing liquefaction plants, specialised LNG carriers and re-gasification facilities. So, even in a fully "converged" world of gas prices, there would still be substantial differences in price between the US Henry Hub price and the respective import prices in Europe and Japan.

In the Gas Price Convergence Case, these differentials narrow to $4.5/MBtu between Henry Hub and the European import price, with an extra $1/MBtu for imports to Japan, to reflect the additional distance. These figures are at the low end of our estimates for the various components of inter-regional LNG transportation in 2020 (Table 3.7). Price differentials of this type would require that North American projects escape the sort of cost inflation that has beleaguered LNG developments in some other parts of the world (the large North American market for engineering and contracting services gives some cause for optimism on this point) and that the United States realises major cost savings by making use of existing infrastructure, including the pipelines, storage and loading facilities at existing regasification terminals. On the shipping side, costs at the low end of the range shown in Table 3.8 would require a new wave of investment in LNG tankers, bringing charter rates down towards our estimate of long-run marginal costs.[20]

**Table 3.7 ▷ Indicative range of cost estimates for conversion and inter-regional transportation for LNG, 2020** (2012 dollars per MBtu)

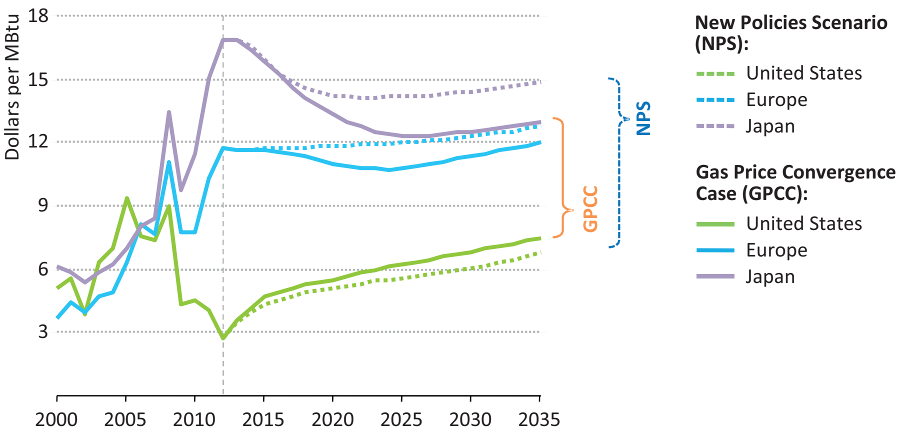
| | US to Europe | | US to Japan | |
|---|---|---|---|---|
| | Low | High | Low | High |
| Liquefaction | 3.0 | 4.5 | 3.0 | 4.5 |
| Shipping | 1.0 | 2.5 | 2.0 | 3.5 |
| Regasification | 0.3 | 0.5 | 0.3 | 0.5 |
| **Total** | **4.3** | **7.5** | **5.3** | **8.5** |

These cost estimates compare with gas price differentials between Henry Hub and the European import price in 2035 in the New Policies Scenario of $6/MBtu; and around $8/MBtu between Henry Hub and the Japanese import price. With a pessimistic view on the evolution of LNG liquefaction and shipping costs (at the high end of this range), it could be argued that the New Policies Scenario already represents a case in which prices have largely converged. This serves to underline that developments in future trade patterns and pricing depend not only on developments in production, but also on the way that costs evolve all along the LNG value chain.

20. Responding to today's high shipping charter rates, almost 120 LNG ships are under order as of September 2013; this compares with just over 20 ships on order at the start of 2011.

A global price signal could emerge based on the spot market for LNG, but in the Gas Price Convergence Case we consider that it comes instead from Henry Hub, which becomes a reference point for global pricing that is transmitted to the various regional gas markets via LNG trade. Convergence in prices is assumed to be largely complete by the mid-2020s, *i.e.* over the next ten years (although it takes longer to complete fully in the case of prices in the Asia-Pacific region). Because of higher levels of LNG exports from the United States, the Henry Hub price is higher than it is in the New Policies Scenario (the price impact here is consistent with the findings of the study commissioned by the US Department of Energy on the effect of increased natural gas exports on domestic energy markets [EIA, 2012]). The average price of gas imported to Europe falls to $11/MBtu in the mid-2020s, before rising in line with changes in the Henry Hub price, while the Japanese import price falls to around $12/MBtu over the same timeframe, remaining around this level before edging slightly higher after 2030 (Figure 3.11).

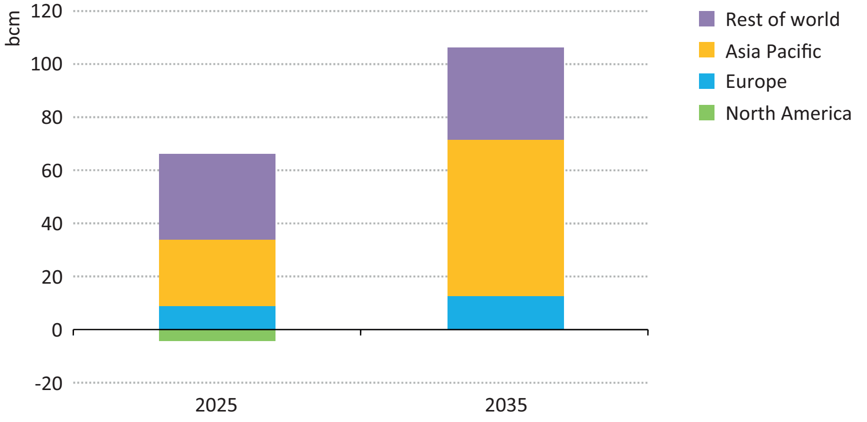
**Figure 3.11 ▷ Regional gas prices in the New Policies Scenario and in the Gas Price Convergence Case**




The prospect of a significant wave of supplies from new LNG capacity coming onstream in the early to mid-2020s is assumed to strengthen the hand of buyers during contract negotiations, precipitating a shift in the pricing paradigm in favour of greater flexibility and of indices beyond (or in addition to) oil indexation. This provides a boost to inter-regional trade, which, in the Gas Convergence Case, is 30 bcm higher than in the New Policies Scenario by the mid-2020s and 60 bcm higher by 2035, all in the form of LNG. A greater share of this LNG arriving on the market (including not only North American, but also East African volumes) is not bound by contract to a specific market. Market and regulatory policies are assumed to be in place, including in the premium Asia-Pacific market, to allow for the growth of short-term gas trading and the emergence of transparent regional prices based on gas-to-gas competition. This would replicate, to a degree, the gradual transformation of continental European systems of gas price formation which started in the late 2000s; but – in this case – it would contribute to a wider process of interconnection between all the major regional gas markets.

What are the implications of this Gas Price Convergence Case for gas consumption? As one might expect, lower prices stimulate extra demand, with global gas use 107 bcm (2.1%) higher by 2035 than in the New Policies Scenario (Figure 3.12). Some of this additional demand is related to the increased competitiveness of gas versus other fuels. Coal consumption grows more slowly in this Case than in the New Policies Scenario (it is 46 million tonnes of coal equivalent lower by 2035), although this effect is muted because a continued gap persists in most markets between gas and coal prices for power generation. A larger part of the additional demand for gas stems from the assumption that cheaper gas stimulates more aggressive action on issues such as local pollution. This facilitates faster growth among emerging Asian economies in particular.[21] China, India and the ASEAN countries, see notable increases in gas consumption of around 4-5% in 2035, compared with the New Policies Scenario. In the rest of the world (excluding North America), the increase in 2035 gas use is closer to 3%. In North America, where gas prices are higher than in the New Policies Scenario, demand does not change. This is a result of two offsetting trends. On the one hand, gas demand in power generation and final consumption declines somewhat, as prices are higher. On the other, increased production and export push up gas consumption for liquefaction and own uses within the oil and gas industry.

**Figure 3.12 ▷ Differences in gas consumption between the Gas Price Convergence Case and the New Policies Scenario**

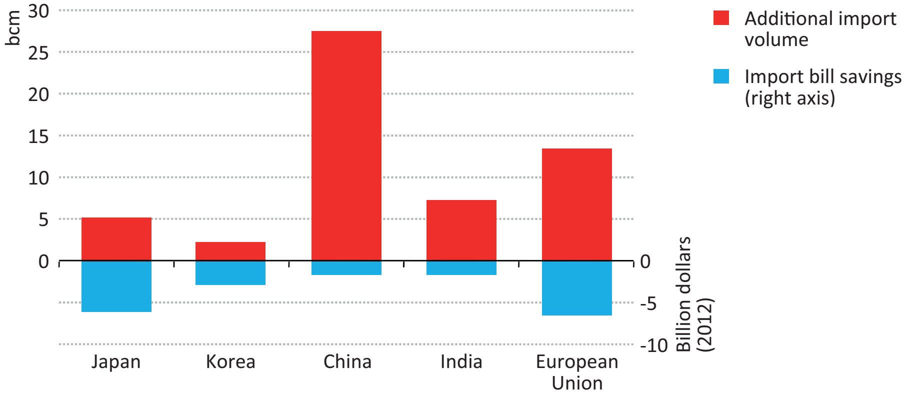



The influx of competitively-priced gas from North America implies some displacement of gas production projects elsewhere at the higher end of the international cost curve; but,

21. Policies supporting renewables and nuclear do not change in the Gas Price Convergence Case, compared with the New Policies Scenario. However, in regions where natural gas prices are lower and feed-in tariffs are in place for renewables, support schemes become more expensive, creating an extra burden on household and industry bills. This could, in practice, bring the support schemes into question, increasing gas and coal use as a result (although this is not part of the Case considered here). Conversely, in countries with higher gas prices (in North America and parts of Latin America), subsidies to renewables would be lower than in the New Policies Scenario. Overall $CO_2$ emissions in the Gas Price Convergence Case are very close to those of the New Policies Scenario: lower emissions from coal are largely offset by higher emissions from gas. However, there would be larger reduction in local air pollutants in China, India and ASEAN countries.

in our modelling, an import price level above $12/MBtu in the Asia-Pacific region remains sufficient to bring on additional production (beyond the levels seen in the New Policies Scenario) from a range of suppliers in various locations, including East Africa, Russian east Siberia and – once pressures on costs have eased – from Australia. The export earnings associated with supply projects are, though, lower than in the New Policies Scenario. While the volume of inter-regional trade in the Gas Price Convergence Case rises to 1 150 bcm by 2035, 5% above the New Policies Scenario, the total value of this trade is 3% lower.

**Figure 3.13 ▷ Change in import volumes and imports bills for selected regions in the Gas Price Convergence Case, relative to the New Policies Scenario, 2035**

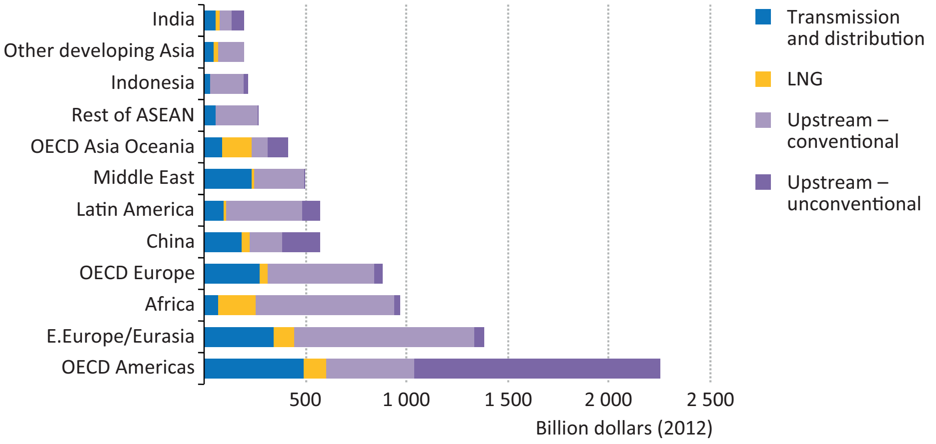



In the Gas Price Convergence Case, gas-importing countries benefit from access to lower-priced gas than in the New Policies Scenario: even for higher volumes of gas, import bills are reduced for all the major gas-importing countries and regions (Figure 3.13). But even though a key attraction to buyers, access to "cheaper gas" should not be considered a reliable outcome of this Case – not least because future oil and gas price movements are so uncertain. Indeed, there are no guarantees that gas priced under a system of gas-to-gas competition would always be cheaper than equivalent oil-indexed volumes (even if, at crude oil prices above $100/barrel, this seems likely aside from periods of very cold weather or supply disruption). A more significant feature of this Gas Price Convergence Case is that regional and global price signals would emerge reflecting the supply-demand fundamentals of the fuel itself, thereby changing the basis of decision-making on new upstream and infrastructure spending and driving gas prices worldwide closer to costs.

## *Investment*

The projected trends in gas demand in the New Policies Scenario imply a need for cumulative investment along the gas-supply chain of almost $8 500 billion dollars (in year-2012 dollars) over 2012-2035, or around $370 billion per year. Two-thirds of that spending, or $250 billion per year, is needed in the upstream, for new greenfield projects and to combat decline at existing fields.[22] Transmission and distribution networks account for 23% and LNG facilities – liquefaction plants, carriers and re-gasification terminals – for the remaining 9%.

**Figure 3.14 ▻ Cumulative investment in natural gas supply infrastructure by region in the New Policies Scenario**




Well over half of the investment is needed in non-OECD countries, where local demand and production grow the most, though unit costs there tend to be lower than in OECD countries (Figure 3.14). The United States and Canada, where output is projected to rise significantly, account for one-quarter of total gas investment worldwide; investment needs there are boosted by the high capital intensity of unconventional gas drilling. Projected global annual investment needs to 2035 in the gas industry have risen substantially over the last few years, as unit capital costs in both the upstream and downstream sectors have increased, due to increases in the prices of labour, equipment and raw materials. LNG plant costs have also increased rapidly.

Although the broad global distribution of gas resources, conventional and unconventional, gives some cause for comfort, it is far from certain that all the investment required to meet the projections in the New Policies Scenario will be forthcoming. The uncertainties apply, in particular, to large upstream and transportation projects (pipeline and LNG), during times of transition away from the traditional models of project financing, based on long-term oil-indexed contracts. Although the gas industry and financial sector have shown their ability to think creatively about ways to mitigate risks and meet financing requirements, there is a risk that some of the required projects may be delayed. A range of regulatory issues, including domestic under-pricing of oil and gas, can also serve as impediments to investment. The experience of Trinidad and Tobago is indicative of the opportunities and pitfalls that can arise as countries seek to capture full economic benefits from the development of their hydrocarbon resources (Box 3.8).

22. A more detailed discussion of upstream oil and gas investment and costs can be found in Chapter 14.

**Box 3.8 ▷ Trinidad and Tobago: seeking a new foothold in a changing gas world**

Natural gas is instrumental to Trinidad and Tobago's economy, but a number of challenges will have to be dealt with if it is to remain an important source of revenue for the country. The chosen strategy for making best use of the gas resources has been two-pronged: export both LNG and chemicals. The first LNG exports were made in 1999, and Trinidad and Tobago has since become one of the world's largest LNG exporters: 14 million tonnes (19 bcm) were shipped to various countries in 2011. The energy sector, including petroleum, accounts for some 45% of GDP. Large-scale investment in the domestic petrochemical industry has been attracted by making gas available below the international price, turning the country into the world's largest exporter of ammonia and methanol.

But continued growth in LNG and petrochemical exports may be constrained by faltering upstream investment, rising domestic consumption and growing competition from other exporters. Under-pricing of natural gas sold to the power sector, industry and households, has contributed to a near doubling in gas use between 2000 and 2012. Discoveries have failed to keep pace with the growth of production and proven reserves have dropped by one-third since 2002, to around 375 bcm. The reserves-to-production ratio has declined to ten years. In an effort to regain the dynamism of the past, new incentives for upstream investment (primarily tax-related) have led to an increase in exploration activity and the annual decline rate of reserves has been curtailed from 9.5% (2008) to 1.1% (2012). A deepwater licensing round in 2012 awarded four of six blocks on offer.

Trinidad and Tobago's oil sector faces similar challenges. Prior to the dramatic increase in natural gas production and exports, oil dominated the economy. Production peaked at 230 thousand barrels per day (kb/d) in the late 1970s and has since been in decline, standing at 120 kb/d in 2012. The country remains a net exporter of oil, but levels have been falling, while demand continues to grow, abetted by economic growth and subsidised motor fuels. We estimate that oil subsidies alone amounted to $290 million in 2012, with the bulk going to transport fuels, limiting (directly or indirectly) the resources available to government for other spending priorities and leading to problems like fuel smuggling, which the government is now trying to stamp out, *e.g.* by means of increased penalties. Steps are also being taken to tackle the subsidy issue: the price of premium gasoline was sharply increased in October 2012, and the government is encouraging motorists to switch from oil-based fuels to compressed natural gas by providing fiscal incentives and developing re-fuelling infrastructure at service stations.

Chapter 4

# Coal market outlook

## Blockbuster or losing lustre?

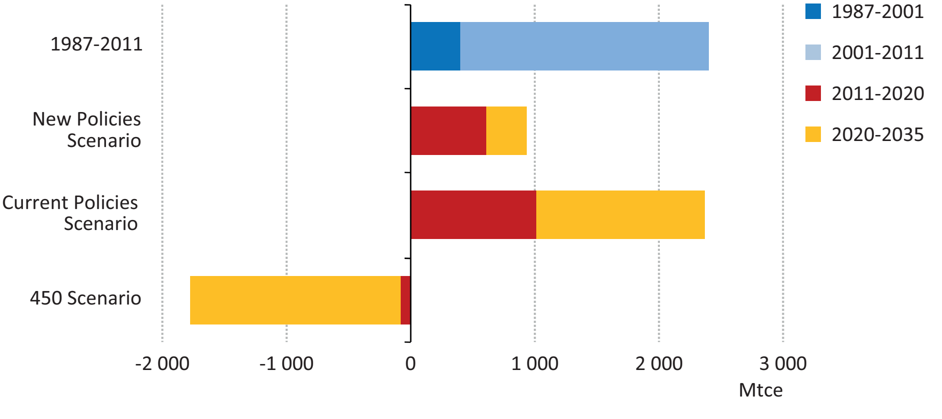
### Highlights

- The magnitude of future global coal demand growth is uncertain, particularly because of the varying stringency of environmental policies assumed in the three scenarios. In the New Policies Scenario, global coal demand grows by 0.7% per year over 2011-2035, slowing noticeably after 2020 as announced policies to foster renewables, penalise $CO_2$ emissions and address other environmental issues take effect. Demand increases more than twice as fast in the Current Policies Scenario, while in the 450 Scenario coal demand drops by one-third relative to 2011.
- Coal demand trends diverge across regions. In the New Policies Scenario, OECD coal use falls by one-quarter by 2035 as coal is backed out of power generation. By contrast, demand expands by one-third in non-OECD countries – predominantly in India, China and the ASEAN region – despite China reaching a plateau after 2025.
- Globally, coal remains the leading source of electricity generation in the New Policies Scenario, though its share falls from 41% to 33% in 2035. The power sector accounts for around 63% of total coal use in the period to 2035. Industry coal demand growth saturates over the period, however, feedstock in the petrochemicals industry and coal-to-liquids emerge as significant growth sectors.
- Growth in coal production over 2011-2035 comes mainly from non-OECD countries, with India, Indonesia and China accounting for 90% of incremental coal output. Australia is the principal OECD country with higher production. Coal resources will not be a constraint for many decades, yet the cost of supply is likely to increase moderately in real terms as a result of rising mining and transportation costs.
- Already the world's largest coal user, producer and now importer, China continues to dominate coal markets in the New Policies Scenario. Nonetheless, China's rate of growth in coal demand is set to slow as efficiency measures bear fruit, the power sector diversifies and industrial coal growth saturates with its peaking steel and cement output. Subject to price arbitrage, China's coal net imports peak by 2020.
- India becomes the second-largest coal user in the next decade, surpassing the United States. Despite abundant coal resources, domestic supply is not keeping pace with demand, which has caused imports to double since 2008. India overtakes Japan and the European Union within a few years and China early in the next decade to become the world's largest coal importer, with imports reaching 350 Mtce in 2035.
- The efficiency of China's coal plants is improving. However, many units under construction or planned in the ASEAN region and India use subcritical technologies, which consume up to 15% more coal for a given power output than more efficient supercritical technologies and lock in higher $CO_2$ emissions for decades to come.

## Overview

Coal use has increased substantially over the last decade, driven by and contributing to an unprecedented expansion in economic activity, as well as reducing poverty across the developing world (Figure 4.1). In fact, coal provided nearly half of the increase in global primary energy demand over the decade to 2012 (Box 4.2).[1] But its use has serious drawbacks, especially if inefficient: coal is a major source of local air pollution and, as the most carbon-intensive fossil fuel, it is the main contributor to rising energy-related carbon dioxide ($CO_2$) emissions. The magnitude of future coal demand growth hinges critically on the actions that governments take to address these issues, taking into account their aspirations for energy security, affordability and improved access to modern energy.[2] The wide divergence in outcomes for coal in the three scenarios, notably after 2020, reflects primarily the different degrees of stringency of the policies adopted to promote energy efficiency, reduce greenhouse-gas emissions and improve local air quality (see Annex B). Put another way, the differences in the scenarios reflect the importance of coal use – in particular in the power sector – as a factor in energy and climate change policies.

**Figure 4.1 ▷ Incremental world coal demand, historical and by scenario**




In the New Policies Scenario, which assumes the cautious implementation of announced policy measures, growth in global coal demand averages 0.7% per year over 2011-2035. This is a marked slowdown compared with the 2.5% averaged over the past 25 years. Coal demand expands from around 5 390 million tonnes of coal equivalent[3] (Mtce) in 2011 (5 425 Mtce in 2012 based on preliminary data) to 6 325 Mtce in 2035. Two-thirds of this occurs in the period to 2020, with demand growing by only 0.4% per year thereafter.

1. For 2012, preliminary data for aggregate coal demand, production and trade by country are available; the sectoral breakdown for coal demand is estimated (complete data are available to 2011).

2. It is estimated that around 1.3 billion people (18% of the world's population) did not have access to electricity in 2011; around 2.6 billion (38% of the world's population) relied on the traditional use of biomass for cooking (see Chapter 2).

3. A tonne of coal equivalent equals 7 million kilocalories (kcal) or equivalent to 0.7 tonnes of oil equivalent.

Demand increases strongly in non-OECD countries, more than offsetting a decline in the OECD (Table 4.1). Nearly three-quarters of the increase in global coal demand comes from the power sector, even though coal's share of global electricity generation declines by eight percentage points as many countries diversify their power mixes. At 33%, coal remains the leading source of electricity generation in 2035. Coal production today is dominated by non-OECD countries, whose share of output rises further in all three scenarios.

**Table 4.1 ▷ Coal demand, production and trade by scenario** (Mtce)



| | | | | New Policies | | Current Policies | | 450 Scenario | |
|---|---|---|---|---|---|---|---|---|---|
| | | 1990 | 2011 | 2020 | 2035 | 2020 | 2035 | 2020 | 2035 |
| OECD | Demand | 1 543 | 1 518 | 1 469 | 1 156 | 1 524 | 1 502 | 1 264 | 627 |
| | Production | 1 533 | 1 397 | 1 430 | 1 300 | 1 536 | 1 697 | 1 215 | 691 |
| Non-OECD | Demand | 1 643 | 3 872 | 4 533 | 5 170 | 4 880 | 6 262 | 4 043 | 2 992 |
| | Production | 1 661 | 4 101 | 4 573 | 5 026 | 4 868 | 6 066 | 4 092 | 2 928 |
| World | Demand | 3 186 | 5 391 | 6 003 | 6 326 | 6 404 | 7 764 | 5 307 | 3 619 |
| | Steam coal | 2 244 | 4 220 | 4 689 | 5 152 | 5 049 | 6 440 | 4 067 | 2 712 |
| | Coking coal | 542 | 858 | 993 | 929 | 1 025 | 1 017 | 959 | 810 |
| | Lignite | 400 | 313 | 321 | 246 | 330 | 307 | 281 | 97 |
| | Production | 3 194 | 5 498 | 6 003 | 6 326 | 6 404 | 7 764 | 5 307 | 3 619 |
| | Inter-regional trade* | 309 | 900 | 1 152 | 1 261 | 1 295 | 1 649 | 958 | 635 |
| | Steam coal | 162 | 652 | 850 | 922 | 975 | 1 276 | 672 | 383 |
| | Coking coal | 186 | 255 | 316 | 348 | 331 | 388 | 300 | 267 |

* Total net exports for all *WEO* regions, not including trade within regions. Notes: Historical data for world demand differ from world production due to stock changes. Lignite also includes peat.

Restrained less by climate change policy intervention, coal demand in the Current Policies Scenario grows more than twice as fast as in the New Policies Scenario. The increase of around 2 375 Mtce is slightly less than over the last 25 years. In OECD countries, coal demand in the Current Policies Scenario falls only marginally by 2035, unlike the marked decline in the New Policies Scenario. The strong growth in coal demand in non-OECD countries in the Current Policies Scenario results in global coal use overtaking oil use soon after 2020 and coal remains the leading fuel throughout the period to 2035.

The 450 Scenario, which assumes that strong policy measures are implemented to keep long-term greenhouse-gas-induced temperature changes to 2 degrees Celsius, sees global coal use fall by 33% over 2011-2035. This is a return to the level of demand in the early 2000s. As a result, coal's share in the global energy mix declines by twelve percentage points, reaching 17% in 2035. Coal demand in the power sector is cut by more than half during the projection period, with the fuel providing only 14% of global electricity generation in 2035, compared with 33% in the New Policies Scenario. Of total coal-fired electricity output in 2035, nearly 60% comes from plants fitted with carbon capture and storage (CCS) technology.

Demand for steam coal varies more than that for coking coal across the three scenarios, since steam coal is used mainly (70%) for power generation – the sector that is most affected by local air pollution and climate change policies. In the New Policies Scenario, steam coal use in 2035 is four-fifths of the level projected in the Current Policies Scenario, but nearly twice that in the 450 Scenario. International steam coal trade is more strongly affected: relative to demand, small volumes (15%) of steam coal are traded and, consequently, small changes in demand or supply can impact trade disproportionately. In the Current Policies Scenario, steam coal trade between the main *WEO* regions increases by half in the period to 2020 and continues to rise steadily thereafter, with trade nearly doubling over the entire projection period. In the New Policies Scenario, by contrast, steam coal trade grows by 30% over 2011-2020, but slows thereafter. In the 450 Scenario, steam coal trade peaks at about 765 Mtce around 2015 and then falls steeply to half that level by 2035. Coking coal is less easily substituted in industrial applications and so demand and trade are far less affected by government policies (Box 4.1). In all three scenarios, coking coal trade underpins a significant share (around 35%) of global coking coal use in 2035. Even in the 450 Scenario, coking coal trade in 2035 remains at around 2011 levels.

### Box 4.1 ▷ A quick guide to the different types of coal[4]

Coal is a generic name given to a wide range of solid organic fuels of varying composition (*e.g.* volatile matter, moisture, ash and sulphur content or other impurities) and energy content. For convenience, the IEA divides coal into three distinct categories:

- Steam coal accounts for nearly 80% of global coal demand today. It is mainly used for heat production or steam-raising in power plants (70%) and, to a lesser extent, in industry (15%). Typically, steam coal is not of sufficient quality for steel making.
- Coking coal accounts for around 15% of global coal demand. Its composition makes it suitable for steel making (as a chemical reductant and source of heat), where it produces coke capable of supporting a blast furnace charge.
- Lignite accounts for 5% of global coal demand. Its low energy content and usually high moisture levels generally make long-distance transport uneconomic. Over 90% of global lignite use today is in the power sector. 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.

The rapid build-up of new coal-fired power stations, many using relatively inefficient subcritical technology, runs the risk of a large-scale lock-in of $CO_2$ emissions for decades ahead, notably in non-OECD countries. One possible set of measures to address climate change is to ensure that inefficient subcritical power plants are no longer built, and to limit the use of existing ones where possible without putting the reliability of electricity

4. Detailed classifications and definitions of coal types are available in *WEO-2011* (IEA, 2011).

supply at risk (IEA, 2013a). Beyond 2020, when demonstrated and deployed at new high efficiency plants, or retrofitted at suitable existing plants, CCS may play a key role in curbing $CO_2$ emissions from coal-based power generation and industry (see Chapter 1). As such, CCS could act as an asset protection strategy, enabling more fossil fuels to be used and potentially reducing the overall cost of power sector decarbonisation by around $1 trillion between 2012 and 2035 (IEA, 2013a).

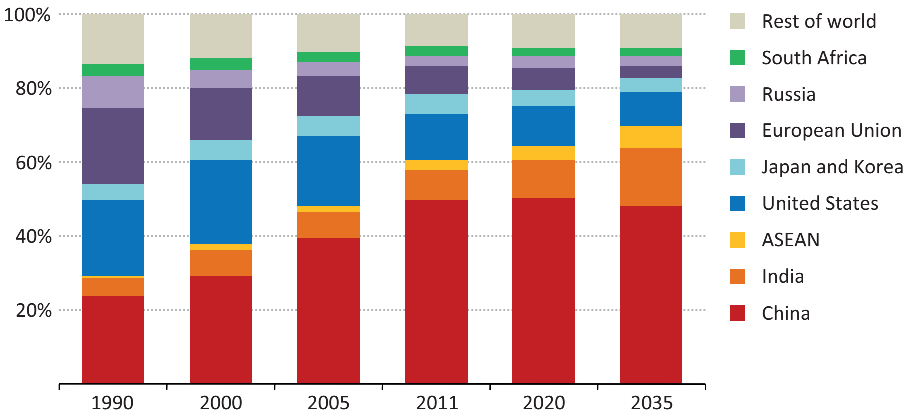


## Demand

### *Regional trends*

In the New Policies Scenario, coal demand trends continue to diverge across regions (Figure 4.2). Coal demand in OECD countries declines further throughout the projection period, with the fall accelerating after 2020 as renewables and gas increase their combined share of electricity generation in Europe, the United States and Asia Oceania. In Europe, coal use falls steeply: in 2035 it is just 57% of its 2011 level and accounts for only 11% of OECD Europe's electricity needs in 2035, compared with 25% today. The role of coal is reduced by the growth of renewables and the retirement of old coal-fired plants at a faster rate than new coal capacity is commissioned (see Chapter 5). In the United States, coal demand falls at a more modest pace, with the decline accelerating after 2020, as the retired old coal-fired plants are replaced by renewables and gas. In Japan, coal for power generation also slides over the *Outlook* period as renewables gain market share.

**Figure 4.2 ▹ Coal demand by key region in the New Policies Scenario**




Coal demand in non-OECD countries continues to increase in the New Policies Scenario, though at a much slower rate than in the last two decades. Rates of growth vary widely across non-OECD countries (Table 4.2). China and India, which possess large, relatively low-cost indigenous resources, remain the main centres of coal use, with their combined share of global demand rising from 58% in 2011 to 64% in 2035. Yet trends differ markedly in the

**Box 4.2 ▷ Was 2012 an aberration or a harbinger of change in coal demand?**

Coal use continued to grow strongly in 2012 in several large coal-consuming countries, according to preliminary data. In Japan and India, it grew by around 6% and 4%. Coal is a major source of electricity generation in Japan (nearly 30%) and is set to grow in the short term, especially in the context of reduced nuclear output after the Fukushima Daiichi accident. Some European countries, where gas was relatively expensive and $CO_2$ prices were low (see Box 5.1 in Chapter 5), also registered substantial increases in coal use, notably the United Kingdom (26%) and Spain (22%). Coal-fired electricity output in Europe rose by 6%, an increase greater than Portugal's total electricity generation.

It was a different story, however, in the world's two largest coal markets: China and the United States. China, where coal demand surged by about 10% per year from 2001 to 2011, experienced a marked slowdown in 2012. In the United States, where coal demand fell by 2.5% per year over 2005-2011, it declined by 11% in 2012. As a result, global coal demand rose by just under 1% in 2012, compared with average growth of almost 5% per year over the past decade. Are these trends an aberration or the first signs of more profound changes coming in global coal markets?

The answer lies, perhaps, somewhere in between the two. In China, a slowdown in the rate of economic growth is leading to a marked deceleration in energy demand growth, and coal demand growth in particular. Coal use in industry, which makes up nearly one-quarter of the country's total coal demand, increased by 4.5% in 2012, compared with 7.5% on average in the last decade. Demand in the power sector, which accounts for over half of China's coal demand, rose marginally, compared with double-digit growth rates in prior years. To some extent, this was the result of China adding a record 16 gigawatts (GW) of hydro capacity and 2012 being a particularly wet year, factors that boosted hydro output and reduced the need to run baseload coal plants. But the slowdown in coal demand growth also reflects progress by China in promoting energy efficiency and diversifying its power sector. Projects due to come online in the period to 2020 are expected to further limit the need for increased coal consumption (Figure 4.7).

In the United States, a very different phenomenon reduced coal use in the power sector (which accounts for 90% of US coal use) in 2012. The rise of unconventional gas production, coupled with a historically mild winter, saw Henry Hub gas prices fall to as low as $1.82 per million British thermal units (MBtu) in April 2012, making gas highly competitive against coal in the sector, especially in eastern regions where coal is relatively expensive. This led to gas displacing coal on a large scale. By early September 2013, gas prices rebounded to an average of $3.7/MBtu for the year to date, leading to coal regaining market share. In the first half of 2013, coal-fired plants accounted for just under 40% of electricity output, compared with an average of 35% in the first half of 2012 (US EIA, 2013). Nonetheless, in the longer term, renewables and gas are expected to gradually displace coal for electricity generation as US environmental restrictions on coal burning become more stringent (see Box 4.4).

two countries, reflecting in large part their different stages of economic development. In China, growth in coal use slows over 2020-2030 and stabilises around the end of the projection period as a result of lower electricity demand growth and other fuels gaining market share (Spotlight). Therefore China's share of global coal demand, which has risen notably in the past decade, levels off at around half. In India, coal use continues to grow briskly throughout the projection period, in line with the country's strong electricity demand growth. India displaces the United States as the world's second-largest coal market before 2025. Association of Southeast Asian Nations (ASEAN) countries see a tripling of coal use; their collective consumption is nearly double that of the European Union in 2035.



**Table 4.2 ▷ Coal demand by region in the New Policies Scenario** (Mtce)

| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011-2035 | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | Delta | CAAGR* |
| **OECD** | **1 543** | **1 518** | **1 469** | **1 369** | **1 262** | **1 156** | **-362** | **-1.1%** |
| Americas | 701 | 734 | 714 | 683 | 649 | 631 | -103 | -0.6% |
| United States | 657 | 684 | 657 | 625 | 598 | 587 | -97 | -0.6% |
| Europe | 645 | 445 | 408 | 351 | 302 | 253 | -193 | -2.3% |
| Asia Oceania | 198 | 339 | 347 | 335 | 311 | 272 | -67 | -0.9% |
| Japan | 109 | 153 | 157 | 153 | 149 | 140 | -13 | -0.4% |
| **Non-OECD** | **1 643** | **3 872** | **4 533** | **4 792** | **4 993** | **5 170** | **1 298** | **1.2%** |
| E. Europe/Eurasia | 525 | 329 | 334 | 337 | 338 | 346 | 17 | 0.2% |
| Russia | 273 | 166 | 165 | 170 | 171 | 175 | 9 | 0.2% |
| Asia | 991 | 3 355 | 3 974 | 4 211 | 4 403 | 4 561 | 1 206 | 1.3% |
| China | 762 | 2 666 | 3 026 | 3 094 | 3 095 | 3 050 | 384 | 0.6% |
| India | 148 | 465 | 607 | 713 | 840 | 972 | 507 | 3.1% |
| ASEAN | 18 | 129 | 224 | 275 | 331 | 399 | 269 | 4.8% |
| Middle East | 1 | 4 | 6 | 7 | 7 | 8 | 4 | 2.7% |
| Africa | 106 | 152 | 176 | 185 | 188 | 194 | 41 | 1.0% |
| South Africa | 95 | 140 | 151 | 155 | 153 | 154 | 14 | 0.4% |
| Latin America | 21 | 32 | 44 | 52 | 58 | 61 | 30 | 2.8% |
| Brazil | 14 | 22 | 27 | 30 | 32 | 34 | 12 | 1.9% |
| **World** | **3 186** | **5 391** | **6 003** | **6 160** | **6 255** | **6 326** | **936** | **0.7%** |
| European Union | 651 | 409 | 356 | 300 | 250 | 207 | -202 | -2.8% |

* Compound average annual growth rate.

## *Sectoral trends*

The power sector has been an increasingly dominant source of global coal demand. Over 1990-2011, its share of coal use rose from 55% to 63%. This trend slows considerably in the New Policies Scenario, as the sector's share increases only marginally between 2011 and 2035. This reflects a rapid decline in coal use in the power sectors of OECD countries being offset by continued growth in non-OECD countries (Figure 4.3).

SPOTLIGHT

## Is China's coal demand set to peak soon?

In the decade to 2011, China's coal use more than doubled and its share in global coal demand rose from 30% to nearly 50%. There is little doubt that such strong growth will taper off in the future, with some industry analysts even expecting China's coal demand to peak in the current decade. In 2012, the rate of coal demand growth in China was one of the lowest over the past decade: the drivers of change may already be at work.

China's 12th Five-Year Plan (the Plan), adopted in 2011, includes targets to reduce energy intensity by 16% and cut $CO_2$ intensity by 17% by 2015, compared with 2010. Measures to achieve overarching targets have been reinforced by detailed industry targets, particularly in terms of diversifying the power sector, which today accounts for some 55% of China's coal use. The diversification aims to add 70 gigawatts (GW) of wind and 35 GW of solar capacity by 2015, and to start construction by that year of 120 GW of hydro and 40 GW of nuclear capacity. In addition, growing public concerns about deteriorating air quality in many cities have led Chinese authorities to announce further measures to reduce pollution from particulate matter, including greater use of natural gas. Will these measures curb coal demand growth? Yes, but to reduce coal demand, the rate of new technology deployment and efficiency improvements would have to outpace power demand growth. To reduce air pollution, the likely near-term solution will be to shut down some of the dirtiest power plants and steel mills while installing or enforcing the use of emissions control technologies at newer plants. In addition to coal, oil use in transport impacts air quality and has a key role in this debate.

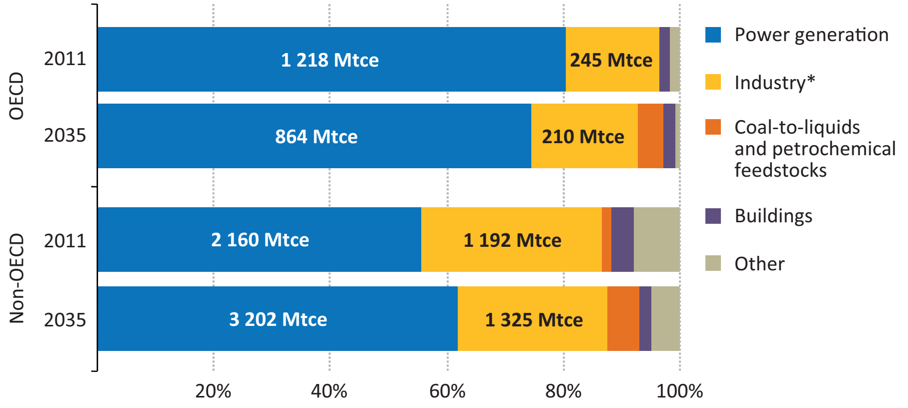
The Plan also envisages rebalancing away from energy-intensive industry and stronger pursuit of energy efficiency gains, while moving away from double-digit GDP growth. This will curb China's coal demand growth, yet its household electricity consumption today is significantly lower than the OECD average. How quickly the economy can be rebalanced depends on global demand for Chinese products. Bold policy measures, an economic "hard landing" or a rapid shift to a services-based economy are potential game-changers that could unexpectedly impact China's coal demand.

Shifting away from a fuel that presently accounts for almost 70% of China's total energy demand and 80% of its electricity output is expected to take time. In the New Policies Scenario, China's coal demand growth slows before 2020, with demand reaching a plateau after 2025. Even then, coal continues to dominate China's total primary energy demand (57%) and electricity generation (59%). Costs are on the rise in mature mining regions in northern China and long transport distances to the demand hubs can make some domestic coal expensive. Low-cost suppliers from the international market will therefore remain competitive against high-cost domestic producers, especially in China's southern coastal provinces. Hence, in our projections, China continues to import substantial amounts of coal, remaining a strong force in global coal markets.

Industry, including own use and transformation in blast furnaces and coke ovens, accounts for most of the remaining global coal demand. Coal use in industry continues to expand rapidly in the New Policies Scenario until 2020, and then begins to decline. After 2020, other energy sources and energy efficiency measures are deployed more widely in non-OECD countries (mirroring past trends in the OECD) and global crude steel output flattens (around 2030). Overall, the share of industrial energy supplied by coal falls globally from 27% in 2011 to 24% in 2035. Iron and steel production remains the largest coal user in industry. Coal use in industry peaks around 2020 as other technologies (such as electric arc furnaces) become more widespread, efficiency improvements are achieved and crude steel production in China begins to decline. There is also a significant increase in the use of coal as a feedstock in the petrochemicals industry and in coal-to-liquids plants, notably in China (see Chapter 15).

4

**Figure 4.3 ▷ Coal demand by key sector in the New Policies Scenario**




* Includes own use and transformation in blast furnaces and coke ovens.

## Supply

### *Resources and reserves*[5]

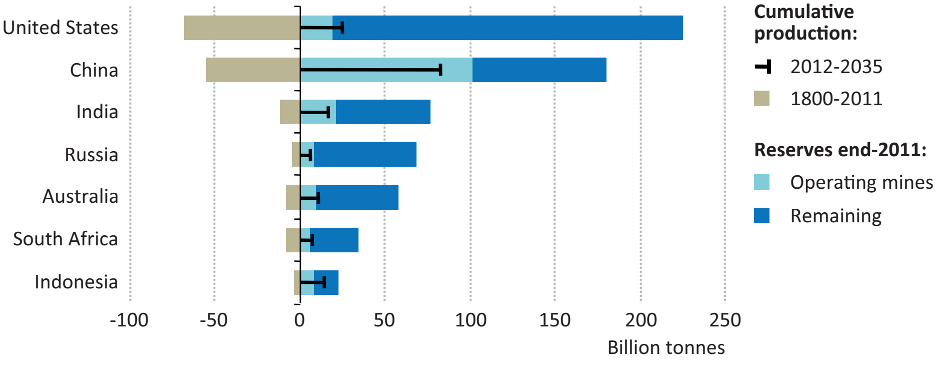
Coal is the most abundantly available fossil fuel worldwide (despite large recent additions to natural gas resources), and the resource base is easily sufficient to meet any plausible level of demand for decades to come. Proven coal reserves – volumes that are known to exist and are thought to be economically and technically exploitable at today's prices – totalled around 1 040 billion tonnes at the end of 2011, of which coking and steam coal make up nearly three-quarters (BGR, 2012).[6] Proven coal reserves worldwide have increased by around 35 billion tonnes in 2011 (production was around 7.7 billion tonnes) thanks to reserve additions mainly in Australia, South Africa and Indonesia. Coal constitutes around

5. A detailed assessment of coal resources and production technologies is available in *WEO-2011* (IEA, 2011).
6. Classifications of coal types can differ between BGR and IEA due to statistical allocation methodologies.

55% of the world's total proven fossil fuel reserves. Resources are more than twenty times larger than reserves and make up about 90% of global remaining fossil fuel resources. A significant portion can be readily exploited with relatively modest price increases or technical innovations.

Coal reserves and resources are widely distributed: 32 countries have reserves of more than 1 billion tonnes (roughly the level of annual international coal trade); 26 countries have resources of more than 10 billion tonnes (BGR, 2012). Non-OECD Asia contains around 30% of the world's proven reserves and Australia has a further 10%. In all major producer countries, proven reserves comfortably exceed their projected cumulative production to 2035 in the New Policies Scenario (Figure 4.4). In several of these countries, cumulative production over 2011-2035 could in theory be met by drawing solely on the reserves of mines currently operating, but in practice this would be impeded by capacity constraints.

**Figure 4.4 ▷ Reserves and cumulative production by major coking and steam coal producers in the New Policies Scenario**




Sources: Etemad, *et al.* (1991); BGR (2012); Wood Mackenzie databases; IEA analysis.

## *Production*

While coal resources will not constrain coal production for many decades, supply costs are likely to increase in real terms as a result of rising input costs, such as fuel or explosives (the cost of which is often closely linked to oil prices), and higher labour costs. The development of mines in more remote or undeveloped regions, where infrastructure and transport costs tend to be higher, will also add to coal supply costs.

Steam coal prices rose sharply over the period 2009-2011, outpacing rising production costs and incentivising investments in mining, processing and transportation facilities (Figure 4.6). Since 2011, however, steam coal prices have fallen while costs have continued to climb (and even accelerate in some countries), weakening investment incentives. The prospect of continued low coal prices and cost pressures (in the absence of strong productivity gains) may limit investment and production growth in some countries. Additionally, potential export bans and policy interventions related to environmental policies can significantly impact coal demand and investment. In the New Policies Scenario, which assumes cautious implementation of climate change policies and greater competition between natural gas and coal in the power sector, the average OECD steam coal import price rises from $99 per tonne (in year-2012 dollars) in 2012 to $106/tonne in 2020 and then more slowly to $110/tonne in 2035 (see Chapter 1).

Coal production prospects differ markedly between OECD and non-OECD countries (Table 4.3). In the New Policies Scenario, OECD coal output grows modestly to 2020, falling steadily thereafter. OECD Europe experiences a halving of coal output, reflecting the phase-out of coal mining subsidies in some countries as well as cost escalation in coal fields that have been producing for many decades. The United States, by far the largest coal producer among OECD countries, sees a slower decline in production of 0.7% per year over 2011-2035. Although some mature coal basins in the United States are experiencing cost escalation, there are still large quantities of coal that can be extracted at relatively low costs (Figure 4.10). Australia's production grows by almost 50% between 2011 and 2035, fuelled by rising exports.



**Table 4.3 ▷ Coal production by region in the New Policies Scenario** (Mtce)

| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011-2035 | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | Delta | CAAGR* |
| **OECD** | **1 533** | **1 397** | **1 430** | **1 384** | **1 343** | **1 300** | **-97** | **-0.3%** |
| Americas | 836 | 826 | 797 | 768 | 728 | 700 | -126 | -0.7% |
| United States | 775 | 766 | 735 | 708 | 674 | 653 | -113 | -0.7% |
| Europe | 526 | 248 | 218 | 180 | 151 | 123 | -125 | -2.9% |
| Asia Oceania | 171 | 323 | 415 | 435 | 464 | 478 | 154 | 1.6% |
| Australia | 152 | 318 | 410 | 431 | 459 | 473 | 155 | 1.7% |
| **Non-OECD** | **1 661** | **4 101** | **4 573** | **4 776** | **4 912** | **5 026** | **925** | **0.9%** |
| E. Europe/Eurasia | 533 | 429 | 448 | 437 | 433 | 432 | 3 | 0.0% |
| Russia | 275 | 257 | 269 | 264 | 261 | 258 | 1 | 0.0% |
| Asia | 952 | 3 377 | 3 755 | 3 945 | 4 069 | 4 162 | 785 | 0.9% |
| China | 741 | 2 605 | 2 779 | 2 860 | 2 871 | 2 835 | 230 | 0.4% |
| India | 150 | 360 | 392 | 451 | 527 | 624 | 263 | 2.3% |
| Indonesia | 8 | 296 | 449 | 489 | 519 | 549 | 254 | 2.6% |
| Middle East | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 1.1% |
| Africa | 150 | 209 | 244 | 259 | 264 | 277 | 68 | 1.2% |
| South Africa | 143 | 204 | 224 | 231 | 229 | 231 | 28 | 0.5% |
| Latin America | 25 | 85 | 125 | 134 | 146 | 155 | 70 | 2.5% |
| Colombia | 20 | 80 | 116 | 124 | 134 | 142 | 62 | 2.4% |
| **World** | **3 194** | **5 498** | **6 003** | **6 160** | **6 255** | **6 326** | **829** | **0.6%** |
| European Union | 528 | 239 | 202 | 162 | 130 | 103 | -136 | -3.5% |

* Compound average annual growth rate. Note: Historical data and the global CAAGR differ from world demand in Table 4.2 due to stock changes.

The picture differs outside of OECD countries. Output in China continues to increase in line with domestic demand, but at a much slower rate than in recent years, with most growth coming before 2020. Production growth saturates before 2030, at a level 280 Mtce higher than in 2011. Indonesia and India both increase their coal production rapidly in response to growing domestic demand and, in the case of Indonesia, to meet growing exports. Colombia and South Africa also expand output, while new producers, such as Mongolia and Mozambique, ramp up their production.

### *Trade*

The recent shift in the pattern of international trade, with developing Asian countries relying increasingly on imports, is set to continue in the New Policies Scenario (Table 4.4). Responding to global demand trends, coal trade between *WEO* regions is projected to rise from 900 Mtce in 2011 to 1 150 Mtce in 2020. It increases at a more subdued pace after 2020, reaching 1 260 Mtce in 2035.

**Table 4.4 ▷ Inter-regional coal trade in the New Policies Scenario**

| | 2011 | | 2020 | | 2035 | | 2011-35 |
|---|---|---|---|---|---|---|---|
| | Mtce | Share of demand* | Mtce | Share of demand* | Mtce | Share of demand* | Delta Mtce |
| **OECD** | **-115** | **9%** | **-40** | **3%** | **144** | **12%** | **259** |
| Americas | 85 | 11% | 82 | 11% | 68 | 10% | -16 |
| United States | 79 | 11% | 77 | 11% | 66 | 11% | -12 |
| Europe | -197 | 65% | -190 | 70% | -130 | 74% | -67 |
| Asia Oceania | -2 | 1% | 68 | 17% | 206 | 44% | 208 |
| Australia | 263 | 89% | 337 | 86% | 412 | 90% | 149 |
| Japan | -154 | 100% | -157 | 100% | -140 | 100% | -13 |
| **Non-OECD** | **157** | **4%** | **40** | **1%** | **-144** | **3%** | **-301** |
| E. Europe/Eurasia | 98 | 28% | 115 | 31% | 86 | 23% | -13 |
| Russia | 92 | 42% | 104 | 45% | 84 | 38% | -9 |
| Asia | -48 | 1% | -219 | 6% | -400 | 9% | 352 |
| China | -129 | 5% | -247 | 8% | -215 | 7% | 86 |
| India | -106 | 24% | -214 | 37% | -349 | 37% | 242 |
| Indonesia | 251 | 85% | 363 | 81% | 385 | 70% | 134 |
| Middle East | -3 | 75% | -5 | 81% | -6 | 83% | 3 |
| Africa | 56 | 27% | 69 | 28% | 83 | 30% | 27 |
| South Africa | 63 | 31% | 73 | 33% | 77 | 33% | 14 |
| Latin America | 53 | 63% | 81 | 65% | 93 | 61% | 40 |
| Colombia | 75 | 94% | 110 | 94% | 134 | 94% | 59 |
| **World**** | **900** | **17%** | **1 152** | **20%** | **1 261** | **21%** | **361** |
| European Union | -170 | 62% | -155 | 67% | -105 | 72% | -66 |

* 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. The difference between OECD and non-OECD in 2011 is due to stock changes.

Asia is set to consolidate its position as the centre of gravity of international coal trade (Box 4.3). China became a net importer of coal in 2009: just three years later it was the world's largest net importer. At about 220 Mtce – a world record – China's net imports in 2012 were larger than total coal use in any OECD country except the United States. In the New Policies Scenario, China's net imports of coal peak before 2020, as lower demand growth and improvements in mining productivity weaken price differentials between domestic production and imported coal. Nonetheless, imports stay above or around 2012 levels throughout the projection period. The sheer size of China's coal demand and production means that even small changes in either demand or output can have a very large impact on its import needs. In India, coal imports continue to climb throughout the *Outlook* period, more than tripling by 2035. India became the world's fourth-largest importer in 2012, overtaking Korea, and its imports are set to surpass those of Japan and the European Union within a few years. Soon after 2020, India is projected to overtake China to become the world's largest importer. By 2035, Japan's coal imports drop by 10% and the European Union's fall by 40%.



**Box 4.3 ▷ Steam coal trade thrives as demand stutters**

While around 85% of global steam coal is still produced and used domestically, international trade in steam coal has flourished, nearly doubling from 1990 to 2000, and doubling again in the period to 2011. According to preliminary data, worldwide steam coal trade grew strongly in 2012, compared with marginal demand growth, taking the expansion in the trade since 2007 to 50%. Over two-thirds of steam coal trade now serves Asia, both OECD and non-OECD countries. Japan and Korea have traditionally been the cornerstones of this market. Both will remain key importers throughout the projection period, although their import volumes decline. Over the next two decades, it is clear that developing Asian countries will be the most dynamic forces in this market. The largest suppliers are Indonesia and Australia, which account for nearly 60% of traded steam coal. Steam coal exporters also include Russia, Colombia, South Africa and the United States. Considerable uncertainty exists around future coal demand, as noted earlier, and, by extension, coal trade. However, coal trade has grown rapidly, and proved surprisingly resilient. Depending on the evolution of mining costs and seaborne freight rates, export mines may have a cost advantage over domestic production and therefore trade may play a growing role in meeting global energy demand.

Among suppliers, Australia and Indonesia are the biggest beneficiaries of increased coal trade in the New Policies Scenario. Australian coal exports expand by 57% over 2011-2035. Indonesian exports increase by 54%, with most of the growth occurring before 2020, as thereafter more of its production goes to meet domestic needs. Australia overtakes Indonesia as the world's largest coal exporter by 2030, though Indonesia remains by far the world's biggest steam coal exporter. By the end of the projection period, Indonesian steam coal exports exceed the combined steam coal exports of Australia and Colombia, the second- and third-largest steam coal exporters. The United States remains an important net exporter of coal through to 2035, with coking coal dominating. Because there are fewer opportunities to substitute for coking coal (contrasting with steam coal), major producers and exporters of coking coal – namely Canada, the United States and Australia – are less affected by the environmental policies of importing countries.

Mozambique could emerge as an important new source of export growth, though the timeline for it to do so remains uncertain. Recently, coal producers' plans to ship coal via barge on the Zambezi River were not approved because of environmental concerns. In addition, heavy rainfall and threats from rebel groups have hampered coal transport on the key railway line recently. With current infrastructure being insufficient to accommodate large-scale exports, industry and the government are discussing plans to build a rail link to the coast that would allow up to 25 million tonnes (Mt) per year of coal exports. In the New Policies Scenario, Mozambique's exports are projected to rise to 6 Mtce in 2020 and nearly 20 Mtce in 2035.

### *Costs and investment*

Since the capital costs of coal production are relatively low compared with oil and gas, it is the variable costs of coal supply – often termed the cash costs – that determine the competitiveness of individual exporters. The cash costs of coal exports set the minimum price that an exporter could charge to cover the operating expenses of a mine. However a further margin is required to provide an adequate return on capital expenditure and to attract new capital investment. The evolution of coal prices is closely linked to supply cost developments worldwide. The fundamental cost drivers of an existing mine, many of which are likely to remain in production through to 2035, are input costs such as labour, fuel, explosives and maintenance costs. The costs of a new mine are determined chiefly by the geological conditions of the deposit, access to infrastructure and the distance to transport coal to the point of sale.

Even though some coal exporters need prices in excess of $80/tonne (excluding sea freight to the customer) to cover just their cash costs, the bulk of internationally traded steam coal is currently available at a free on board (FOB) cash cost[7] of $40-60/tonne (Figure 4.5). This cash cost has shifted up significantly over the last few years. Exchange rates are a major factor. The mechanism is simple: as international coal trade is settled mostly in US dollars, coal exporters generate a revenue stream in US dollars, while they incur a large part of their costs in local currency. Therefore, a devaluation of the US dollar reduces returns to producers from the international market.[8] The currencies of most coal-exporting countries

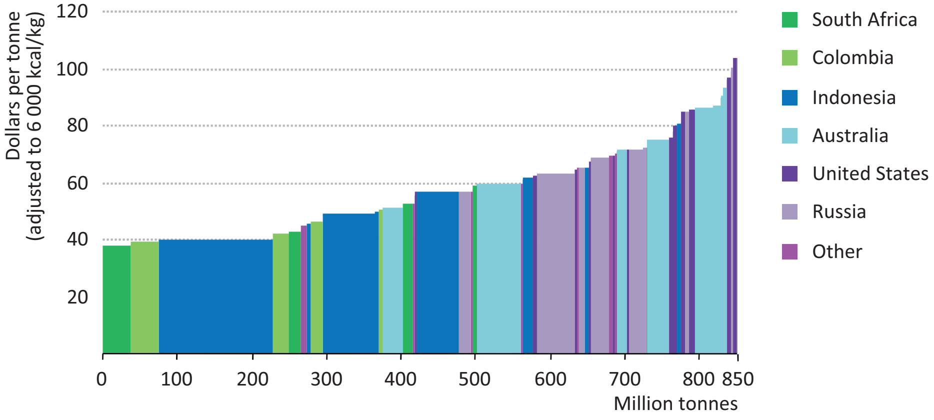
7. FOB (free on board) cash cost includes mining costs, costs of coal washing and preparation, inland transport, mine overhead as well as port charges (this definition corresponds to the C1-cash cost definition widely used in the mining industry). It excludes royalties and taxes, as well as seaborne shipping costs.

8. Coal importers, buying coal in US dollars and selling, for example, electricity, in local currency, are exposed to a converse effect: a devaluation of the US dollar lowers their procurement cost compared with the value of their product in local currency.

have risen against the dollar in the past three years, especially the Australian dollar (A$). With increasing labour costs, this has meant that Australia has shifted, in terms of US dollars, from a mid-cost supplier to being a high-cost supplier within a few years. With increases in other operating costs and construction costs, both existing and new projects are under strain and some new projects are experiencing serious delays. Some $30 billion of new coal mining and infrastructure (notably port expansions) in Australia have been delayed or cancelled in the last year (BREE, 2013).



**Figure 4.5** ▷ **FOB cash costs for seaborne steam coal exports, 2012**




Sources: Wood Mackenzie databases and IEA analysis.

Local factors have also contributed to higher cash costs in many cases. Indonesia, the largest steam coal exporter, has built market share rapidly over the past decade on the basis of low mining and transport costs, using barges instead of generally more expensive rail systems to get exports to coastal shipping points. However, the last two years have seen sharp increases in Indonesian operating costs, with higher labour costs and oil prices being major factors, as well as worsening qualities of coal seams in some operations. Nonetheless, Indonesia remains in the lower half of the global steam coal cash cost curve, underpinning its ongoing rapid expansion. Steam coal exports have increased nearly five-fold over the decade to 2010 and by a further 40% (or 88 Mtce) in the last two years.

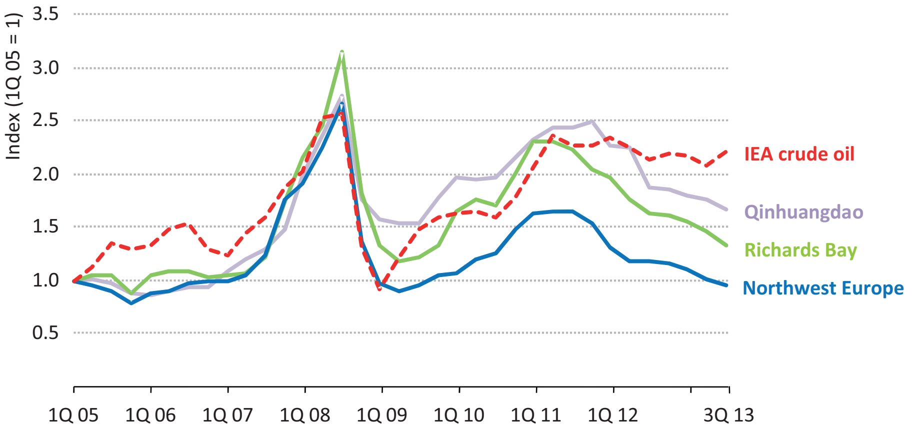
In the New Policies Scenario, cumulative global investment in the coal supply chain (new coal mines, ports and shipping) amounts to $860 billion (in year-2012 dollars) over 2013-2035, of which the majority is in mining. The coal supply chain accounts for only around 2.5% of total investment globally in fuel supply and power generation. This reflects that coal has a relatively low capital intensity and that It grows much slower than other energy sources, such as renewables and gas, over the *Outlook* period. Projected coal supply-chain investments are centred in non-OECD countries, which account for three-quarters of the total. China alone accounts for 55% of the non-OECD total. Nearly 60% of OECD coal investments, or $90 billion, are made in Australia.

## *Pricing of internationally traded coal*

Developments in the power sector are, and will remain, one of the most important demand-side influences on coal prices and trade. Even moderately higher natural gas prices, compared with today's levels in the United States, would probably trigger a rise in the share of coal in its power supply, potentially reducing US steam coal exports. And even a modest rise in global coal prices might see China's coal imports falter from their current record levels, as utilities and factories located in coastal China are adept at arbitraging domestic and international coal prices. By contrast, India's imports are less sensitive to price. Policy decisions in China and India, or even discussions of possible policy changes, will undoubtedly strongly influence international coal markets.

The global coal market consists of various regional sub-markets, which are typically separated according to geography, coal quality or infrastructure constraints. The international market for coal is a comparatively small sub-market (around 17% of global coking and steam coal production is traded internationally), yet it plays a key role as it links the various domestic markets through imports, exports and price movements. The degree to which regional coal prices fluctuate with price movements on the international market depends on how well the regional and international markets are connected. US coal prices are a good example: while western coal prices are quite flat and low, prices in the eastern United States fluctuate strongly with international prices as local producers have the option to export. International coal markets have seen sharp price fluctuations in recent years, followed by a general price decline in the last two years (Figure 4.6): from levels of around $120/tonne for steam coal in most of 2011, prices have declined to $80-90/tonne in 2013.

**Figure 4.6** ▷ **Quarterly indices for IEA crude oil and steam coal prices**




Notes: Qinhuangdao is a major coal port in northeast China. Richards Bay is the major South African export port. Northwest Europe is the marker price for the Amsterdam-Rotterdam-Antwerp region. Analysis is based on prices expressed in real terms.

Sources: McCloskey Coal Report databases and IEA analysis.

Relatively high coal prices in the period 2007-2011 were paralleled by cost escalations driven by exchange rate effects as well as rising costs for mining materials, consumables and labour as a result of the global mining and resources boom. Furthermore, healthy margins had taken pressure off mining companies to increase productivity and cut costs in that period. Finally, strong coal demand kept high-cost mines in the market that were only marginally profitable, even at high prices. Consequently, falling prices since mid-2011 have squeezed margins and put pressure on the coal industry worldwide.



Currently, high costs and ample supply capacity is driving consolidation and restructuring of mining industries in many countries. The United States experienced a wave of consolidation starting in 2012 with large-scale production cuts and mine closures, mainly in the Appalachian basins. However, since international coal prices dropped below \$80/tonne for all key exporters in the summer of 2013, other countries have been affected as well. Australian and Canadian companies have reduced their workforce, idled unprofitable mines and revised or delayed investment in new mines and infrastructure. At current prices even some Indonesian producers are considering production cuts and a reduction of the workforce. Many coal companies have reacted to the plummeting prices with output expansion, trying to maintain revenues, causing prices to drop further. Given the current cost structure in the international market, prevailing price levels are not sustainable in the long run without further reductions in high-cost supply.

Rampant growth in coal demand and imports means that Asia is increasingly the focus of coal markets. Qinhuangdao, the world's largest coal port and China's primary transhipment hub, has rapidly developed into a key pricing point in international steam coal trade. While Europe is still a large coal importer, accounting for one-fifth of global steam coal imports, currently prices there tend to be lower, because of over-supply in the Atlantic Basin. Russia, the world's third-largest steam coal exporter, is able to swing some of its exports between the Atlantic and Pacific markets and, in recent years, growing volumes have been sold to Asian buyers.[9] In 2011, these volumes amounted to some 30% of Russian steam coal exports, with Japan and Korea the main buyers.

Competition with natural gas in the power sector will be pivotal to coal price formation. Anywhere that a $CO_2$ price is in place, coal use and coal-fired power will be affected, to an extent that depends on the stringency of the $CO_2$ price. In the European Union, the largest region with explicit carbon pricing under a cap-and-trade system, $CO_2$ prices have been low for several years and fell further in 2012 and 2013. In the summer of 2013, they stood at less than \$6/tonne. This, coupled with low coal prices in the Atlantic Basin, meant that coal was often the lowest-cost fuel choice in the power sector. At coal and gas price levels prevailing in Europe in early 2013, the $CO_2$ price would need to increase to close to \$60/tonne to enable even a highly-efficient gas-fired power plant to compete against a 1980s coal-fired power station.

9. See *Medium-Term Coal Market Report 2013* for an in-depth analysis of the Russian coal market (IEA, 2013b).

Other factors will also affect future coal price formation. High cost exporters, such as Australia, the United States and Russia, may limit supplies to the international market if cost escalation continues, putting upward pressure on international coal prices. In addition, seaborne bulk freight rates, which have been low since they fell sharply in 2008, could rise in the longer term. That would favour suppliers closer to the main Asian markets, such as Indonesia and Australia, at the expense of exporters from South Africa and the United States. A weaker US dollar would increase local costs (expressed in US dollar terms) in countries with a high proportion of locally sourced inputs, while a strengthening US dollar would tend to reduce them. Significant devaluation of currencies in importing countries, such as in India recently, will limit their ability to pay higher prices.

## Regional insights

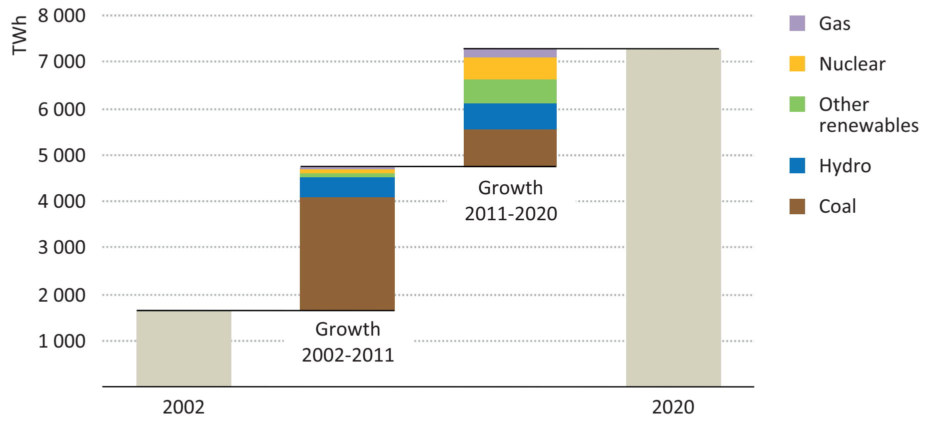
### *China*

As the world's largest coal user, producer and now importer, China dominates the global coal market. It maintains this pivotal role in the New Policies Scenario even though some trends are set to change markedly. China's economic success has been fuelled primarily by coal, which provides over two-thirds of China's primary energy demand. The country now uses nearly twice as much coal as all OECD countries combined.

Coal is the backbone of China's power system, comprising almost 80% of electricity generation. Yet, the power sector only accounts for about 55% of China's coal consumption, a much lower share than in other major coal users, like the United States, European Union and India. The remainder of China's coal consumption is in the iron and steel, and cement industries and in burgeoning applications, such as petrochemical feedstocks. Even the buildings and agriculture sectors use substantial amounts of coal.

Nevertheless, developments in the power sector will be critical to the prospects for Chinese coal demand and imports. In the period 2002-2011, electricity generation in China nearly tripled, with about 80% of the incremental output coming from coal. In the period to 2020, electricity generation in China increases by a further 55% in the New Policies Scenario, but only one-third is coal-fired (Figure 4.7). Renewables, especially hydro but also wind, supply more than 40% of incremental output, generating an additional 1 075 terawatt-hour (TWh) by 2020, compared with 2011 (roughly equal to the current electricity output of Japan). A significant contribution also comes from nuclear, with 29 reactors currently under construction in addition to the 17 units already in operation. As a result, growth in coal use in the power sector slows markedly, from 10.5% per year on average over 2002-2011 to 1.5% per year over 2011-2020. After 2020, the growth in power sector demand falls to 0.8% per year, as the power mix is diversified further and efficiency gains curb the growth in electricity demand. However, the massive stock of coal-fired stations already in place, combined with the country's enormous coal reserves, ensures that coal remains the key source of electricity generation, despite its share falling from 79% in 2011 to 55% in 2035.

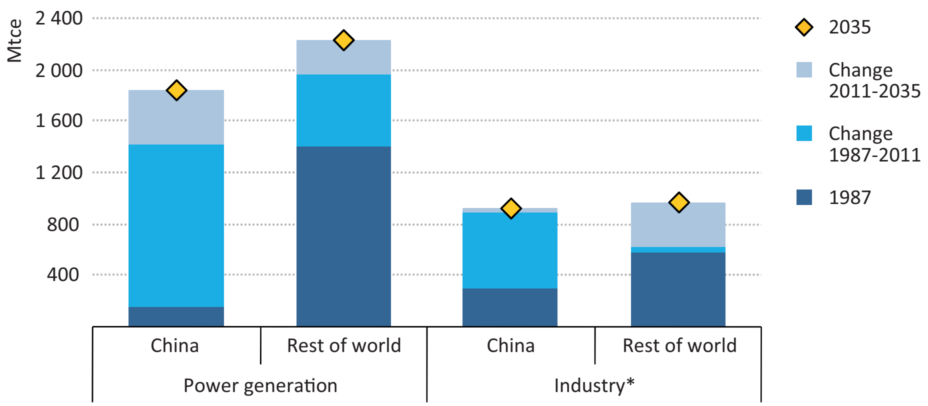
**Figure 4.7** ▷ **China's electricity generation in the New Policies Scenario**






Coal is also the dominant fuel in China's industry sector. Coal consumption in industry (including coke ovens, blast furnaces, petrochemical feedstocks and coal-to-liquids) is greatest in the iron and steel industry, which accounts for over 50%, while the cement industry accounts for 20%. Over the period 2002-2011, industrial coal demand grew very quickly, averaging 9.5% per year. In the New Policies Scenario, growth is projected to slow significantly to 1.9% per year in the period to 2020, as a result of slower industrial growth and structural transformation of the economy away from heavy industries (Figure 4.8). The production of crude steel and cement peaks before 2020 and declines thereafter, which results in a fall in industrial coal use of 0.9% per year in the period 2020-2035. Wider deployment of alternative technologies in steel production, such as electric arc furnaces, and achievements in efficiency improvements reduce coal demand.

**Figure 4.8** ▷ **Coal demand in China and the rest of the world by major sector in the New Policies Scenario**




* Includes own use and transformation in blast furnaces and coke ovens, coal-to-liquids, and petrochemical feedstocks.

By contrast, both coal-to-liquids and coal use as feedstock in the chemical industry grow strongly, the latter by 4.7% annually in the period to 2035, driven by increasing demand for methanol. In the second half of the *Outlook* period, a substantial amount of domestically produced methanol is directed towards the production of olefins in the petrochemical industry, making use of the methanol-to-olefin process. Given the coal, oil and gas prices derived from IEA World Energy Model, production economics favour coal-based petrochemical production over that based on oil and gas, helping to reduce China's dependence on imports.

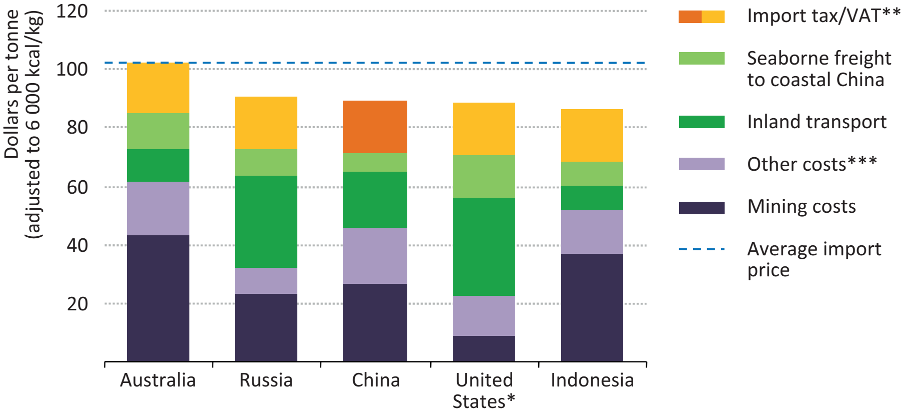
In previous years, rapidly increasing coal demand put strains on coal supply. To address this, China's 11th Five-Year Plan, issued in 2007, included mining industry reform that targeted productivity and safety improvements, as well as capacity expansion. In a wave of industry consolidation, more than 9 000 small coal mines have been closed or incorporated into large mining complexes (IEA, 2012). The reforms have been successful, improving safety and productivity, and increasing coal mining capacity. Although coal mines are scattered across China, three provinces located in the north and northeast – Inner Mongolia, Shanxi, and Shaanxi – produce around 60% of the country's coal.

China's coal production grows by 0.7% per year between 2011 and 2020 in the New Policies Scenario, but stabilises thereafter, reflecting slower growth in power sector coal use and declining coal use in heavy industry. The recent slowdown in growth has squeezed the profitability of coal mining in China, especially in old high-cost mines, increasing incentives to cut costs and triggering discussions about a possible ban on certain coal imports of low calorific value, leading to the introduction of a modest import tax on such coals in August 2013. Since Indonesian coals come under China's free-trade agreement with ASEAN countries, they are not affected, so the immediate impact of the tax seems likely to be small. However, it may serve as a warning to potential investors considering the development of projects for export to China and elsewhere. Other measures are also being considered to help domestic coal producers, including tax rebates.

The key challenge in China's coal market is the geographic mismatch of supply and demand, which requires coal to be hauled long distances. While more than 80% of Chinese steam coal output can be produced at less than $60/tonne, production costs in some older operations in Shanxi are closer to $80/tonne. Adding transport costs to southern or coastal demand centres can make some Chinese coal relatively expensive (Figure 4.9). This has opened the door to growing imports.

China's coal imports reached a record level of about 220 Mtce in 2012 and have continued to grow strongly in the first half of 2013. In the New Policies Scenario, imports are projected to peak within the current decade, then to decline slowly, though they remain, on average, above 2012 levels over the projection period. Fierce competition will persist between domestic supply and imports in southern and coastal China over the *Outlook* period. In China's more mature mining areas, costs are projected to rise, encouraging new mines to open further west, where mining costs are low, but transport distances are longer.

**Figure 4.9** ▷ **Average costs of steam coal delivered to coastal China, 2012**




* United States refers to exports from the Powder River Basin only. ** VAT is value-added tax. *** Includes coal preparation, mine overhead, port charges, royalties and other taxes.

Sources: Wood Mackenzie databases and IEA analysis.

## United States

The United States is the world's second-largest coal consumer, making up 13% of the global market, and by far the largest in the OECD, accounting for 45% of OECD coal use.[10] In 2011, coal met around one-fifth of US energy needs, based on large and, in many cases, easily mined and low-cost reserves. Traditionally, coal has fuelled more than half of electricity production in the United States. However, over the past two decades or so, gas-fired plants have been preferred for new capacity, causing coal's share of total electricity generation to drop, from 53% in 1990 to 43% in 2011. Gas-fired generation was favoured in 2012, particularly in eastern regions where coal prices are relatively high, due to low-cost gas (from continued growth in shale gas production) and reduced electricity needs (from a historically warm winter). At one point in early spring 2012, gas and coal had almost the same share of electricity output, at around 33% each (US EIA, 2013). Since that time, gas prices have risen to around $3.8/MBtu in June 2013 and coal has regained some market share: it was back to almost 40% of total electricity, with gas falling to 28%.

The power sector, as in most other countries, holds the key to US coal demand. In the New Policies Scenario, coal-fired generation declines both in relative and absolute terms over the projection period, despite a temporary rebound in the medium term. Power sector coal consumption stood at nearly 625 Mtce in 2011 and is projected to drop to just under 520 Mtce in 2035. Furthermore, the US fleet of coal-fired power plants is ageing and will be affected by increasingly stringent environmental regulations.

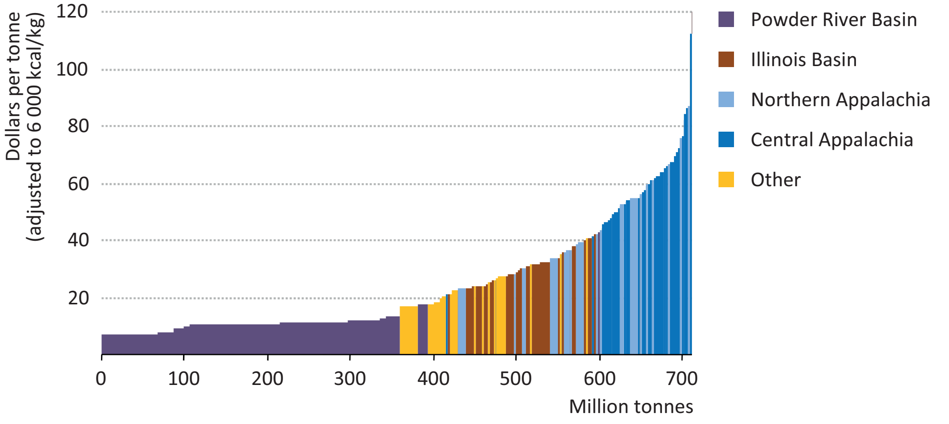
One new set of regulations, the Mercury and Air Toxics Standards, which are expected to be implemented by 2016, could lead to the closure of more than 20 GW of coal-

10. See *Medium-Term Coal Market Report 2012* for an in-depth analysis of the US coal market (IEA, 2012).

fired capacity by some estimates (Beasley, *et al.*, 2013).[11] Recent announcements by the US administration, instructing the US Environmental Protection Agency (EPA) to draft carbon pollution standards for new and existing coal-fired power stations, if adopted, may have an even bigger impact (Box 4.4). The New Policies Scenario cautiously implements emissions reduction strategies, and accordingly, coal-fired capacity falls by 20%, from 335 GW in 2011 to 265 GW in 2035.

US coal production at 765 Mtce in 2011, after a modest recovery in the medium term, is projected to enter a slow decline, echoing falling demand in the New Policies Scenario and reaching 655 Mtce in 2035. High-cost producers in the central Appalachia region (mainly southern West Virginia and eastern Kentucky) are likely to be hit hardest: producing coal there costs on average $65/tonne (Figure 4.10). These high costs put massive pressure on the region's producers in 2011-2012 as low gas prices stimulated unprecedented fuel switching from coal to gas. Among the other main mining regions, costs are lowest in the Powder River Basin (Wyoming and Montana), at around $10/tonne, though energy content is low and transport distances are long. Depending on how far Powder River Basin coal is transported, freight can add costs of $25-35/tonne, though this coal is still cost competitive with coal from most other US regions and with gas (even at low gas prices) as long as coal does not carry a substantial cost burden as a result of policy interventions, *e.g.* for environmental purposes. Production costs in the other main regions – the Illinois Basin (western Kentucky, Illinois, and Indiana) and northern Appalachia (mainly Pennsylvania, northern West Virginia and Ohio) – lie between the two. Adjusting for energy content, the United States can produce around 600 Mt per year at a mine-mouth cost of $40/tonne or less.

**Figure 4.10 ▷ US production cash costs for domestic steam coal, 2012**




Sources: Wood Mackenzie databases and IEA analysis.

11. The Cross-State Air Pollution Rule, a separate rule to the Mercury and Air Toxics Standards, that could have had a significant impact on coal-fired power plants, was ruled void in late 2012.

**Box 4.4 ▹ US President's Climate Action Plan**

In June 2013, the US administration outlined a climate action plan, encompassing measures to reduce the country's greenhouse-gas emissions, prepare the nation for the impacts of climate change and lead international efforts to combat climate change. In the absence of congressional agreement on climate policy, the plan relies mainly on executive powers. One important measure covers carbon emissions from existing and new power plants, potentially covering, *inter alia*, some 335 GW of coal-fired generating capacity. The plan includes a mandate to the EPA to develop regulations to control $CO_2$ emissions from power plants, similar to existing federal limits on emissions of arsenic, lead and mercury.

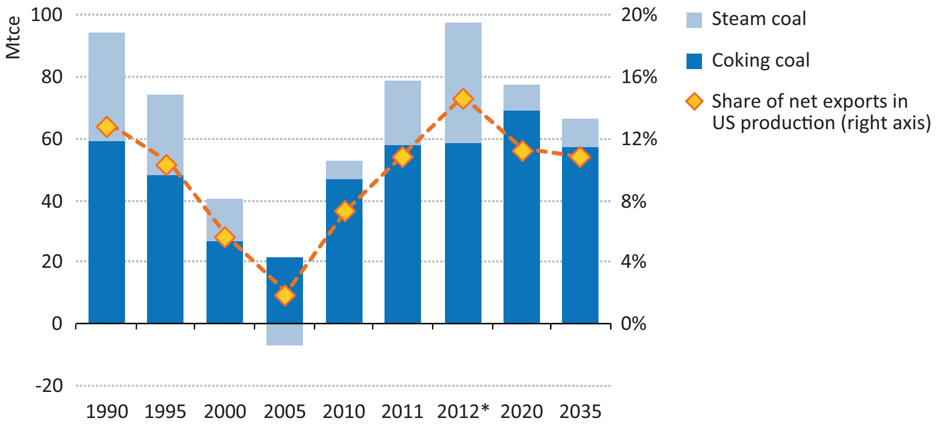
The first ever national standards for new power plants, which require them to limit $CO_2$ emissions to 1 000 pounds (454 kg) per megawatt-hour (MWh), were proposed in March 2012. Following extensive public consultation, a revised standard was issued in late September 2013, limiting new coal-fired plants to emissions of 1 100 pounds (499 kg)/MWh. New gas-fired plants were limited to emissions of 1 000 pounds/MWh. Since even best practice coal-fired plants cannot produce electricity with emissions below 700 kg/MWh, the latest EPA provision effectively means that no new coal-fired plants can be built without a significant portion of emissions being captured and sequestered. Best practice combined-cycle gas units can meet the EPA gas-fired power emissions standard without CCS.

With the standard set for new power plants, the EPA can be expected to issue guidance on standards for existing power plants, based on wide ranging consultations with a variety of stakeholders, and using a co-operative approach with states. Each state will be asked to develop and submit plans to reduce emissions from existing coal-fired plants, using strategies that are flexible, account for regional diversity, and allow every available fuel source to continue to be utilised. The timing for this part of the initiative is ambitious, with a first proposal from EPA by June 2014, a final one by June 2015 and state plans in 2016. Compliance actions could be required as soon as 2018. An alternative compliance method, which would allow the averaging of emissions over a number of years, is also being considered, and depending on its final form, could significantly alter the impact of the regulations.

The US President's Climate Action Plan is also designed to stimulate investment in advanced fossil energy projects, with up to $8 billion in loan guarantees to be offered for innovative technologies that can avoid, reduce or sequester $CO_2$ emissions. The plan also includes working with other countries heavily dependent on coal-fired power to speed up the development and deployment of clean coal technologies, as well as measures to promote coal-to-gas switching in the power sector.

The prospects for US coal production depend on export demand as well as domestic needs. Net exports of coal in the New Policies Scenario are projected to remain around 80 Mtce for much of the projection period, helping to compensate for falling domestic demand, before dipping to 65 Mtce by 2035. The share of net exports in total production remains broadly flat at around 11%; however net exports of steam coal are quite modest after 2015 (Figure 4.11). Net exports of steam coal alone increased by over 80% to reach record levels of 40 Mtce in 2012 as steam coal, especially from the eastern states, was increasingly displaced by gas in the power sector. Much of the displaced coal went to Europe, where higher gas prices prevailed, making increased coal imports competitive in the power sector (see Chapter 5, Box 5.1). The recent rapid growth of US exports, in combination with dwindling US coal imports from Colombia, has been a major contributor to ample supply on the international steam coal market.

**Figure 4.11 ▷ US net exports of coal in the New Policies Scenario**




* Preliminary data.

The regional origin of exported coal from the United States is expected to shift gradually from the east to west in the New Policies Scenario. High costs and reserves depletion reduce steam coal exports from the Appalachian basins, while steam coal exports from the Illinois basin and the western United States grow moderately. For coking coal the situation is different, as exported coal comes exclusively from the Appalachian basins. Coal exports from the Powder River Basin are profitable under current market circumstances, but any large-scale expansion of these exports would require substantial capital investment in US or Canadian port facilities on the west coast, as well as the upgrading of the existing railway infrastructure. Public opposition to coal exports through west coast ports is growing and is likely to delay projects. Moreover, due to the relatively low energy content of the Powder River Basin coals and the long transport distance to Asian demand centres, the economics of coal exports are particularly exposed to changes in freight rates and railway tariffs. Uncertainty about future export demand is an element of investment risk, while China's current and potential future policies towards restricting low calorific-value coal imports further exacerbate this risk. Nonetheless, the current price differentials between western US and international coal prices provide a strong incentive to seek innovative ways of exporting this coal to Asia (Figure 4.9).

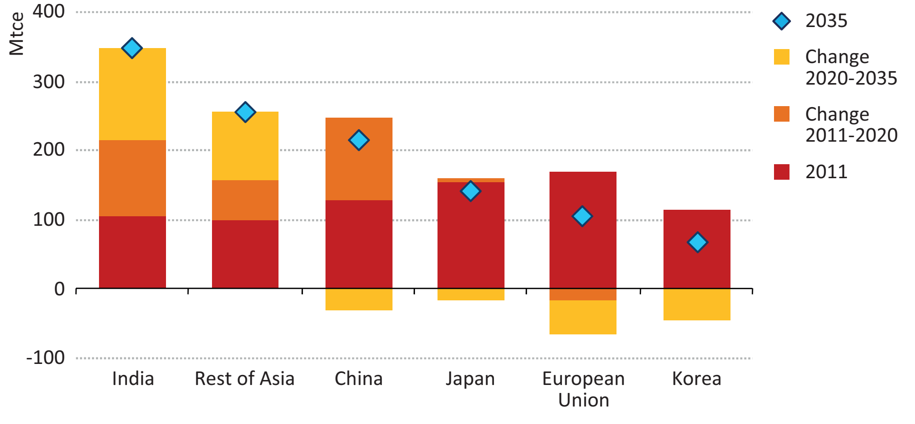
### *India*

The outlook for coal demand in India – the world's third-largest coal consumer – contrasts starkly with that of China. As in China, coal has played a pivotal role in India's recent economic growth – coal use doubled between 2000 and 2011 to 465 Mtce (and nearly 485 Mtce in 2012 based on preliminary data), with growth accelerating in the latter half of this period. Two-thirds of demand now comes from the power sector, where coal accounts for 68% of electricity output. Industry makes up almost all the balance of coal demand, dominated by iron and steel, and cement. Unlike China, demand continues to grow strongly in the New Policies Scenario, more than doubling by 2035. India overtakes the United States as the world's second-largest coal user soon after 2020; yet per-capita electricity use remains very low at that time, suggesting considerable potential for further demand growth for electricity (and coal). It is estimated that in 2011, one out of four people in India (about 306 million) did not have access to electricity, while two out of three (about 818 million) relied on the traditional use of biomass for cooking (see Chapter 2). Despite the doubling in coal use to generate power, coal's share of electricity output declines, from 68% in 2011 to 56% in 2035, as renewables, nuclear and gas gain share. Around half of the new coal-fired capacity installed over the projection period is based on subcritical technologies. Industrial coal demand also more than doubles to 2035, increasing its share in the sector, on the back of a tripling of crude steel output and a doubling of cement production.

India has a large, although generally poor quality, coal resource base of around 210 billion tonnes (BGR, 2012). Coal output expanded rapidly – by more than two-thirds – between 2000 and 2009. Output has barely increased since then, as the state-owned mining company, Coal India Limited, which dominates the sector, has faced a number of difficulties, including lack of access to coal deposits, a lack of or mismatch of rail capacity and limited access to advanced mining technology. Many coal deposits are in populated or forested areas, necessitating significant disturbance to ecosystems or the movement of large numbers of people if open-cut mining methods are to be used. Increasing the level of competition in the Indian coal sector, as well as allowing for foreign investment, would introduce advanced mining technology, and facilitate an expansion of supply and higher productivity. The difficulties in bringing new mining capacity online are expected to persist in the current decade, resulting in the majority of India's projected 75% increase in coal output in the New Policies Scenario occurring after 2020.

With domestic coal output struggling to keep up with booming demand (which has resulted in coal-fired capacity running well below technical limits in many regions), Indian imports have nearly doubled since 2008. India's coal-import dependency has increased significantly over the past decade, a trend that is expected to persist over the projection period. Imports as a share of supply jumped from 9% in 2000 to 23% in 2011. According to preliminary data, imports grew a further 17% in 2012, resulting in India overtaking Korea to become the world's fourth-largest coal importer, behind China, the European Union and Japan. India's coal imports in the New Policies Scenario overtake those of both Japan and the European Union before 2020 and, shortly thereafter, those of China, making India the world's largest coal importer (Figure 4.12). Imports reach 350 Mtce by 2035, although this expansion is contingent both on a massive expansion of port infrastructure and rail delivery systems, and also on strategically locating several new plants closer to the importing ports.

**Figure 4.12 ▷ Major net importers of coal in the New Policies Scenario**



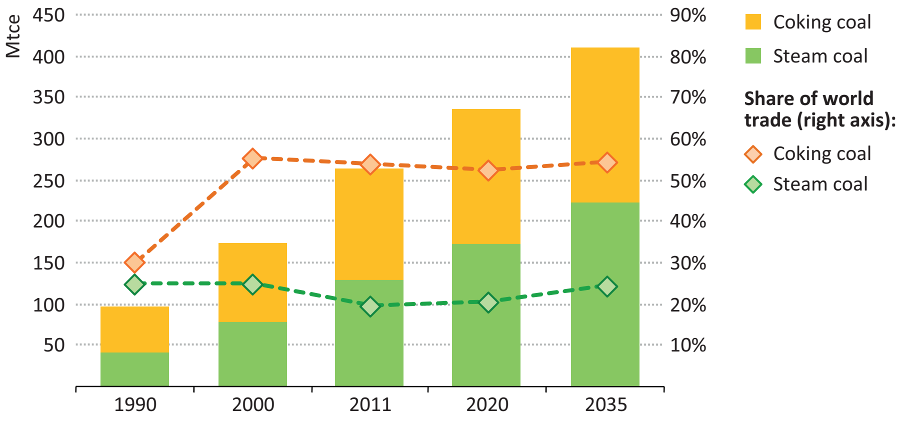

The price of imported coal to Indian power generators will determine the level of demand. Private generators have recently been squeezed by long-term fixed prices under power purchase agreements coupled with rising costs from more expensive coal imports, compared with local output. A price pooling system has recently been agreed, whereby local and imported coal prices are rolled together and the resultant price applied uniformly to all generators. In addition, the government has also recently agreed to allow the pass- through of imported coal prices for power producers. While only the first steps in opening this market, these developments are likely to facilitate increased coal supply.

Australia is the major supplier of coking coal to India, while Indonesia and South Africa are the main sources of steam coal. Indonesia is set to remain the largest steam coal supplier to India into the medium term, but Australia figures more prominently later in the projection period. To satisfy the growing need for imports, Indian investors are acquiring resources overseas, including in Australia, Mozambique and Indonesia. For example, in Australia, large steam coal projects supported by Indian investors are planned for the Galilee Basin in Queensland, with an annual export capacity of some 120 Mt (BREE, 2013).

### *Australia*

Australia is now the second-largest coal exporter in the world, having been overtaken by Indonesia in 2012. It is set to continue to vie for the top spot over the projection period, regaining it around 2030 in the New Policies Scenario. Based on preliminary data, Australian coal exports jumped almost 6% in 2012, to nearly 280 Mtce, about half of which was coking coal (Australia still leads coking coal exports, supplying over 50% of all internationally traded coking coal). Australian coal exports are projected to continue to increase substantially, to 410 Mtce in 2035 – up 57% from 2011 levels (Figure 4.13). Steam coal exports grow by three-fourths to around 225 Mtce, with most of the increase expected to come from the as yet undeveloped Galilee Basin in central Queensland, while coking coal exports grow by nearly 40%, to 190 Mtce. Australia's share of international trade in steam and coking coal rises by five percentage points (to 24%) and one percentage point (to 54%), respectively, largely at the expense of the United States. The main destinations for Australian steam coal are Japan, Korea, Chinese Taipei and, since 2009, China. Australian coking coal is sold as far away as Brazil and Europe, as the higher value of the coal justifies transport over longer distances.

**Figure 4.13 ▷ Australian coal exports by type in the New Policies Scenario**




A few years ago, high productivity, favourable geological conditions and good coal quality meant that Australian coal exporters were positioned roughly half way along the global supply cost curve for internationally traded steam coal – despite comparatively high labour costs. Today, the costs of Australian mines are among the highest (Figure 4.5). This change has come about as a result of deteriorating mining conditions, escalating labour costs, the increased costs of mining materials and appreciation of the Australian dollar.[12] The first two of these effects are a direct or indirect result of the resources and minerals boom that has been a feature of the Australian economy in recent years. Cutting costs to remain

12. The importance of the exchange rate is illustrated by a simple calculation: coal sales at \$100/tonne yield A\$128/tonne at the 2009 exchange rate of \$1 = A\$1.28, but at the 2012 rate of A\$0.97, only A\$97/tonne, slashing revenues needed to pay costs in local currency (such as labour or transport) by more than A\$30.

competitive in the international market is a key challenge for Australian coal exporters over the *Outlook* period. A recent fall in the exchange rate by around 15%, indicating a decline in the value of the Australian dollar, will certainly improve profitability, but the currency remains well above its historical level, with continuing impacts on investment prospects.

Investment in Australia's resource sector has seen a massive boom over recent years. While liquefied natural gas (LNG) projects have played a large part (see Chapter 3), expanding production of steam and coking coal has also been significant. However, new coal mines have become more capital-intensive in recent years, due to escalating costs for mining equipment and construction labour. Australia is now one of the most expensive places to build a new mine. Even so, 93 coal projects are planned, with total capacity of up to 590 Mt per year, although only 16 of these, with a capacity of some 60 Mt per year, have been committed (BREE, 2013). Of greatest interest among the uncommitted projects are five large, greenfield steam coal mines in the Galilee Basin (with capacities totalling nearly 180 Mt), three of which have significant Indian involvement.

### *ASEAN*[13]

Coal use in ASEAN countries is poised to triple, driven by rapid economic and population growth (see Chapter 2). The power sector will be the principal driver of coal demand. In the New Policies Scenario, electricity demand more than doubles from around 700 TWh in 2011 to 1 880 TWh in 2035, growth equivalent to more than Japan's electricity output in 2010. Mirroring the trend seen in China and India, coal is emerging as the fuel of choice for power generation in the ASEAN region. Coal already accounts for some three-quarters of thermal power generation capacity under construction in ASEAN countries, resulting in coal's share of the electricity mix growing rapidly from around 30% to 49% over 2011-2035, mainly at the expense of natural gas and oil. This boosts ASEAN coal demand from 130 Mtce in 2011 to 400 Mtce in 2035, a growth rate of 4.8% per year – the fastest of any major coal-consuming region or country (Figure 4.14). Coal use in ASEAN exceeds that in the European Union before 2030.

ASEAN coal demand growth is supported by the relative abundance and low cost of local resources and, as yet, a lack of stringent environmental standards. At the same time, gas faces increasing development costs, sometimes low domestic prices and the possibility of realising higher value through LNG exports. One important trend is that the majority of coal-fired power plants under construction or planned employ subcritical technology, locking in low efficiency technology for decades to come. Such plants use up to 15% more coal for a given power output than more efficient supercritical plants, which are financially viable at current coal prices and capital costs (IEA, 2013c).

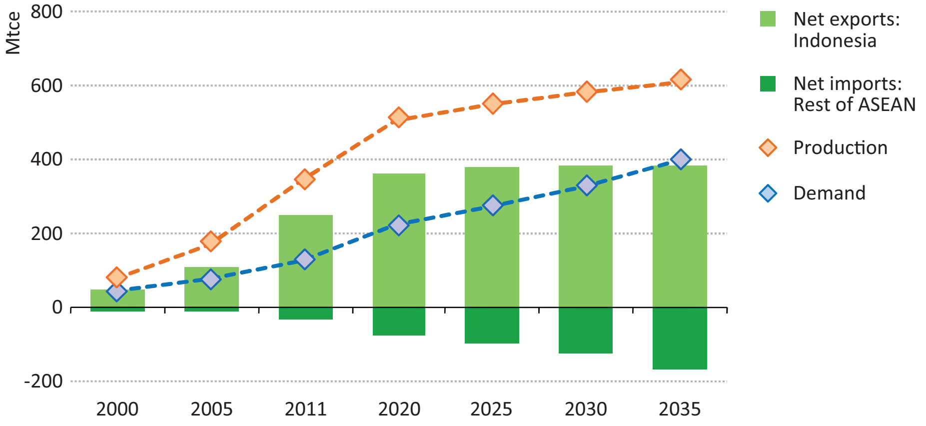
Indonesia, the country with the world's fourth-largest population and ASEAN's largest energy user, is set to lead the growth in the region's coal demand, with its abundant coal resources and an already booming export sector. Coal demand in Indonesia has increased

13. ASEAN energy prospects are analysed in-depth in the *Southeast Asia Energy Outlook*, a *WEO* special report (IEA, 2013c).

at 11% per year for the last two decades. It more than triples in the New Policies Scenario, reaching 165 Mtce in 2035, exceeding the current level of use in Japan. The government plans to meet rapidly rising power demand through a large expansion of coal-fired power generation. It has given priority to increasing coal supply to the domestic market *vis-à-vis* exports. Consequently, the government has set a minimum share of coal production that must be sold to domestic customers. Also, the government has discussed banning low quality coal exports (less than 5 600 kilocalories per kilogramme) to ensure fuel supply for new coal-fired power plants (though formal regulations have not been adopted).



**Figure 4.14 ▷ ASEAN coal balance in the New Policies Scenario**




Thailand, the region's second-largest energy user, currently has a power sector dominated by gas, but interest in coal-fired power is increasing, mainly in response to energy security and cost issues. In Malaysia, coal also grows in importance as the rise in gas demand outstrips indigenous gas supply growth. In the Philippines, coal accounts for two-thirds of incremental power generation over 2011-2035 (IEA, 2013c).

In the New Policies Scenario, the ASEAN region sees a continuation of strong growth in coal production in the medium term with output rising to 510 Mtce in 2020. Indonesia is the main source of coal to meet both strong growth in domestic use and demand for steam coal exports to the Asia-Pacific market. Over the long term, production from the region slows as coal producers face rising costs in developing their resources, as a result of higher costs for mining, labour and transport, which undermine the competitiveness of exports.

Excluding Indonesia, ASEAN countries as a group see coal imports rise more than five-fold over the projection period, exceeding Japan's current import levels. A significant increase in Vietnam's coal-fired power generation in the short term, to improve electricity reliability, is set to shift the country from being a net exporter to a net importer of coal, though the extent and timing depends on the efficiency of generating technologies chosen for these plants, as well as the pace at which they are commissioned. Facilities are being developed that would receive coal imports from Australia, Indonesia and Russia.

# Power sector outlook

## Capacity to change?

### Highlights

- Demand for electricity grows more than demand for any other final form of energy. In the New Policies Scenario, world electricity demand increases by more than two-thirds over the period 2011-2035, growing at an average rate of 2.2% per year. It is driven by increasing electrification of industry, where electricity's share grows from 26% to 32%, expanded use of electrical appliances and more cooling in buildings.
- Non-OECD countries account for the greater part of incremental electricity demand by far, led by China (36%), India (13%), Southeast Asia (8%), Latin America (6%) and the Middle East (6%). In terms of electricity demand per capita, the gap narrows between non-OECD and OECD countries, but only Russia, China and the Middle East exceed even half of the OECD average in 2035; sub-Saharan Africa reaches just 6% of the OECD average at the end of the projection period.
- Global installed generating capacity grows by over 70%, from 5 649 GW in 2012 to about 9 760 GW in 2035, after retiring some 1 940 GW of generating capacity. About 60% of retirements are in OECD countries, where about two-thirds of the coal fleet is already over 30 years old. China's additions of coal, nuclear (more than current nuclear capacity in the United States) and renewables are the most of any region. Additions of renewables in the European Union are the second-largest globally.
- Though it remains the leading fuel, coal's share of generation falls from 41% to 33%. The share of renewables rises from 20% to 31% while the shares of gas and nuclear hold steady at 22% and 12% respectively. Though total $CO_2$ emissions increase, greater use of lower-carbon sources and more efficient fossil-fuelled plants contribute to a 30% drop in the $CO_2$ emissions intensity of the power sector.
- The length of transmission and distribution (T&D) lines expands from 69 million km in 2012 to 94 million km in 2035, largely in response to fast-growing electricity demand in non-OECD countries, including that of new end-users. By 2035, around 50% of today's grid infrastructure will have reached 40 years of age, necessitating major investments in refurbishment during the projection period.
- Substantial investments in the power sector will be required over the projection period to satisfy rising electricity demand and to replace or refurbish ageing infrastructure. Cumulative global investment in the power sector is $17.0 trillion over 2013-2035, averaging $740 billion per year. New plants account for 58% of the total, while the rest is needed in T&D networks.
- Electricity prices rise in most regions, with widening regional differences. By 2035, US industrial electricity prices are half the level in the European Union and 40% lower than those in China, which could have important ramifications for competitiveness.

## Introduction

The power sector is a complex amalgam of thousands of power plants, millions of kilometres of lines in the transmission and distribution network and billions of end-users, with system operators balancing demand and supply in real time. Many factors influence the pace of electricity demand growth such as gross domestic product (GDP), electricity prices, population growth, the proportion of population with access to electricity supply, standards of living, and the extent of the deployment of energy-efficient equipment. The evolution of the mix of generating plants to meet demand depends largely on the relative economics of different energy technologies, taking account of fossil-fuel prices, carbon-dioxide ($CO_2$) pricing (if applicable), the capital costs of power plants, financing conditions, policies to promote or limit the deployment of specific technologies, the availability of domestic fuel resources, the age of the existing power plant fleet and the structure of the power market.

Which power plants are run to meet electricity demand typically depends on the variable costs of their operation. Plants with the lowest variable costs are generally dispatched first, however, much depends on how the local power market is organised. There are two basic designs: fully liberalised markets and fully regulated systems though, in practice, most systems have some features of both designs. Worldwide, most power is generated in relatively highly regulated systems. The design of the system determines how prices are formed and the conditions for investment. Policy interventions have to be tailored to the design of the individual system.

The last twelve months have seen significant developments in a number of electricity markets around the world. For example, in the United States, exceptionally low gas prices in 2012 led to a strong surge in gas-fired electricity generation, displacing coal-fired generation. The opposite was true in the European Union: as natural gas became increasingly expensive, compared to coal, this – in combination with low $CO_2$ prices, weaker economic activity, lower electricity demand and continued expansion of renewable-based capacity – led to a noticeable drop in gas-fired generation in 2012 compared to the previous year. Europe has also seen continued strong growth of variable renewables that have increasingly impacted the operation of conventional power plants and lowered wholesale power prices in some systems.

Japan saw a surge in renewables capacity, in response to new support policies put in place, in particular for solar photovoltaics (PV), designed to curtail the sharp rise in the cost of importing fuels for oil- and gas-fired generation following the substantial reduction of nuclear power generation after the Fukushima Daiichi accident. In Korea, the temporary closure of almost 40% of the nuclear fleet while safety reviews were conducted increased the call on fossil-fuelled power plants and created a tight supply-demand balance for electricity, requiring energy saving measures, such as limiting air conditioning.

In China in 2012, the rate of growth of electricity demand diminished, while it was a particularly good year for hydropower production (due to relatively high rainfall). One result was that coal-fired generation remained fairly flat. A temporary suspension of approvals for nuclear plants was lifted and construction of new plants restarted, although at a slower pace than before the Fukushima Daiichi accident. An ambitious new target for 2015 for solar PV was introduced towards the end of the year. In India in 2012, low availability of gas and lower than planned capacity additions (partly due to unfavourable market frameworks) tightened the demand-supply balance. Similar tightness was experienced in Brazil, due to low hydropower reservoir levels, resulting in a strong call on fossil fuel-fired power plants throughout the year. Southeast Asia saw a continued push towards investment in new coal-fired power plants, aimed either at reducing costly gas-fired generation, or boosting gas exports (in gas-producing countries).



## Electricity demand

World electricity demand nearly doubled between 1990 and 2011, growing at an average rate of 3.1% per year. Between 2011 and 2035, demand for electricity grows more than any other final form of energy in all of the three scenarios analysed in this *Outlook*. Electricity demand is strongly linked to future economic growth, the overall level of which tends to be reflected in the level of economic activity in key electricity-consuming sectors (such as in industry and services). The rate of electricity demand growth in the three scenarios depends primarily on the nature and extent of government interventions, particularly policies related to energy efficiency, the environment and energy security. Some of these policies influence electricity demand directly, such as measures to improve end-use efficiency and to encourage fuel switching, and some indirectly, through their impact on final prices. In the New Policies Scenario, the central scenario in this *Outlook*, world electricity demand increases by more than two-thirds over the period 2011-2035, growing at an average rate of 2.2% per year. Demand rises more quickly in the Current Policies Scenario (2.5% per year) and more slowly in the 450 Scenario (1.7% per year) (Table 5.1).

In the three scenarios, differing policy measures and electricity prices determine the rate of uptake of more energy-efficient technologies and overall rates of improvement in energy efficiency. In 2035, world demand is projected at 32 150 terawatt-hours (TWh) in the New Policies Scenario, with variations 12% below this figure and 7% above it. Taking electricity intensity – electricity consumption per unit GDP – as a broad indicator of energy efficiency[1] in electricity end-uses, the New Policies Scenario sees an average annual rate of improvement of 1.1% during the projection period, whereas energy efficiency advances more slowly in the Current Policies Scenario (0.8% per year) and more quickly in the 450 Scenario (1.6% per year). Without any change in electricity intensity with respect to the last five years, world electricity demand would rise to 43 100 TWh in 2035. In the New Policies Scenario, it is lower by about one-quarter (Figure 5.1). Energy efficiency is the main driver of this difference (Chapter 7), although the shift towards less energy-intensive sectors plays an important role too.

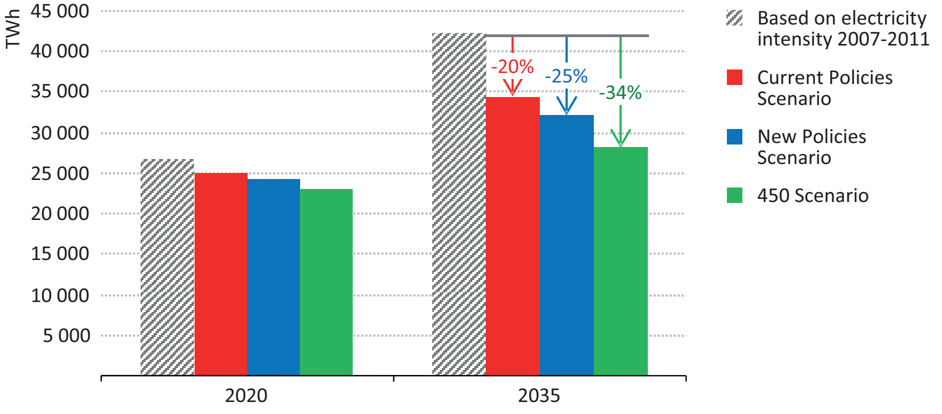
1. For any country, measuring energy efficiency is challenging as it requires extensive data collection and analysis. As an imperfect proxy, the electricity intensity gives a broad indication of strides towards improvements in energy efficiency, but it is important to note that each country will have significantly different electricity intensities based on factors such as level of industrialisation and climate.

**Table 5.1 ▷ Electricity demand* by region and scenario** (TWh)

| | 1990 | 2011 | New Policies | | Current Policies | | 450 Scenario | |
|---|---|---|---|---|---|---|---|---|
| | | | 2035 | 2011-2035** | 2035 | 2011-2035** | 2035 | 2011-2035** |
| **OECD** | **6 591** | **9 552** | **11745** | **0.9%** | **12 369** | **1.1%** | **10 934** | **0.6%** |
| Americas | 3 255 | 4 694 | 5 912 | 1.0% | 6 103 | 1.1% | 5 457 | 0.6% |
| United States | 2 713 | 3 883 | 4 753 | 0.8% | 4 883 | 1.0% | 4 438 | 0.6% |
| Europe | 2 320 | 3 160 | 3 740 | 0.7% | 4 040 | 1.0% | 3 564 | 0.5% |
| Asia Oceania | 1 016 | 1 698 | 2 093 | 0.9% | 2 226 | 1.1% | 1 912 | 0.5% |
| Japan | 758 | 954 | 1 119 | 0.7% | 1 195 | 0.9% | 993 | 0.2% |
| **Non-OECD** | **3 493** | **9 453** | **20 405** | **3.3%** | **22 084** | **3.6%** | **17 323** | **2.6%** |
| E. Europe/Eurasia | 1 584 | 1 367 | 2 004 | 1.6% | 2 171 | 1.9% | 1 730 | 1.0% |
| Russia | 909 | 838 | 1 256 | 1.7% | 1 375 | 2.1% | 1 075 | 1.0% |
| Asia | 1 049 | 5 888 | 13 913 | 3.6% | 15 211 | 4.0% | 11 758 | 2.9% |
| China | 558 | 4 094 | 8 855 | 3.3% | 10 023 | 3.8% | 7 417 | 2.5% |
| India | 212 | 774 | 2 523 | 5.0% | 2 582 | 5.2% | 2 198 | 4.4% |
| Middle East | 190 | 702 | 1 484 | 3.2% | 1 587 | 3.5% | 1 216 | 2.3% |
| Africa | 262 | 584 | 1 296 | 3.4% | 1 304 | 3.4% | 1 094 | 2.7% |
| Latin America | 407 | 912 | 1 708 | 2.6% | 1 811 | 2.9% | 1 525 | 2.2% |
| Brazil | 214 | 471 | 939 | 2.9% | 1 001 | 3.2% | 834 | 2.4% |
| **World** | **10 085** | **19 004** | **32 150** | **2.2%** | **34 454** | **2.5%** | **28 256** | **1.7%** |
| European Union | 2 241 | 2 852 | 3 246 | 0.5% | 3 512 | 0.9% | 3 120 | 0.4% |

* Electricity demand is calculated as the total gross electricity generated less own use in the production of electricity, less transmission and distribution losses. ** Compound average annual growth rate.

**Figure 5.1 ▷ World electricity demand by scenario relative to electricity demand assuming no change in electricity intensity**



In the New Policies Scenario, industry maintains its position as the largest consumer of electricity throughout the *Outlook* period, accounting for 41% of total electricity demand in 2035. Industry demand growth averages 2.2% per year during the projection period (Table 5.2), underpinned by increasing electrification of industrial processes, with electricity increasing its share of total energy supply to the sector from 26% to 32%. Demand in the residential sector expands at 2.5% per year, more than two-and-a-half times faster than the rate of population growth, reflecting increased use of electrical appliances, more cooling and improved access to electricity. The share of the world population without access to basic electricity services falls from 18% (1.2 billion) in 2011 to 12% (970 million) in 2030 (see Chapter 2). Demand in the services sector increases more slowly, by 1.9% per year, the slower rate of growth reflecting energy efficiency measures in OECD countries and the direct use of renewables for heat. Electricity demand in the transport sector is the fastest-growing (averaging 3.9% per year), due to a doubling of electricity demand from rail. However, transport accounts for only just over 2% of total electricity demand in 2035, despite the inroads made by electric vehicles between 2011 and 2035, and the associated demand increasing by about 30% per year (though from a low level).



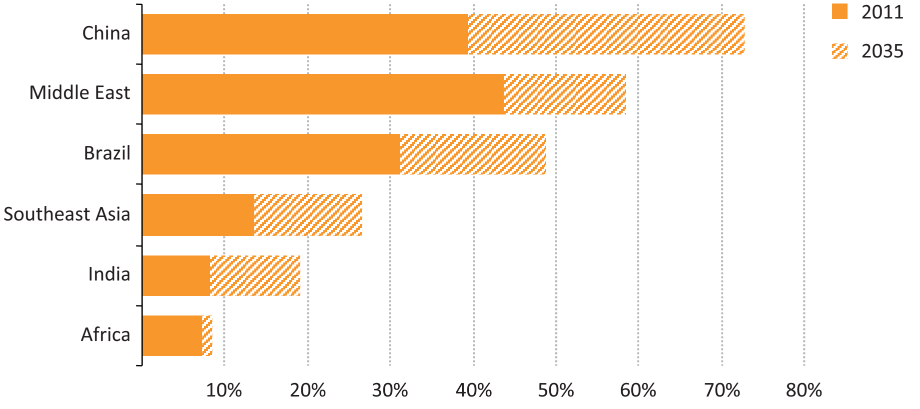
**Table 5.2 ▹ World electricity demand by sector and generation in the New Policies Scenario** (TWh)

| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011-2035** |
|---|---|---|---|---|---|---|---|
| **Demand** | **10 085** | **19 004** | **24 249** | **26 974** | **29 520** | **32 150** | **2.2%** |
| Industry | 4 419 | 7 802 | 10 288 | 11 385 | 12 268 | 13 187 | 2.2% |
| Residential | 2 583 | 5 195 | 6 507 | 7 362 | 8 325 | 9 336 | 2.5% |
| Services | 2 086 | 4 560 | 5 636 | 6 214 | 6 698 | 7 137 | 1.9% |
| Transport | 245 | 292 | 408 | 486 | 590 | 734 | 3.9% |
| Other sectors | 748 | 1 151 | 1 419 | 1 535 | 1 648 | 1 763 | 1.8% |
| T&D losses | 1 003 | 1 816 | 2 308 | 2 589 | 2 862 | 3 138 | 2.3% |
| PG own use | 733 | 1 298 | 1 434 | 1 550 | 1 668 | 1 791 | 1.4% |
| **Gross generation*** | **11 818** | **22 113** | **27 999** | **31 121** | **34 058** | **37 087** | **2.2%** |

* Gross generation includes demand in final uses (industry, residential, services, transport and other), losses through transmission and distribution (T&D) grids, and own use by power generators (PG). ** Compound average annual growth rate.

Non-OECD countries account for by far the greater part of incremental electricity demand, driven by faster economic and population growth, shifts from rural to urban living and rising standards of living. In the New Policies Scenario, the largest sources of additional global demand are China (36%), India (13%), Southeast Asia (8%), Latin America (6%) and the Middle East (6%). Electricity demand growth in China abates considerably: having averaged 12% per year over 2000-2011, it slows to 3.3% per year over 2011-2035 (with slowing economic growth and a restructuring of the economy towards less energy-intensive sectors). Demand increases most rapidly in India (5.0% per year) and Southeast Asia (4.2%). In terms of electricity demand per capita, the gap narrows between non-OECD and OECD countries, but among developing countries, only China and the Middle East exceed even half the OECD average in 2035 (Figure 5.2). The level remains very low in sub-Saharan Africa, at 520 kWh, or just 6% of the OECD average, in 2035.

**Figure 5.2 ▷ Electricity demand per capita in selected regions as a share of the OECD average in the New Policies Scenario**




Note: In the New Policies Scenario, average electricity demand per capita in OECD countries grows from 7 670 kWh in 2011 to 8 500 kWh in 2035.

## Electricity supply

World electricity generation increases in line with incremental growth in electricity demand in each of the scenarios.[2] The mix becomes more diverse, though the nature of its evolution varies by region according to government policies and competition between generation types. The scenarios differ most with respect to the pace of the transition from fossil-fuelled to low-carbon generation (Table 5.3). This depends critically on the timing and the rigour of policies adopted to address environmental concerns (local pollution and $CO_2$ emissions) – which arise earliest and are strongest in the 450 Scenario (see Chapter 2) and are more limited in the Current Policies Scenario than in the New Policies Scenario – as well as on relative investment costs and fuel prices for different generating technologies.

In the New Policies Scenario, world electricity generation increases from 22 113 TWh in 2011 to almost 37 100 TWh in 2035 (or by two-thirds), growing at an average rate of 2.2% per year. Fossil fuels continue to have a dominant role, although their combined share declines from 68% to 57%: coal remains the largest source of electricity generation, growing steadily at around 1.2% per year. Natural gas expands most by almost 3 500 TWh. Amongst the renewable energy technologies, increases in generation from hydropower and wind, about 2 300 TWh each, are highest, with renewables as a group accounting for almost half of the increase in global electricity generation over 2011-2035.

2. In each of the scenarios the rate of growth for electricity generation is actually slightly lower than that for demand, reflecting falling shares of transmission and distribution losses, and own use by power generators.

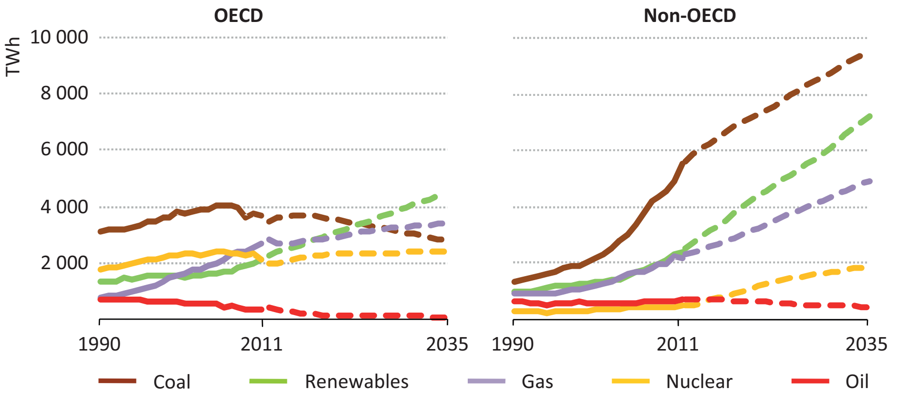
**Table 5.3 ▷ Electricity generation by source and scenario** (TWh)

| | | | New Policies | | Current Policies | | 450 Scenario | |
|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2035 | 2020 | 2035 | 2020 | 2035 |
| **OECD** | **7 629** | **10 796** | **11 827** | **13 104** | **11 990** | **13 835** | **11 415** | **12 123** |
| Coal | 3 093 | 3 618 | 3 529 | 2 775 | 3 681 | 3 835 | 2 961 | 1 116 |
| Gas | 770 | 2 630 | 2 855 | 3 398 | 2 979 | 3 710 | 2 813 | 2 307 |
| Oil | 697 | 345 | 149 | 84 | 153 | 92 | 126 | 44 |
| Nuclear | 1 729 | 2 087 | 2 300 | 2 412 | 2 273 | 2 246 | 2 355 | 2 826 |
| Hydro | 1 182 | 1 388 | 1 490 | 1 615 | 1 476 | 1 586 | 1 523 | 1 730 |
| Other renewables | 157 | 728 | 1 504 | 2 820 | 1 428 | 2 367 | 1 637 | 4 099 |
| **Non-OECD** | **4 189** | **11 317** | **16 172** | **23 983** | **16 799** | **26 018** | **15 139** | **20 173** |
| Coal | 1 333 | 5 522 | 7 089 | 9 537 | 7 901 | 12 296 | 6 043 | 3 544 |
| Gas | 960 | 2 217 | 3 128 | 4 915 | 3 242 | 5 463 | 2 958 | 3 686 |
| Oil | 635 | 717 | 652 | 472 | 666 | 522 | 578 | 278 |
| Nuclear | 283 | 497 | 1 100 | 1 881 | 1 049 | 1 668 | 1 191 | 3 011 |
| Hydro | 963 | 2 102 | 3 065 | 4 212 | 2 936 | 3 891 | 3 144 | 4 665 |
| Other renewables | 15 | 263 | 1 138 | 2 965 | 1 004 | 2 177 | 1 225 | 4 989 |
| **World** | **11 818** | **22 113** | **27 999** | **37 087** | **28 789** | **39 853** | **26 554** | **32 295** |
| Coal | 4 426 | 9 140 | 10 618 | 12 312 | 11 582 | 16 131 | 9 004 | 4 660 |
| Gas | 1 730 | 4 847 | 5 983 | 8 313 | 6 222 | 9 173 | 5 771 | 5 993 |
| Oil | 1 332 | 1 062 | 801 | 556 | 819 | 614 | 705 | 323 |
| Nuclear | 2 013 | 2 584 | 3 400 | 4 294 | 3 322 | 3 914 | 3 546 | 5 837 |
| Hydro | 2 144 | 3 490 | 4 555 | 5 827 | 4 412 | 5 478 | 4 667 | 6 394 |
| Other renewables | 173 | 992 | 2 642 | 5 785 | 2 432 | 4 544 | 2 861 | 9 089 |

The evolution of the power mix in OECD countries is markedly different from that in non-OECD countries, with a stronger shift towards low-carbon technologies, mainly renewables (Figure 5.3). In OECD countries, coal-fired generation declines in absolute terms by almost one-quarter, compared to the level in 2011, and oil-fired generation by three-quarters. By contrast gas-fired generation grows as does nuclear generation (to a lesser degree). Output from renewables sees the strongest growth, increasing by slightly more than the net growth in generation in OECD countries, primarily led by the increase in wind power.

In non-OECD countries, by contrast, coal remains the largest source of generation by a wide margin with coal-fired generation meeting more than 30% of the growth of electricity demand, increasing the most of any source in absolute terms. However, generation from all forms of renewables taken together increase even more in absolute terms and account for almost 40% of non-OECD incremental generation from 2011-2035, led by hydropower and wind. In absolute terms the second-largest increase in non-OECD generation from a single-energy source comes from gas, primarily in the Middle East, China and India, due to the combination of burgeoning energy needs, the availability of gas and policies that support gas use in the power sector. Nuclear is the second-fastest growing source of generation from a single energy source, behind non-hydro renewables.

**Figure 5.3 ▷ Electricity generation by source in the New Policies Scenario**




Relative costs, which are partly influenced by government policies, are one of the main drivers of the projected changes in the types of fuels and technologies used to generate power. For fossil-fuelled generation, especially natural gas, the cost of generation is very sensitive to fuel prices, while for nuclear power and renewables the capital cost of the plant is far more important. Generating costs for each technology vary widely across regions and countries, according to local fuel prices, regulations and other cost factors (IEA/NEA, 2010). Water scarcity, which can pose reliability risks for coal-fired and nuclear plants that use large amounts of water for cooling, can influence the generation mix and generating costs (IEA, 2012). In some regions, including particular areas in Europe and the United States, public opposition to building power infrastructure of almost all types – coal-fired plants as well as wind turbines and transmission lines – is becoming a more important factor in determining the pace at which new projects can be completed.

## *Capacity retirements and additions*

In the New Policies Scenario, generation capacity increases by almost three-quarters from 5 649 gigawatts (GW) in 2012 to 9 760 GW in 2035 in order to satisfy growing demand needs and after allowing for capacity closures over the period (Figure 5.4).[3] Over the projection period, gross capacity additions total 6 050 GW, with about one-third replacing the retirement of 1 940 GW (34% of current installed capacity). The majority of new plants are powered by gas (1 370 GW), wind (1 250 GW) and coal (1 180 GW).

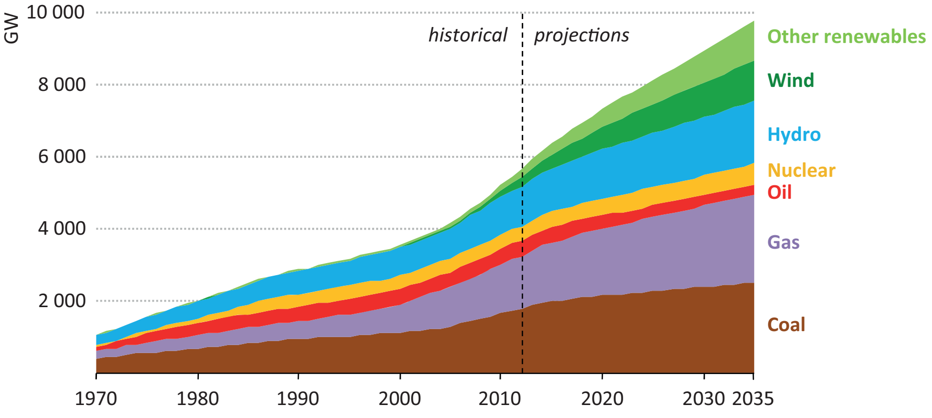
In the *Outlook,* generating capacity is retired once it reaches the end of its technical lifetime.[4] The technical lifetimes of hydropower, coal and nuclear plants are longest (assumed to be 70 years for hydropower, 50 years for coal, and 40-60 years for nuclear depending on the country), followed by gas plants (40 years) and, wind turbines and solar PV installations (20 years). Where the economic case is sound, owners may choose to invest in upgrades or

3. All electrical capacities presented in this *Outlook* are expressed in gross capacity terms.

4. Power plant lifetimes are expressed in both technical and economic terms. The technical lifetime corresponds to the design life of the plant. The economic lifetime is the time taken to recover the investment in the plant and is usually shorter than the technical lifetime (Table 5.5).

refurbishments to extend the lifetime of an ageing plant rather than to retire it and build a new one. In addition, refurbishing an existing power plant may offer a short-term solution to manage the risks from developing environmental regulations, given the long lifetimes for new thermal power plants.

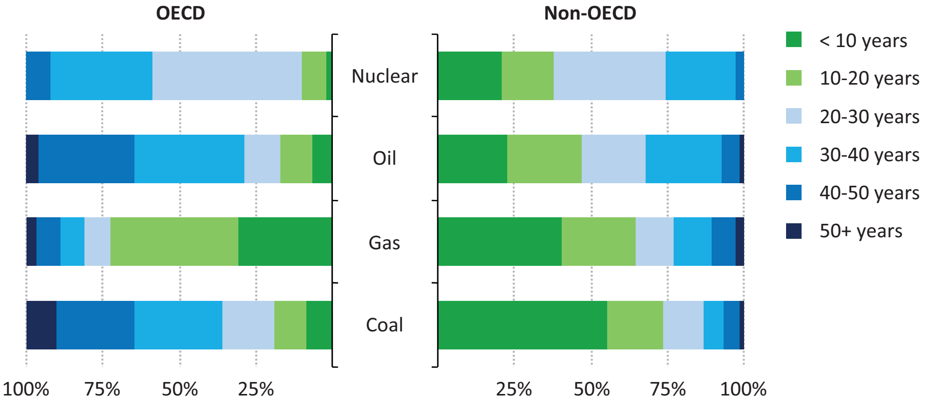
**Figure 5.4 ▷ Installed capacity by source in the New Policies Scenario**






Thermal power plants are older, on average, in OECD countries than in non-OECD countries, meaning that a higher proportion of OECD plants face retirement during the projection period. At the end of 2012, almost two-thirds of the coal-fired capacity in OECD countries was more than 30 years old (Figure 5.5). By contrast, almost three-quarters of coal-fired capacity in non-OECD countries is less than 20 years old. The majority of gas-fired capacity in OECD countries, particularly in the United States and European Union, is young as new plants in the last two decades have been largely gas (and renewables). Age profiles for nuclear power capacity reflect its earlier development in OECD countries and recent growth in developing countries, where most plants in operation were built after 1990.

**Figure 5.5 ▷ Age profile of installed thermal capacity by region, end-2012**




Sources: Platts World Electric Power Plants Database, December 2012 edition; IAEA (2013).

**Table 5.4 ▷ Cumulative capacity retirements by region and source in the New Policies Scenario, 2013-2035** (GW)

| | Coal | Gas | Oil | Nuclear | Bioenergy | Hydro | Wind | Geo-thermal | Solar PV | CSP* | Marine | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **OECD** | **265** | **178** | **147** | **81** | **60** | **80** | **231** | **6** | **124** | **3** | **0** | **1 176** |
| Americas | 109 | 104 | 59 | 10 | 19 | 36 | 86 | 3 | 13 | 1 | 0 | 440 |
| United States | 98 | 96 | 46 | 10 | 16 | 22 | 74 | 3 | 12 | 1 | - | 377 |
| Europe | 123 | 31 | 41 | 45 | 34 | 35 | 135 | 1 | 81 | 2 | 0 | 530 |
| Asia Oceania | 33 | 42 | 46 | 26 | 7 | 10 | 10 | 1 | 31 | 0 | 0 | 205 |
| Japan | 10 | 35 | 42 | 25 | 5 | 7 | 5 | 1 | 27 | - | - | 157 |
| **Non-OECD** | **195** | **183** | **103** | **36** | **22** | **20** | **167** | **4** | **36** | **0** | **0** | **765** |
| E. Europe/Eurasia | 92 | 113 | 17 | 32 | 1 | 1 | 5 | 0 | 2 | - | - | 262 |
| Russia | 43 | 80 | 5 | 20 | 1 | - | 0 | 0 | 0 | - | - | 149 |
| Asia | 78 | 17 | 25 | 2 | 13 | 9 | 150 | 3 | 31 | 0 | 0 | 329 |
| China | 43 | 1 | 3 | - | 7 | 3 | 122 | 0 | 26 | 0 | 0 | 205 |
| India | 26 | 3 | 2 | 1 | 3 | 3 | 26 | - | 3 | - | - | 68 |
| Middle East | 0 | 30 | 38 | - | 0 | 1 | 1 | - | 0 | - | - | 69 |
| Africa | 22 | 13 | 10 | - | 0 | 2 | 2 | 0 | 1 | - | - | 50 |
| Latin America | 3 | 10 | 14 | 1 | 7 | 7 | 10 | 1 | 1 | - | - | 54 |
| Brazil | 2 | 1 | 1 | 1 | 5 | 5 | 8 | - | 1 | - | - | 24 |
| **World** | **460** | **361** | **249** | **117** | **82** | **100** | **398** | **10** | **160** | **3** | **0** | **1 941** |
| European Union | 130 | 33 | 43 | 42 | 34 | 27 | 134 | 1 | 81 | 2 | 0 | 528 |

*CSP = concentrating solar power.

**Table 5.5 ▷ Cumulative gross capacity additions by region and source in the New Policies Scenario, 2013-2035** (GW)

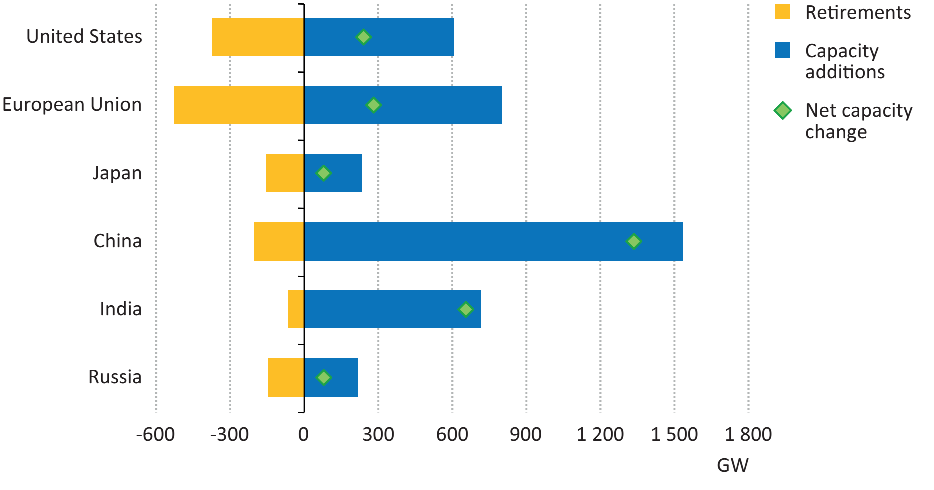
| | Coal | Gas | Oil | Nuclear | Bioenergy | Hydro | Wind | Geo-thermal | Solar PV | CSP* | Marine | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **OECD** | **117** | **525** | **21** | **83** | **113** | **147** | **611** | **24** | **367** | **24** | **13** | **2 046** |
| Americas | 34 | 266 | 8 | 23 | 49 | 60 | 231 | 12 | 104 | 13 | 2 | 802 |
| United States | 27 | 206 | 6 | 19 | 40 | 32 | 169 | 8 | 92 | 11 | 1 | 611 |
| Europe | 52 | 156 | 5 | 31 | 49 | 66 | 325 | 4 | 165 | 9 | 9 | 870 |
| Asia Oceania | 32 | 102 | 8 | 29 | 15 | 21 | 55 | 8 | 98 | 3 | 3 | 374 |
| Japan | 9 | 77 | 7 | 3 | 10 | 15 | 27 | 4 | 79 | - | 1 | 232 |
| **Non-OECD** | **1 065** | **850** | **63** | **219** | **134** | **593** | **635** | **18** | **385** | **45** | **1** | **4 007** |
| E. Europe/Eurasia | 84 | 177 | 1 | 51 | 10 | 29 | 21 | 3 | 7 | - | 0 | 384 |
| Russia | 38 | 116 | 0 | 33 | 7 | 18 | 6 | 2 | 1 | - | - | 222 |
| Asia | 902 | 353 | 11 | 150 | 94 | 370 | 534 | 11 | 302 | 18 | 1 | 2 745 |
| China | 454 | 142 | 1 | 114 | 57 | 188 | 384 | 2 | 177 | 13 | 0 | 1 533 |
| India | 288 | 100 | 2 | 26 | 16 | 82 | 106 | 0 | 92 | 4 | 0 | 717 |
| Middle East | 1 | 153 | 31 | 7 | 4 | 12 | 26 | - | 32 | 14 | - | 281 |
| Africa | 70 | 87 | 11 | 5 | 10 | 61 | 18 | 2 | 26 | 11 | - | 302 |
| Latin America | 8 | 79 | 9 | 5 | 17 | 120 | 36 | 2 | 17 | 3 | - | 295 |
| Brazil | 4 | 32 | 5 | 3 | 12 | 72 | 29 | - | 9 | 1 | - | 166 |
| **World** | **1 182** | **1 374** | **84** | **302** | **247** | **740** | **1 246** | **42** | **752** | **70** | **14** | **6 052** |
| European Union | 49 | 129 | 5 | 29 | 47 | 48 | 311 | 3 | 162 | 9 | 9 | 800 |
| Average economic lifetime (years) | 30 | 25 | 25 | 35 | 25 | 50 | 20 | 25 | 20 | 20 | 20 | |

*CSP = concentrating solar power.

Future gross additions of baseload generation using coal, hydropower and nuclear are concentrated overwhelmingly in non-OECD countries. Gross additions of gas-powered plants during the projection period are also greater in non-OECD countries, which have installed a lower proportion of gas-fired capacity to date. More than 3 100 GW of renewables is added worldwide, nearly double the present installed capacity, though these installations usually generate less electricity overall than the equivalent thermal counterpart, due to the lower capacity factors typically associated with variable resources (see Chapter 6).

In non-OECD countries, most capacity additions are built to meet new demand. China installs more than 1 530 GW during the projection period (Figure 5.6). Of this, 630 GW is non-hydro renewables, accounting for over one-quarter of the global total in that category (about as much as the European Union and Japan combined). Significant additions also come from coal (30% of the total), hydropower (12%) and gas (9%). China adds more nuclear capacity than the total installed nuclear capacity in the United States at present. Its total capacity additions are more than twice those of India, where coal-fired plant makes the biggest contribution to gross capacity additions (about 40%) over 2013-2035. These coal-fired plants are split almost evenly between subcritical and supercritical technologies. Deployment of supercritical technologies helps to raise the average efficiency of Indian coal-fired generation from its very low present level. Non-hydro renewables account for some 30% of India's additions, boosted by the National Solar Mission target and other support policies.

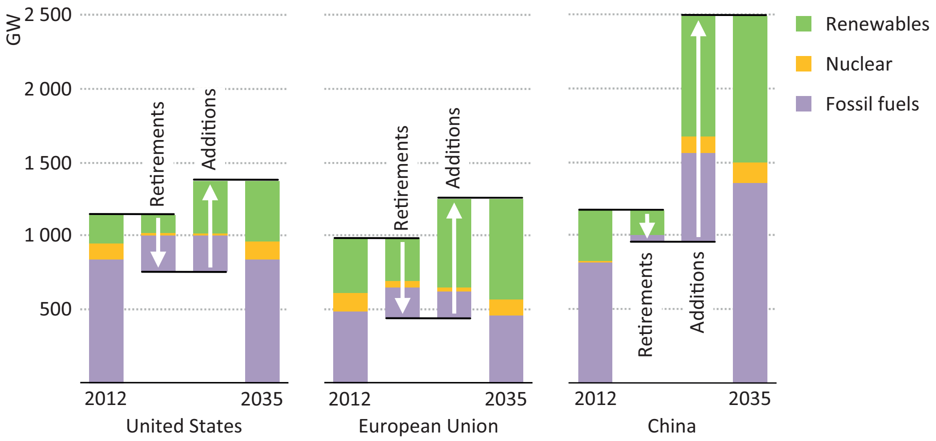
**Figure 5.6 ▷ Power generation gross capacity additions and retirements by selected region in the New Policies Scenario, 2013-2035**




In OECD countries, replacing retired capacity and decarbonising the power mix capacity are the main drivers of capacity additions. In the European Union, significant retirements (530 GW) and large-scale deployment of non-hydro renewables – which require greater capacity additions to ensure adequate system reliability – mean that the European Union sees the second-largest gross capacity additions in the world during the projection period (Figure 5.7). Two-thirds of its additions effectively replace capacity that is retired (including some wind and solar PV). The United States also installs significant capacity to replace retired units (62% of total gross additions). One-third of additions are gas, followed by wind (28%) and solar PV (15%). Limited coal capacity (4%) is added, with operators choosing to retire or refurbish existing plants. Net additions in Japan over 2013-2035 are relatively low, but 54% of capacity operating today is retired and has to be replaced (mainly gas and renewables).



**Figure 5.7 ▷ Power capacity changes in selected regions in the New Policies Scenario**



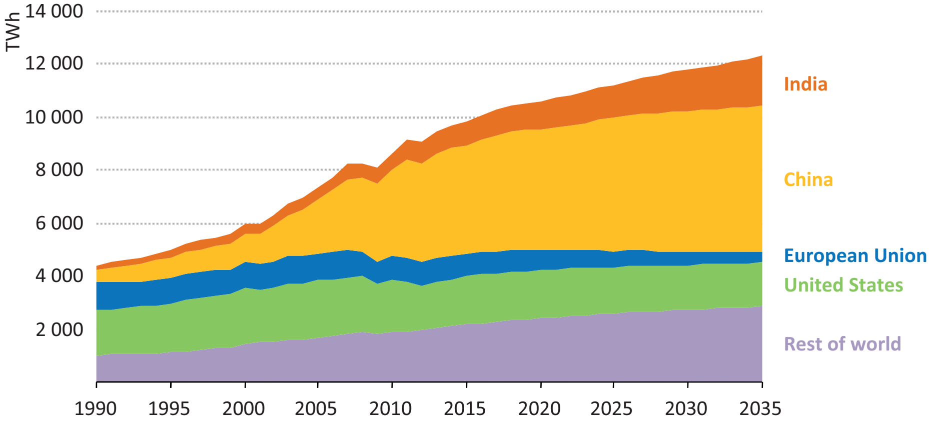

Around 20% of the global gross additions of thermal capacity projected through 2035, or about 590 GW, are already under construction. Nearly all of this capacity will be in operation by 2018, though some nuclear reactors will come online later. Of the thermal capacity being built at present, 56% is coal-fired and 28% is gas-fired. These figures may understate the role that is likely to be played in the medium term by gas, as gas-fired plants can be built much faster than coal-fired plants: combined-cycle gas turbines (CCGTs) can usually be built within 2-3 years and open-cycle gas turbines in 1-2 years, while coal-fired power plants often take more than four years to start generating electricity.

## *Fossil-fuelled generation*

The amount of generation from fossil fuels (coal, gas and oil) in each of the three scenarios depends, among other things, on policy factors such as the implementation and level of carbon prices, the strength of support for renewables and nuclear, and the stringency of environmental regulations. In the New Policies Scenario, the share of fossil fuels in total generation falls from 68% to 57%.

In this scenario, global coal-fired generation increases from 9 140 TWh in 2011 to 12 310 TWh in 2035 (or by 35%), despite its share of total generation falling from 41% to 33%. All of the growth comes from non-OECD countries, which are projected to continue to rely on coal as a secure and affordable means to support economic growth and development. In China, generation from coal grows by half during the projection period, though the average rate of growth slows from 2.2% per year until 2020 to 1.2% per year thereafter (Figure 5.8). Notwithstanding strong efforts to diversify its power sector, China's coal-fired generation in 2035 is projected to exceed present generation from all sources in the United States and Japan combined, at more than 5 500 TWh. India's coal-fired generation more than doubles, making it the second-largest user of coal in the power sector by the end of the projection period. In OECD countries, the improving competitiveness of alternatives, resting on policies that increasingly promote low-carbon sources of generation, lead to a 23% decline in coal-fired generation over 2011-2035.

**Figure 5.8 ▷ Coal-fired power generation by region in the New Policies Scenario**

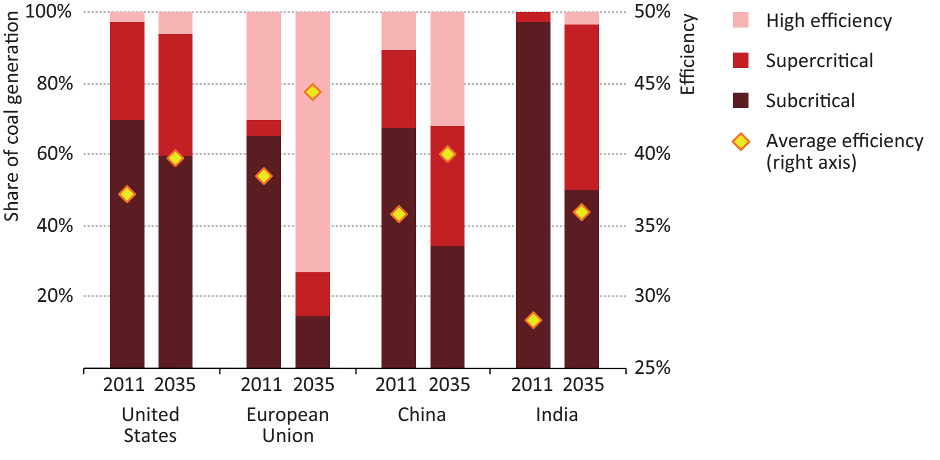



The average efficiency of coal-fired generation worldwide improves from 36% to 40% during the projection period as old plants, based on subcritical technology, are retired and are increasingly replaced by supercritical and other higher efficiency technologies, such as ultra-supercritical, integrated gasification combined-cycle (IGCC) and combined heat and power (CHP) plants. Contributing to the shift in technologies are increases in carbon pricing (see Chapter 1) and the fuel savings resulting from higher efficiency, which result in lower fuel costs, and can reduce import dependency. The development of carbon capture and storage (CCS) remains limited in the New Policies Scenario, with 56 GW of coal-fired power plants fitted with CCS generating about 390 TWh in 2035, around 3% of total coal-fired power generation.

For each region, the average level of efficiency of coal-fired generation reached at the end of the projection period depends on the extent of retirement of old subcritical plants, the rate of construction of new plants, the type of technologies chosen for new plants and the way that the coal-fired fleet is operated. In China, the share of generation from supercritical and high efficiency coal capacity rises from one-third to two-thirds over 2011-2035, raising average efficiency from 36% to 40% (Figure 5.9). The present average efficiency of India's coal-fired generation is extremely low because of heavy reliance on an ageing subcritical fleet and the use of low quality coal. The projected addition of new plants, some of which use subcritical and supercritical technologies, improves average efficiency by eight percentage points, from 28% to 36%. In the European Union the efficiency of coal-fired generation increases from 38% to 44% as subcritical plants are almost entirely phased out of service by 2035. In the United States, little coal-fired capacity is added during the projection period (limiting opportunities to deploy high efficiency technologies) and many existing plants are refurbished to extend their lifetime, resulting in only a small gain in the overall efficiency of coal-fired generation.



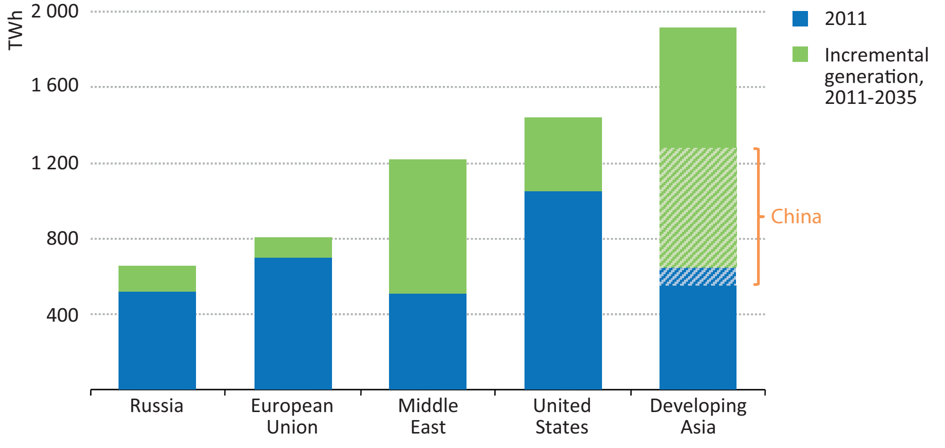
**Figure 5.9 ▷ Share of coal-fired power generation by technology and average efficiency in selected regions in the New Policies Scenario**




Gas-fired generation rises from 4 847 TWh in 2011 to 8 310 TWh in 2035 (or by 72%), its share of total generation remaining constant at 22%. Gas-fired generation fitted with CCS accounts for less than 1% of total gas-fired generation. Nearly 80% of incremental generation over 2011-2035 comes from non-OECD countries. Around 20% of incremental generation comes from the Middle East. In China, driven by the policy of increasing gas use to diversify the energy mix (Figure 5.10), gas generation is expected to increase eight-fold by 2035, to reach an absolute level slightly exceeding that of the European Union today. In the United States, the availability of relatively cheap gas throughout the projection period – the combined result of booming shale gas production and a competitive gas market – underpins a 38% expansion of gas-fired generation. For countries in the European Union, the combination of low electricity demand growth, support to renewables, high gas-to-coal price spreads and low $CO_2$ prices stifles additional gas-fired generation in the period to 2020; beyond that, gas-fired generation increases as inefficient coal capacity is retired,

$CO_2$ prices rise and the need for system flexibility becomes greater (to complement the large-scale deployment of renewables). Despite the higher gas prices in the European and Asia-Pacific markets, gas-fired generation still has characteristics that make it an attractive option relative to the alternatives, notably, lower capital costs, shorter construction times, greater operational flexibility and lower emissions.

**Figure 5.10 ▷ Gas-fired power generation by selected region in the New Policies Scenario**



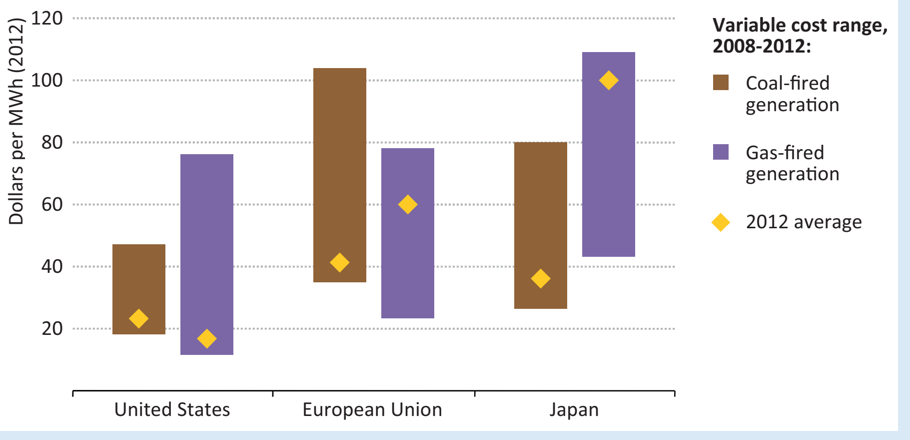

## Box 5.1 ▷ Coal-to-gas switching in the power sector

In power systems which have sufficient spare capacity (*e.g.* in the United States), competition between coal-fired plants and combined-cycle gas turbines (CCGTs) can result in fuel switching between coal and gas. Dispatch choices depend on which of the plants can be run at lower cost and, consequently, on plant efficiencies and relative fuel prices. Coal and gas prices vary across regions and fluctuate over time, so the potential for fuel-switching also varies. In some cases, as in the European Union, relative fuel prices are affected by $CO_2$ prices that benefit gas-fired generation because of its lower carbon intensity relative to coal.

Fuel switching results from the changing circumstances of relative prices in the underlying coal and gas markets. Sustained coal-to-gas switching requires either a substantial expansion of gas supply, leading to falling gas prices, (shale gas development in China, for example), stronger carbon pricing or environmental regulations, or gas pricing reforms that encourage gas pricing based on gas-to-gas competition, rather than oil-indexation. Such fuel switching is unlikely to happen in rapidly growing and tight power systems in Asia or Africa.

The rapid growth in shale gas production over the last several years has caused a dramatic fall in natural gas prices in the United States. They averaged $2.7 per million British thermal units (MBtu) in 2012, leading to an unprecedented switch from coal to gas in the US power sector (and a significant drop in $CO_2$ emissions). But as of mid-2013, gas prices had risen to around \$3.7/MBtu, allowing coal to regain some market share. Without environmental or other regulations to set a price on $CO_2$ emissions, the bulk of the coal-fired fleet becomes competitive with CCGTs at current efficiencies when gas prices are in the range of \$4.5-5/MBtu.

**Figure 5.11 ▷ Electricity generating costs for coal and gas by selected region and for 2008-2012 fuel prices**




Notes: MWh = megawatt-hour. The assumed coal-fired plant efficiency is 40%; gas-fired plant efficiency is 57%. Fuel prices are assumed to be the spot prices for central Appalachian coal and Henry Hub gas in the United States; the spot prices for ARA coal and NBP gas in Europe; the MCR Japanese marker for coal and LNG import price for gas in Japan. Generating costs in Europe include $CO_2$ prices.

In Europe, fuel switching depends on the interplay of prices for coal, gas and emitted $CO_2$. The combination of softening $CO_2$ prices, low coal prices (the result of ample coal availability on the international market) and high gas prices has recently favoured coal-fired generation in Europe, leading to a gas-to-coal switch. Taking the coal, gas and $CO_2$ prices in the New Policies Scenario, coal looks set to remain economically preferable to gas in Europe through 2020. For the $CO_2$ price to alter the outlook, it would have to be much higher than it is at present. For example, in 2020 a highly efficient CCGT would require a $CO_2$ price of more than \$60/tonne to displace a typical coal-fired plant with an efficiency of 39%. Fuel switching potential in the Asia-Pacific region is very limited, due to very high prices for imported liquefied natural gas. In Japan and Korea, the limitations are exacerbated by tight power systems that lack spare capacity for large-scale fuel switching. In the longer term, the potential for a switch from coal to gas will also be influenced by the increasing need for flexible plants as the share of variable renewables grows (see Chapter 6).

Oil-fired generation is projected to decline from 1 062 TWh in 2011 to just below 560 TWh in 2035 (or by 48%), continuing its long-term historical decline, its share of total generation falling from 5% to 1.5% during the projection period. In the OECD countries, it falls to a mere 0.6%. High oil prices, cuts to expensive fuel price subsidies in some countries and the falling relative costs of alternatives make the economics of oil-fired generation increasingly unattractive. In most regions, oil is consigned to only a marginal role as emergency backup and in distributed applications in remote areas, or is used where gas distribution networks are under-developed. The use of oil for power generation falls in almost all regions. The decline is slowest in Africa and in the Middle East, the latter accounting for almost half of global oil-fired generation in 2035, because of the assumed persistence of fuel price subsidies in several countries and strong electricity demand growth.

## *Nuclear power*[5]

There were 437 nuclear reactors in operation worldwide at the end of 2012, with a capacity of 394 GW (IAEA, 2013).[6] More than 80% of capacity is in OECD countries, 11% in Eastern Europe and Eurasia, and 8% in developing countries. Though their share of installed capacity is low today, non-OECD countries will account for the bulk of future growth. Of the 73 GW presently under construction, about 80% is in non-OECD countries.

In the United States, lower electricity prices (as a result of cheap gas) and high repair costs have led to the retirement of four reactors at three power plants in 2012-2013. Construction has begun on two new units and a further two units have received construction licences. In Korea, the second National Basic Energy Plan is currently under discussion, including a review of the future role of nuclear. Several reactors were temporarily shut down in Korea in 2012 and 2013 during a thorough safety review. As of June 2013, ten of the country's 23 nuclear reactors (including those undergoing scheduled maintenance) were offline, or 37% of Korea's total nuclear capacity. In Japan, electricity companies submitted applications to restart fourteen reactors of the 50 in place that were shut down following the accident at Fukushima Daiichi. Subject to conformity with the new regulatory requirements of the Nuclear Regulation Authority, the plants could come online in late 2013/early 2014 at the earliest. In the United Arab Emirates, where plans for nuclear plants have advanced very quickly in a short period, due to the availability of financing and fast regulatory approval, construction is underway on two of four planned units. Saudi Arabia is considering the development of nuclear power as well, to meet rapidly growing demand and to reduce the need for oil-fired generation. In China, construction of new nuclear plants has once again started, following a temporary suspension while a safety review was conducted. Construction began on four plants in 2012, though this rate of build is considerably lower than the average of eight per year over 2008-2010.

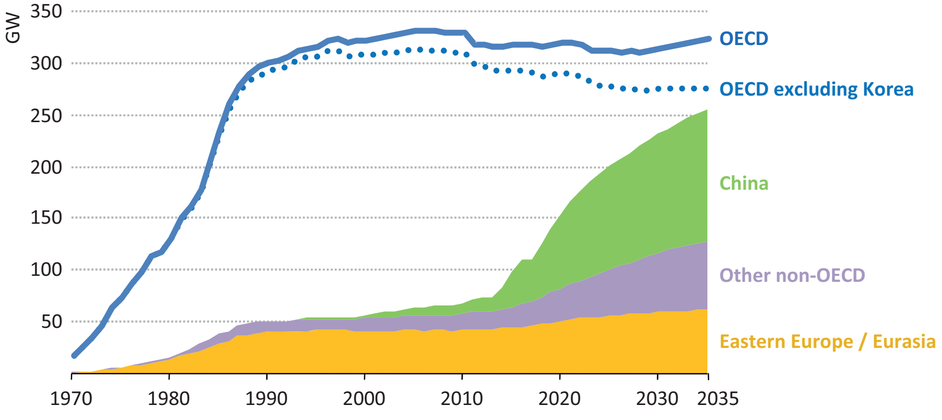
5. The *WEO-2014* will feature an in-depth analysis of the outlook for nuclear power.

6. In net terms (excluding the own use of electricity within the plants) this is equivalent to 373 GW.

In the New Policies Scenario global nuclear generation grows from 2 584 TWh in 2011 to 4 300 TWh in 2035, its share of total generation remaining constant at 12%. Growth in generation is underpinned by a corresponding expansion of capacity, which rises from 394 GW in 2012 to 578 GW in 2035. This is the net result of 117 GW of retirements and 302 GW of capacity additions during the projection period. The rate of expansion of nuclear power continues to be mainly policy driven. It expands in markets where there is a supportive policy framework, which in some cases actively targets a larger role for nuclear in the mix in order to achieve energy security aims. But policy frameworks can also hinder or eliminate nuclear power, often as a result of public opposition: even where there is no explicit ban, long permitting processes, such as in the United States, can significantly hinder development by increasing uncertainty about project completion and increasing costs.



**Figure 5.12 ▷ Nuclear power installed capacity by region in the New Policies Scenario**

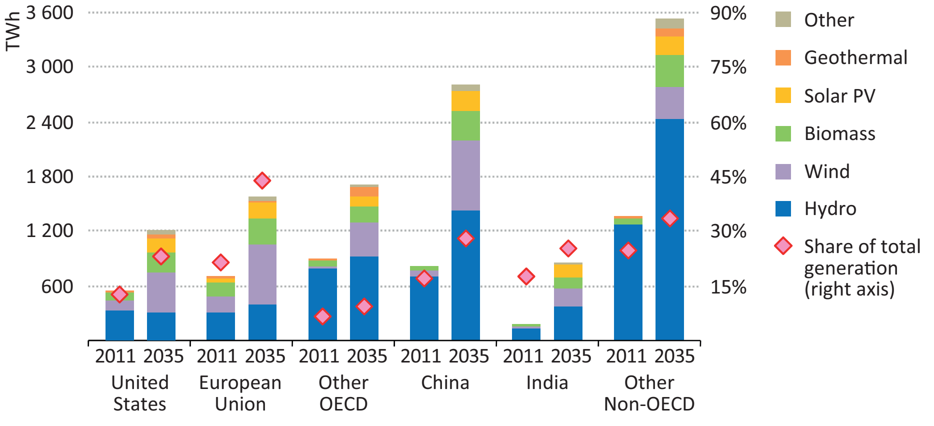



The largest nuclear gross capacity additions are in China, which adds 114 GW during the projection period (or 38% of global nuclear additions before taking into account retirements). Of the total projected to be added, 28% is already under construction, with building expected to begin on several other plants by 2015. Russia adds 33 GW, the second-largest total globally (though around 60% is needed to replace units that are retired). Among OECD countries, Korea sees the biggest growth in installed capacity during the projection period, with gross capacity additions of 27 GW (Figure 5.12). If Korea is excluded, the OECD's capacity declines from present levels, with retirements of about 80 GW outweighing additions of 60 GW over 2013-2035. Capacity increases in the United States, which builds new units but also uprates existing plants (through the modification or replacement of certain plant components). Significant nuclear capacity is added in India (26 GW) to meet rapid growth in electricity demand. Moreover, several countries that aim to develop a nuclear power programme are projected to add their first units over the projection period, notably the United Arab Emirates, Turkey and Vietnam.

## *Renewables*[7]

Generation from renewable energy sources continues to increase rapidly, growing more than two-and-a-half times over the projection period, from 4 482 TWh to over 11 600 TWh and accounting for almost half of total incremental generation over the period. This growth is driven by improving competitiveness, a result of falling costs for renewables technologies, rising fossil fuel prices and carbon pricing, but mainly government support, in the form of subsidies to accelerate the deployment of renewables (see Chapter 6). The share of renewables in the overall mix grows from 20% to 31% during the projection period. Hydropower remains the largest source of renewables generation, continuing to provide 16% of total generation over the projection period. Similar to the absolute level of growth in hydropower, wind generation grows by some 2 340 TWh, the third-largest increment behind only gas and coal. Generation from solar PV increases at a much higher rate than wind, reaching 950 TWh in 2035.

**Figure 5.13 ▷ Renewables-based power generation and share of total generation by region in the New Policies Scenario**




Two-thirds of incremental growth in renewables generation occurs in non-OECD countries. China, which is already the world's largest producer of renewable electricity, accounts for 28% of global growth (more than the combined growth of the European Union, the United States and Japan), its renewables generation more than tripling from 814 TWh in 2011 to 2 800 TWh in 2035 (Figure 5.13). The United States and the European Union both see generation from renewable sources double. Hydropower plays a much more significant role in some regions than in others. It accounts for 44% of incremental renewables generation in non-OECD countries, where a sizeable amount of cost-competitive potential is untapped at present. OECD countries, by contrast, have already developed much of their economic hydropower potential and incremental renewables generation comes mainly from wind (47%), biomass (16%) and solar PV (16%).

7. A more detailed analysis of the prospects for renewables for heat and power generation can be found in Chapter 6.

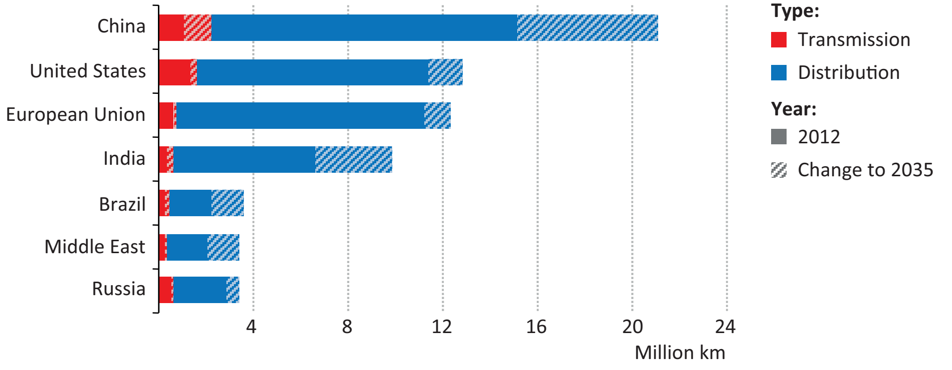
## *Transmission and distribution*

Transmission and distribution (T&D) networks are critical to deliver electricity reliably to end-users. Reinforcement and expansion of T&D networks will be necessary to maintain or improve the quality of service to existing customers, provide access for new end-users (mainly in developing countries) and connect new sources of generation. Bottlenecks exist today in many T&D networks around the world and removing them would help reduce losses and improve the access to available spare capacity that is needed in power systems. However, like other energy infrastructure, T&D projects in several regions, particularly in OECD countries, face public opposition that delays projects.



In the New Policies Scenario, the length of T&D lines globally expands from some 69 million kilometres (km) in 2012 to 94 million km in 2035. Distribution networks deliver power over short distances from substations to end-users, whereas transmission grids transport power over long distances from generators to local substations near customers. Because of their much higher density, distribution networks account for more than 90% of the total length of T&D networks at present and more than 85% of growth during the projection period. T&D networks increase most in China (7 million km) and India (3.5 million km), to cover increasing demand and the connection of new end-users (Figure 5.14). By 2035, around 50% of today's grid infrastructure will have reached 40 years of age, which is the average technical lifetime of T&D assets, highlighting the need for significant investment in refurbishments and replacements during the projection period.[8] The age of the grid varies across regions: younger grids can be found in regions with recent and ongoing infrastructure expansions (such as China, Southeast Asia and Africa), while in Europe, the United States and Russia current grid infrastructure is older and 60% or more need to be refurbished or replaced over the *Outlook* period.

**Figure 5.14 ▷ Existing and additional kilometres of transmission and distribution lines by selected region in the New Policies Scenario**




8. The average technical lifetimes of T&D assets vary according to the type of asset, the conditions under which they are used and maintenance performed. In some cases, they operate much longer than 40 years.

T&D networks play a fundamental part in enhancing system flexibility and in providing for increased use of renewables. The best sites for some renewable energy technologies are located far from demand centres and additional high-voltage transmission lines are needed to exploit them. The growing contribution of power generation from renewables necessitates increased co-ordination between grid infrastructure and renewable projects (see Chapter 6). Future grids are expected increasingly to deploy smart grid technologies, such as digital communication and control technologies, to co-ordinate the needs and capabilities of electricity generators, end-users and grid operators. Additional benefits include greater system reliability, a lower cost of electricity supply (through fuel savings and avoided investment in additional generation capacity) and reduced environmental impact.

### *$CO_2$ emissions*

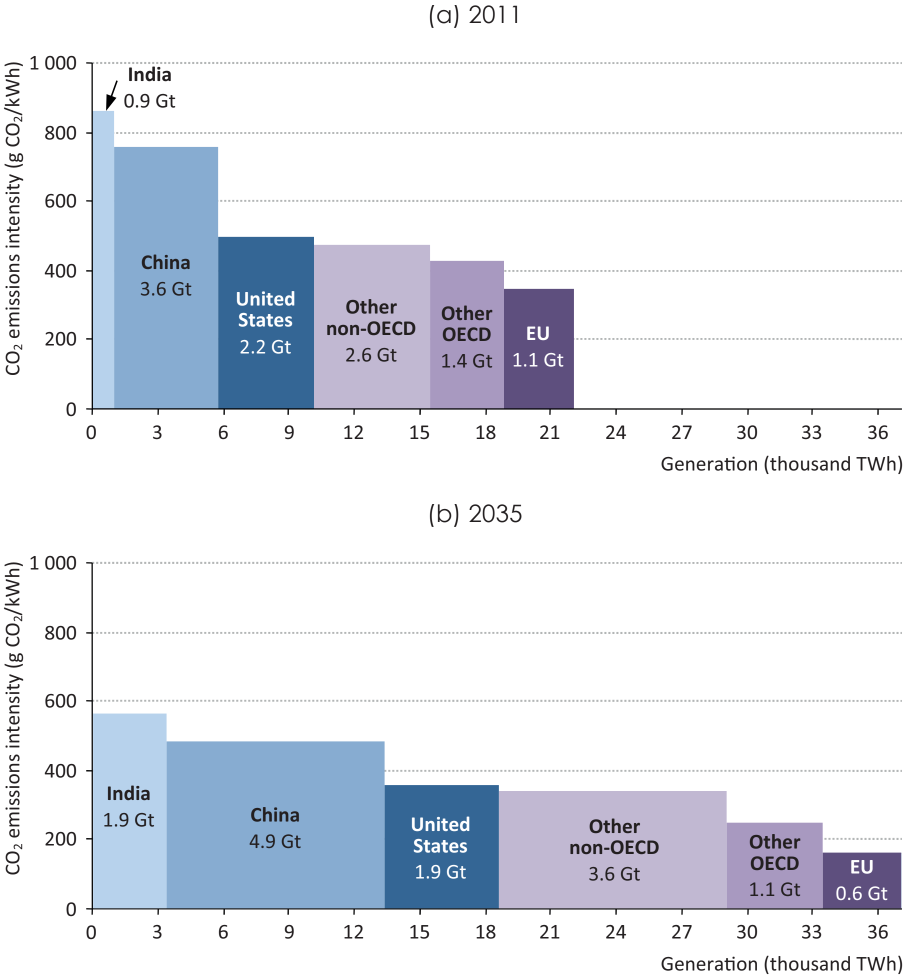
Increasing penetration of low-carbon technologies and improvements in the thermal efficiency of fossil-fuelled power plants help to temper the growth in $CO_2$ emissions from the power sector. In the New Policies Scenario, $CO_2$ emissions from the global power sector rise from 13.0 gigatonnes (Gt) in 2011 to 15.2 Gt in 2035, including some 1.3 Gt from heat production throughout the period. Emissions growth slows with time, falling from 0.9% per year over 2011-2020 to 0.5% per year during the remaining period, while electricity generation grows by 2.7% per year and 1.9% per year, over the respective periods.

Globally, the $CO_2$ emissions intensity of electricity generation falls from 532 grammes of $CO_2$ per kilowatt-hour (g $CO_2$/kWh) in 2011 to 374 g $CO_2$/kWh in 2035 (an improvement of 30%). In the Current Policies Scenario, emissions from the world power sector total 19.1 Gt in 2035. Increased use of low-carbon technologies (including a small amount of CCS) is responsible for 42% of the savings in the New Policies Scenario, compared with the Current Policies Scenario, reduced energy demand is responsible for 53% and coal-to-gas switching and improvements in the average efficiency of coal- and gas-fired power plants are responsible for the rest.

A shift toward higher efficiency coal-fired plants lowers the $CO_2$ emissions intensity of India's power sector by one-third, though a significant expansion of generation causes emissions to double during the projection period (Figure 5.15). China sees its $CO_2$ emissions intensity decline by 36% for similar reasons (in addition to a strong effort to diversify the mix towards low-carbon sources) while emissions from electricity generation increase in total by one-third. OECD power sector $CO_2$ emissions fall throughout the projection period, as limited growth in electricity demand is provided by a power mix with a steeply declining emissions intensity. Today, the emissions intensity of the European Union (345 g $CO_2$/kWh) is slightly lower than the average of a CCGT plant[9] (355 g $CO_2$/kWh), but by 2035 it is around 45% of the present average (160 g $CO_2$/kWh), reflecting the large increment of generation that comes from renewables over 2011-2035.

9. With an assumed 57% efficiency.

**Figure 5.15 ▷ $CO_2$ emissions intensity in the power sector and electricity generation by region in the New Policies Scenario**




Note: EU = European Union.

## Investment[10]

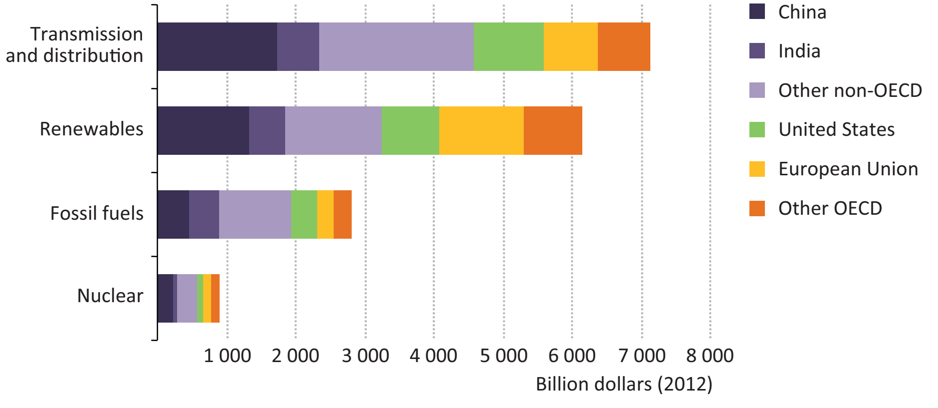
Substantial investments in the power sector will be required over the projection period to satisfy rising electricity demand and to replace or refurbish ageing infrastructure. In the New Policies Scenario, cumulative global investment in the power sector is $17.0 trillion (in year-2012 dollars) over 2013-2035, averaging $740 billion per year (Figure 5.16).[11] New generating capacity accounts for 58% of total investment, while the remainder is needed

10. A *WEO* special report analysing the investment and financing needs of the world's energy infrastructure will be published in mid-2014.

11. Investment assumptions can be found at *www.worldenergyoutlook.org/weomodel/investmentcosts/*.

in T&D networks. Renewables account for 62% of investment in new power plants, led by wind, hydropower and solar PV. The share of investment in renewables is higher than their share of capacity additions (just over half), reflecting their higher capital costs compared with fossil-fuelled capacity. Average annual investment in renewables rises marginally to 2025, before picking up at a faster rate due to an escalated rate of deployment at the end of the projection period (which is partly due to the retirement of renewables capacity). Reductions in the costs of renewable technologies partially offset the effect of elevated deployment towards the end of the projection period.

**Figure 5.16 ▷ Power sector cumulative investment by type and region in the New Policies Scenario, 2013-2035**




Cumulative investment in T&D infrastructure projected over 2013-2035 in the New Policies Scenario is $7.1 trillion, or about 42% of total power sector investment. Two-thirds of the cumulative investment takes place in non-OECD countries, where strong growth in electricity demand necessitates the construction of new T&D lines. While 68% of T&D investment in non-OECD countries goes to the installation of new lines, 29% goes to the refurbishment and replacement of existing lines, with the remaining investment needed for supporting the integration of increasing renewables capacity. China accounts for one-quarter of the investment in T&D infrastructure worldwide. In OECD countries, refurbishment and replacement of existing assets accounts for the bulk of T&D investments, while one-third goes to build new lines that satisfy demand growth. This is due to the age structure of the assets, but also reflects relatively stable energy demand. Increasing renewables deployment means that 5% goes to renewables integration.

## Electricity prices

End-user electricity prices are determined by the underlying costs of supplying electricity – including the cost of generating electricity, transmitting and distributing it through the network, and selling it to the final customer – and by any taxes or subsidies applied by governments to electricity sales. In many countries, the costs of subsidies to renewable energy are also passed on to the consumers through the electricity price.

Differences in wholesale electricity prices are a primary driver of differences in end-user electricity prices between regions, although subsidies, taxes, grid costs and support mechanisms can have a significant influence. In the United States, wholesale prices are projected to be among the lowest in the world, having fallen in recent years. This expectation stems mainly from cheaper gas from abundant domestic shale gas supplies, which reduce fuel costs and investment costs, as CCGT plants have one of the lowest capital costs. Wholesale prices in the European Union are projected to be 75% higher than in the United States in 2035. Strong deployment of wind and solar PV lowers fuel costs in the European Union, but raises operation and maintenance (O&M) costs and investment costs. Slowly rising gas prices – gas-fired generation maintaining a share of around 20% of the mix throughout the projection period – and increasing $CO_2$ costs also drive up European Union wholesale prices over time.

Japan's power system has been under extreme stress following the accident at Fukushima Daiichi and the subsequent reduction in generation from nuclear power plants. Japan's fossil-fuelled power plants have had to run much more frequently to meet electricity demand (even with strong efforts to reduce demand). For example, the Japanese fleet of oil-fired power plants ran at an average capacity factor of 20% in 2010, but over 40% in 2012. As Japan relies heavily on high-cost imported fossil fuels, total fuel costs for power generation have risen substantially in recent years. With some of its nuclear power plants expected to come back online and increased generation from renewable sources (wind, solar and geothermal), expensive oil- and gas-fired generation is projected to fall, lowering fuel import bills and reducing wholesale prices, improving competitiveness by the end of the projection period. However, wholesale prices in Japan are still more than 90% higher than in the United States in 2035.

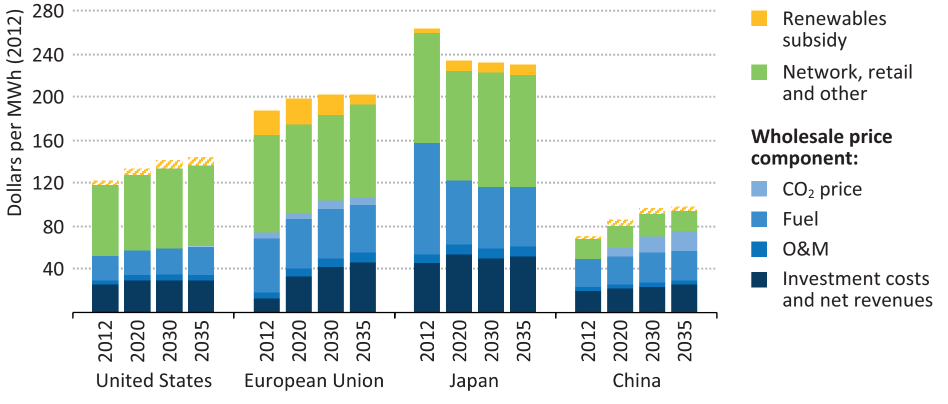
China's wholesale prices are also among the lowest in the world, though they increase to 23% above the level of the United States in 2035. In large part, they are pushed up by the assumed $CO_2$ price, though whether or not the associated costs will be passed on to consumers depends on the eventual design of the market. Total $CO_2$ costs for power generation in China reach nearly $150 billion at the end of the projection period, five times its level of support for renewables in the same year. Continued expansion of generation from nuclear, renewables and coal helps to keep the fuel cost per unit of generation broadly constant, despite upward pressure from expanded gas-fired generation, but raises investment costs per unit of generation.

Wholesale prices can vary markedly within countries or regions, such as in the United States and Europe, depending on the design and characteristics of intra-regional electricity markets. Moreover, they can fluctuate from year-to-year with changes in the weather, economic conditions, fuel prices and unexpected events. Volatility in wholesale prices can complicate the financing and building of new power plants, particularly capital-intensive projects such as nuclear power plants, potentially limiting installed capacity and putting upward pressure on prices. The projections of wholesale prices ensure that all plants in operation recover the direct costs of generating electricity (the variable costs of generation), and that newly built power plants are able to recover all of their fixed costs in addition to their variable costs. Based on gradual fuel price changes, electricity prices in the projections tend to evolve smoothly over time. However, real-world prices will vary around these long-term trends, due to short-term fuel price volatility and investment cycles.

### *Residential*

Residential electricity prices are projected to increase in nearly all regions through 2035 along with generally rising fuel prices worldwide. In addition to the wholesale cost, residential prices (excluding taxes) take account of transmission and distribution network costs, retailing and, where appropriate, the cost of renewable energy subsidies passed on to consumers. Wholesale prices remain low, helping to keep residential prices in the United States amongst the lowest in OECD countries (Figure 5.17). Residential prices in the European Union stabilise around 2030, despite continually rising wholesale prices. This occurs largely due to the improving competitiveness of renewables and the expiration of subsidy commitments to higher cost renewables, which receive decreasing subsidies per unit of generation. Increased network costs stem principally from refurbishment and extension of grid infrastructure, with a smaller part from renewables integration. Within the European Union, current residential end-user prices (excluding taxes) span a wide range, with prices in 2012 as high as $240 per megawatt-hour (MWh) in Ireland and as low as $120/MWh in France, and this is expected to continue. In Japan, residential prices follow the wholesale price trend, declining continually after 2012 as the power system stabilises. In China, rising wholesale prices contribute to the more than 30% increase in residential prices in real terms between 2012 and 2035. By 2035, residential prices in China are still about one-third below the level of the United States.

**Figure 5.17 ▷ Average residential electricity prices (excluding taxes) by region and cost component in the New Policies Scenario**




Notes: Hatched areas represent subsidies that are partly or fully borne by taxpayers rather than consumers. Chinese prices have a low component to cover network, retail and other costs, due to subsidisation.

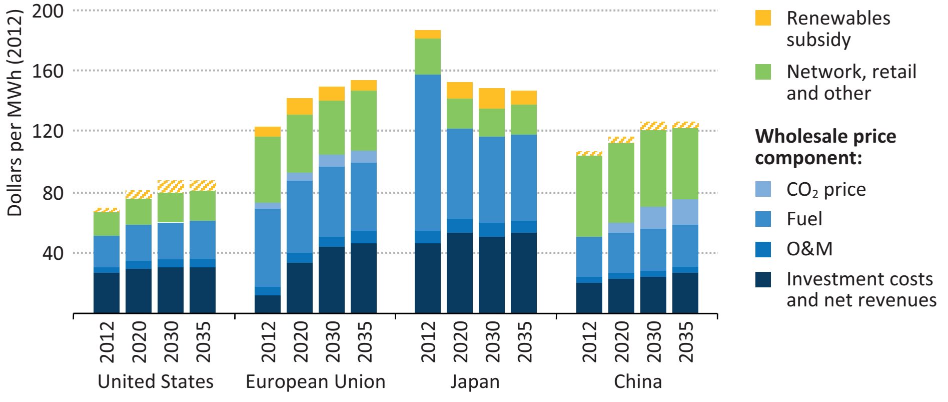
Residential electricity bills are projected to increase as a result of the combination of higher prices and, in most regions, higher per-capita electricity consumption. Per-capita spending on electricity in the New Policies Scenario rises by 26% in the European Union, to around \$375 in 2035; by 14% in the United States, to almost \$600; and by only 2% in Japan, to about \$640. The share of income spent on electricity falls during the projection period, as incomes increase more quickly than electricity bills in these OECD countries. In China, per-capita spending on electricity triples, reaching \$120 in 2035, as electricity prices increase and per-capita electricity consumption rises sharply. Despite this rapid increase, income per capita more than keeps up, reducing the share of income spent on electricity over time.

5

### *Industry*

Projected electricity prices to industrial consumers in the New Policies Scenario show a modest widening of differentials between the United States and regions such as the European Union and China over 2012-2035 (Figure 5.18). This is partly explained by larger increases of wholesale costs in the European Union and China. European Union industry prices increase by 24% during the projection period and, by 2035, are the highest in major industrialised countries and roughly twice the level of those in the United States. Along with a decline in the cost of renewables subsidies, the European Union experiences rising network, retail and other costs in the latter half of the *Outlook* period, in part due to the rapid deployment of renewables. Industrial prices in Japan are extremely high at present, given the extent of dependency on fossil fuel imports, but these fall over time to levels similar to those in the European Union. China's industrial prices rise by almost 20%, remaining much higher than prices in the United States through 2035. The competitive implications of these differences in prices between regions are discussed in Chapter 8.

**Figure 5.18 ▷ Average industry electricity prices (excluding taxes) by region and cost component in the New Policies Scenario**




Notes: Hatched areas represent subsidies that are partly or fully borne by taxpayers rather than consumers. The prices presented exclude taxes (see Chapter 8, Figure 8.7 for prices inclusive of taxes). Industry and residential wholesale prices are assumed to be equal but could differ, for example, due to long-term power purchasing agreements.

# Renewable energy outlook

## Basking in the sun?

### Highlights

- The share of renewables in primary energy use in the New Policies Scenario rises to 18% in 2035, from 13% in 2011, resulting from rapidly increasing demand for modern renewables to generate power, produce heat and make transport fuels. Limiting this rapid growth is the continued shift away from the use of traditional biomass in developing countries in favour of modern energy services.
- Power generation from renewables increases by over 7 000 TWh from 2011 to 2035, making up almost half of the increase in total generation. Renewables become the second-largest source of electricity before 2015 and approach coal as the primary source by 2035, with continued growth of hydropower and bioenergy, plus rapid expansion of wind and solar PV. Almost two-thirds of the increase in power generation from renewables is in non-OECD countries. The increase in China is more than that in the European Union, United States and Japan combined.
- Consumption of biofuels increases from 1.3 mboe/d in 2011 to 4.1 mboe/d in 2035, to meet 8% of road-transport fuel demand in 2035. The United States, Brazil, European Union and China make up more than 80% of all biofuels demand. Advanced biofuels, helping to address sustainability concerns about conventional biofuels, gain market share after 2020, reaching 20% of biofuels supply in 2035.
- Cumulative investment of $6.5 trillion is required in renewable energy technologies from 2013 to 2035, only 5% of which is for biofuels. Renewables account for 62% of investment in new power plants through to 2035. In addition, investments in new transmission and distribution lines of $260 billion are needed for the integration of renewables. Increasing generation from wind and solar PV has impacts on power markets and system operation, which can reduce the profitability of other generators, but also stimulate changes in market design.
- Renewable energy technologies are becoming more competitive compared to wholesale electricity prices, but their continued growth hinges on subsidies to facilitate deployment and drive further cost reductions. Subsidies to renewables reached $101 billion in 2012, up 11% relative to 2011. Almost 60% of these were paid in the European Union. Global subsidies to renewables increase to over $220 billion by 2035. Wind becomes competitive in a growing number of regions, as does solar PV, but only in a limited number of markets.
- Along with reducing $CO_2$ emissions, deploying renewables delivers co-benefits, including reduction of other pollutants, enhancing energy security, lowering fossil-fuel import bills and fostering economic development. The challenge is to design creative renewable support schemes that are effective and cost-efficient, but also take into consideration existing and planned infrastructure in order to minimise adverse effects.

## Recent developments

Renewables are steadily becoming a greater part of the global energy mix, in particular in the power sector and in regions that have put in place measures to promote their deployment. Double-digit growth rates have been observed in the last decade for some renewable energy technologies and renewables are projected to continue to grow strongly over the *Outlook* period to 2035, provided that the necessary support measures are kept in place. However, the situation is nuanced across the three main energy uses: electricity, heat and transport. Electricity generation from renewable sources is growing rapidly for most technologies; while renewable energy use for heat is growing more slowly and remains under-exploited. After a period of rapid expansion, the rate of growth of biofuels use has recently slowed, due largely to adverse weather conditions that reduced harvests and increased feedstock prices, as well as sustainability concerns. Investment in renewable power generation has also been rising steadily but it fell, for the first time, in 2012. In part, this reflects falling unit costs; but it is perhaps also a sign that the prospects for renewables are becoming more complex.

In Europe, rapid expansion of renewable power generation, particularly wind and solar, has occurred in recent years, driven by the requirements of the European Union's Renewable Energy Directive and national targets. However, low rates of power demand growth and a difficult economic situation raise doubts about the timelines of future investments and policymakers in several countries have started to express concerns about the affordability of high shares of certain types of renewable power generation. These concerns relate, particularly, to higher than anticipated rates of deployment of solar photovoltaic (PV) systems, driven, in some countries, by generous and unlimited subsidy schemes and rapidly falling PV system cost. For example, Spain acted in 2010 to adjust over-generous renewables subsidies and, more recently, a moratorium has been put on further subsidies to renewables. Difficulties about integrating high levels of variable renewables into the electricity system are also emerging in some European countries.

In the United States, the market for renewables has been growing strongly, in large part due to the continuation of stimulus policies directed at renewable energy, such as the provision of cash grants (instead of a tax credit) of up to 30% of investment costs for eligible renewable energy projects (US Treasury 1603 Program). This programme expired at the end of 2012, but many projects were able to pre-qualify and will receive this support if completed by the end of 2016. An investment tax credit and production tax credits also provided support for renewables in the United States, despite uncertainty over the future of the programmes. Indeed, doubts about their renewal at the end of 2012 led to high growth in that year; as developers pressed to complete projects in time to receive support. (Uncertainty surrounding future policy support measures has often caused "boom and bust" cycles for capacity additions of renewables). Renewable portfolio standards, currently in effect in 30 states and the District of Columbia, continue to provide an important incentive to boost deployment. Along with blending mandates, annually increasing volume requirements under the Renewable Fuels Standard (RFS) have been a major driver for higher consumption of biofuels each year since its enactment in 2005.

With rapidly growing power demand and concerns over energy security and local pollution, deployment of renewables has been accelerating and is expected to continue to do so in non-OECD countries. In China, the energy development plan, published in January 2013 as part of the 12th Five-Year Plan, sets ambitious renewables targets with mandatory 2015 targets for non-fossil energy use, energy intensity, carbon intensity and particulate emissions. India's 12th Five-Year Plan foresees an increase in grid-connected renewable generation capacity of 11 GW from large hydropower and 30 GW from other renewable sources by 2017. Major increases in renewables capacity are planned in the coming years in Brazil, led by hydropower, bioenergy and onshore wind (see Chapter 10). Tendering schemes in South Africa, the United Arab Emirates and Morocco are prompting investment in wind, solar PV and concentrating solar power (CSP), and many other countries with rising power demand are also embarking on large-scale deployment (IEA, 2013a).



After global biofuels production more than doubled between 2006 and 2010, driven by supportive policies in Brazil, the United States and the European Union, growth in 2011 and 2012 stagnated, despite high oil prices. A combination of physical and policy-related issues was to blame. Ethanol output in Brazil and the United States was affected by poor sugarcane and corn harvests, leading to a lack of feedstock supply and high prices. In Europe, high feedstock prices and poor margins, as well as strong competition from non-European producers, posed challenges for biodiesel producers. Provision for the blending of more than 10% ethanol in the gasoline pool in the United States has raised technical and economic challenges, while doubts about the sustainability of biofuels production in the European Union have led to a proposal to limit the use of food-crop derived biofuels to 6% of transport fuel. The production of advanced biofuels – which offer the prospect of requiring less land, improving greenhouse-gas balances and lower competition between food and fuel – has been expanding, but only slowly.

The portion of modern renewable energy for heat in total final heat demand has risen only slowly and is currently just above 10%. Most of this contribution comes from bioenergy, although solar thermal and geothermal are playing an increasing part as they become progressively more cost competitive in a number of markets and circumstances. However, these technologies face distinct market and institutional challenges to deployment, with renewable heat receiving much less policy attention than electricity from renewables or biofuels. To date, only 35 countries have policy frameworks supportive of renewable heat (mostly within the European Union stemming from the Renewables Directive).

## Renewables outlook by scenario

There is a rapid increase in the use of renewable energy in each of the three scenarios presented in this *Outlook* (Table 6.1). This is primarily the result of the creation of an environment, through policy, in which costs can be driven down so that renewable energy technologies become more competitive with other energy sources. In a limited, but growing, number of cases, they become fully competitive.

Reflecting differences in the assumed level of policy action across the scenarios, the share of renewables in total primary energy demand in 2035 varies markedly, from 26% in the

450 Scenario, to 18% in the New Policies Scenario and 15% in the Current Policies Scenario. By comparison, renewables met 13% of the world's primary energy demand in 2011. Because renewables include both traditional and modern forms, its growth is the net result of two opposing trends. Dominant is a dramatic rise in demand for modern renewable energy (albeit from fairly low levels). The other is a shift away from the use of traditional biomass – mostly fuel wood, charcoal, animal dung and agricultural residues used for heating and cooking – in favour of modern forms, such as gas, electricity and liquefied petroleum gas (LPG). Reducing traditional biomass brings important health benefits by limiting exposure to local air pollutants (see Chapter 2). In the New Policies Scenario, the share of traditional biomass in total primary energy demand drops from 5.7% in 2011 to 3.9% in 2035, as the reduction of traditional biomass use in Asia more than offsets the population-driven increase in Africa.

**Table 6.1 ▷ World renewable energy use by type and scenario**

| | | New Policies | | Current Policies | | 450 Scenario | |
|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2035 | 2020 | 2035 | 2020 | 2035 |
| **Primary energy demand** (Mtoe) | **1 727** | **2 193** | **3 059** | **2 130** | **2 729** | **2 265** | **3 918** |
| United States | 140 | 196 | 331 | 191 | 282 | 215 | 508 |
| Europe | 183 | 259 | 362 | 250 | 326 | 270 | 452 |
| China | 298 | 392 | 509 | 373 | 445 | 405 | 690 |
| Brazil | 116 | 148 | 207 | 146 | 204 | 150 | 225 |
| *Share of global TPED* | *13%* | *15%* | *18%* | *14%* | *15%* | *16%* | *26%* |
| **Electricity generation** (TWh) | **4 482** | **7 196** | **11 612** | **6 844** | **10 022** | **7 528** | **15 483** |
| Bioenergy | 424 | 762 | 1 477 | 734 | 1 250 | 797 | 2 056 |
| Hydro | 3 490 | 4 555 | 5 827 | 4 412 | 5 478 | 4 667 | 6 394 |
| Wind | 434 | 1 326 | 2 774 | 1 195 | 2 251 | 1 441 | 4 337 |
| Geothermal | 69 | 128 | 299 | 114 | 217 | 142 | 436 |
| Solar PV | 61 | 379 | 951 | 352 | 680 | 422 | 1 389 |
| Concentrating solar power | 2 | 43 | 245 | 35 | 122 | 56 | 806 |
| Marine | 1 | 3 | 39 | 3 | 24 | 3 | 64 |
| *Share of total generation* | *20%* | *26%* | *31%* | *24%* | *25%* | *28%* | *48%* |
| **Heat demand***(Mtoe) | **343** | **438** | **602** | **432** | **551** | **446** | **704** |
| Industry | 209 | 253 | 316 | 255 | 308 | 248 | 328 |
| Buildings* and agriculture | 135 | 184 | 286 | 177 | 243 | 198 | 376 |
| *Share of total final demand* | *8%* | *10%* | *12%* | *9%* | *11%* | *10%* | *16%* |
| **Biofuels** (mboe/d)** | **1.3** | **2.1** | **4.1** | **1.9** | **3.3** | **2.6** | **7.7** |
| Road transport | 1.3 | 2.1 | 4.1 | 1.9 | 3.2 | 2.6 | 6.8 |
| Aviation*** | - | - | 0.1 | - | 0.1 | - | 0.9 |
| *Share of total transport* | *2%* | *4%* | *6%* | *3%* | *4%* | *5%* | *15%* |
| **Traditional biomass** (Mtoe) | **744** | **730** | **680** | **732** | **689** | **718** | **647** |
| *Share of total bioenergy* | *57%* | *49%* | *37%* | *50%* | *40%* | *47%* | *29%* |
| *Share of renewable energy demand* | *43%* | *33%* | *22%* | *34%* | *25%* | *32%* | *17%* |

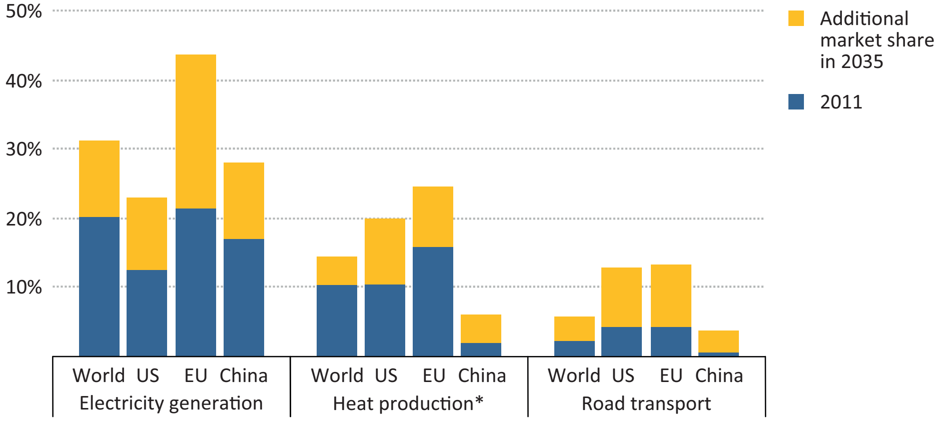
* Excludes traditional biomass. ** Expressed in energy-equivalent volumes of gasoline and diesel.
*** Includes international bunkers. Note: Mtoe = million tonnes of oil equivalent; TPED = total primary energy demand; TWh = terawatt-hour; mboe/d = million barrels of oil equivalent per day.

## Renewables outlook by use in the New Policies Scenario

Renewables contribute an increasing share to total primary energy in the New Policies Scenario and reach 18% in 2035, with the share increasing for all uses and in almost all regions (Figure 6.1). Demand for modern renewable energy – including hydropower, wind, solar, geothermal, marine and bioenergy – rises almost two-and-a-half times, from 983 million tonnes of oil equivalent (Mtoe) in 2011 to almost 2 400 Mtoe in 2035. Its share of total primary energy demand increases from 8% to 14%. A rapid uptake of hydropower occurs mainly in non-OECD countries, where significant resources remain untapped and offer a cost-effective means of meeting fast-growing electricity demand. For most other technologies, the growth is driven by continued support, although other factors, such as falling technology costs and, in some regions, rising fossil fuel prices and carbon pricing also contribute. Traditional biomass remains an important energy source in parts of the world that continue to lack access to clean cooking facilities, although at the global level its use drops from 744 Mtoe in 2011 to 680 Mtoe in 2035.



**Figure 6.1 ▷ Renewable energy share in total primary energy demand by category and region in the New Policies Scenario, 2011 and 2035**




* Excludes traditional biomass. Note: US = United States; EU = European Union.

### *Power generation*

In the New Policies Scenario, renewables power generation expands by over 7 000 terawatt-hours (TWh) between 2011 and 2035. This is equivalent to around one-third of current global power generation, and almost half of the projected increase in total power generation to 2035 (see Chapter 5). The share of renewables in the global power mix rises from 20% in 2011 to 31% in 2035 (Table 6.2). Collectively, renewables become the world's second-largest source of power generation before 2015 and approach coal as the primary source by the end of the period. There is rapid expansion of wind and solar PV, coupled with steady increases in both hydropower and bioenergy.

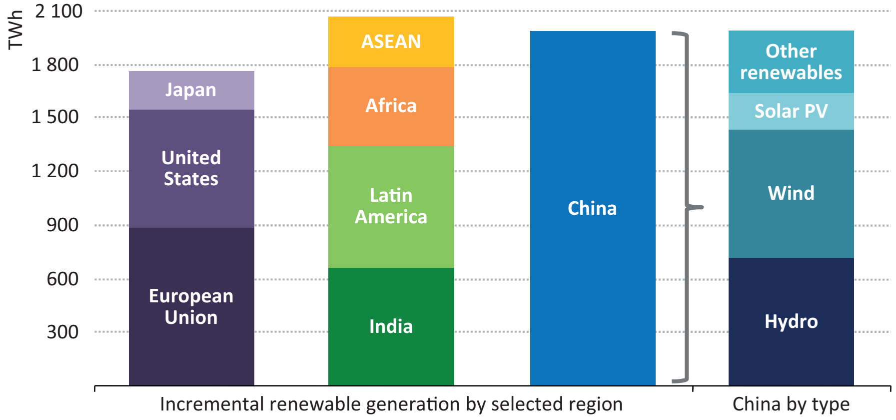
**Table 6.2 ▷ Renewables-based electricity generation by region in the New Policies Scenario** (TWh)

| | Renewables generation | | | | Share of total generation | | Share of variable renewables* in total generation | |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2030 | 2035 | 2011 | 2035 | 2011 | 2035 |
| **OECD** | **2 116** | **2 994** | **3 943** | **4 434** | **19.6%** | **33.8%** | **3.6%** | **14.2%** |
| Americas | 1 014 | 1 313 | 1 733 | 1 965 | 19.0% | 29.6% | 2.6% | 11.0% |
| United States | 544 | 740 | 1 039 | 1 211 | 12.6% | 23.0% | 2.9% | 10.7% |
| Europe | 900 | 1 353 | 1 710 | 1 889 | 24.9% | 45.2% | 6.3% | 21.0% |
| Asia Oceania | 203 | 329 | 500 | 581 | 10.9% | 25.5% | 1.1% | 10.9% |
| Japan | 133 | 213 | 304 | 343 | 12.7% | 28.2% | 0.9% | 11.4% |
| **Non-OECD** | **2 365** | **4 202** | **6 099** | **7 178** | **20.9%** | **29.9%** | **1.0%** | **7.8%** |
| E. Europe/Eurasia | 290 | 357 | 457 | 528 | 16.9% | 21.8% | 0.2% | 2.3% |
| Russia | 169 | 200 | 265 | 312 | 16.1% | 20.5% | 0.0% | 1.1% |
| Asia | 1 173 | 2 569 | 3 787 | 4 423 | 16.9% | 27.2% | 1.4% | 9.1% |
| China | 814 | 1 888 | 2 515 | 2 804 | 17.1% | 28.0% | 1.5% | 9.9% |
| India | 183 | 350 | 666 | 850 | 17.4% | 25.2% | 2.3% | 10.4% |
| Middle East | 21 | 48 | 141 | 226 | 2.4% | 12.9% | 0.0% | 6.8% |
| Africa | 116 | 205 | 403 | 550 | 16.8% | 36.0% | 0.4% | 5.6% |
| Latin America | 765 | 1 023 | 1 312 | 1 451 | 69.0% | 71.0% | 0.4% | 6.2% |
| Brazil | 463 | 614 | 782 | 862 | 87.1% | 79.5% | 0.5% | 8.9% |
| **World** | **4 482** | **7 196** | **10 042** | **11 612** | **20.3%** | **31.3%** | **2.2%** | **10.0%** |
| European Union | 696 | 1 113 | 1 427 | 1 580 | 21.4% | 43.8% | 6.9% | 23.1% |

* Variable renewables include solar PV and wind power.

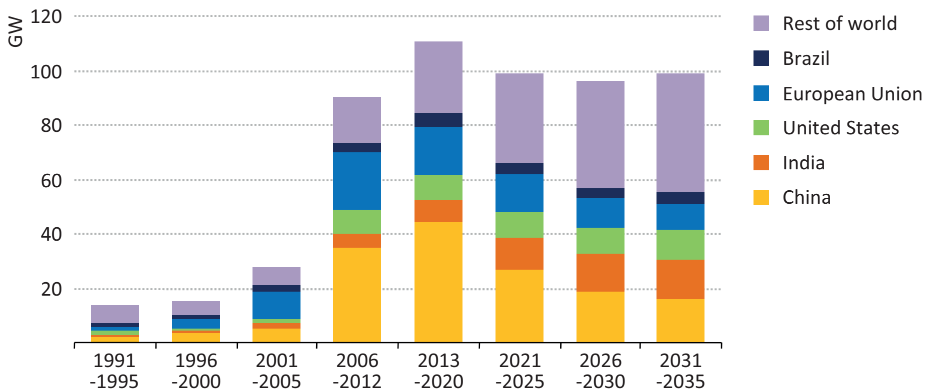
Two-thirds of the increase in power generation from renewables occurs in non-OECD regions, with these countries accounting for 62% of total renewables generation in 2035, up from 53% in 2011. China alone accounts for 28%, or 1 990 TWh, of the total growth in generation from renewables, more than the European Union, United States and Japan combined (Figure 6.2). Considerable growth is also seen in Latin America, India, Africa and Southeast Asia, mainly driven by policy interventions. The increase in the United States, which contributes over 70% of the increase in its total generation over the period, comes despite strong competition from natural gas and also thanks to the decline in coal-fired generation. It is driven by federal tax credits and state-level renewable energy standards, which are assumed to continue also beyond 2020. In the European Union, the increase in generation from renewables far exceeds the increase in total generation, as output falls from coal-fired and nuclear plants. In Japan, mainly in response to the generous support policies recently put in place, electricity generation from renewables increases by 160%, its share increasing from 13% in 2011 to 28% in 2035. Policy action is also the main driver of growth in India, where ambitious targets have been set to scale-up renewable energy capacity in order to overcome electricity shortages and increase access. There is an eleven-fold increase in generation from renewables in the Middle East, reflecting the region's considerable solar and wind resources and growing recognition of their potential importance in satisfying rapid growth in power demand, while freeing up oil and natural gas for export.

**Figure 6.2 ▷ Incremental electricity generation from renewables in selected regions, 2011-2035**




More than 3 100 gigawatts (GW) of renewables capacity are added over the period, equivalent to almost three times the present total installed capacity of the United States. After taking account of the retirement of older installations, this results in installed capacity of renewables increasing by a factor of around 2.5, from almost 1 600 GW in 2012 to nearly 4 000 GW by 2035. Annual capacity additions rise steadily over the period, with a brief downturn around 2020, when rapid expansion of hydropower in China slows as higher-quality sites become scarcer (Figure 6.3). Including the replacement for retiring capacity, annual gross capacity additions are around 180 GW by the end of the projection period, compared with over 115 GW in 2012.

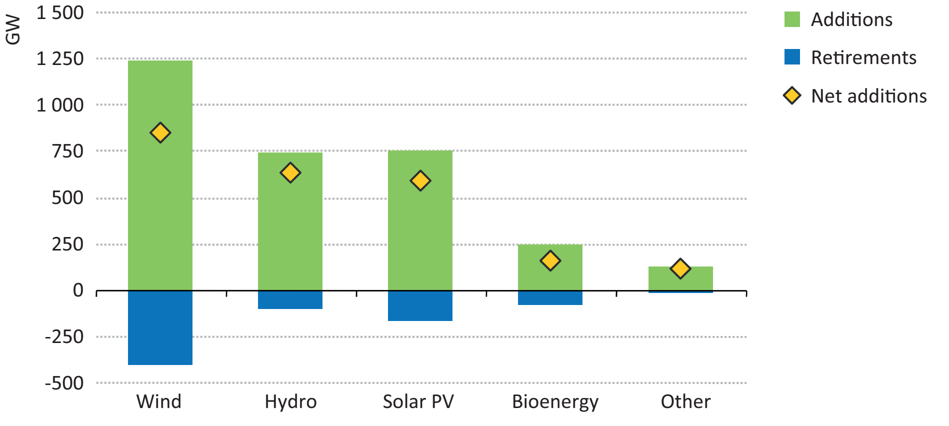
**Figure 6.3 ▷ Average annual increases in renewables-based capacity* by region in the New Policies Scenario**




* Excludes capacity that directly replaces retired capacity of the same technology type.

Renewable energy technologies make up more than 50% of gross capacity additions in the power sector, pushing their share of installed power capacity from 28% in 2012 to 40% in 2035. Wind, with gross capacity additions of almost 1 250 GW, makes the largest contribution to the growth, followed by solar PV (750 GW) and hydro (740 GW) (Figure 6.4).

**Figure 6.4 ▷ Cumulative global renewables-based capacity additions and retirements by technology in the New Policies Scenario, 2013-2035**




Electricity generation from bioenergy more than triples over the projection period, with China, United States and the European Union accounting for over half of the growth. Its share of total generation doubles from 2% to 4%. The share of hydropower in total power generation stays stable throughout the *Outlook* period, at about 16%. Hydropower remains the leading source of renewables-based power, although its share of renewable electricity generation falls from almost 80% today to around half in 2035, as the scope for further additions is gradually reduced and other renewable technologies are deployed at a faster rate. Hydropower output rises from almost 3 500 TWh in 2011 to 5 800 TWh in 2035, based on an increase in installed capacity from 1 060 GW to 1 730 GW over the same period. The expansion is concentrated in non-OECD countries. China accounts for almost 25% of the increase in generation, its capacity rising from 246 GW in 2012 to 430 GW in 2035. China added 16 GW of new hydropower capacity in 2012 and further strong growth is projected until around 2020, when growth slows as China gets closer to utilising its full potential. Brazil also continues to rely heavily on hydropower to meet electricity demand, adding around 70 GW of capacity over the projection period, to reach an installed capacity of 151 GW in 2035 (see Chapter 10). In the OECD, generation from hydropower increases by a modest 16%, with the growth focused in North America and the European Union.

## *Biofuels*

Consumption of biofuels is projected to rise from 1.3 million barrels of oil equivalent per day (mboe/d) in 2011 to 2.1 mboe/d in 2020, and 4.1 mboe/d in 2035 (Table 6.3). By 2035, biofuels meet 8% of total road-transport fuel demand, up from 3% today. Ethanol remains the dominant biofuel, making up about three-quarters of global biofuels use throughout the period. Consumption of biodiesel in road transport more than triples over the *Outlook* period, to 1.1 mboe/d in 2035. Combined, the United States, Brazil, the European Union, China and India account for about 90% of world biofuels demand throughout the *Outlook* period, with government policies driving the expansion in these regions. These projections are similar to those made in *WEO-2012,* despite a drop in investment in the sector last year and a temporary slowdown in production growth, due primarily to poor harvests in the United States and Brazil. Continued policy support and a return to normal harvests put biofuels consumption back on track over the long term. In addition to the use of biofuels in road transport, its use in aviation begins to make inroads over the projection period.

**Table 6.3 ▷ Ethanol and biodiesel consumption in road transport by region in the New Policies Scenario** (mboe/d)

| | Ethanol | | Biodiesel | | Biofuels total | | Share of road transport energy use | |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2035 | 2011 | 2035 | 2011 | 2035 | 2011 | 2035 |
| **OECD** | **0.7** | **1.5** | **0.2** | **0.8** | **0.9** | **2.3** | **4%** | **12%** |
| Americas | 0.6 | 1.3 | 0.1 | 0.3 | 0.7 | 1.6 | 4% | 13% |
| United States | 0.6 | 1.2 | 0.1 | 0.3 | 0.7 | 1.5 | 5% | 15% |
| Europe | 0.0 | 0.2 | 0.2 | 0.5 | 0.2 | 0.7 | 4% | 12% |
| **Non-OECD** | **0.3** | **1.4** | **0.1** | **0.4** | **0.4** | **1.8** | **2%** | **5%** |
| E. Europe/Eurasia | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0% | 2% |
| Asia | 0.0 | 0.7 | 0.0 | 0.1 | 0.1 | 0.8 | 1% | 4% |
| China | 0.0 | 0.4 | 0.0 | 0.0 | 0.0 | 0.4 | 1% | 4% |
| India | 0.0 | 0.2 | 0.0 | 0.0 | 0.0 | 0.2 | 0% | 4% |
| Latin America | 0.3 | 0.8 | 0.1 | 0.2 | 0.4 | 1.0 | 10% | 20% |
| Brazil | 0.2 | 0.6 | 0.0 | 0.2 | 0.3 | 0.8 | 19% | 30% |
| **World** | **1.0** | **2.9** | **0.4** | **1.1** | **1.3** | **4.1** | **3%** | **8%** |
| European Union | 0.0 | 0.2 | 0.2 | 0.5 | 0.2 | 0.7 | 5% | 15% |

The United States remains the largest biofuels market, spurred on by the Renewable Fuel Standard (RFS) through 2022 and assumed continuation of support thereafter, with consumption increasing from around 0.7 mboe/d to 1.5 mboe/d in 2035, by which time biofuels meet 15% of road-transport energy needs. Driven by blending mandates and strong competition between ethanol and gasoline, Brazil remains the second-largest market and continues to have a larger share of biofuels in its transport fuel consumption than any other country. In 2035, biofuels meet 30% of Brazilian road-transport fuel demand up from 19% today. Supported by the Renewable Energy Directive and continued policy support, biofuels use in the European Union more than triples over the period to 0.7 mboe/d in 2035, representing 15% of road-transport energy consumption. In China, government plans for expansion lead to demand for biofuels reaching 0.4 mboe/d in 2035, many times the current level. India established an ambitious National Mission policy on biofuels in 2009, but the infancy of the ethanol industry and difficulty in meeting current targets constrains future demand growth in the projections.

The outlook for biofuels is highly sensitive to possible changes in government subsidies and blending mandates, which remain the main stimulus for biofuels use. Over the past year much uncertainty has developed about how biofuel policies in several key markets will evolve. At the time of writing, discussions in the European Union were continuing on the possible introduction of a 6% cap on the amount of conventional biofuels that can be counted towards the level of renewable energy in transport mandated in the Renewable Energy Directive. These discussions are driven by sustainability issues, including concern that feedstock production for biofuels contributes to deforestation or pre-empts land that could be used to grow food. The European Union has also placed temporary anti-dumping duties on biofuel imports from the United States, Argentina and Indonesia, with material impact on trade in biofuels, so clouding the picture for future trade. In the United States, a review of the federal RFS is underway, which could significantly alter the long-term outlook for ethanol, amid widespread concerns that the supply targets for 2022 are not achievable. One key concern is the amount of ethanol that can be consumed by vehicles on the road (often referred to as the "blend wall"), due to strong resistance from various parts of the industry to blending levels higher than 10% (E10) and logistical barriers to supplying the current flex-fuel vehicle fleet with high-ethanol content fuels, such as E85. A second concern is whether domestic production of cellulosic biofuels can meet official volume goals, as cellulosic biofuel supply targets have had to be lowered in the past few years. On the other hand, Brazil has made policy changes over the last year pointing to higher growth for biofuels, including restoring the ethanol blending mandate to 25%, after reducing it to 20% in late 2011 due to poor sugarcane harvests.

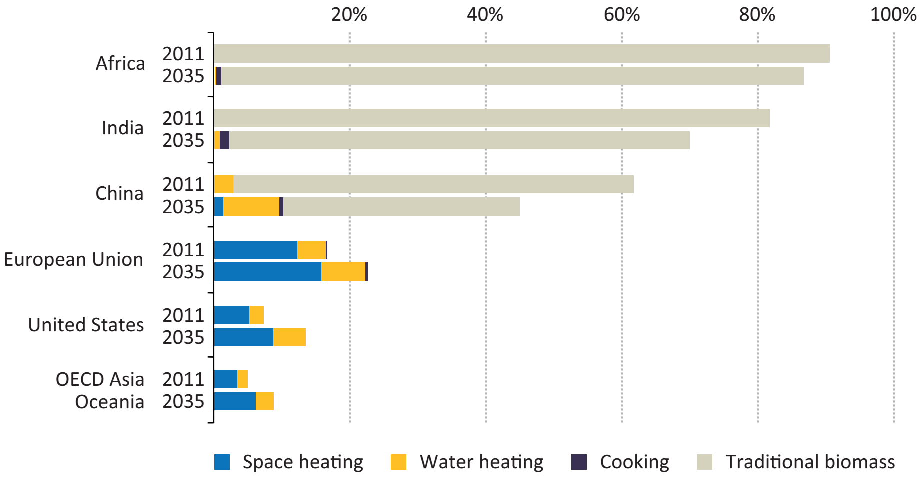
Advanced biofuels offer the prospect of increasing biofuels supply while reducing or eliminating sustainability concerns for biofuels. Cellulosic ethanol is a promising advanced biofuel that can be derived from a variety of feedstocks, including bagasse and agricultural residues, as well as dedicated energy crops. Much work on advanced biodiesel at present is concentrated on the use of feedstocks with far higher yields than conventional feedstock, including palm oil, rapeseed and jatropha. But all the feedstocks depend on conversion technologies that are mainly in the research and development, pilot or demonstration phases. If developed successfully, they hold the promise of achieving lower overall unit costs and imposing lower land requirements than conventional biofuels. While a few commercial-scale units and about 100 plants at pilot or demonstration scale already exist, widespread deployment will require lower costs which further technological progress could bring (IEA 2013b). Because of the lack of commercial scale production of advanced biofuels, the supply mandate for cellulosic biofuels under the RFS in the United States was reduced again in 2013. In the New Policies Scenario, advanced biofuels become available at commercial scale around 2020, with their share of total biofuels supply rising from below 1% today to almost 20% in 2035, led by the United States, Europe, China and Brazil.

## *Heat*

Heat is the largest energy service demand worldwide, typically used for process applications in industry, and for space and water heating, and cooking in the buildings sector. The energy use required to meet this service demand accounts for around half of total final energy consumption. Currently, most of the contribution of renewables to heat production comes from biomass used in traditional ways for cooking and heating in developing countries (Figure 6.5). The use of traditional biomass for heat amounted to 744 Mtoe in 2011 and made up 18% of total global energy use for heat. Such use is often unsustainable because of the low efficiency with which the fuels are converted, the emissions produced (leading to potential health problems) and the difficulty in maintaining supply. More modern and efficient technologies utilising renewable energy – (non-traditional) bioenergy, geothermal and solar thermal in particular – are playing an increasing role in heat supply and met 8% of total global demand for heat in 2011.



**Figure 6.5 ▷ Share of renewables in heat production in the residential sector for selected regions in the New Policy Scenario**




In the residential sector, more than 40% of the heat supplied globally today by modern renewables is consumed in Europe, mainly in the form of bioenergy for space heating. The United States and China account for 14% and 11% of modern renewable use for heat respectively. Recent growth in China has outpaced all other regions. In the last five years, China accounted for almost 40% of global growth in the use of modern renewable energy for heat in the residential sector, driven by the rapid deployment of solar water heaters, which are increasingly cost competitive with conventional fuels (Eisentraut and Brown, 2013), and household biogas systems. In industry, 70% of renewable energy use for heat is in the light industry sector such as food, tobacco and machinery. Almost all of it is bioenergy, which accounts for 11% (136 Mtoe) of global light industry's total energy demand.

Global modern renewable energy use for heat production increases by 75% in the New Policies Scenario, reaching 600 Mtoe in 2035. By the end of the period, modern renewables meet 12% of total heat demand, compared with 8% in 2011. The use of traditional biomass for heat production falls some 10%, to 680 Mtoe in 2035. It continues to be the main source of heat in the residential sector in many developing countries, although in others the switch to modern energy services is made possible by rising incomes, ongoing urbanisation and programmes to foster access to modern energy sources. Demand for modern renewables for heat in the residential sector almost doubles, growing from 88 Mtoe in 2011 to 165 Mtoe by 2035. Most of the growth occurs in China and Europe, with modern bioenergy remaining the dominant source even though solar and geothermal both grow at much faster rates, largely driven by the use of solar thermal heaters in China.

## Focus on power generation from variable renewables

Unlike dispatchable power generation technologies, which may be ramped up or down to match demand, the output from solar PV and wind power is tied to the availability of the resource.[1] Since their availability varies over time, they are often referred to as variable renewables, to distinguish them from the dispatchable power plants (fossil fuel-fired, hydropower with reservoir storage, geothermal and bioenergy). Wind and solar PV power are not the only variable renewables – others include run-of-river hydropower (without reservoir storage) and concentrating solar power (without storage) – but PV and wind power are the focus of this section as they have experienced particularly strong growth in recent years and this is expected to continue.

The characteristics of variable renewables have direct implications for their integration into power systems (IEA, forthcoming 2014a). The relevant properties include:

- **Variability:** power generation from wind and solar is bound to the variations of the wind speed and levels of solar irradiance.
- **Resource location**: good wind and solar resources may be located far from load centres. This is particularly true for wind power, both onshore and offshore, but less so for solar PV, as the resource is more evenly distributed.
- **Modularity:** wind turbines and solar PV systems have capacities that are typically on the order of tens of kilowatts (kW) to megawatts (MW), much smaller than conventional power plants that have capacities on the order of hundreds of MW.
- **Uncertainty**: the accuracy of forecasting wind speeds and solar irradiance levels diminishes the earlier the prediction is made for a particular period, though forecasting capabilities for the relevant time-frames for power system operation (*i.e.* next hours to day-ahead) are improving.

1. Electricity generation from (non-dispatchable) variable renewables, such as wind and solar, is weather dependent and can only be adjusted to demand within the limits of the resource availability.

- **Low operating costs:** once installed, wind and solar power systems generate electricity at very low operating costs, as no fuel costs are incurred.
- **Non-synchronous generation:** power systems are run at one synchronous frequency: most generators turn at exactly the same rate (commonly 50 Hz or 60 Hz), synchronized through the power grid. Wind and solar generators are mostly non-synchronous, that is, not operating at the frequency of the system.

The extent to which these properties of variable renewables pose challenges for system integration largely depends on site-specific factors, such as the correlation between the availability of wind and solar generation with power demand; the flexibility of the other units in the system; available storage and interconnection capacity and the share of variable renewables in the overall generation mix. The speed at which renewables capacity is introduced is also important, as this influences the ability of the system to adapt through the normal investment cycle. Effective policy and regulatory design for variable renewables needs to co-ordinate the rollout of their capacity with the availability of flexible dispatchable capacity, grid maintenance and upgrades, storage infrastructure, efficient market operation design, as well as public and political acceptance.



### *Wind power*

Generating power from wind turbines varies with the wind speed. Although there are seasonal patterns in some regions, the hourly and daily variations in wind speed have a less predictable, stochastic pattern. Geographically, good wind sites are typically located close to the sea, in flat open spaces and/or on hills or ridgelines, but the suitability of a site also depends on the distance to load centres and site accessibility.

For onshore wind turbines, capacity factors – the ratio of the average output over a given time period to maximum output – typically range from 20% to 35% on an annual basis; excellent sites can reach 45% or above. The power output from new installations is increasing, as turbines with larger rotor diameters and higher hub heights (the distance between the ground and the centre of the rotor) can take advantage of the increased wind speeds at higher altitudes. Moreover, wind projects are increasingly being tailored to the characteristics of the site by varying the height, rotor diameter and blade type. Wind turbines that are able to operate at low wind speeds offer the advantage of a steadier generation profile, reducing the variability imposed upon the power system, but likely reducing annual generation.

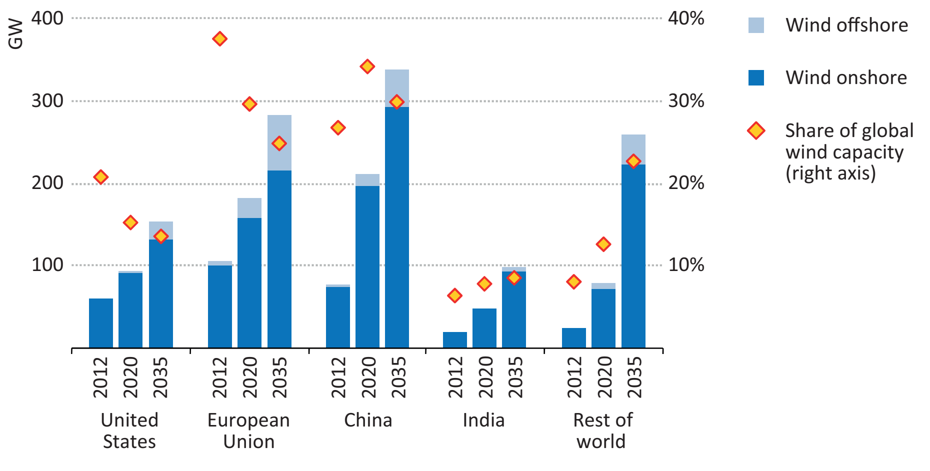
Wind turbines located offshore can take advantage of stronger and more consistent sea breezes. Wind speeds tend to increase with increasing distance from the shore, but so too does the seafloor depth, requiring more complex foundation structures. Capacity factors are generally higher ranging from 30% to 45% or more, as distance from the shore or hub height increases. However, offshore wind turbines are more expensive to install because of the high costs associated with the foundations and offshore grid connections. Bottlenecks can also occur due to a shortage of specialised installation vessels.

*Recent trends and projections*

After experiencing growth of around 25% per year over the past decade, wind power made up 2.3% of global power generation in 2012. Globally, wind capacity rose by 44 GW in 2012, a record year, to 282 GW. This is almost five times the capacity in place in 2005. New installations were concentrated in China (adding 13 GW in 2012) and the United States and the European Union (both adding 12 GW). There was a surge in installations in the United States, as developers sought to secure production tax credits, which were set to expire at the end of 2012. Additions in China were 5 GW lower than in 2011 due to bottlenecks for connections to the grid. Out of this total, offshore wind saw a 32% increase in global installed capacity in 2012, a rise of 1.3 GW to 5.4 GW, the highest annual capacity addition to date. Some 90% of this was added in the European Union, mainly in the United Kingdom, Germany, Belgium and Denmark.

In the New Policies Scenario, electricity generation from wind (onshore and offshore) is projected to increase at an annual average rate of 6% between 2011 and 2035. Wind generation approaches 2 800 TWh in 2035, when its share of global power supply is 7.5%, and total capacity reaches 1 130 GW. Around 80% of the capacity additions are onshore, although offshore wind installations gradually increase in importance. While today the European Union has the largest share of global wind capacity, China has the largest share in 2035 (Figure 6.6).

**Figure 6.6 ▷ Installed wind power capacity by region in the New Policies Scenario**




## *Solar photovoltaics*

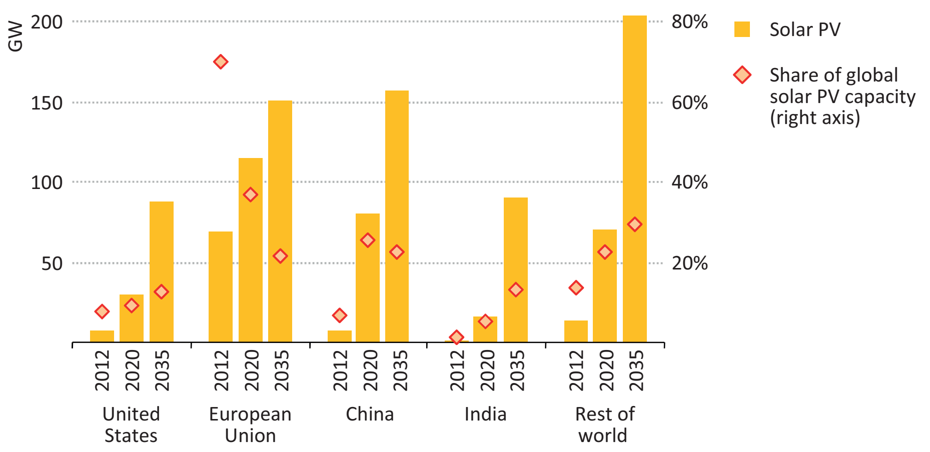
Power generation from solar PV installations varies with the level of solar irradiation they receive. Geographically, solar irradiation increases with proximity to tropical regions and is more uniformly distributed than wind. Seasonal and daily patterns in output from solar PV systems can be fairly well forecast – on a clear day, solar generation follows a bell shape, reaching its maximum around midday – but there remains an element of unpredictability, such as the extent of cloud cover or interference through snow, sand or dust cover.

Capacity factors vary widely, but generally lie within 10% and 20%, or above. The last ten years brought important technology progress, with significant cost reductions. Newer technologies, such as thin film technologies, are gaining growing market shares and bring further potential for cost reductions. Systems which include sun tracking systems can reduce variability, as can an array of panels with differing orientations, but in both cases costs are increased.

### *Recent trends and projections*

Solar PV generation expanded by 50% per year worldwide over the last decade, reaching almost 100 TWh in 2012. In this year, total installed capacity of solar PV increased by 43%, or 29.4 GW, representing 15% of the total growth in global power generation capacity. Germany alone, under the impetus of strong government support, accounted for more than one-quarter of the increase with 7.6 GW of additions. Other countries with major additions include Italy (3.6 GW), China (3.5 GW), United States (3.3 GW), Japan (2.0 GW) and India (1.1 GW). In each country, the growth was driven by government support programmes and subsidies.

**Figure 6.7 ▷ Installed solar PV capacity by region in the New Policies Scenario**




In the New Policies Scenario, electricity produced from solar PV rises to 950 TWh in 2035, as its share of global electricity generation increases from 0.4% to 2.6%. This is underpinned by a seven-fold increase in installed solar PV capacity over the *Outlook* period, reaching 690 GW in 2035 (Figure 6.7). Generation from solar PV increases faster than installed capacity due to technical improvements and deployment in regions with high quality resources. Solar PV on buildings accounts for the majority of installations, its share declining over the *Outlook* period as large-scale facilities operated by utilities gain market share. Driven by big increases in China (150 GW) and India (90 GW), non-OECD regions account for almost 60% of the increase in global solar PV capacity. Large increases also occur in the European Union and the United States (both around 80 GW), and Japan (50 GW). Through ongoing reductions, generation costs become comparable to retail electricity prices in several countries, but growth of solar PV will continue to be closely linked to the provision of government subsidies as, over the course of the *Outlook* period, solar PV is expected to become competitive in only a limited number of circumstances when compared to the average wholesale electricity price (Spotlight).

## Implications for electricity systems and markets

The impact of a growing component of variable renewables on the power system depends on the timing and co-ordination of renewables capacity additions, the investment cycles in the power system and the rate of deployment of measures to facilitate their integration into the system. The main impacts of location constraints and modularity are on the transmission and distribution network, while variability and uncertainty impact the way other power plants in the mix are operated.

### *Implications for grids*

The location of good variable renewable resources can be remote from demand centres, making transmission grid extensions necessary. Early and integrated planning of transmission corridors is necessary to maximise use of good resources and reduce public opposition. In some locations, transmission corridors will have to cross state or national borders, requiring co-operation between transmission system operators and regulators.

The transmission system costs involved to connect and integrate variable renewables depend on the distance to be covered, the status of development of the existing grids and the amount of capacity of variable renewables to be integrated. Costs range between $100 and $250 per kW of added variable renewables capacity (Dena, 2010; EnerNex, 2011; NREL, 2010). In total, about $170 billion or some 10% of the global investment in transmission grids in the New Policies Scenario is required to extend the grid to accommodate the growth in renewables. The amount varies significantly by region. In Europe and Japan, high levels of deployment mean that the integration of renewables accounts for a share of overall transmission investment of about 25% and 20% respectively. The comparable figure is about 10% in the United States, China and India.

The modularity of variable renewables can also have significant impacts on distribution grid needs. Bypassing the high-voltage transmission grids that transport power from large conventional power plants, wind and solar generators are typically connected at the distribution level (wind at mid-voltage and solar mainly at low-voltage). At low levels of installed wind and solar capacity, their generation can be consumed close to the production site (especially for solar PV) and may reduce the strain on distribution grids. At higher levels, the capacity of the distribution grid may need to be raised to accommodate increasing volumes of electricity sold back to the grid by distributed generators. Voltage transformers can be an initial bottleneck; a need to upgrade line capacities may follow.

The amount of investment to upgrade distribution grids also depends on their current condition. If these grids are in need of refurbishment, the additional costs may be low. In France and Germany, for example, each kilowatt of new variable renewables capacity will add an estimated $100 to $300 to the costs of the distribution grids (Lödl, *et al.*, 2010; Dena, 2012; CRE, 2012). In the New Policies Scenario, total investment in distribution grids to accommodate variable renewables amounts to over $90 billion globally, or about 2% of total distribution investment. Bringing together transmission and distribution (T&D) costs attributable to variable renewables, the additional investment is about $260 billion, or some 4% of total T&D investment over the *Outlook* period.

### *Implications for dispatchable power plants*

In the absence of a widespread uptake of the measures available to alleviate the challenges posed by variables renewables (Box 6.1), an increase in generation from wind and solar power has implications for the operation and use of dispatchable plants as well as for investment in such plants.



**Box 6.1 ▷ Reducing the challenges posed by variable renewables**

A number of operational and infrastructure measures can be taken to address the challenges posed by variable renewables. These include:

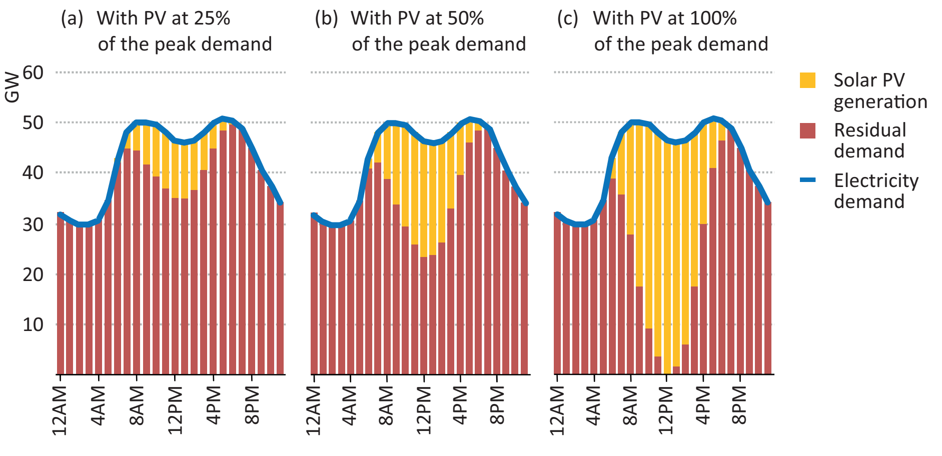
- Adapting the operation of power systems. This can include the application of advanced forecasting techniques, and adapting the market and power plant dispatch rules, for example reducing the time between the commitment of power plants to generate electricity and real-time operation.
- Extending the transmission grid to capture remote resources and increase cross-border trade, so as to reduce the effects of variations in solar irradiation and wind speed on the system. This can be especially effective for wind (Schaber, *et al.*, 2012).
- Promoting demand-side integration. Modifying electricity demand according to the variable supply could reduce the system impacts of wind and solar and also avoid the need for other integration measures.
- Investing in storage (such as pumped hydro storage, compressed air, hydrogen or batteries). If deployed on a small scale (such as batteries for solar PV), storage can help to sustain reliance on local generation and defer grid investment (IEA, 2014b).
- Balancing fluctuations from variable renewable output with flexible forms of generation, such as gas turbines.
- Curtailing extreme wind and solar power generation peaks, when variable renewables output is very high compared to electricity demand, to reduce the ramping up and down of power output from other sources (Baritaud, 2012).

While all measures may be advantageous individually, co-ordination between the integration measures is needed to maximise their benefits.

Electricity demand varies considerably during the course of a day, but it generally follows a predictable profile. For example, on a weekday demand may peak in the early evening as people arrive home and be lowest during the early hours of the morning when most people are asleep. However, generation from wind and solar power is tied to the availability of their resources and is often not well matched with the electricity demand profile. The pattern of the remaining electricity demand, after variable renewables production has been taken into account, also called residual electricity demand, can differ markedly from the total electricity demand (Figure 6.8). The variability of wind and solar generation alters the peaks and troughs in the residual demand profile which requires the dispatchable plants to adjust their output level accordingly. However, where variable renewables generation is well correlated with electricity demand (*e.g.* solar PV coinciding with air conditioning loads at midday) their generation pattern – up to a certain level of deployment – may be advantageous to the system by smoothing the demand profile.

The greater the variability of residual demand, the greater the flexibility of dispatchable power plants must be to be able to respond to changes not only of demand but also to supply side changes. This can raise their operational costs (through not running at optimal efficiency) and increase the wear-and-tear of power plant components. These "balancing costs" vary from system to system, depending on the presence of storage, the flexibility of the power plant fleet and also the quality of wind and solar resources and forecasts.

**Figure 6.8 ▻ Indicative hourly electricity demand and residual electricity demand with expanding deployment of solar PV**

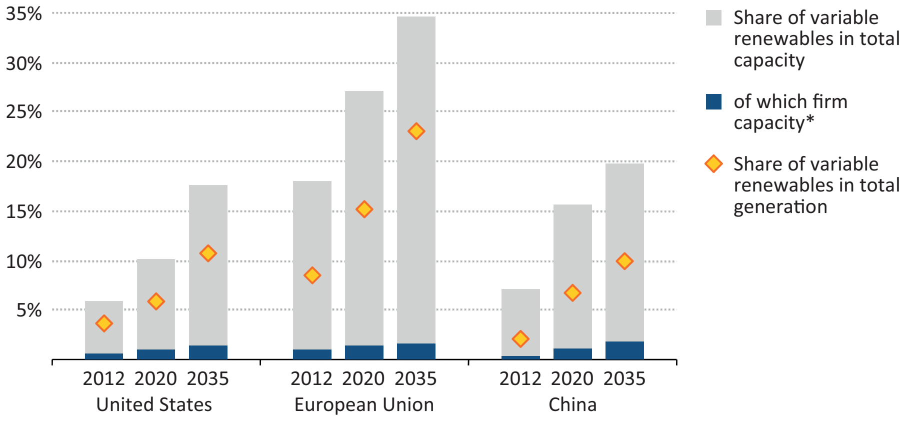



In regions where the electricity generation of variable renewables increases faster than demand, utilisation of existing plants is reduced. In the New Policies Scenario, total wind capacity increases by around 850 GW and solar PV by almost 600 GW in the period to 2035 with about 40% of this increase occurring before 2020 (in the 450 Scenario wind and solar capacity increases by 1 400 GW and some 900 GW until 2035, respectively [Box 6.2]). Until 2020, many of the existing dispatchable power plants will continue to be needed, but will likely experience less use, especially in regions that see major expansions of wind and solar generation, such as Europe. In countries with fast-growing power demand, such as China, this effect is less pronounced.

Despite the increasing capacity of wind and solar, their variable and uncertain generation profile mean that the need for dispatchable capacity is not reduced significantly. The reason is that the share of installed wind and solar capacity that can be confidently relied upon at times of high demand is much lower than for dispatchable plants. This share is referred to as "capacity credit". It depends on the respective correlation of wind and solar supply with the load profile and the level of penetration of variable renewables.[2] For example, in the European Union, it typically falls between 5% and 10% for wind and 0% to 5% for solar PV.

In the New Policies Scenario, wind and solar account for about 19% of global installed power capacity in 2035, reaching almost 35% in the European Union (Figure 6.9). However, globally they contribute only about 2% to firm capacity (capacity that can be relied upon to generate electricity at any given time). The provision of sufficient dispatchable capacity can entail additional costs. Assuming that additional gas turbines are used to meet this requirement, these adequacy costs are estimated to range from between $3-5 for each megawatt-hour (MWh) of additional generation from variable renewables (IEA, 2011). Since the use of other power plants declines with increasing levels of variable renewables, the capacity mix gradually shifts to less capital-intensive power plant types, such as gas-fired power plants, for which profitability at low utilisation rates is easier to achieve.

**Figure 6.9 ▷ Shares of wind and solar power capacity and generation in the New Policies scenario**




* Firm capacity of wind and solar is computed based on the capacity credit.

2. For solar, the capacity credit can be higher in systems where peaks in electricity demand are driven by demand for air conditioning, for example. Through interconnection over larger geographic areas, smoothing can be achieved, and the capacity credit can also be raised.

### Box 6.2 ▷ Variable renewables in the 450 Scenario

The stronger deployment of renewable energy technologies is one of the key features of the 450 Scenario. By 2035, their share of global power generation increases to 48%, compared to 31% in the New Policies Scenario. The global share of wind and solar power generation in the 450 Scenario increases to 18% in 2035 (compared to 10% in the New Policies Scenario), with important implications for the power system. Total wind and solar capacity reaches 2 700 GW, which corresponds to 50% of peak demand in 2035. At a regional level, the capacity of variable renewables compared to peak load can be considerably higher; for example, in Europe it is more than 90% of peak demand and in China and Japan about 60% of peak demand. This means that the likelihood of momentary regional excess supply increases, when wind and solar generate electricity at their full capacity. In that case, there would be an important challenge for stable operation of the system, due to the non-synchronous generation of wind and solar power. A solution, such as keeping online a share of thermal generators at all times, would have to be considered. The commercial viability of these other power plants is a challenge, since they would operate at a very low utilisation rate. Moreover, additional investments would be required in T&D grids, as well as in other integration measures.

#### *Implications for market price formation*

In most liberalised electricity markets, spot wholesale prices are largely determined by the operational costs of the most expensive generating unit used. Whenever low marginal cost power from wind and solar is fed into the system, generators with high operating costs, at the upper end of the merit order,[3] are needed less and the wholesale electricity price is, in consequence, lowered. Electricity end-users might benefit from this decrease depending on how much of the cost subsidies to renewables is passed through to them (see Chapter 8). The merit order effect may also reduce profit margins for all power generators, to the point that some generators become unprofitable. This has been observed recently, for example, in some European markets, and has put in question whether some utilities will be able to recover the investment costs of dispatchable plants under current market conditions. This could potentially jeopardise the reliability of power supply if the situation worsens.

Market reforms have been introduced or are under consideration in several countries where there is concern that price signals resulting from this effect may not be sufficient to stimulate timely and sufficient investment in new dispatchable power plants or to maintain older plants in operation. The options include different forms of capacity remuneration or regulatory obligation to maintain strategic reserve capacity or to allow hourly wholesale prices to increase unconstrained during times of scarcity (for example, when peak demand periods coincide with limited generation from variable renewables). Discussion of these issues remains open. One possibility is to incorporate measures which can reduce capacity needs, such as storage or demand-side management.

3. The merit order ranks the different generating units that are available in a power market in terms of their marginal cost of generation. It is often used to determine which units will be used to supply expected demand, with the cheapest units being used first.

## Competitiveness and unit costs

The cost of producing electricity from solar PV and wind has fallen dramatically over the last decade, leading to debate about whether they are now competitive, without subsidies, with the costs of power generated from fossil fuels. When measuring the competitiveness of different renewable energy technologies, it is important to distinguish between generating power for sale and power produced by households for auto-consumption.[4] The latter typically involves solar PV.

### Competitiveness of variable renewables as a wholesale power generation source

For electricity produced to sell on wholesale markets, it is usually considered that breakeven is achieved when the levelised cost of electricity (LCOE)[5] of a technology does not exceed the average wholesale electricity price received for generation over its lifetime. Variable renewables, however, have limited or no means to adjust their power output across the day to maximise their revenues. At increasing rates of penetration in the power mix, the price that they would receive in the market is likely to decrease over time, due to the so-called merit order effect (Hirth, 2013; Mills and Wyser, 2012).

One consequence of decreasing prices over time is that the support needed would be higher than currently calculated in the New Policies Scenario, where the benchmark is the average annual wholesale price. If the reference price considered for the calculations of the wind and solar PV subsidies were to be lower than the annual average by 10%, the subsidies for wind and solar PV would be 12% higher. With a price 20% lower, they would be 25% higher. For the end-user, the higher cost of subsidies would, at least in part, be compensated by the lower wholesale prices.

### Competitiveness of solar PV for households

For household auto-consumers, the break-even point for solar PV has typically been considered to be when the cost to the consumer reaches "grid parity" or "socket parity", that is, the point at which the levelised cost of electricity (excluding subsidies) falls to the average retail price for electricity. However, this approach has shortcomings and we question whether it is the appropriate metric to evaluate the competitiveness of solar PV in households. An alternate approach, that takes account of other relevant costs, is to measure competiveness on the basis of "cost parity". This is the break-even point for the costs incurred, on the one hand, by a household with a solar PV system and, on the other hand, by a corresponding household that is solely reliant on the grid (Spotlight).

The distinction between grid parity and cost parity has important real-world implications. In most markets, the fixed costs are only partially recovered through a fixed component in the electricity bills and the remaining part (often larger) is recovered through the

4. Auto-consumers are defined as those households which generate principally for their own consumption, with any excess being sold to the grid.

5. The levelised cost of electricity represents the average cost of producing electricity from a given technology, including all fixed and variable costs, expressed in terms of the present value equivalent.

variable component. From the single household perspective, under such an electricity tariff structure, it might, therefore, be economically attractive to invest in PV, where grid parity is reached. This could lead to a significant additional amount of PV installations.

However, from a system perspective, this creates a free-rider effect, where households with PV systems do not pay fully for their share of the system's fixed costs, shifting the burden to households without PV systems. This could concentrate fixed costs on fewer households, raising the retail prices against which the competitiveness of PV systems is measured according to grid parity. These system level issues require thorough assessment and attention from policymakers, regulators and retailers, who may need to consider the use of time-based metering and pricing, and tariffs adjusted to user profiles to ensure both the full recovery and fair allocation of system costs.

**SPOTLIGHT**

## Is residential solar PV already competitive?

A fall of over 40% in the price of solar panels since 2010 has led some parties to make the case that electricity generated from residential solar PV installations has become – or is fast becoming – competitive with electricity generated from fossil fuels. These arguments have often been based on the concept of "grid parity". But is grid parity the right criterion to measure the full competitiveness of residential PV, after which it can stand on its own without the need for subsidies?

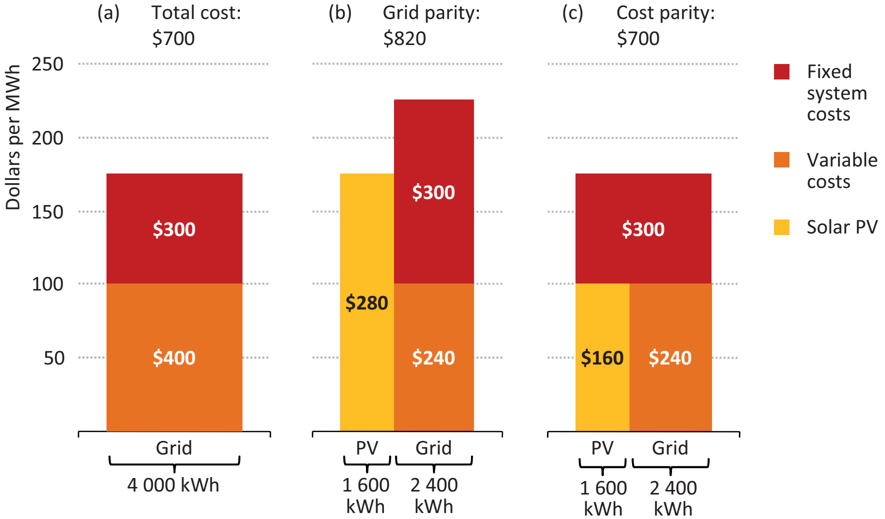
The short answer is no, at least for households that remain connected to the grid. The reason is that fixed system costs are not included in the calculations of grid parity. The fixed costs of a power system include costs such as the construction and maintenance of the transmission and distribution grids, metering and billing. From a system perspective, these costs always need to be recovered. When allowance is made for these costs, the cost of generation from solar PV systems would have to fall below grid parity to become competitive.

Take an example, in which residential solar PV has just reached grid parity. In the first case, the household does not install solar PV. It pays $300 per year in fixed charges (assuming all fixed costs are passed through) and another $400 per year for the 4 MWh it consumes, to give an average retail price of $175/MWh (Figure 6.10a).

In the second case, the household installs a solar PV system which produces 1.6 MWh for consumption on site, for a total cost of $280 (equal to 1.6 MWh × $175/MWh). It additionally purchases 2.4 MWh from the grid at cost of $540 per year (including fixed charges of $300, plus $240 for the energy consumed). This means that, at grid parity, the consumer pays a total of $820 per year for electricity when installing the solar PV system, higher than without it (Figure 6.10b).

A more accurate means of gauging the break-even point of solar PV is to consider "cost parity", which measures the point at which a household that installs a solar PV system incurs the same overall costs as it would if solely reliant on the grid. Using the example, the cost of the PV system would have to drop to $160 (1.6 MWh × $100/MWh), well below some current notions of grid parity, for it to make economic sense (Figure 6.10c). This is equal to the variable cost that the PV system is displacing.

**Figure 6.10 ▷ Indicative breakeven costs of residential solar PV using the "grid parity" and "cost parity" approaches**

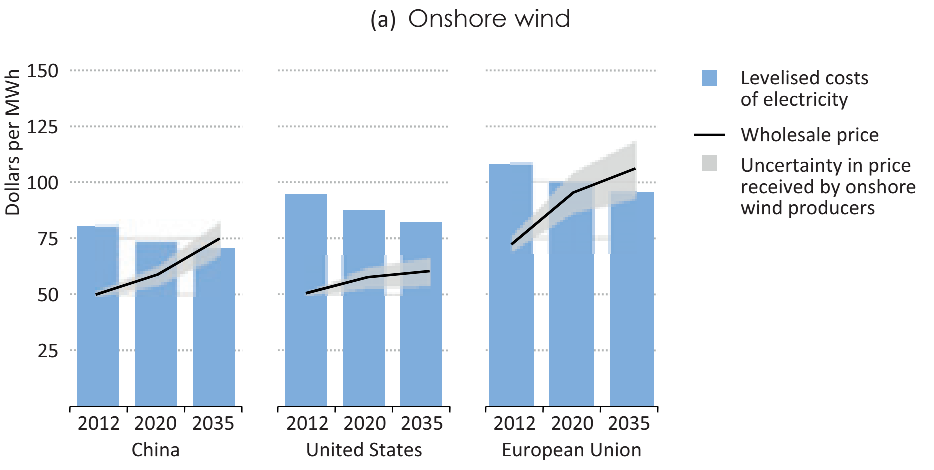


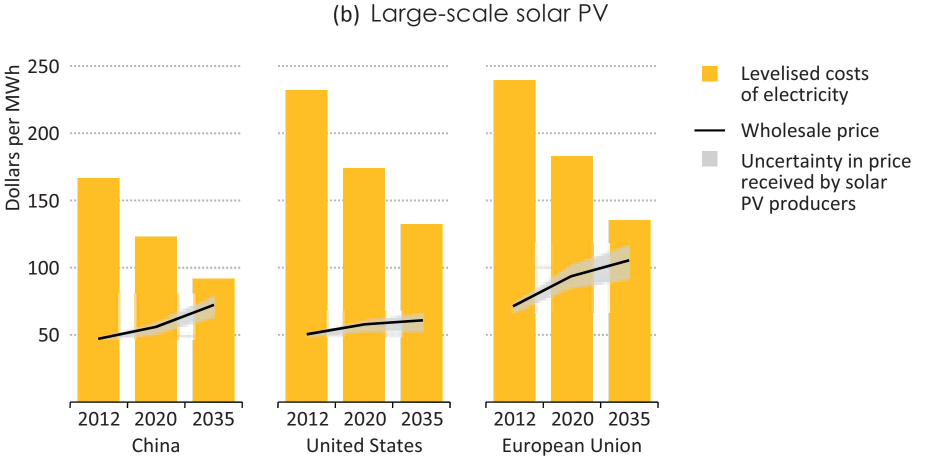

There are several other factors that could influence the competitiveness of solar PV. For example, the calculations would change if the household with the PV system did not consume all its generation on site but sold the excess to the grid. In that case, for the PV generator to be fully competitive, the electricity would have to be sold at the actual wholesale market prices, *i.e.* the same price that other suppliers receive at that time. Any higher price for electricity sales, if fixed by regulation, would result in windfall profits for the PV generator. Also, if the renewables integration costs were passed on to the seller, it would make competitiveness harder to achieve. On the other side, potential savings through reduced infrastructure needs could lower costs.

### *Unit costs*

Generating costs for solar PV and wind power vary significantly across regions, according to local cost factors and the quality of the resources available (Figure 6.11). The evolution of these costs is largely determined by two factors: reductions in capital costs and technological advancements to harness more of the resource. Although increased deployment of wind and solar PV leads to prime sites becoming increasingly scarce within each region, which will tend to reduce capacity factors, at the global level this effect is expected to be more than offset by technological improvements and deployment in regions with untapped high-quality resources. Average capacity factors for wind onshore rise from 21% in 2012 to 26% in 2035, and for large-scale PV from 11% to 17% over the same period.

**Figure 6.11** ▷ **Renewable electricity production costs relative to the wholesale prices for selected technologies and regions in the New Policies Scenario**




Notes: The cost of production is the average levelised cost of electricity at deployed sites over the *Outlook* period, based on a weighted average cost of capital, assumed at 8% for OECD countries and 7% for non-OECD countries. Wholesale electricity prices are taken as the averages projected for respective regions in the New Policies Scenario. In the mid-term, they include the recovery of investment costs for new capacity. The pricing methodology can be found at *www.worldenergyoutlook.org*.

The global average investment cost of onshore wind was about $1 700/kW in 2012. Average costs for offshore wind turbines are still hard to quantify, due to the small number of projects in operation, but they are estimated to range from $3 000/kW to $4 500/kW. In the New Policies Scenario, the global average investment costs for onshore wind decrease by about 10%, partly due to learning effects and economies of scale, as well as a shift of new installations towards non-OECD countries and related lower investment costs. Investment costs for offshore wind decline by around one-third, with increased deployment.

Due to stepped up deployment and overcapacity in manufacturing, the price of solar PV systems dropped more than 40% between 2010 and end-2012. Demand for new capacity was around 30 GW while production capacity was about 55 GW in 2012. Much of the growth in production facilities occurred in China, raising concerns that subsidies were enabling Chinese manufacturers to flood the European market with panels sold below cost. An agreement has been reached, prescribing a cap of 7 GW per year and a minimum price for exports from China to the European Union and it is expected to run until end 2015. Assuming that learning and economies of scale lead to an average cost decrease of about 20% each time capacity doubles (Frauenhofer ISE, 2012), about half of the price decrease over the last two years has been due to overcapacity. As this temporary situation is resolved, market prices will tend to return to the long-term trend. Investments costs at the end of 2012 showed large regional differences. They ranged from some $1 800-5 500/kW for residential rooftop systems and $1 500-3 000/kW for large installations, with China on the low side of the range, and the United States and Japan towards the higher side. In the New Policies Scenario, by the end of the *Outlook* period, the cost for both types declines by around 40%.



## Bioenergy

### *Demand*

Total global demand for bioenergy across all sectors increases from 1 300 Mtoe in 2011 to about 1 850 Mtoe in 2035, about two-thirds of the primary energy demand for natural gas today.[6] The largest proportion of demand for bioenergy is in the buildings sector (including traditional biomass) throughout the *Outlook* period, though this declines in both absolute terms and share over time, largely as a result of relatively high levels of demand in non-OECD countries. Demand for bioenergy in the power sector increases most in absolute terms from 2011 to 2035, by about 280 Mtoe, especially due to significant expansion in non-OECD countries such as China, India and Brazil. This growth is mainly driven by policies to reduce air pollution, boost productive use of domestic agricultural residues and speed deployment of renewables. Also driven by government support policies, demand for biofuels in the transport sector grows at the fastest rate over the *Outlook* period. It more than doubles in OECD countries and increases five-fold in non-OECD countries. Biofuels increase to more than 10% of total bioenergy demand (Figure 6.12).

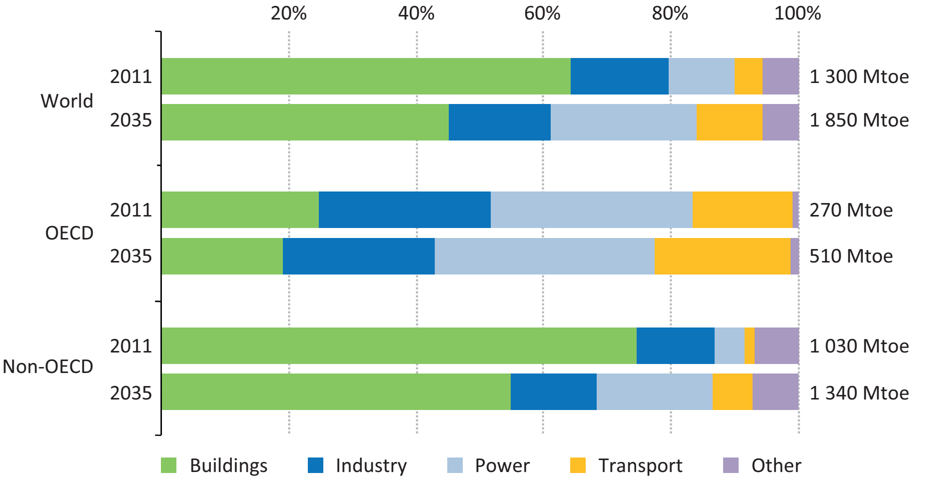
### *Production and Trade*

To meet strong demand growth in the New Policies Scenario, the supply of all types of modern biomass will increase substantially, including biogas and municipal waste. Globally, the potential supply of biomass exceeds the demand in 2035 by an order of magnitude, without competing with food supply or displacing current forestry activities, although land

6. Global biomass use in the "other energy sector" in 2011 was reported at 65 Mtoe. In several cases, biomass use in biofuels production was understated, and it is estimated that there were some 50 Mtoe of unreported biomass use. If this amount would be included, it would result in an additional 200 Mtoe in 2035, or about 12% of global primary biomass demand.

use implications need to be carefully considered (IEA, 2012).[7] On the one hand, for some regions, it will be difficult for the domestic supply of various biomass feedstocks to keep pace with growing demand. For example, the European Union has taken strong measures to support the use of bioenergy in several sectors, including power and transportation, but already imports large volumes of both biomass pellets and biofuels and will continue to do so. India is another region that, despite having large supply potential for many feedstocks, particularly agricultural residues, struggles to ramp up the collection of feedstocks to meet the strong growth in domestic demand for bioenergy, for both power sector applications and biofuels production. The challenge to meet the growing demand domestically will be especially difficult where markets already exist for waste products from agricultural and forestry activities. On the other hand, a few regions have ample supplies to meet both domestic demand and international demand. Brazil, Canada and the United States stand out in this group.

**Figure 6.12 ▷ World bioenergy use by sector in the New Policies Scenario**




Note: Buildings includes the use of traditional biomass.

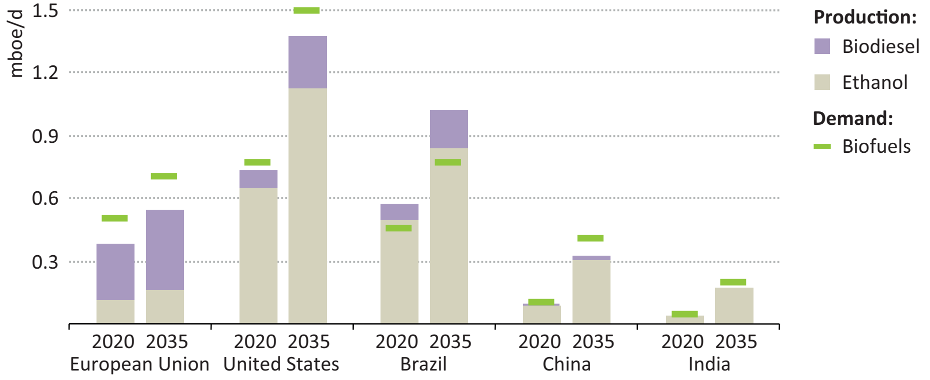
The demand for bioenergy for power generation and heat increases from 136 Mtoe in 2011 to 420 Mtoe in 2035. Over 90%, of world demand is met from domestic resources throughout the *Outlook* period. To meet the remaining demand, some regions will increasingly turn to international supplies of solid biomass for power generation, most commonly in the form of biomass pellets.[8] In total, inter-regional trade of solid biomass for power generation increases from a few percent of biomass consumption to generate electricity to upwards of 8% by 2035.

7. This technical potential, based on conservative technological improvements, is an evaluation of available supply of forestry products, energy crops, and residues from forestry and agricultural activities. For more information, please see www.*worldenergyoutlook.org*.

8. A processed product that has a relatively high energy density is fairly uniform and easier to transport than untreated biomass feedstocks.

The European Union is the largest importer of biomass for power generation by 2035, importing about 6.7 Mtoe. At current biomass pellet prices of $170 per tonne (Govan, 2012), the cost of these imports, largely coming from the United States, Canada and Russia, would reach almost $3 billion. Other regions may also become important players in this market, including countries in Latin America and Africa. In Japan, policy support pushes demand for biomass for power generation and heat well beyond available domestic resources, driving up biomass imports to up to 4.4 Mtoe in 2035, coming mainly from Australia and the United States. Korea and India also look set to become significant importers of solid biomass for power generation. In India, demand for solid biomass in power generation reaches 37 Mtoe, almost triple current levels, requiring some 100 million tonnes of dry biomass feedstocks. While a similar order of magnitude of agricultural residues is available, it will be difficult to collect and transport a high proportion of these to power plants at reasonable costs. As for many fuels in the power sector, China will become the largest consumer of biomass for power generation and heat by 2035. It also has one of the highest supply potentials, through a combination of agricultural and forestry residues, as well as forestry products. In the New Policies Scenario in 2035, China is a net exporter of biomass to other regions in Asia, though, as has happened for other fuels such as coal, a small shift in China's supply and demand balance could have a large impact on global trade.

**Figure 6.13 ▷ Biofuels demand and production in selected regions**




The international market for biofuels increases from 0.2 mboe/d in 2012 to about 0.7 mboe/d in 2035, providing a broadly constant share of total biofuels demand over time. The European Union is the largest net importer of biofuels in 2035, with over 20% of its biofuels demand, about 0.2 mboe/d (Figure 6.13), met through imports from many different countries, including Brazil, the United States and several countries in Asia and Latin America. These trade patterns re-emerge despite recent action by the European Union to impose anti-dumping duties on biofuel imports from Argentina, Indonesia and the United States, and the need for exporters to Europe to first meet sustainability criteria, verifying reductions in greenhouse-gas emissions and demonstrating limited direct and indirect environmental impacts. Furthermore, a cap for conventional biofuels of 6% (at the time of writing) in the transport sector is under discussion in the European Union, which could have important impacts on the global picture. The United States is both a major importer and exporter of biofuels throughout the *Outlook* period, importing sugarcane-based ethanol from Brazil to help meet rising targets for advanced biofuels under the Renewable Fuel Standard and exporting to the European Union to help meet blending targets there. The United States also continues to export lower volumes of ethanol to Canada and Mexico. Brazil is the main supplier for international biofuel markets, especially for fuel ethanol, and it is by far the largest exporter by the end of the *Outlook* period, providing about 0.2 mboe/d to the international market by 2035, about 40% of global biofuels trade.

China and India are both expected to increase their biofuels consumption several times over by 2035, making it difficult for domestic supply to keep up (Figure 6.13). By 2035, both require some imports to meet demand. They are expected to come mainly from Brazil, but also from Indonesia and other countries in Asia. The assumed development of advanced biofuels at commercial scale after 2020 affects the biofuels market in several ways. First, it creates a single market for biomass feedstocks for the power and transport sectors. For some regions, this limits available supply for one or both of these sectors. For example, in India available supplies of residues become relatively scarce by the end of the *Outlook* period due to demand from multiple sectors. The development of advanced biofuels also allows some regions to reduce their reliance on imports of biofuels, as they are able to tap alternative feedstocks to produce biofuels. For example, the European Union is able to limit imports of biofuels after 2025 due to a rise in domestically produced advanced biofuels.

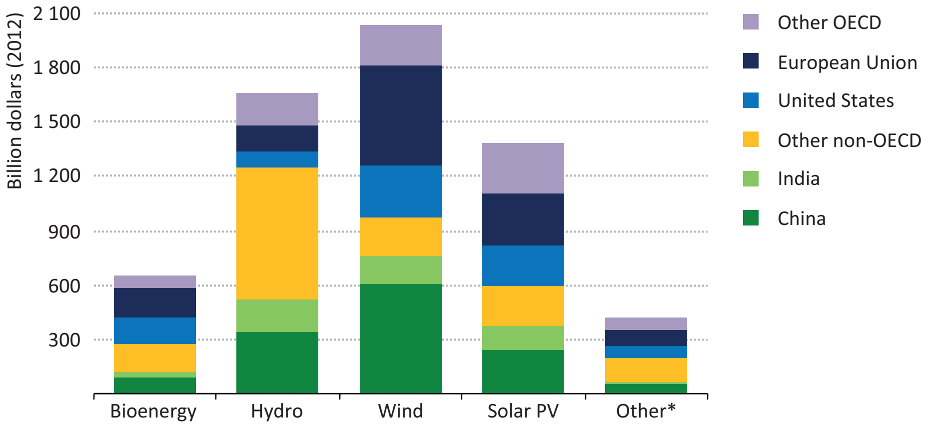
## Investment

Cumulative investment of $6.5 trillion (in year-2012 dollars) is required in renewable energy between 2013 and 2035 in the New Policies Scenario. This corresponds to $280 billion per year on average. Annual investments increase over the period, reaching almost $370 billion in 2035.[9] Renewables for power generation account for more than 95% of the total, with the remainder for biofuels.

Projected investment for renewables in the power sector amounts to $6.2 trillion between 2013 and 2035 (Figure 6.14). Renewables account for 62% of investment in new power plants over the projection period, providing just over half of total capacity additions. Wind power accounts for one-third of the total investment in renewables capacity, followed by hydropower (27%) and solar PV (23%). Investment for renewables in non-OECD countries are $3.3 trillion, higher than the $2.9 trillion required in OECD countries at. Additional global investment of $260 billion (4% of total grid infrastructure investment) is needed to upgrade transmission and distribution networks to accommodate more renewables-based capacity. Investment to meet the expansion of biofuels supply amounts to $330 billion over 2013-2035, or $14 billion per year on average. Conventional production of ethanol requires the bulk of the total (60%), followed by conventional biodiesel (14%) and the remainder for advanced biofuels. OECD countries account for around 60% of total investment.

9. Investments for renewables used for heat are included in the buildings sector investments (see Chapter 7).

**Figure 6.14** ▷ **Cumulative investment in renewables-based power generation capacity, 2013-2035**




* Other includes geothermal, marine and solar CSP.

## Subsidies

Renewable energy subsidies take a variety of forms, including blending mandates, quotas, portfolio obligations, tax credits and feed-in tariffs, which all offer a higher return than market prices, to offset higher costs. With schemes like feed-in tariffs, blending mandates or portfolios and quota obligations, this remuneration is paid by the end-users (though some schemes, such as tax credits are funded from government budgets). Many forms of support mechanisms are specific to electricity produced by renewables capacity installed in a particular year, and have a fixed duration, typically twenty years. Subsidies for biofuels predominately take the form of blending mandates.

Hydropower and geothermal, have long been economic in many locations. Newer technologies, such as wind and solar, are often an attractive option for generating electricity in remote, isolated areas with limited or no existing grid infrastructure, but they require policy support to foster their deployment in most countries. The costs of generation from onshore wind are getting closer to the average wholesale price level in many countries – and are already there in some, such as New Zealand, Brazil, Ireland and parts of the United States. Reductions in production costs for conventional biofuels have not been as pronounced and these costs remain vulnerable to high feedstock prices and weather conditions. Outside Brazil and some parts of the United States, conventional biofuels generally still cost more than oil-based gasoline or diesel. Advanced biofuels remain even more costly, although there are promising signs that significant cost reductions in the production process are on the horizon.

In addition to playing a crucial role in driving down the costs of renewable energy technologies, subsidies to renewables can have important co-benefits (Box 6.3). But support schemes for renewables need to be carefully designed to ensure their efficiency and effectiveness. They should be predictable and transparent and, where possible, provide for competition between technologies best suited to meet short- and long-term objectives. They need to be accompanied by ambitious, yet credible, targets and offer support differentiated according to the maturity of each technology. As cost reductions are achieved, the level of support provided for new installations needs to decline to avoid unnecessary increases in the cost of energy services.

### Box 6.3 ▻ Multiple benefits of renewables

The contribution of renewable energy to global energy needs has continued to grow in recent years, stimulated by policy initiatives in an increasing number of countries. The benefits of renewables within a national energy portfolio can be summarised as:

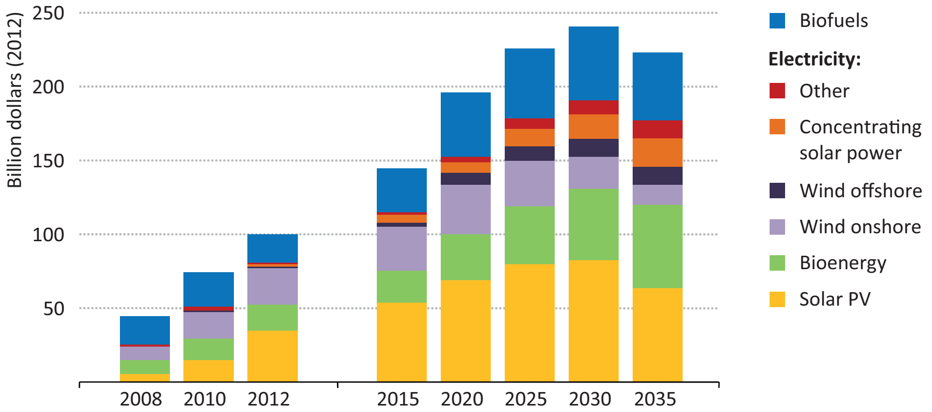
- **Energy security and diversity**: renewable energy technologies can contribute to energy security by providing more diversity in energy supply. They can also reduce the need for fossil fuels, in turn, reducing fuel import bills.
- **Environment**: the deployment of renewables in the New Policies Scenario saves some 4.1 gigatonnes (Gt) of $CO_2$ emissions in 2035 compared with the 2010 fuel mix at the same level of total generation (IEA, 2012). Renewables also help reduce local air pollution and emissions of other pollutants, such as sulphur dioxide and nitrogen oxides.
- **Economic benefits**: the development and deployment of renewables can form part of comprehensive strategies aimed at more sustainable economic growth (often called "green growth"). Renewable energy has featured strongly in economic recovery packages put in place in response to the global economic downturn.
- **Energy access and affordability**: renewables can play an important role in providing electricity access modern energy services to the 1.3 billion people currently without access to electricity and the 2.6 billion that still rely on traditional use of biomass. Mini-grid and off-grid solutions, including solar PV, are often less costly than grid extension to rural areas (see Chapter 2).

Based on a survey of established national policies, renewables are estimated to have received $101 billion in subsidies in 2012, 11% higher than 2011.[10] This includes $82 billion to renewables for electricity generation and $19 billion to biofuels for transport. The rise in 2012 was primarily due to the increase in solar PV capacity, increased generation from capacity installed towards the end of 2011 and the increase of onshore wind capacity. The level of renewables subsidies is less than one-fifth of the fossil-fuel consumption subsidies in the same year (see Chapter 2). However, the geographical distribution is very different, with OECD countries paying about 85% of the renewables subsidies. Subsidies were most generous in the European Union ($57 billion) almost 60% of the total, the United States ($21 billion) and China ($7 billion). Ranked by generating technology, subsidies for solar PV ($35 billion) were the highest, followed by wind ($26 billion) and bioenergy ($17 billion).

10. The subsidy estimates do not include integration costs or subsidies for renewable energy use for heat. See *www.worldenergyoutlook.org* for the methodologies on how renewables subsidies and fossil-fuel consumption subsidies are calculated.

Subsidies to biofuels declined by almost 20% in 2012 from the previous year. This is partly due to reform of taxation levels (or tax incentives) in some of the main subsidising regions, notably the United States and Brazil. In the United States, the US Congress did not extend the ethanol import tariff nor the production tax credit for ethanol, which had been in place for decades. In Brazil, subsidies to biofuels fell by more than half due to lower ethanol supply, following a reduction in the blending mandate, and a decrease in the tax preference provided to ethanol, when gasoline taxes were reduced in the middle of the year. China, too, drastically lowered subsidies for ethanol from $155/tonne to $80/tonne and, although biofuels use increased, the total subsidy level declined.

**Figure 6.15 ▷ Global renewable energy subsidies by source in the New Policies Scenario**



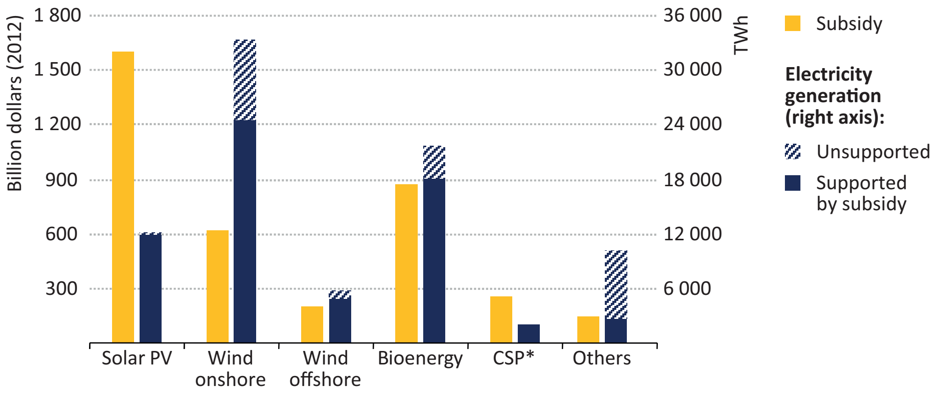

Notes: Other includes geothermal, marine and small hydro.

The New Policies Scenario projects an almost six-fold increase in electricity generation from non-hydro renewables and a tripling of the use of biofuels. Subsidies to renewable energy amount to over $220 billion per year in 2035, after peaking just above $240 billion around 2030 (Figure 6.15). From 2013 to 2035, cumulative subsidies to renewables amount to $4.7 trillion, or around 0.15% of cumulative global GDP. These estimates are calculated by taking the difference between the levelised cost of electricity generated by the renewable energy technology and the regional wholesale electricity price, multiplied by the amount of generation. For biofuels, they are calculated by multiplying the volumes consumed by the difference between their cost and the reference price of the comparable oil-based products.

In total, annual subsidies for renewables for power generation reach $177 billion in 2035. They peak around 2030 and then decline, thanks to increasing wholesale power prices, the decreasing unit costs of most renewable energy technologies, and because older installations are gradually retired, meaning that newer and cheaper units make up a larger share of the installed capacity. Subsidies for onshore wind power peak just after 2020, earlier than those for any other technology, reflecting the increasing competitiveness of this technology. Subsidies for biofuels continue to increase until 2030 to $50 billion, reaching $45 billion in 2035. The bulk of this goes to conventional biofuels, which remain uncompetitive in most locations with conventional gasoline or diesel.

Over the projection period, onshore wind becomes competitive in more and more regions, generating over 33 300 TWh cumulatively, supported by subsidies of some $620 billion (Figure 6.16), corresponding to a low level of subsidy per unit of output ($19/MWh on average over the *Outlook* period, including non-subsidised generation). Solar PV requires $1 600 billion of cumulative subsidies and generates almost 12 200 TWh, meaning a higher average unit subsidy of $131/MWh. Where support policies are committed for many years (typically twenty years for feed-in tariffs), subsidies for older capacity continue to be paid, even after new projects reach competitiveness. For bioenergy, the unit subsidy remains broadly constant through 2035, as costs are not expected to decline significantly. For this reason, and due to a more than three-fold increase in bioenergy generation, subsidies to bioenergy become the second-largest of all by 2035, behind solar PV.

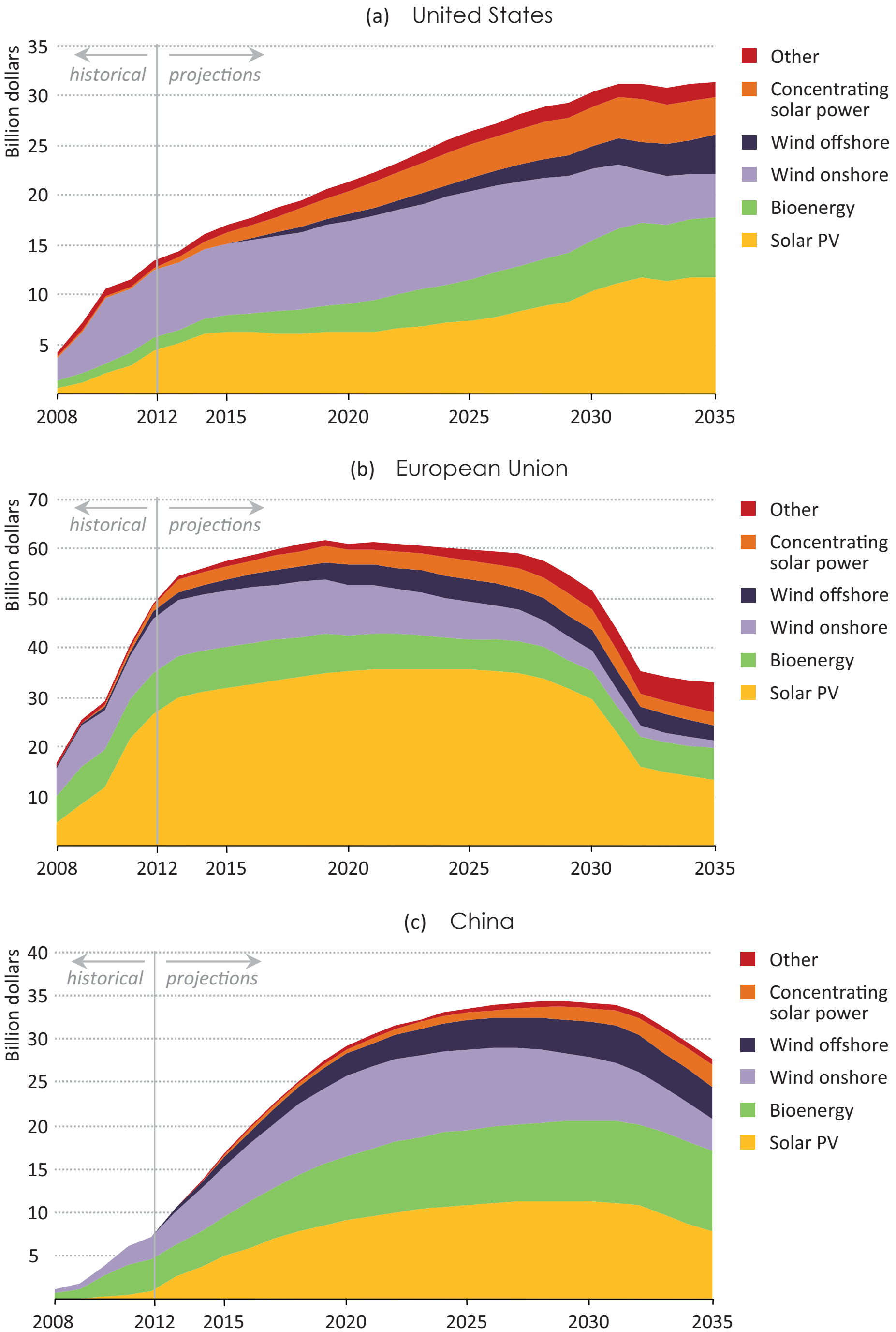
**Figure 6.16** ▷ **Global subsidies for renewable electricity generation and generation by source in the New Policies Scenario, 2013-2035**




* Concentrating solar power.

Similar to the global trend, total subsidies to electricity from renewables peak over the projection period in the European Union and in China (Figure 6.17). In the European Union, subsidies level off in 2020 at $60 billion per year, before declining to about half that level by 2035, as the subsidies to some 52 GW of PV solar added in the last three years come to an end and wholesale prices increase. The peak in China reaches about $35 billion per year around 2030 and then falls to below $30 billion in 2035. The bulk of the increase is attributable to bioenergy and solar PV. The share of wind decreases from 37% in 2012 to 26% in 2035. In the United States, subsidies increase from $13 billion in 2012 to just above $30 billion in 2035, while generation from non-hydro renewables almost quadruples. Subsidies to onshore wind decrease over the *Outlook* period, as the technology gains in competitiveness, while subsidies to bioenergy increase strongly, due to a three-fold increase in generation and the replacement of a large amount of aging capacity.

**Figure 6.17 ▷ Renewables-based generation subsidies by source and selected region in the New Policies Scenario**




Note: Other includes geothermal, marine and small hydro.

# Energy efficiency outlook

## On track for more with less?

### Highlights

- A government-led renewed focus on energy efficiency, at a time of higher energy prices, has accelerated the previously slow rate of improvement in global energy intensity. The amount of energy used to produce a unit of GDP declined by 1.5% in 2012, compared with an average annual decline of just 0.4% between 2000 and 2010. The biggest improvements in 2012 were in countries with energy intensities above the global average, including China and Russia. China's energy intensity has gone from almost four times the world average in 1990, to less than twice the world average now, driven by significant improvements in industry.

- Motivated both by competitiveness considerations and environmental factors, major new energy efficiency policies are being implemented or discussed, including the EU Energy Efficiency Directive, strengthened appliance standards in the United States and initiatives under the US-China Climate Change Working Group to enhance truck efficiency standards and efficiency in buildings in both countries. In the New Policies Scenario, the implementation of policies for efficiency, which are under discussion, leads to savings of 910 Mtoe in 2035 (compared with the Current Policies Scenario), which is just over half of the current energy use of the European Union.

- Industry accounts for 37% and buildings for 26% of efficiency-related primary energy savings in 2035 in the New Policies Scenario. In both sectors, the bulk of the savings are made in the use of electricity, led by efficiency improvements in electric motor systems, stricter standards for appliances, and more efficient lighting. Improved fuel-economy standards in transport lead to oil savings of around 5 mb/d in 2035, or 31% of the total primary energy savings. Improvements in the average efficiency of fossil fuel-fired power plants, particularly in China, India and the United States, account for most of the remainder.

- Subsidies to energy consumption are a major barrier to investments in energy efficiency. Depending on the region, the payback period can be extended up to nine times. For example, in the Middle East, due to low gasoline prices, an investment in a hybrid car is recovered through lower fuel costs only after almost eighteen years, compared with four years in Europe.

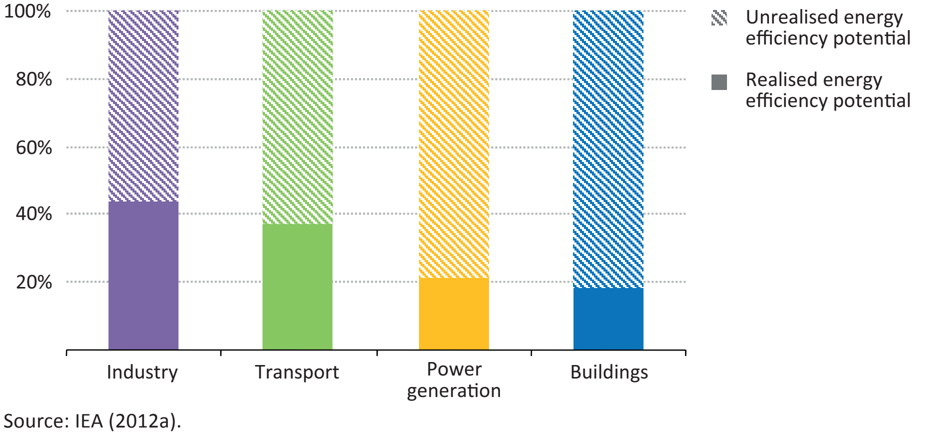
- The New Policies Scenario gives rise to an additional \$3.4 trillion of investment in energy efficiency through to 2035 (on top of the \$4.7 trillion required in the Current Policies Scenario). These additional investments generate cumulative savings in energy expenditures of \$6.1 trillion. Household energy bills are reduced by \$2.6 trillion through energy efficiency. These savings free up disposable income, which leads to an increase in the use of non-energy goods.

## Introduction

Although not always as visible as supply-side options, energy efficiency is an essential component of a sustainable energy future. Policies to improve the efficiency of energy use can start delivering benefits fairly quickly, including by improving energy security and industrial competitiveness, cutting household energy bills and reducing problems linked to local air pollution and climate change. In contrast to supply-side options, energy efficiency options are often obscured by the fact that efficiency is rarely traded or priced. Furthermore, improving efficiency involves a wide range of actions affecting a variety of energy services across different sectors – including buildings, industry and transport – so the overall achievement is often difficult to quantify.

Energy efficiency was the "fuel" of focus in the 2012 edition of the *World Energy Outlook* (*WEO*) (Box 7.1). The report found that policies and measures that are enacted or are currently under discussion will fall well short of tapping the full economic potential of energy efficiency by 2035 (Figure 7.1). In order to raise the visibility of energy efficiency and to put it on the same footing as its supply-side alternatives, we have decided to dedicate a chapter of each year's *WEO* to energy efficiency, along with the chapters on the primary fuels and electricity.[1] This decision is designed to encourage and support the increasing attention that is now being directed to energy efficiency policy in all parts of the world, not least as a means of reducing costs and improving competitiveness (see Chapter 8).

**Figure 7.1 ▷ Proportion of long-term economic energy efficiency potential achieved in the New Policies Scenario, 2012-2035**




Source: IEA (2012a).

This chapter first considers recent energy efficiency trends by region and sector and discusses recent policy developments. It then focuses on the impact of energy efficiency policies yet to be implemented or under discussion, as assumed in the New Policies

1. For similar reasons, alongside the medium-term market reports for different fuels, the IEA has recently published the first edition of the *Energy Efficiency Market Report* (IEA, 2013a).

Scenario. Energy efficiency is examined by sector, fuel and region. The analysis quantifies the avoided energy use due to energy efficiency in the New Policies Scenario compared with the Current Policies Scenario. Further, the chapter discusses energy efficiency investment needs and describes the multiple benefits the energy efficiency policies under discussion would provide, including macroeconomic benefits, savings in import bills and reduced levels of local air pollution and carbon-dioxide ($CO_2$) emissions.

**Box 7.1 ▷ The Efficient World Scenario – tackling competitiveness, energy security and climate change simultaneously**

To quantify the implications for energy markets, the economy and the environment of undertaking all economically viable energy efficiency investments, the *WEO-2012* (IEA, 2012a) presented the Efficient World Scenario, setting out the policies needed to overcome the various barriers to the comprehensive adoption of energy efficiency measures. This scenario shows that the policies under discussion, included in the New Policies Scenario, achieve only one-third of the economic potential of energy efficiency (Figure 7.1). The Efficient World Scenario provides a blueprint that identifies the policies and measures required in each sector to unlock this full potential, along with an estimate of the required investment. Those investments pay back well before the end of the technical lifetime of the energy capital stock.

In the Efficient World Scenario, growth in primary energy demand through to 2035 is halved (in net terms, *i.e.* after taking the rebound effect into account), relative to the New Policies Scenario. The vast majority of savings relative to the New Policies Scenario are achieved by end-users: more than 40% in buildings,[2] 23% in industry and 21% in transport. The Efficient World Scenario leads to a more efficient allocation of resources and delivers economy-wide benefits. The global economy generates an additional $18 trillion in cumulative output by 2035, corresponding to the combined gross domestic product (GDP) of the United States, Canada, Mexico and Chile in 2011. The energy security of importing nations increases, while exporters are able to sell volumes, which would otherwise have gone to internal consumption. Along with reduced local pollution, energy-related $CO_2$ emissions peak before 2020 and decline thereafter, a trajectory consistent with a long-term temperature increase of 3 °C. This is a significant improvement compared to the New Policies Scenario, though still falling short, in isolation, of limiting the global temperature increase to 2 °C. The aim of the Efficient World Scenario was to highlight the very large potential for energy efficiency. As this does not change on a yearly basis, the Efficient World Scenario has not been updated for this edition of the *Outlook*.

2. Buildings comprise the residential and services sector, including energy consumption for space and water heating, cooking, lighting, appliances and cooling.

## Current status of energy efficiency

### *Recent progress*

Global energy intensity, measured as the amount of energy required to produce a unit of GDP, declined by 1.5% in 2012, which was similar to the improvement in 2011.[3] A renewed policy focus on energy efficiency and higher energy prices have together accelerated the previous slow pace of energy intensity improvement (Box 7.2). The decade to 2010 had seen an average annual improvement of only 0.4% per year with energy intensity worsening in 2009 and 2010, partly because of colder-than-usual winters and the economic recession.

**Box 7.2 ▻ Energy efficiency, energy intensity and energy savings**

Energy intensity, in general defined as primary energy demand per unit of economic output, is not a good indicator of energy efficiency as it is influenced by the structure of an economy and climatic conditions (IEA, 2008 and 2012a). For analysis of past trends, energy intensity is nevertheless often used as a proxy for energy efficiency in the absence of more detailed data.

This chapter discusses trends in energy efficiency in the New Policies Scenario. Energy savings are stated by reference to the Current Policies Scenario, which does not attempt to capture the effect of policies under discussion but not yet adopted. These savings can arise in end-use sectors (*i.e.* transport, buildings, industry and agriculture) and in supply (*i.e.* power generation, oil and gas extraction and refineries).

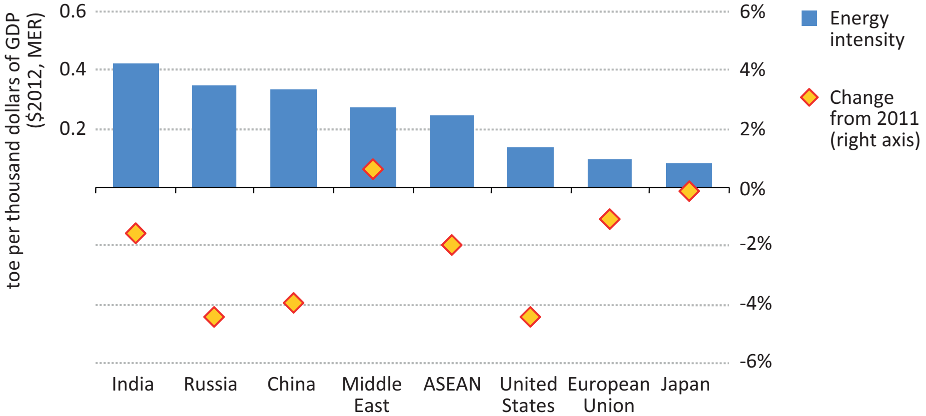
Energy savings can be grouped in three broad categories: reductions in the demand for energy services; savings due to fuel and technology switching; and savings due to energy efficiency improvements. Changing end-user prices lead to changes in the demand for energy services, reducing the demand for final energy consumption. Fuel and technology switching, for example switching from gasoline cars to electric cars, adopting heat pumps for space and water heating or producing steel in electric arc furnaces instead of basic oxygen furnaces can reduce final consumption. Energy efficiency savings, strictly defined, are different: they provide the same energy service while consuming less energy. Such energy efficiency improvements may be provided by adopting more efficient technologies, including, for example, better insulation of a buildings shell, or by improving system efficiency through energy management systems and process control. In order to distinguish these three different effects, we employ a decomposition analysis based on our technology-rich World Energy Model results.[4]

3. While energy intensity is presented here using GDP at market exchange rate (MER), it can also be expressed in terms of purchasing power parity (PPP). For a discussion on the use of GDP at MER or PPP see also IEA/World Bank (2013).

4. For more information on the decomposition analysis and the World Energy Model, see *www.worldenergyoutlook.org/weomodel/documentation/.*

Energy intensity in 2012 declined, in relative terms, mostly in countries where its level was above the global average, leaving greater remaining potential for improvement (Figure 7.2). Countries with the highest energy intensities often have considerable fossil fuel resources and often subsidise fossil fuel consumption (IEA/World Bank, 2013). On the contrary, those countries with the lowest energy intensities among the world's top-twenty energy consumers are all characterised by high energy prices and strict efficiency legislation, *e.g.* Japan and members of the European Union.

**Figure 7.2 ▷ Primary energy intensity levels and trends in selected regions, 2012**




Notes: GDP is expressed in year-2012 dollars in market exchange rate (MER) terms; toe = tonnes of oil equivalent.

In 2012, the United States made the biggest relative improvement in energy intensity, as a result of efficiency gains in industry and services, together with fuel switching in power generation to natural gas. The second-biggest improvement was in Russia due primarily to lower energy use per unit of output in industry and services. Russia was closely followed by China, where efficiency improvements in industry (Box 7.3) and higher output from hydropower and other renewables led to a 4% improvement in energy intensity in 2012.[5] From being four times higher than the global average in 1990, China's energy intensity is now less than twice the global average. In the Middle East, in contrast to other regions, energy intensity increased in 2012, mainly due to increased activity in energy-intensive industry (*e.g*. petrochemicals) and rapid energy demand growth in buildings and transport.

At its simplest, assessment of the improvement in energy intensity simply involves measuring the reduction in energy use per unit of GDP that has been achieved over a given period. On this basis, energy intensity across almost all regions improved over the last two decades. Between 1990 and 2000, global energy intensity (disregarding changes in the regional make-up of regional GDP) improved by 1.4% per year, and 1.8% per year over the period since 2000 (Figure 7.3).

5. The physical energy content method, applied by the IEA, uses the physical energy content of the primary energy source as the primary energy equivalent. Accordingly, the conversion efficiency for hydro and wind power is 100%.

### Box 7.3 ▷ Energy efficiency does deliver[6]

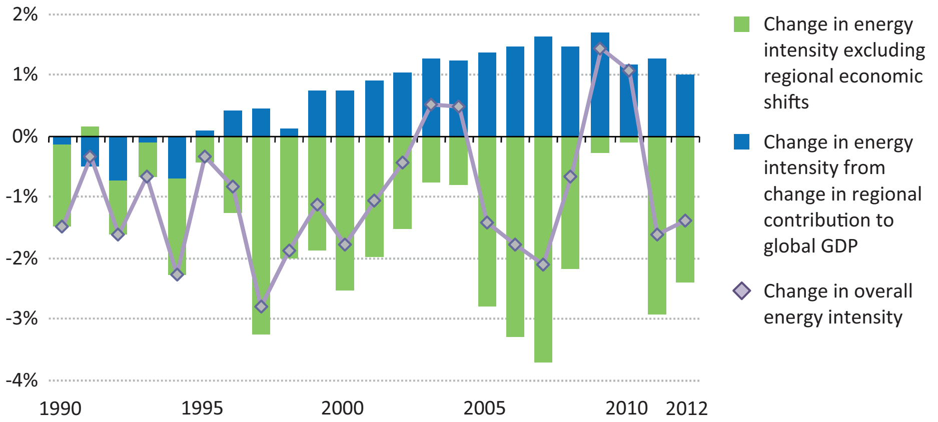
There has been a long-standing debate on whether energy efficiency really can deliver long-term energy savings, mostly due to different estimates of the rebound effect and the extent to which demand savings will influence energy prices (IEA, 2012a; Sorrell, 2007; Frondel, Ritter and Vance, 2012). A common perception is that little progress has been made in improving energy efficiency. However as measurement of energy efficiency improves, it is possible to show evidence that it really is making a difference. Here are three examples of recent policies and their impact:

- During its 11th and 12th Five-Year Plans, China introduced wide-ranging policies to reduce energy use in industry, which accounts for about half of its total final energy consumption. China's industrial energy consumption is dominated by the steel and cement sector, which previously consumed much more energy per unit of output than the OECD average. Measures that have reduced industrial energy intensity have included energy performance standards; targets for annual energy consumption for the biggest companies; the closure of small and outdated plants; energy audits and the introduction of energy management systems; and financial incentives. Official reports and independent analysis estimate that China saved 105 million tonnes of oil equivalent (Mtoe) in its industrial energy demand over four years (2006-2009) through its Top-1 000 Programme, an amount equivalent to the entire annual energy demand of Poland (Jing, *et al.*, 2012). The energy intensity of China's cement industry is now comparable with the OECD average.
- Japan's Top-Runner Programme, set the first fuel-economy standards in the transport sector in 1999. The goal was to reduce specific fuel consumption of new passenger light-duty vehicles by about 23% within fifteen years. The target was achieved in 2005, five years ahead of schedule. The Top-Runner Programme is estimated to have saved around 0.2 million barrels per day in oil consumption in 2010 and thus cut annual fuel bills by almost $6 billion ($2012) in the same year (GWPH, 2013).
- The German KfW Development Bank has a long record of providing low-interest loans and other subsidies to incentivise renovations in existing buildings to improve their energy efficiency (75% of German homes were built before any energy efficiency regulations came into force). Renovations financed through the Bank improved energy performance in houses and reduced their average energy consumption by 30% in 2011. It has been independently estimated that the KfW programmes saved €690 in annual energy costs for each household in 2011. Moreover, $CO_2$ emissions have been cut by 4 million tonnes per year between 2005 and 2011 while creating or securing around 220 000 jobs and leveraging significant private investment (Diefenbach, *et al.,* 2012; Schröder, *et al.*, 2011).

6. Increased energy efficiency can lead beneficiaries to spend part of the revenue saved on new or additional energy services, so offsetting part of the original efficiency savings. This is called rebound effect and is taken into account in the World Energy Model projections.

But, at the same time, countries with higher energy demand per unit of GDP were increasing their share of global economic output: the shares of different regions in global output were shifting. Taking this into account, there has been a significant slowdown in the global rate of energy intensity improvement. Global energy intensity on this basis declined by 1.3% per year on average in the 1990s, but the decline dropped to 0.4% per year during the 2000s. The case of China illustrates this effect. China's economy is significantly more energy intensive than the world average. As its weight in the global economy increases, so the global average improvement in energy intensity is dampened (Figure 7.3). At the start of the 1990s, this effect was offset by the collapse of the Soviet Union and the consequent decline in its economic activity.

**Figure 7.3 ▷ Annual relative change in global primary energy intensity by driver, 1990-2012**




Notes: Changes in energy intensity are split into two drivers – energy intensity on a regional level and regional GDP share – using a rolling decomposition analysis. Energy intensity is measured using GDP at market exchange rate in year-2012 dollars.

## *Recent policy developments*

Improvements in energy efficiency over the past two years have been accompanied by encouraging signs of increasing action on the policy front in many regions (Table 7.1). In July 2013, China and the United States drafted a co-operation plan, pledging to make heavy-duty vehicles and coal-fired power plants more efficient. Further, the US administration's plan on climate action, announced in June 2013, has strong energy efficiency components. The plan includes: the imposition of carbon pollution standards on new and existing power plants (which would lead to increased average fossil-fuel power plant efficiency); strengthening fuel-economy standards for heavy-duty vehicles beyond 2018; and tightening efficiency standards for electric appliances. In 2012, Canada extended fuel-economy standards for cars to 2025, introduced stringent performance standards on new power plants (banning the construction of coal-fired power stations, unless equipped with carbon capture and storage technology) and introduced Minimum Energy Performance Standards (MEPS) for several products, including lighting and water heating.

Among others in OECD, the European Union's Energy Efficiency Directive, which came into force in December 2012, must be implemented by member states by mid-2014. Several regulations for appliances, such as computers and vacuum cleaners, have been implemented under the EU Ecodesign Directive. In Australia, the government has taken further steps as part of the Clean Energy Future package to exploit the remaining energy efficiency potential and financial support will be provided and research promoted through the Clean Technology Program and the Clean Energy Finance Corporation. In industry, the Energy Efficiency Opportunities programme has been opened up to medium-size energy consumers. Discussion has also begun on setting efficiency standards for light-duty vehicles. Japan added windows and heat-insulating materials to the Top-Runner Programme in May 2013, which is expected to promote technology innovation. Also in Japan, an evaluation is to be carried out of industrial consumer's efforts to reduce electricity use during peak hours.

Action on energy efficiency has not been confined to OECD countries. The world's biggest energy consumer, China, introduced an extensive set of efficiency goals and measures at the start of its 12th Five-Year Plan in 2011 with the objective of reducing energy intensity 16% by 2015 compared with 2010. Over the past year, some concrete policy actions have been taken to realise the target. The National Development and Reform Commission announced more market-oriented pricing for oil products and a price increase for natural gas for businesses. Furthermore, Beijing plans to eliminate large coal-fired boilers from the city centre by the end of 2015.

In India, the Energy Conservation in Building Code has become mandatory for large commercial and residential buildings in several states, with the objective of reducing energy consumption from lighting and hot water systems, and the MEPS for air conditioners have been tightened. Southeast Asian countries are also increasingly turning attention to energy efficiency, but subsidies remain commonplace across the region (IEA, 2013b). In Singapore, the Energy Conservation Act has been implemented, requiring a co-ordinated industrial approach to energy efficiency and, in Malaysia, a long-term National Energy Efficiency Master Plan has been adopted.

Brazil has joined other countries in adopting incentives to increase energy efficiency in the transport sector. The Inovar-Auto programme encourages technology innovation by requiring car manufacturers to increase the efficiency of cars up to 2017 in order to qualify for tax breaks. Its effective implementation is expected to increase the efficiency of light-duty vehicles by at least 12% by 2017 (see Chapter 10). The Inovar-Auto programme is seen as a first step towards the establishment of mandatory targets.

The Middle East saw some intensified action on limiting the spiralling electricity consumption from air conditioners, which account for roughly half of electricity demand in that region. Saudi Arabia strengthened MEPS for air conditioners, while the United Arab Emirates introduced such regulation for the first time.

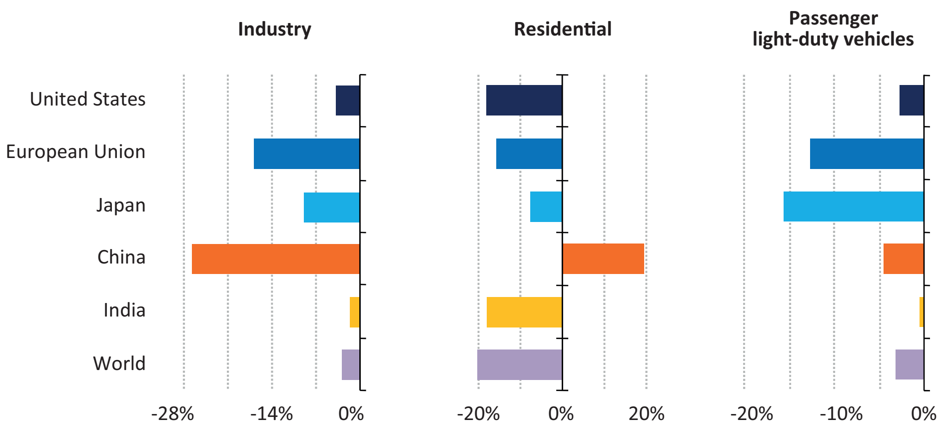
## Table 7.1 ▷ Selected energy efficiency policies announced or introduced in 2012 and 2013

| | Sector | New policy measures |
|---|---|---|
| **United States** | Power | Announcement of carbon pollution standards for new and existing power plants. |
| | Buildings/ industry | Proposal of the Energy Savings and Industrial Competitiveness Act of 2013 to: strengthen building codes; create a financing initiative; and incentivise the application of efficient motors. Tighten efficiency standards for appliances. |
| | Transport | Intention announced to increase fuel-economy standards for heavy-duty vehicles beyond 2018. |
| **Canada** | Transport | Proposed extension of emissions standards for passenger and commercial light-duty vehicles beyond 2016; implementation of emissions standards for heavy-duty vehicles. |
| | Buildings | Increased stringency of MEPS for several products, including lighting, water heating, air conditioners and appliances. |
| | Power | Introduction of performance standards requiring new power stations not to exceed 420 tonnes of $CO_2$ per gigawatt-hour. |
| **Japan** | Buildings/ industry | Extension of the Top-Runner Programme to windows and insulating materials.<br>Evaluation of industrial consumer efforts to reduce electricity use during peak hours. |
| **European Union** | Buildings | Implementation of regulations for vacuum cleaners and computers within the framework of the Ecodesign Directive. |
| | Transport | Agreement on a fuel-economy standard for new cars of 95 grammes of $CO_2$/km by 2020. |
| **Australia** | Industry | Clean Technology Program invests \$1.2 billion to improve energy efficiency and support research and extension of the Energy Efficiency Opportunities programme. Establishment of the Clean Energy Finance Corporation endowed with \$10 billion fund to invest in clean energy including energy efficiency. |
| **China** | General | Energy price reform (more frequent adjustments in oil product prices and an increase in natural gas price by 15% for non-residential users). |
| | Buildings | Introduction of energy standards for new buildings and the refurbishment of existing dwellings. |
| **India** | Buildings | More stringent MEPS for air conditioners.<br>Energy Conservation in Building Code (ECBC) made mandatory in eight states. It applies, among other things, to the building envelope, lighting and hot water. |
| **Southeast Asia** | Industry | Singapore: Energy Conservation Act came into force requiring reporting on energy use, appointing energy managers and elaborating efficiency improvement plans.<br>Malaysia: National Energy Efficiency Master Plan established an overall long-term plan for efficiency, with a goal to reduce electricity consumption by 10% in 2020. |
| **Brazil** | Transport | Inovar-Auto programme approved requiring car manufacturers to produce more efficient vehicles to qualify for a tax discount. |
| **Africa** | Buildings | Economic Community of West African States (ECOWAS): phase-out of incandescent lighting by 2020, adoption of appliance standards and labels by 2014 and development of region-wide standards for buildings. |
| | Industry | South Africa: Manufacturing Competitiveness Programme of \$0.6 billion with one aim being to upgrade current production facilities. |
| **Middle East** | Buildings | Saudi Arabia: more stringent MEPS for air conditioners.<br>United Arab Emirates: introduction of MEPS for air conditioners and mandatory energy labelling scheme for all domestic appliances. |

## *Recent sectoral trends*

Diverging energy intensity developments by sector are apparent at a regional level (Figure 7.4). Global industrial energy intensity decreased by only 3% between 2005 and 2012. In China it decreased by one-quarter, while in the Middle East it increased by one-fifth.[7] In the United States, energy intensity in industry decreased only slightly over the past seven years as efficiency improvements were almost fully offset by an increase in oil and gas production and increased activity in the chemicals industry that shifted the economy, to some extent, to more energy-intensive sectors. The European Union, on the other hand, saw a decline of about 15% in its industrial energy intensity, partially linked to the declining share of energy-intensive industry, such as iron and steel, in total industrial output. Energy intensity levels in Japan's industry sector decreased by about 9% from 2005 to 2012, helped by structural changes in the economy away from energy-intensive sectors, including metals and paper.

**Figure 7.4** ▷ **Energy intensity change by sector and region, 2005-2012**




Decomposition analysis for China shows that structural change from 2005-2010 played only a minor part in the substantial improvement in its industrial energy intensity in those years, meaning that the bulk of the improvement can be attributed to energy efficiency gains (Hasanbeigi, *et al.,* 2013). The share of energy-intensive industries in total industrial value added did not change significantly during the 11th Five-Year Plan, due to strong growth in cement and steel production. Driven by ambitious energy efficiency policies, including the ten key projects and Top-1 000 Energy-consuming Enterprises Programme, efficiency improvements were strongest in the cement and paper industries.

In the residential sector, which accounts for one-quarter of global final energy demand and 73% of total buildings energy demand, energy intensity fell by 20% over the past seven years, but regional trends diverge.[8] In emerging economies, such as China, savings due

7. Industrial energy intensity is defined as energy consumed per unit of industrial value added.

8. Residential energy intensity is defined as modern residential fuel use per square metre and capita, calculated only where the population has access to modern energy.

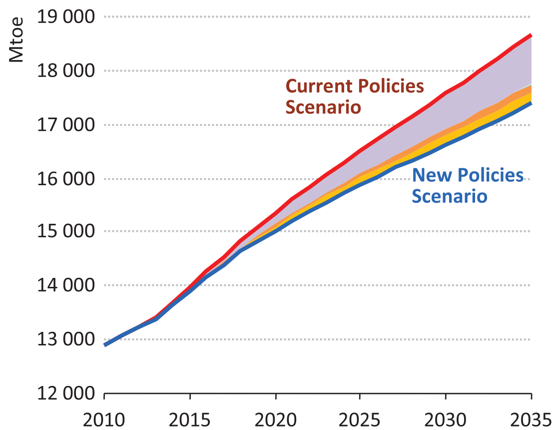
to improvements in energy efficiency are more than offset by an increase in consumption driven by higher wealth and living standards. In OECD countries, energy intensities in households decreased over the period, mainly as a consequence of efficiency measures. In countries where parts of the population lack access to electricity, such as India, the intensity of energy use decreased markedly, as households gaining access to modern energy supply normally consume relatively little compared with the country's average consumption of modern energy per capita and per square metre of floor space. This effect strongly impacts the global intensity trend; therefore a decrease in energy intensity is not entirely driven by efficiency improvements. In road transport, diverging regional trends can also be observed from 2005: in Japan and the European Union, high fuel prices, fuel standards and the sluggish economy led individuals to buy smaller cars, which reduced fuel intensity; while in India fuel intensity stayed roughly constant.[9]

## The outlook for energy efficiency

7

In the New Policies Scenario, energy demand to 2035 increases by one-third, compared with almost 45% in the Current Policies Scenario, saving 1 260 Mtoe in 2035. Efficiency accounts for almost three-quarters, or 910 Mtoe, of the energy savings in 2035, reflecting the policies and measures already being discussed (Figure 7.5). The bulk of the savings occur in end-use sectors, with a much smaller share achieved in energy supply and transformation. The amount of energy required to generate a unit of GDP is reduced by 37% compared with today. Global energy intensity improvements average 1.9% per year, compared with 1.6% in the Current Policies Scenario (and 2.5% in the 450 Scenario).

**Figure 7.5 ▷ Change in global primary energy demand by category in the New Policies Scenario relative to the Current Policies Scenario**




| Energy savings in 2035 | |
|---|---|
| Efficiency in end-uses | 70% |
| Efficiency in energy supply | 2% |
| Fuel and technology switching | 12% |
| Energy service demand | 16% |
| **Total** (Mtoe) | **1 259** |

9. Transport energy intensity is defined as on-road fuel consumption in passenger light-duty vehicles in litres per 100 kilometres.

Apart from greater efficiency, other measures that contribute to reducing energy demand include fuel switching and reduced demand for energy services.[10] Fuel and technology switching is particularly concentrated in the power sector being achieved by increasing the share of generation from gas-fired power plants, solar photovoltaics (PV), wind and hydropower, and, in the buildings sector, by the installation of heat pumps for space heating. Demand for energy services is further reduced by higher prices resulting from subsidy removal, $CO_2$ pricing and more expensive electricity generating technologies in the power sector.

### *Trends by region*

Roughly half of the global efficiency-related energy savings in the New Policies Scenario are achieved in China, North America and Europe. This reflects not only their current and expected shares in total global energy demand, but also their emphasis on efficiency (Table 7.2).

In 2035, the largest share of the differential energy savings between the Current and New Policies Scenarios is achieved in China, representing about 40% of the global total (Figure 7.6). Due to energy efficiency, Chinese energy demand growth from 2011 to 2035 slows from an annual average of 2.2% to 1.9%. Energy efficiency, together with structural changes in the economy, contributes to a decline in China's energy intensity of 60% between 2011 and 2035. The main contributing factor to energy savings in China in the New Policies Scenario, compared to the Current Policies Scenario, is the more intense shift in the Chinese economy from energy-intensive industries to light industry and services.

North America achieves the second-largest savings, at roughly 190 Mtoe in 2035, almost halving the annual growth in its energy demand to 2035 compared with the Current Policies Scenario. North American energy intensity declines by about 40%, based on more ambitious energy efficiency policies in transport, industry and buildings. As a result, the gap between energy intensity in North America and OECD Europe narrows: in 2011 North America was using 49% more energy than Europe to produce one unit of GDP; by 2035 it uses 37% more. Europe's energy demand in the New Policies Scenario is 7% lower than in the Current Policies Scenario (about 120 Mtoe in 2035). The main driver behind the energy savings in Europe is the implementation of the EU Energy Efficiency Directive. The main components that reduce final energy consumption are the energy efficiency obligation scheme, together with, the renovation of the building stock, accurate and individual billing, and mandatory energy audits in industry.

In the New Policies Scenario, India's total primary energy demand more than doubles over the *Outlook* period; annual growth averages 3.0%, compared with 3.3% in the Current Policies Scenario. A key driver of the reduction is the assumed extension of the current Perform, Achieve and Trade (PAT) scheme, which includes financing mechanisms to support

10. Demand for energy services (*e.g.* for transport, lighting or space heating) is different from final energy consumption. The latter is a result of the fuel used and the efficiency of the end-use device chosen to satisfy the energy service demand.

the implementation of efficiency measures. Other developing countries in Asia, particularly ASEAN countries, have recently stepped-up efforts to improve energy efficiency, using regulations, market-based instruments and financial incentives. Compared to the Current Policies Scenario, other developing countries in Asia save a total of around 60 Mtoe in the New Policies Scenario in 2035, with almost 60% of the savings stemming from ASEAN countries (IEA, 2013b). Persistent subsidies for fossil fuels in several countries in the region increase the payback periods of energy efficiency measures and thus impede efficiency gains.

**Figure 7.6a ▷ Energy intensity by region in the New Policies Scenario**

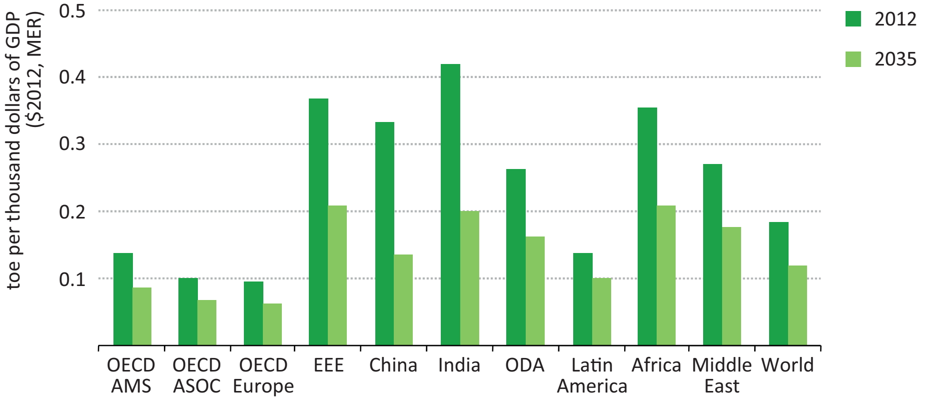
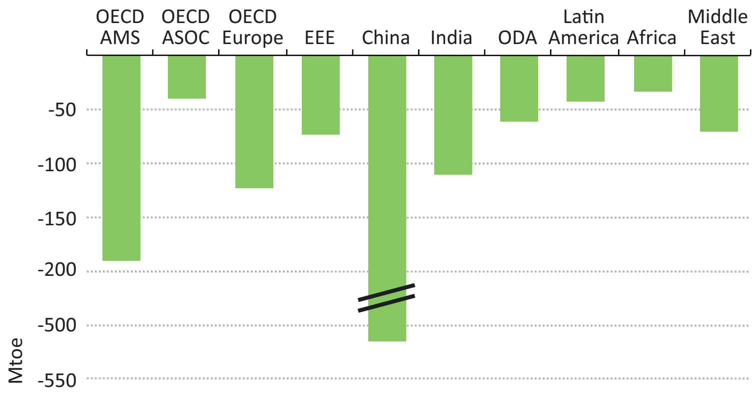



**Figure 7.6b ▷ Primary energy savings by region in the New Policies Scenario relative to the Current Policies Scenario in 2035**




Notes: OECD AMS = OECD Americas; OECD ASOC = OECD Asia Oceania; EEE = Eastern Europe/Eurasia; ODA = Other Developing Asia.

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**Table 7.2 ▷ Key energy efficiency assumptions in major regions in the New Policies Scenarios**

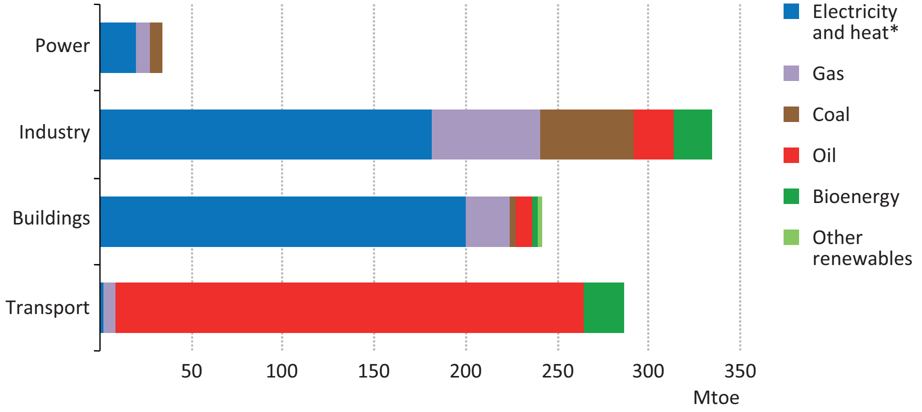
| | New Policies Scenario |
|---|---|
| **United States** | Fuel-economy standards for new passenger light-duty vehicles (PLDV) at 54.5 miles per gallon (4.3 litres per 100 kilometres [l/km]) in 2025, and continued improvement thereafter.<br>Fuel-economy standards for new trucks (up to 20% by 2017/2018, depending on type).<br>Increased state and utility budgets for energy efficiency and continued improvement thereafter.<br>MEPS extended and strengthened for a number of appliances. |
| **European Union** | Partial implementation of the Energy Efficiency Directive by 2020 and improvements thereafter.<br>MEPS for buildings, as specified in the Energy Performance for Buildings Directive.*<br>Mandatory environmental performance requirements for energy-using products, as specified by the Ecodesign Directive.**<br>Fuel-economy standards for PLDVs at 95 g $CO_2$/km in 2020 (3.8 l/100 km), light-commercial vehicles at 147 g $CO_2$/km (5.9 l/100 km) in 2020. |
| **Japan** | Measures to contain electricity demand growth.<br>Mandatory energy efficiency benchmarking and energy management.*<br>Efficient lighting, net zero energy use for all new buildings from 2030, Top-Runner Programme.<br>Fuel-economy standards for PLDVs at 20.3 km/l (4.9 l/100 km) in 2020* and strengthening thereafter. |
| **China** | Target in the 12th Five-Year Plan (2011-2015) to cut energy intensity by 16% including:<br>- Shift towards a more service-oriented economy.<br>- Top-10 000 Energy-consuming Enterprises Programme.**<br>- Small plant closure and phasing out of outdated capacity.*<br>- Incentives for buildings refurbishment, targets for energy efficiency in buildings.**<br>Fuel-economy standards for PLDVs at 5.0 l/100 km in 2020, and strengthening thereafter.<br>Fossil-fuel subsidies phased out within ten years. |
| **India** | Full implementation and extension of the National Mission on Enhanced Energy Efficiency.*<br>Fuel-economy standards for PLDVs: assumed annual improvement of 1.3% over 2012-2020.<br>Implementation of MEPS and labelling for equipment and appliances, as well as support of efficient lighting.*<br>Fossil-fuel subsidies phased out within ten years. |
| **Brazil** | Phasing out of incandescent lighting.**<br>Measures to increase efficiency in appliances and air conditioners.**<br>Enhanced action according to the national energy efficiency plan.<br>Inovar-Auto initiative targeting fuel efficiency improvement for PLDVs of at least 12% in 2017.** |
| **Middle East** | Partial phase out of fossil fuel subsidies.<br>Measures to increase efficiency of lighting, appliances and air conditioners. |

* Also implemented in the Current Policies Scenario. ** Partially implemented in the Current Policies Scenario. Note: All fuel-economy standards refer to test-cycle fuel consumption.

### *Trends by sector*

Global primary energy demand in the New Policies Scenario in 2035 is 1 260 Mtoe, or 7%, lower than in the Current Policies Scenario. Slightly more than half of the primary energy savings come from the power sector. Only a small portion of the savings in the power sector comes from improved efficiency in the sector itself, the vast majority of the savings being attributable to lower electricity consumption in buildings and industry (Figure 7.7). Once the electricity savings are recalculated into primary energy terms (accounting for conversion losses), industry saves the most (37%), followed by transport (31%) and buildings (26%). While electricity savings dominate the industry and buildings sectors, oil is the dominant fuel in transport and shows the highest savings.

**Figure 7.7 ▷ Primary energy savings from energy efficiency by fuel and sector in the New Policies Scenario relative to the Current Policies Scenario in 2035**




* Electricity and heat demand savings in end-use sectors are converted into equivalent primary energy savings and attributed to each end-use. The savings allocated to the power sector arise from the increased efficiency of the plant and of grid and system management (efficiency improvements in transmission and distribution are labelled as "electricity and heat" in power). Note: Energy savings of 17 Mtoe in agriculture are not depicted, while non-energy use does not have any efficiency-related savings between the two scenarios.

#### *Industry*

The industry sector is responsible for 30% of global final energy consumption and one- third of energy-related $CO_2$ emissions (including indirect emissions from electricity and heat). Over the projection period, industrial energy consumption grows to some 3 530 Mtoe from today's level of 2 550 Mtoe (Table 7.3). Most of this growth arises in non-energy-intensive sectors, such as food, textiles, machinery and transport equipment, whose energy consumption increases by 60%, while energy consumption in iron and steel grows by only 16% and is almost flat in cement.

**Table 7.3 ▷ Savings in industrial energy demand and $CO_2$ emissions from energy efficiency in the New Policies scenario** (Mtoe)

| | Demand | | | Change versus Current Policies Scenario | | | |
|---|---|---|---|---|---|---|---|
| | | | | Total | | Due to efficiency | |
| | 2011 | 2020 | 2035 | 2020 | 2035 | 2020 | 2035 |
| Coal | 727 | 848 | 814 | -27 | -73 | -11 | -35 |
| Oil | 324 | 355 | 348 | -10 | -30 | -7 | -20 |
| Gas | 502 | 624 | 783 | -14 | -61 | -12 | -46 |
| Electricity | 671 | 885 | 1134 | -27 | -98 | -20 | -66 |
| Heat | 126 | 143 | 148 | -2 | -10 | -3 | -9 |
| Bioenergy* | 199 | 242 | 300 | -2 | 6 | -6 | -18 |
| **Total** | **2 548** | **3 096** | **3 528** | **-82** | **-265** | **-59** | **-194** |
| $CO_2$ emissions (Gt)** | 9.7 | 11.8 | 12.3 | -0.5 | -2.0 | -0.3 | -0.9 |

* Includes other renewables. ** $CO_2$ emissions include indirect emissions from electricity and heat; Gt = gigatonnes.

Compared with the Current Policies Scenario, industrial energy consumption is 7% lower in the New Policies Scenario in 2035. Almost three-quarters of the reduction is driven by energy efficiency gains. Most of the new policies currently under discussion focus on energy audits, energy management systems and financial incentives, particularly for small and medium-size enterprises. Many of these companies are in non-energy-intensive industries, as heavy industries are generally dominated by large corporations. Consequently, three-quarters of the efficiency-related savings come from light industries in 2035. The optimisation of electric motor systems, including the increased adoption of variable speed drives, is responsible for most of the electricity savings, given the large share of these systems in consumption and their improvement potential (IEA, 2013c).

Reduced demand for energy services accounts for about one-quarter of the energy savings in 2035 in the New Policies Scenario, compared with the Current Policies Scenario. Most of these demand-related savings occur in China as a result of a shift from heavy industries to lighter ones and to the services sector. While demand declines in regions that phase out fossil-fuel subsidies, it slightly increases elsewhere, due to lower energy prices. The effect of fuel and technology switching is minimal, as the positive effect from technology switching (*e.g.* from primary to secondary steel making) is almost completely offset through the growth in the share of bioenergy, which is usually less efficient than fossil fuels.

The steel sector[11] is the world's second most energy-consuming industry (after chemicals and petrochemicals), consuming as much energy each year as Russia. There is over-capacity in steel making, and since energy is an important cost factor, efficient energy use is a key determinant of plant competitiveness (see Chapter 8). Energy intensity can be reduced in many ways: by adopting more efficient technologies, by optimising and managing systems,

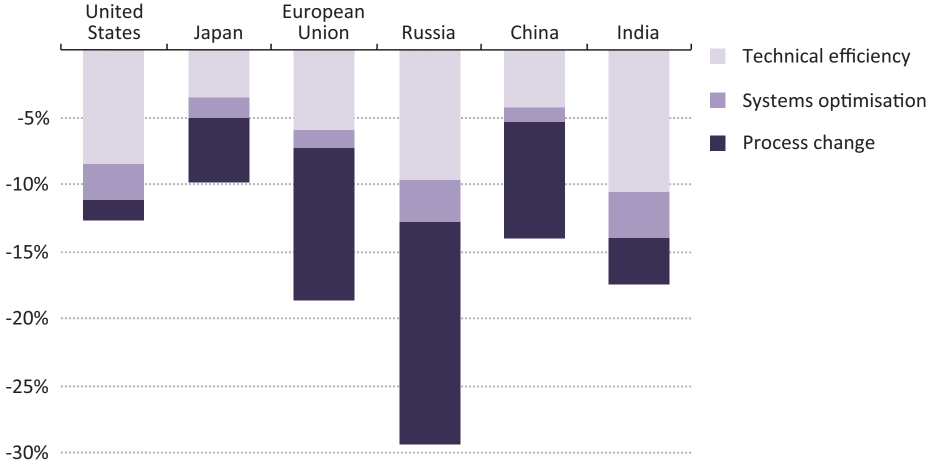
11. For the purpose of this analysis, the steel sector is defined to include coke ovens and blast furnaces.

and by process change (IEA, 2012a). In the steel sector, process changes include a shift towards the use of scrap metal or direct reduced iron instead of pig iron for iron making, and a shift from primary steel making via blast furnaces (BF) and basic oxygen furnaces (BOF) (or open hearth furnaces) to the use of electric arc furnaces (EAFs). Process change is particularly important in countries where a significant share of steel is produced via the BF/BOF route and where scrap metal is available. These include Japan, the European Union, Russia and China. Steel production from EAFs using scrap metal is less than half as energy intensive as the BF/BOF route and most steel products nowadays can be produced in EAFs. While energy costs and environmental considerations influence the choice of whether to use EAFs, scrap metal availability and steel quality are stronger factors.

In the New Policies Scenario, process changes in the steel industry play an important role in reducing energy intensity up to 2035, accounting for slightly more than half of all energy savings (Figure 7.8). This means that improved energy efficiency is responsible for less than half of the energy intensity reduction.



**Figure 7.8 ▷ Energy intensity reduction in the iron and steel sector by type of improvement, 2011-2035**




Note: These regions account for almost 80% of global steel production.

Russia achieves significant energy savings by moving away from outdated open hearth furnace technology. Steel production in China is currently dominated by BOFs. Increasing the use of scrap metal in EAFs, as well as raising the share of steel production from EAFs by nine percentage points reduces the energy consumption per unit of steel by 9%. For Japan, we project in the New Policies Scenario a slightly higher domestic consumption of scrap metal and higher production share from EAFs to a similar level as in the late 1990s. In the European Union, increasing the share of secondary steel making from the current 43% to 58% in 2035 and higher use of scrap metal are responsible for the majority of the energy intensity reduction. The United States and India do not make a big contribution to energy savings through process change because steel making via the EAF route already accounts for around 60% in both countries. In India, most of the input to EAFs is from coal-based direct reduced iron, which is significantly less efficient than the gas-based variant.

The remaining energy intensity reductions in steel production come from the adoption of more efficient technical equipment and systems optimisation via process control, automation and monitoring systems. Systems improvements account for roughly one-fifth of the non-process related efficiency gains. The intensity reductions from technical efficiency are particular significant in Russia, India and the United States. Further efficiency improvements in China are limited, mainly due to the limited amount of new capacity additions. China added substantial steel capacity over recent years and domestic steel production is expected to peak around 2020, with declining production thereafter.

### *Transport*

Almost 30% of global final energy consumption is in the transport sector. This sector is heavily reliant on oil, with the notable exceptions of electricity in rail networks and natural gas in the operation of pipelines. In the New Policies Scenario, energy consumption increases by 1.3% annually to reach 3 300 Mtoe in 2035, which compares to a growth rate of 2.1% per year over the past twenty years. The slowdown in growth mainly reflects trends in road transport, but growth in rail travel and aviation outpaces growth in road travel in the coming decades. Transport-related $CO_2$ emissions increase from 7 gigatonnes (Gt) in 2011 to 9 Gt in 2035, which is the fastest increase of all end-use sectors (Table 7.4).

**Table 7.4 ▷ Savings in transport energy demand and $CO_2$ emissions from energy efficiency in the New Policies Scenario** (Mtoe)

| | Demand | | | Change versus Current Policies Scenario | | | |
|---|---|---|---|---|---|---|---|
| | | | | Total | | Due to efficiency | |
| | 2011 | 2020 | 2035 | 2020 | 2035 | 2020 | 2035 |
| Coal | 3 | 2 | 0 | 0 | 0 | 0 | 0 |
| Oil | 2 264 | 2 572 | 2 878 | -47 | -348 | -33 | -248 |
| Gas | 93 | 122 | 186 | 5 | 39 | -2 | -10 |
| Electricity | 25 | 35 | 63 | 1 | 12 | -1 | -1 |
| Biofuels | 59 | 101 | 192 | 13 | 40 | -1 | -19 |
| **Total** | **2 444** | **2 832** | **3 319** | **-27** | **-258** | **-38** | **-278** |
| $CO_2$ emissions (Gt) | 7.0 | 8.0 | 9.0 | -0.1 | -0.9 | -0.1 | -0.8 |

Transport energy demand in the New Policies Scenario is about 260 Mtoe, or 7%, lower in 2035 than in the Current Policies Scenario. Higher efficiency in transport decreases consumption by about 280 Mtoe in 2035, mainly as a result of stricter fuel-economy standards for light-duty vehicles. In several regions in the New Policies Scenario – namely Southeast Asia, Latin America, the Middle East and China – efficiency improvements are partly offset by the rebound effect, increased demand for road travel as a result of lower oil prices.

The approach most commonly used to improve energy efficiency in road transport is the introduction of fuel-economy standards. The impact of such policies considered in the New Policies Scenario on total fuel savings in road transport, are greatest in China, followed by the United States and the European Union (Figure 7.9). In China, under the State Council's Development Plan for Energy Saving and the Automobile Industry for 2012-2020, the aim is to reach an average level of fuel consumption of 5.0 litres per 100 kilometres (l/100km) for new cars, saving roughly 12 Mtoe in 2020 in the New Policies Scenario relative to the Current Policies Scenario. In the United States, the Corporate Average Fuel Efficiency (CAFE) standards applicable to 2025 save 61 Mtoe by 2035, relative to the Current Policies Scenario. These standards may undergo mid-term evaluation, thus making their outlook uncertain not only in the United States but also in Canada, which has recently adopted similar standards. In the European Union, the target of reaching an average emissions level of 95 grammes of $CO_2$ per kilometre (g $CO_2$/km) in 2020 for passenger light-duty vehicles (PLDVs), which is still awaiting approval from the European Council, is responsible for the majority of savings in the New Policies Scenario, totalling 24 Mtoe in 2035.

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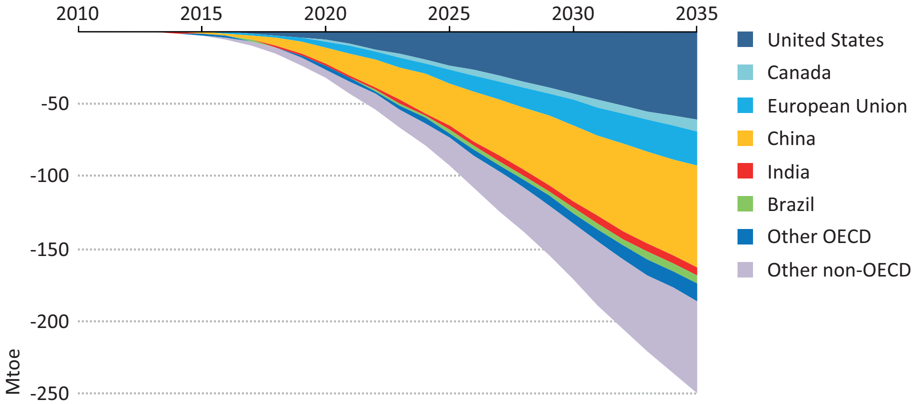
**Figure 7.9 ▹ Fuel savings from energy efficiency in road transport in the New Policies Scenario relative to the Current Policies Scenario**




Compared with road transport, the energy efficiency of other transport sectors has so far come under less scrutiny, but recently some encouraging developments have taken place. After aviation was included in the EU Emissions Trading Scheme in 2012, international airlines announced, for the first time, in early 2013 their readiness to curb their greenhouse-gas emissions. The International Air Transport Association issued a resolution urging governments to manage $CO_2$ from air travel from 2020 onwards, using a market-based mechanism. The goal of the association is to increase fuel efficiency on average by 1.5% per year until 2020, broadly in line with the efficiency improvements achieved in the New Policies Scenario (IATA, 2009). In addition, the United Nations International Civil Aviation Organisation also reached consensus in October 2013 on a roadmap to create a market-based mechanism to reduce carbon emissions. In the maritime sector, the major initiative to improve fuel efficiency is the Energy Efficiency Design Index for new ships.

Adopted by the International Maritime Organization in 2011, it foresees the application of progressively more stringent efficiency targets. The index entered into force in January 2013 and applies to all ships of 400 gross tonnage and above (which account for 70% of $CO_2$ emissions from ships), though exemption from the requirements for new ships may be available for up to a maximum of four years (Hughes, 2013).

### *Buildings*

Final energy demand in the buildings sector grows from 2 890 Mtoe in 2011 to 3 690 Mtoe in 2035, 180 Mtoe or 5% less than in the Current Policies Scenario (Table 7.5). Most of the final energy savings arise from energy efficiency measures targeting the building shell, but also from efficiency standards for lighting and other energy-consuming equipment, such as heating systems and appliances, as well as from better use of automation and control systems. A lower call for energy services is particularly important in countries phasing out fossil-fuel subsidies for households, including China and Russia, with fuel and technology switching playing a smaller role.

**Table 7.5 ▷ Savings in buildings energy demand and $CO_2$ emissions from energy efficiency in the New Policies scenario** (Mtoe)

| | Demand | | | Change versus Current Policies Scenario | | | |
|---|---|---|---|---|---|---|---|
| | | | | Total | | Due to efficiency | |
| | 2011 | 2020 | 2035 | 2020 | 2035 | 2020 | 2035 |
| Coal | 118 | 117 | 95 | -5 | -16 | -1 | -2 |
| Oil | 324 | 318 | 271 | -11 | -33 | -3 | -8 |
| Gas | 597 | 689 | 815 | -12 | -44 | -5 | -21 |
| Electricity | 839 | 1 044 | 1 417 | -29 | -105 | -13 | -64 |
| Heat | 149 | 158 | 167 | -3 | -9 | -1 | -4 |
| Modern renewables* | 115 | 157 | 243 | 6 | 38 | 0 | -1 |
| Traditional biomass** | 744 | 730 | 680 | -2 | -9 | -1 | -4 |
| **Total** | **2 886** | **3 213** | **3 688** | **-57** | **-178** | **-26** | **-103** |
| $CO_2$ emissions (Gt)*** | 8.1 | 8.7 | 9.4 | -0.5 | -1.9 | -0.2 | -0.7 |

* Modern renewables include wind, solar and geothermal energy as well as modern, efficient biomass use. ** Traditional biomass includes fuelwood, charcoal, animal dung and some agricultural residues. *** $CO_2$ emissions include indirect emissions from electricity generation and energy use for heat.

Around 60% of the savings between the Current Policies and New Policies Scenarios in 2035 are in electricity, with the amount saved representing more than the current annual generation in Japan. Despite the large absolute savings, electricity becomes a more important energy carrier over time, increasing its share of buildings energy use from 29% today to 38% in 2035, as the relative importance of direct use of fossil fuels and traditional biomass declines. Space and water heating contribute most to these savings in the New Policies Scenario, closely followed by appliances and cooling. Savings in coal and oil use account for around 30% of total savings, mainly driven by better insulation, which increases the efficiency of buildings (and thus reduces demand for space heating/cooling) and the uptake of more efficient water heaters and cookstoves in developing countries. Traditional biomass still makes up 26% of final energy consumption in buildings today, mostly used for cooking in developing countries in fairly simple and mostly inefficient cookstoves (see Chapter 2). With increasing household income and political support, modern fuels including charcoal, kerosene, liquefied petroleum gas (LPG), gas and electricity could gradually take the place of traditional biomass (IEA, 2010).

In the services sector, the energy consumption per unit of value added has been declining in all regions and this trend is projected to continue, reaching 70% of its current value in 2035. In the residential sector, energy intensity, defined as consumption of modern fuels[12] per square metre and per capita, is projected to decrease by 39% in total, but shows larger regional differences. In OECD countries, energy intensity in residential buildings decreases by 25%, mainly driven by efficiency improvements. In non-OECD countries, energy intensity decreases by more than 30%, while residential floor space increases by 60% by 2035. In emerging economies, such as China, India and ASEAN countries, efficiency improvements are partly offset by a significantly increased demand for energy services, reflecting increased income per capita. In poorer developing countries, improved access to electricity and reduced use of traditional biomass for cooking also play important roles: increasing electricity access leads to increased modern fuel consumption, but the low consumption of newly connected households reduces the energy intensity of the residential sector at a national level.

China achieves about one-third of the global residential energy savings differential between the Current Policies Scenario and New Policies Scenario, thanks to policies under discussion and energy price reforms (Spotlight). Whether countries realise their economic potential for savings is closely linked to the structure of the buildings sector and the conditions governing energy supply. Savings in space heating in the residential sector in China, for example, remain below the full economic potential, due to the flat rate tariff structure of district heating systems in northern urban areas, which is a barrier to efficiency changes (Figure 7.10). More stringent standards in appliances and air conditioners are expected to deliver most of the savings in the residential sector. Cooling needs in China and other developing countries in warm climate zones are expected to increase strongly over time as people become more affluent, highlighting the importance of the prompt introduction of relevant efficiency standards. Cooling needs also rise due to climate change (IEA, 2013c).

In Europe, the savings between the Current and New Policies Scenario account for more than 15% of the global savings in households in 2035, as policies under discussion take effect. Insulation and retrofit measures provide most of the gains, as a consequence of stricter renovation policies and building codes under the EU Efficiency Directive (the impact of the Energy Performance of Buildings Directive is mainly integrated into the Current Policies Scenario). The implementation of building codes is mandatory in most OECD countries, but, while progress has been made in non-OECD countries, implementation usually remains

12. Excluding traditional biomass.

voluntary there. Achieving high compliance or designing effective building codes can be very challenging. Policies currently in place tend to encourage action by individuals, such as the replacement of windows or boilers, which has only a limited impact on the overall energy consumption, compared to holistic measures, such as deep renovation of the building shell (Saheb, 2013). Consequently, the impact of current policies on building's energy consumption remains limited, as large potential savings remain untapped. Nevertheless, recent analysis shows that the market is starting to reward increased building energy standards: they have been shown to contribute to higher rents and house prices in Europe (BIO, IEEP and Lyons, 2013). The second-largest savings in the European Union come from improvements in appliances and lighting, supported by the EU Ecodesign Directive.

In the United States, increased efficiency standards for appliances and air conditioners are expected to deliver most of the savings in the residential sector, together with savings in space and water heating, thanks to building codes.

**S P O T L I G H T**

### Policies for energy efficiency in buildings in China

China accounts for about one-third of the global savings in the buildings sector between the Current and the New Policies Scenario. This is primarily due to the policies announced in the 12th Five-Year Plan and the central co-ordination of building regulations in the Ministry of Housing and Rural Urban Development (MOHURD).

China's 12th Five-Year Plan introduced the concept of regulating the absolute level of energy demand, rather than energy intensity. Although no cap has yet been announced, this can be seen as an important shift in Chinese energy policy. In May 2012, the MOHURD announced the Building Conservation Plan, which aims to contribute to the overall national intensity target for 2015 by means of efficiency savings in the buildings sector. The plan provides that 95% of new buildings should reduce space heating per square metre ($m^2$) by 55-65%, compared with 1980 levels, depending on the climate zone. Furthermore, in the period to 2015, 450 million square metres of existing buildings are to be refurbished (1% of the existing stock) and 800 million $m^2$ of new "green buildings" built. The criteria for green buildings include resource savings and environmental protection; examples are the deployment of solar PV or natural lighting (Tsinghua University, 2013).

The MOHURD regulates the largest building industry in the world: growth in Chinese residential floor space accounted for more than one-third of the floor space additions worldwide in the last ten years. The MOHURD reports to the state council and supervises provincial building departments. This structure allows the regulator to follow regional developments closely and ensures high compliance with building regulations (up to 95% and higher has been observed) (Zhou, McNeil and Levine, 2011).

**Figure 7.10a** ▷ **Energy consumption by end-use in households by region in the New Policies Scenario, 2011 and 2035**

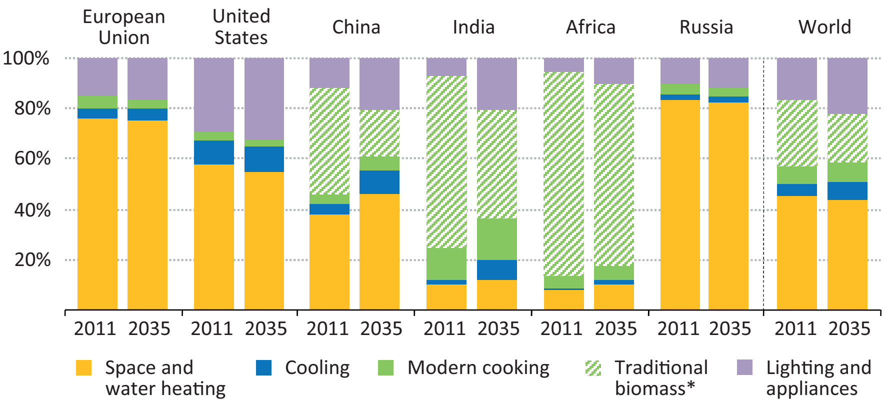
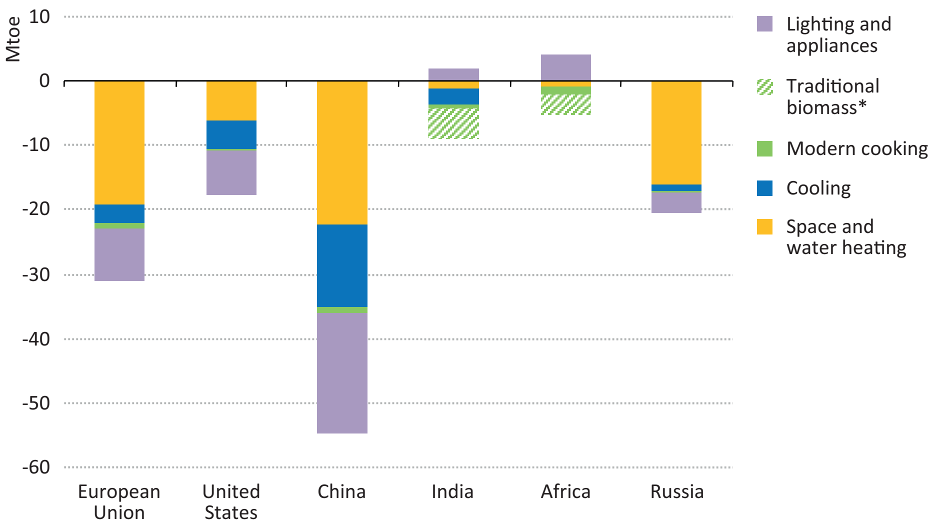



**Figure 7.10b** ▷ **Final energy savings in households in the New Policies Scenario relative to the Current Policies Scenario by region, 2035**



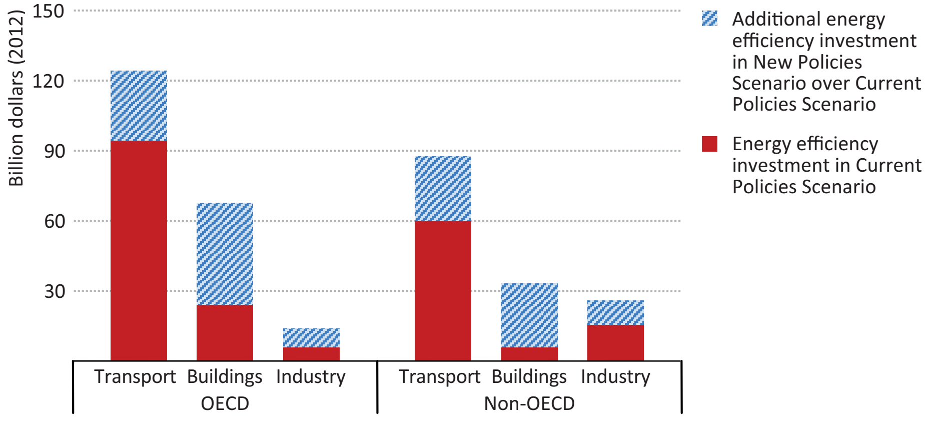

* Due to a lack of comprehensive data on the end-use of traditional biomass, it is assumed to be used primarily for cooking, although it also serves space and water heating purposes.

In developing countries, *e.g.* in Africa and India, the increase in demand for electricity resulting from greater access to electricity offsets the savings due to limited efficiency improvements in lighting and appliances. Important savings in lighting can be achieved by phasing out the use of incandescent bulbs. Legislation to this effect is in place in all major OECD countries and in a number of non-OECD countries, including China, India, most countries of West Africa and Brazil. This single change leads to a reduction in electricity demand for lighting of around 5% in these regions, between the Current and New Policies Scenarios. If all increases in lighting demand were met by the most efficient technology, global electricity demand from lighting could be reduced by more than 40% in 2035, resulting in a reduction of 5% of total residential electricity demand. In countries with limited access to electricity, lower demand as a result of improved efficiency by existing customers provides an important offset to additional electricity generation.

## Investment in energy efficiency

The Current Policies Scenario requires investment of $4.7 trillion in energy efficiency over 2013-2035 (Figure 7.11).[13] Despite a diminishing share in global energy consumption, OECD countries account for 60% of these total investments, due to more stringent policies regulating efficiency in the OECD. In order to realise the energy savings in the New Policies Scenario, additional investment of $3.4 trillion is needed in energy efficiency. As a result of lower electricity demand, cumulative investment in electricity transmission and distribution is $0.8 trillion lower in the New Policies Scenario than in the Current Policies Scenario, and investment in power plants is reduced by $0.6 trillion, more than compensating for the additional investment required to improve energy efficiency in the New Policies Scenario. The $3.4 trillion additional investments in the New Policies Scenario generate savings on energy expenditures of $6.1 trillion up to 2035.

**Figure 7.11 ▷ Average annual energy efficiency investment by scenario and sector**




The transport sector accounts for almost 40% of the cumulative additional investments in the New Policies Scenario. This reflects the large increase in the vehicle fleet (which almost doubles to 2.9 billion vehicles in 2035) and the average amount spent on energy efficiency for each vehicle ($300) throughout the projection period in the New Policies Scenario. Efficiency investments in commercial and residential buildings increase substantially, driven by higher insulation standards for new buildings, a more widespread adoption of

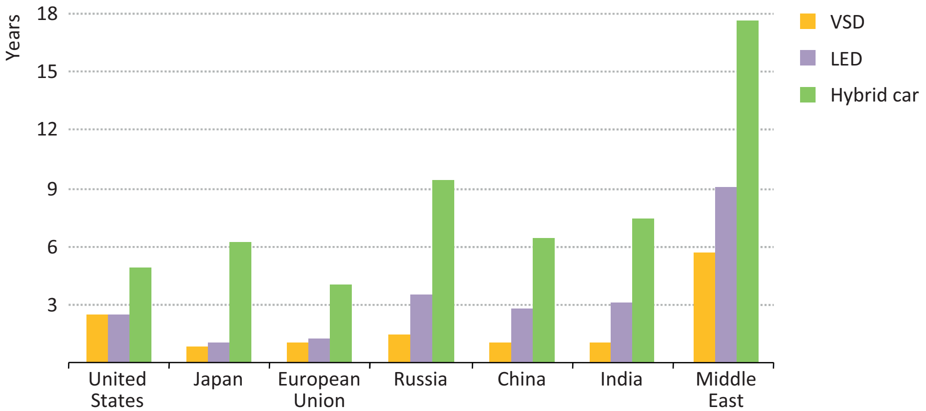
13. Energy efficiency investment (excluding international bunkers) is used to denote expenditure on a physical good or service which leads to future energy savings, compared with the energy demand expected otherwise.

efficient heating technologies, and more efficient lighting, appliances and cooling systems. Investment in industrial energy efficiency in 2035 increases by about 70%, or $26 billion, compared with the Current Policies Scenario, realising energy savings of almost 200 Mtoe in the same year. About half of the investment goes to steam systems and furnaces, while the other half is used to improve electric motor systems, appliances and lighting.

Though various market imperfections inhibit the adoption of energy efficiency measures, energy prices play a key role in stimulating the adoption of efficient technologies. With high energy prices in Europe and Japan, and persistent price subsidies in a few energy exporting countries (see Chapter 2), the payback period for a more efficient technology can be up to nine times higher depending on the region (Figure 7.12). This means that, in some cases, the payback period can exceed the lifetime of the technology, making it uneconomic to invest in such a measure (even if transaction costs are not counted). Including transaction costs would double the payback period for certain countries and sectors (IEA, 2012a).



**Figure 7.12 ▷ Payback periods for selected technologies and regions, 2013**




Notes: VSD = installation of a variable speed drive in a compressed air system. LED = light-emitting diode replacing an incandescent light bulb. Hybrid car = hybrid car replacing an internal-combustion engine car.

The economic incentive to improve efficiency is highest in Japan and the European Union. Installing a variable speed drive (VSD), a device to control the speed of machinery, is one of the best ways of achieving energy savings in industrial electric motor systems, which account for up to 70% of all electricity consumption in industry. As industrial electricity prices are highest in Japan and Europe, the payback period of a VSD is around one year, while it is around two-and-a-half years in the United States, where electricity prices are less than half of the European average. The payback period of a VSD is relatively low in India, because the total cost of installing a VSD is lower, since labour costs are a fraction of OECD levels and account for around one-third of the total costs (UNIDO, 2010).

Lighting accounts for roughly 20% of the current electricity demand in buildings. Light-emitting diodes use around five times less energy than incandescent light bulbs. Given the relatively low electricity prices for households in India, China and Russia, the payback period for installing LEDs, instead of incandescent light bulbs, is more than two years. Because of even lower electricity prices in the Middle East, the payback period there is around nine years. Oil prices are also low in the Middle East, meaning that payback for an investment in a hybrid car stretches to eighteen years, while in Russia where the annual mileage is relatively low, it is nine years. Although gasoline prices are significantly lower in the United States than in Europe, higher vehicle mileage in the United States reduces the difference in payback periods in this case.

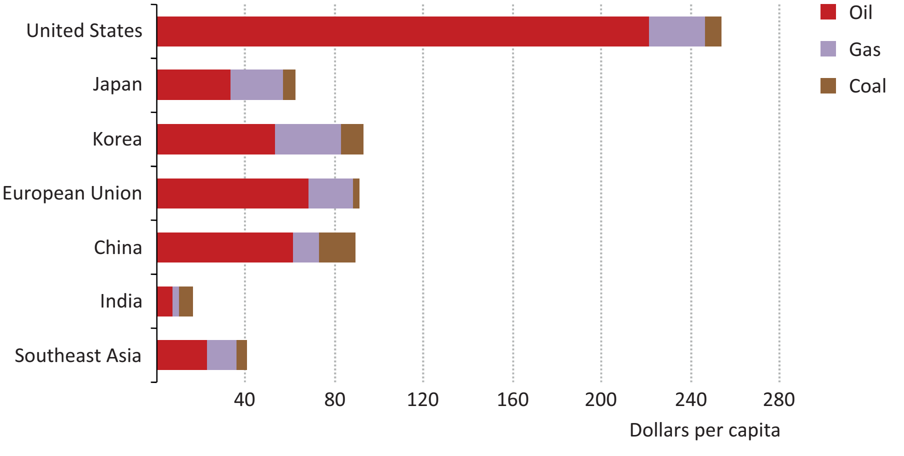
## Broader benefits

Improvements in energy efficiency not only reduce energy consumption and energy bills, but have further benefits including lower energy imports, macroeconomic advantages, and reduced levels of air pollution and $CO_2$ emissions.[14]

### *Energy imports*

In net-importing regions, improved energy efficiency in the New Policies Scenario enhances energy security by reducing energy demand and thereby lowering energy import bills. In 2035, avoided import bills stemming from energy efficiency in the New Policies Scenario are highest in China, at $130 billion, and the United States, at $95 billion. On a per-capita basis, however, avoided import bills are by far the highest in the United States, at $250 per person in 2035 (Figure 7.13). Most savings result from higher efficiency in PLDVs, which reduces oil use. Natural gas-related savings are significant in some countries, such as Japan and Korea, where they account for more than 30% of total savings. Given China's reliance on coal, the fuel comprises almost 20% of China's avoided energy import bills, despite its significantly lower energy-equivalent price when compared with gas or oil.

**Figure 7.13 ▷ Avoided import bills from energy efficiency in the New Policies Scenario relative to the Current Policies Scenario, 2035**

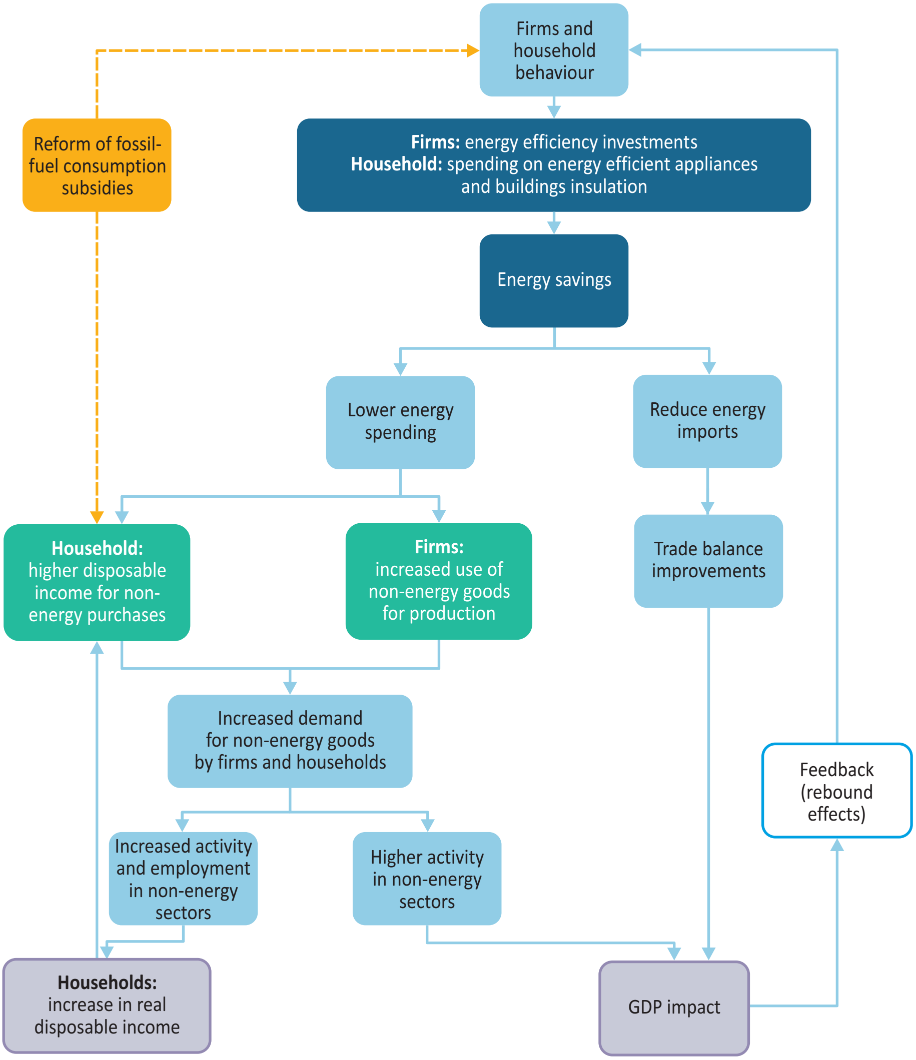



14. For a comprehensive overview of the multiple benefits of energy efficiency, see IEA (2012b).

### *Impact on total household expenditure*

The additional energy efficiency measures implemented in the New Policies Scenario affect the broader economy and alter consumption patterns of all types of goods and services (Figure 7.14). Firms increase investment in more energy-efficient production processes, see a net reduction in their energy costs and spend more on non-energy inputs (*e.g.* capital and labour). These economy-wide changes in consumption patterns follow adjustments in the relative prices of different commodities. The prices of manufactured goods and services, which have less energy embedded, are reduced, stimulating demand from firms and households.

**Figure 7.14 ▷ Economic impacts of energy efficiency**



In parallel, households purchase more efficient electrical appliances, buy more efficient cars and refurbish their homes to improve insulation. Stimulated activity in non-energy manufacturing creates higher labour demand. This shift in employment benefits workers through higher wages and therefore translates into higher disposable income. The overall macroeconomic impact of improving energy efficiency is generally positive, as illustrated in the Efficient World Scenario (IEA, 2012a).

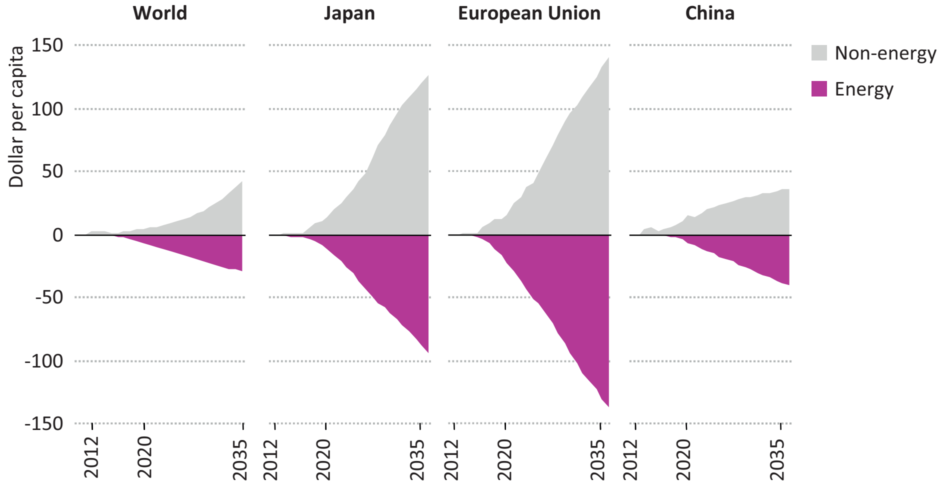
In value terms, household expenditure currently accounts for more than half of global GDP. In OECD countries, where 35% of total final energy savings are achieved in the New Policies Scenario, the share of GDP household consumption is close to 70%. Moreover, it is in residential energy demand and in PLDV fuel demand, the vast bulk of which is consumed by households, that 37% of total efficiency savings are realised.

Energy efficiency measures adopted in the New Policies Scenario result in a net positive outcome for households: the cumulative reduction in household energy spending through to 2035 reaches $2.6 trillion (Figure 7.15), corresponding to about 3% of current global GDP. Reduced energy spending is accompanied by reduced fuel prices in the New Policies Scenario, which in turn bring down other production costs. These energy savings free up disposable income, some of which is allocated to the consumption of cheaper non-energy goods, including energy-efficient appliances. Almost 60% of the reduction in energy spending is made by OECD households, while China accounts for another one-quarter. However, only a small share of additional purchases of non-energy goods occur in OECD countries, mainly because the same amount of disposable income for households in less developed countries, with lower initial endowments, induces larger shifts in consumption patterns. Furthermore, a degree of saturation in the consumption of certain durable goods in OECD countries leaves less room for altering OECD consumption patterns.

European households currently pay among the highest energy prices in the world and their total average spending on energy is more than 10% of their total spending (see Chapter 8), making energy efficiency a particularly attractive option. In the New Policies Scenario, every dollar saved per person in the European Union on energy bills in 2020 is largely offset by additional spending on other goods. Over the projection period, European households see their purchasing power essentially unchanged. Japanese households who spend a lower share of their income on energy (about 8%) make modest gains, in the order of $30 billion.

Chinese households see their net real consumption increasing by about $100 billion over the period. This amount, equivalent to just 0.2% of China's GDP in 2035, is insufficient to trigger a sizeable shift in private consumption in China. In other fast-growing non-OECD countries, such as India and Indonesia, households with the lowest incomes can rarely afford to upgrade inefficient home installations. Hence the potential for direct energy savings in the residential sector is lower. Additionally, the impact of efficiency policies on energy spending is often limited, as in the New Policies Scenario these measures are assumed to be complemented by reforms to fossil-fuel subsidies (Chapter 2). The combined effect of the two sets of measures leaves overall household expenditures largely unchanged.

**Figure 7.15 ▷ Change in annual per-capita household spending on energy and non-energy goods and services in the New Policies Scenario relative to the Current Policies Scenario**




Sources: IEA analysis using the World Energy Model and OECD analysis using the OECD ENV-Linkages model.

## *Local air pollution*

As a result of lower demand for fossil fuels, improved energy efficiency leads to reduced local air pollution, which helps to reduce respiratory diseases. Recent analysis shows that each year more than three million people die from outdoor air pollution, mainly caused by combustion of fossil fuels and bioenergy (Lim, *et al.,* 2012). Today, China and India are responsible for more than 40% of global sulphur dioxide ($SO_2$) emissions, of which more than one-quarter arise from coal power plants. $SO_2$ emissions are reduced by 10% in the New Policies Scenario as a result of efficiency improvements with more than 70% of the reduction achieved in the power sector of non-OECD countries. The largest source of nitrogen oxides ($NO_X$) emissions is currently the transport sector (around 50%), followed by power and industry. The transport sector accounts for 20% of the reduction in $NO_X$ emissions, with the bulk of the improvements seen in non-OECD countries. Particulate matter ($PM_{2.5}$) emissions are caused by the use of traditional biomass and industrial processes. $PM_{2.5}$ emissions are reduced by 4% globally resulting from a reduction of traditional biomass use as more clean cooking facilities are adopted.[15]

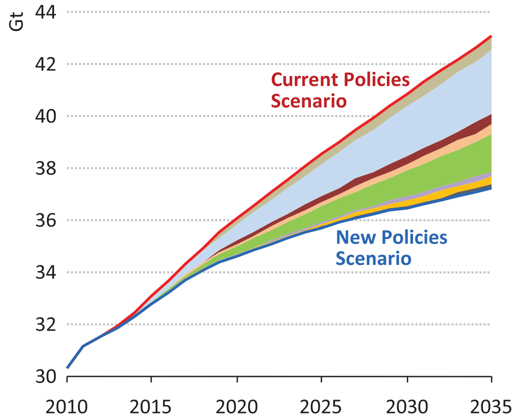
## *$CO_2$ emissions*

In the New Policies Scenario energy-related $CO_2$ emissions increase from 31.5 Gt in 2012 to 37.2 Gt in 2035, which is about 5.9 Gt or 14% lower than in the Current Policies Scenario (Figure 7.16). Energy efficiency measures account for about half of cumulative

15. This is estimated based on IIASA (2012).

$CO_2$ emissions savings in the New Policies Scenario, with the share being even higher in the short term. Energy efficiency measures, including in lighting and electric motor systems, are in most cases quickly deployable and among the cheapest options to reduce $CO_2$ emissions. *Redrawing the Energy-Climate Map*, a *WEO* special report, proposes a set of four pragmatic policies that can have a significant impact by 2020, with no net cost to the overall economy (see Chapter 2). Energy efficiency on its own is, however, not enough to bring down emissions to the level compatible with limiting the long-term temperature increase to 2 °C. It needs to be complemented by increased use of renewables across all sectors and wider deployment of nuclear power, carbon capture and storage (CCS) in power generation and industry, and electric vehicles in transport.

**Figure 7.16 ▷ World energy-related $CO_2$ emissions abatement in the New Policies Scenario relative to the Current Policies Scenario**




| $CO_2$ abatement | 2020 | 2035 |
|---|---|---|
| Energy service demand | 16% | 9% |
| End-use efficiency | 42% | 42% |
| Supply efficiency | 8% | 7% |
| Fuel and technology switching in end-uses | 6% | 6% |
| Renewables | 21% | 25% |
| Biofuels | 3% | 3% |
| Nuclear | 3% | 5% |
| CCS | 1% | 2% |
| **Total** (Gt $CO_2$) | **1.5** | **5.9** |

The largest efficiency $CO_2$ emissions savings stem from end-use sectors, particularly in the form of electricity savings in buildings and industry. While electric motor systems account for the greater part of the electricity savings in industry, a phase-out of incandescent light bulbs and stricter appliance standards contribute most to lower electricity consumption in buildings. Efficiency savings in transport are mainly driven by increased fuel-economy standards for new vehicles, which lead to $CO_2$ emissions savings equal to 12% of total savings in 2035. Efficiency gains in power plants, transmission and distribution, refineries, and oil and gas extraction are responsible for about 7% of savings in 2035. A large share of these savings is achieved by reducing the use of inefficient coal-fired power plants and switching to more efficient gas-fired electricity generation (IEA, 2013c).

# Energy and competitiveness

## How will price disparities alter global economic geography?

### Highlights

- Disparities in energy prices between countries and regions, especially for natural gas and electricity, have widened significantly in recent years with implications for economic competitiveness. Natural gas prices have fallen sharply in the United States, largely as a result of the recent shale gas boom, and today are about one-third of import prices to Europe and one-fifth of those to Japan. Electricity price differentials are also large, with Japanese and European industrial consumers paying on average more than twice as much for electricity as their counterparts in the United States, and even Chinese industry paying almost double the US level.
- Energy-intensive sectors (chemicals; primary aluminium; cement; iron and steel; pulp and paper; glass and glass products; refining) account globally for about 20% of industrial value added, 25% of industrial employment and 70% of industrial energy use. Energy costs can be vital for the international competitiveness of energy-intensive industries, particularly where energy accounts for a significant share of total production costs and where the resulting goods are traded extensively. The importance of energy in total production cost is greatest in the chemicals industry, where in some segments it can account for around 80%, including in petrochemicals.
- Shifts in industrial competitiveness have knock-on effects for the rest of the economy. Recent rising energy prices across many regions have resulted in significant shifts in energy and overall trade balances, as well as in energy expenditures taking a growing share of household income. While natural gas price differentials narrow in our central scenario, gas and industrial electricity prices in the European Union and Japan remain around twice the level of the United States in 2035. The European Union and Japan see a strong decline in their shares of global exports of energy-intensive goods – a combined loss of 30% of their current share – although the European Union still remains the leading exporter. The United States sees a slight increase in its share of exports, with the increase being stronger in many emerging economies, particularly in Asia, where domestic demand growth for energy-intensive goods also supports a swift rise in production.
- High energy prices do not have to result in onerous energy costs for end-users or the national economy. Improvements in energy efficiency have a crucial role in mitigating high energy costs. Policymakers can also boost energy competitiveness by supporting indigenous sources of energy supply as well as by increasing competition in wholesale and retail energy markets. A carefully conceived international climate change agreement can help to ensure that the energy-intensive industries in countries that act decisively to limit greenhouse-gas emissions do not face unequal competition from countries that do not.

## Energy and international competitiveness

The role of energy in international competitiveness has become a live issue in political, economic and environmental debate around the world in recent years, with the emergence of pronounced disparities in energy prices among countries and regions at a time of weaker economic growth (Box 8.1). The widening of regional price differentials has accompanied the interplay of a number of important new trends. These include the rebound in United States oil and gas production thanks to the development of shale and other unconventional energy resources; the opening up of new hydrocarbon provinces in Africa and elsewhere; and a shift in the energy balance away from fossil fuels and nuclear power towards renewable energy sources, notably in the European Union.

### Box 8.1 ▷ Defining "competitiveness"

In this chapter, *international competitiveness* refers to the ability of both individual firms and entire economies to compete internationally. As one of several components of the cost of doing business, the price of energy can have a material impact on the cost of production, or productivity. Differences in energy prices across countries can, therefore, be an important factor in how effectively firms can compete in export markets and with imported goods and services. The term *energy competitiveness* is taken to mean the cost of providing energy services in one economy relative to others.

This chapter's main focus is on the impact of divergences in energy prices on *industrial competitiveness* – the ability of industry (particularly its energy-intensive segments) in a given economy to compete internationally. The rationale for this is that energy generally accounts for a far bigger share of production costs in industry than in services.

*Economic competitiveness* refers to the productivity of an entire economy relative to others, thus capturing the competitiveness of both industry and services. The productivity of an economy determines the level of prosperity that it can attain and the rates of return on investments that can be achieved (WEF, 2013a). Higher productivity allows national economies to grow faster over the longer term and sustain higher wage levels, boosting the welfare of their populations.

The new global energy map that is taking shape has potentially important implications for the relative cost of energy in different countries and, therefore, for the global economic balances established through competition between companies operating in different regions. Those countries facing relatively high primary fuel and end-user prices are concerned that the impact on production costs might deter investment and lead to production and jobs migrating to countries where energy prices are now significantly lower, such as the United States. With many countries facing acute economic difficulties, concerns about a loss of competitiveness are moving to centre stage, especially in energy-importing countries, and these could erode international and national efforts to tackle trade barriers and climate change. Conversely, those countries that are enjoying relatively low energy prices are hopeful of being able to exploit this advantage by boosting production and exports of goods that require significant amounts of energy. To the extent that lower prices on the internal market result from increased domestic energy production, the economy benefits from an additional economic stimulus. That is why several countries with large unexploited resources of unconventional gas are keen to replicate the US experience.

The debate about energy and competitiveness has proceeded without much hard data. This chapter seeks to shed light on the question of how significant energy is to competitiveness in reality, what persistent energy price disparities might mean for future global economic balances and what policymakers can do to improve economic competitiveness, while at the same time addressing energy security and environmental concerns.

The cost of energy is just one of several factors that affect the overall cost of producing goods and services, and, therefore, profitability. Other costs, including labour, capital, other raw materials and maintenance, also affect competitiveness significantly.[1] These costs – and the overall attractiveness of an economy to potential investors – are influenced heavily by institutional factors (including financial, monetary, tax, legal and regulatory systems), politics and geopolitics, infrastructure, technology, education and labour markets (see the example of Korea in the Spotlight). Financing costs can vary substantially from one country to another. To some extent, non-energy costs are influenced by energy prices, as energy is an input to the production of raw materials and to transportation.

Despite recent high energy prices, fuel supply and power generation make up just 5% of the global economy today. In general, energy prices play a relatively minor part in the calculation of competitiveness, as in most sectors and countries energy accounts for a relatively small proportion of total production costs. But for some types of economic activities the share can be much higher, reflecting their degree of energy intensity – the amount of energy needed for each unit of value added. For those activities, marked disparities in energy prices across regions can lead to significant differences in operating margins and potential returns on investment, especially where the output is transported over long distances at relatively low cost. In some cases, energy prices can be the single most important factor in determining investment and production decisions. By contrast, the international competitiveness of many service activities is less affected by price disparities, as their energy intensity is often low and their output is sold mainly domestically (notable exceptions include transport services and data centres).

Persistently high energy price disparities can, therefore, lead to important differences in economic structure over time. Industry (including energy supply) makes up around 30% of world gross domestic product (GDP in purchasing power parity [PPP] terms[2]), but in

1. IMD World Competitiveness Yearbook 2013 ranks the United States highest for overall competitiveness, followed by Switzerland and Hong Kong (*www.imd.org/uupload/imd.website/wcc/scoreboard.pdf*).

2. Purchasing power parities measure the amount of a given currency needed to buy the same basket of goods and services, traded and non-traded, as one unit of the reference currency – in this report, the US dollar. By adjusting for differences in price levels, PPPs, in principle, can provide a more reliable indicator than market exchange rates of the true level of economic activity globally or regionally.

some countries is much higher or lower. Some regions that are well-endowed with energy resources have always held an energy cost advantage and have, in some cases, developed large export-oriented heavy industries based on low energy prices. Conversely, regions reliant on expensive imported energy – including the United States and much of the European Union – have seen a progressive decline in the share of manufacturing in their economies in recent decades, though other factors have also contributed. This suggests that recent changes in relative energy prices could have far-reaching effects on investment, production and trade patterns.

**Table 8.1 ▷ Share of industry in final energy use* by fuel and region, 2011**

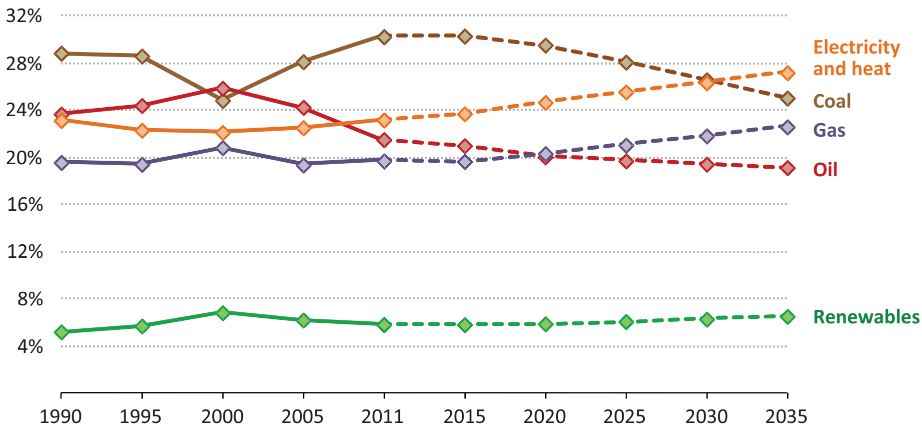
| | Coal | Oil | Gas | Electricity and heat | Renewables | All fuels |
|---|---|---|---|---|---|---|
| **OECD** | **88** | **20** | **41** | **33** | **38** | **32** |
| Americas | 95 | 16 | 42 | 28 | 43 | 27 |
| United States | 96 | 15 | 39 | 25 | 44 | 26 |
| Europe | 75 | 19 | 39 | 37 | 29 | 32 |
| Asia Oceania | 98 | 35 | 37 | 38 | 65 | 45 |
| Japan | 99 | 33 | 25 | 30 | 83 | 41 |
| **Non-OECD** | **88** | **26** | **59** | **51** | **14** | **45** |
| E. Europe/Eurasia | 87 | 21 | 42 | 40 | 12 | 41 |
| Russia | 89 | 22 | 46 | 40 | 14 | 42 |
| Asia | 89 | 28 | 65 | 62 | 10 | 51 |
| China | 88 | 27 | 47 | 68 | <1 | 58 |
| India | 92 | 26 | 91 | 45 | 17 | 42 |
| ASEAN | 95 | 32 | 92 | 41 | 21 | 41 |
| Middle East | 90 | 32 | 69 | 22 | <1 | 45 |
| Africa | 75 | 13 | 74 | 42 | 10 | 20 |
| Latin America | 99 | 22 | 73 | 42 | 49 | 41 |
| Brazil | 99 | 21 | 82 | 46 | 60 | 44 |
| **World** | **88** | **20** | **49** | **43** | **18** | **38** |
| European Union | 79 | 20 | 39 | 36 | 30 | 32 |

* If not explicitly mentioned otherwise in the chapter, energy use within the chemical industry includes petrochemical feedstocks, while the iron and steel sector includes own use and transformation in blast furnaces and coke ovens. Industry energy use does not include power generation or other energy sectors, such as refining and hydrocarbon extraction, unless otherwise mentioned.

The importance of industry in a given country can be an indirect indicator of its energy competitiveness, given that energy can account for a significant share of total input costs to manufacturing. In practice, the share of industry in the overall economy in any given region reflects a number of factors, of which low energy prices – often based on indigenous resources – is just one. The stage of economic development is important too, as is the role of industry, particularly as energy-intensive heavy manufacturing tends to decline in mature economies, which generally rely more on higher-value manufacturing and services.

Today, the share of industry in total final energy use is highest in developing Asia and among the lowest in the United States (Table 8.1). Coal use outside of power generation is particularly concentrated in industry. In the OECD, industry's share of total final energy use has fallen in recent years as energy use grew in the services and residential sectors. Conversely, it has increased in developing Asia, particularly in China and India. Generally, industrial energy use since 2000 has shifted progressively away from oil products towards coal, and electricity and heat (Figure 8.1). These trends are expected to change over the period to 2035, with electricity and heat and gas gaining market share at the expense of coal and oil in the New Policies Scenario, which assumes the cautious implementation of announced policy measures (see Chapter 1).

**Figure 8.1 ▹ World energy use in industry by fuel in the New Policies Scenario**




At any given moment, there can be large differences in energy prices across countries, and even within countries according to the precise point of delivery of the fuel and the type of consumer. There are many reasons for these differences, the principal ones being differences in the cost of transporting energy to market, contractual terms governing the way prices are set, taxes, subsidies, labour, other production costs along the energy supply chain, the degree of competition in energy markets and trade restrictions. Yet relatively high energy prices do not necessarily result in high energy costs, as they can be mitigated by efficient use of energy and conservation (see Chapter 7). Indeed, high prices strengthen incentives to invest in more efficient technologies and deter wasteful use of energy. Subsidies that lower the price of energy to users have the opposite effect (see Chapter 2). Government policies can therefore play an important role in mitigating the impact of declining energy competitiveness caused by an increase in relative energy prices.

SPOTLIGHT

## What role does energy play in Korea's industrial success?

Korea is often cited as an example of successful economic development, having achieved rapid economic growth and prosperity since the 1960s. It has been one of the fastest growing OECD countries, with real GDP rising by 3.6% per year during the ten years to 2012, and is on course to grow by just under 3% in 2013. The economy recovered more quickly from the 2008 global crisis than most OECD countries. Additionally, Korea enjoys low unemployment, low government debt and relatively high per-capita income (OECD, 2012a).

Korea's economy has been built on manufacturing and is, consequently, relatively energy intensive. Oil and coal account for 66% of Korean industrial energy use and electricity for 24%. The country is almost entirely reliant on imported energy, with indigenous resources meeting around 1% each of its oil, gas and coal needs. The cost of shipping, together with customs duties, means that wholesale prices of these fuels to Korean industries are high compared with some other OECD countries. Yet electricity prices, which are regulated, are among the lowest in the OECD and therefore help to strengthen Korea's industrial competitiveness (IEA, 2012a). A sound macroeconomic environment, efficient infrastructure and strong educational system are also key factors supporting Korea's industrial competitiveness. These factors, combined with the readiness to adopt new technologies and relatively high business sophistication, underlie Korea's capacity for innovation (WEF, 2013a).

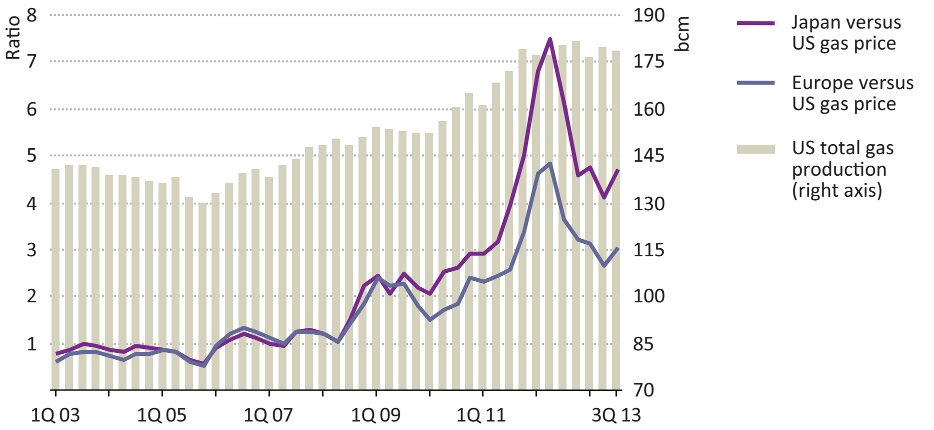
While Korea's low industrial electricity prices help to keep manufacturing costs down, they impose economic costs: low prices have stifled incentives to use energy more efficiently, burdened public finances (the state-owned power company, KEPCO, loses money because prices are too low to cover costs) and impeded investment. Shortfalls in power generation led to rolling blackouts in Seoul in 2011 and constraints on supply to factories in 2013. Within the framework of the "Low Carbon, Green Growth" strategy adopted in 2008 for Korea's economic development over the next 50 years, the government recognises the need to reform the electricity and gas markets. The strategy envisages a shift towards higher-value, less carbon-intensive manufacturing, and to services, where productivity is currently only about half that in manufacturing. Although not yet adopted, the government has also announced plans to introduce an electricity pricing system that adjusts prices in line with global energy commodity prices and allows KEPCO to pass changes in fuel costs on to consumers. In parallel, the government plans to introduce measures to protect energy competitiveness by promoting investment in energy efficiency, and to deploy smart-grid technology nationwide (as set out in the Smart Grid Roadmap 2030).

## Energy price disparities

### *Just how big are regional disparities in energy prices?*

Big differences in energy prices paid by consumers in different countries, whether businesses or households, have always existed. But the last few years have seen a substantial widening of some of the disparities, notably in natural gas prices between the United States, Europe and Asia. This was mainly as a result of the plunge in wholesale gas prices in the United States due to soaring shale gas production; an increase in oil-indexed gas prices in other regions; and higher spot prices for liquefied natural gas (LNG) in Asia, largely as a result of the surge in Japanese gas demand that followed the accident at the Fukushima Daiichi nuclear power plant. Smaller differences have been observed in prices of refined oil products, as they are traded in a highly liquid international market and their transport costs are relatively low. However, some oil-producing states (notably in the Middle East) still subsidise oil products heavily, while, on the other hand, many countries have high taxes on oil products.

**Figure 8.2** ▷ **Ratio of Japanese and European natural gas import prices to United States natural gas spot price**




Notes: The European price is the weighted average price of imports at the German border. The Japanese price is for deliveries of LNG to import terminals. US prices are Henry Hub.

Sources: US EIA, German BAFA (Bundesamt für Wirtschaft und Ausfuhrkontrolle), and Japanese Ministry of Finance databases; and IEA analysis.

The ballooning of wholesale (pre-tax) gas price differentials between the United States and other regions began in early 2008, but has deflated since 2012 (Figure 8.2). By mid-2012, prices in Europe were close to five times higher than in the United States and prices in Japan were over seven times higher. This trend is explained primarily by the surge in US shale gas coupled with a historically mild winter, which has boosted overall gas availability and driven prices down to historically low levels. At the same time, gas import prices in Europe and the Asia-Pacific region, which are mostly indexed to oil prices, have remained high due

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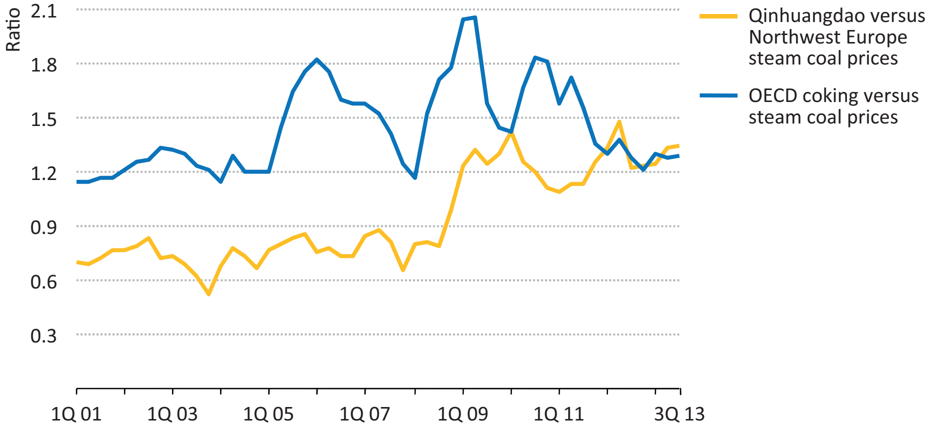
to sustained high oil prices. A softening of international oil prices in early 2013 helped drive gas prices outside the United States down somewhat, while gas prices rebounded in the United States as drilling for shale gas fell in areas with high liquids content. The spot price of gas at Henry Hub in the United States doubled from a low of less than $2 per million British thermal unit (MBtu) in April 2012 to $4.2/MBtu by April 2013, though it fell back to $3.6/MBtu in September 2013.

Coal prices can also differ, both within and across countries, reflecting differences in resource endowments, coal quality and the cost of transporting coal over land and sea. Recently there have also been major shifts in price differentials between the Atlantic and Pacific coal markets. During much of the 2000s, steam coal prices in China were at a price discount of around 25-50% to that in Europe (Figure 8.3). Since 2009, as a result of China becoming and remaining a significant net importer of coal, the price rose above that in Europe and has since commanded a premium of around 20-50% (see Chapter 4). These trends have affected the competitiveness of Chinese industries in coastal regions that rely heavily on coal, relative to their coal-consuming competitors in North America and Europe. Higher coal prices have also created upward pressure on electricity prices in China (though the latter remain regulated), as most Chinese power generation is coal-based. In addition, as demand for coal from US power generators had fallen sharply in 2012 due to the low price of competing gas, this led to a surge in US coal exports to Europe (where coal held up due to increased use from generators in response to high gas prices).

**Figure 8.3 ▷ Ratio of OECD coking to steam coal prices and Asian to European steam coal prices**




Notes: Qinhuangdao is a major coal port in northeast China. NWE ARA is the northwest Europe marker price for the Amsterdam-Rotterdam-Antwerp region.

Sources: McCloskey Coal Report databases and IEA analysis.

Relative to steam coal, the price of coking coal (used primarily in the production of iron) has tended to rise since 2005, due to surging demand and a wave of industry consolidation resulting in a high concentration of supply. The premium has diminished since 2011, as demand from steel producers has slowed and the price of potential high quality substitute steam coal has decreased. This decline in the coking coal price premium has benefited steel producers in countries, such as Japan, that rely heavily on coking-coal imports. In response to pressures from large consumers of coking coal, suppliers have recently moved from mostly annual contracts to quarterly contracts, resulting in more price volatility.

The final prices, including taxes, paid by industry for different fuels vary enormously across countries, especially for electricity (Figure 8.4). The Middle East has by far the lowest prices for most fuels thanks to low production costs, and, in some cases, large subsidies (see Chapter 2). In other regions, the prices for light and heavy fuel oil do not differ greatly, but the price variations are more pronounced for gas. Regional differences in electricity prices reflect, to some degree, differences in the prices of fuels used for power generation: the recent decline in gas prices in the United States has helped reduce electricity prices to a level below that in any other major country outside the Middle East. China's industrial electricity prices have increased significantly in recent years, largely because of rising coal prices and cross-subsidies in favour of residential customers. Additionally, even within countries and industrial sub-sectors, the prices paid for energy by industry can vary significantly.

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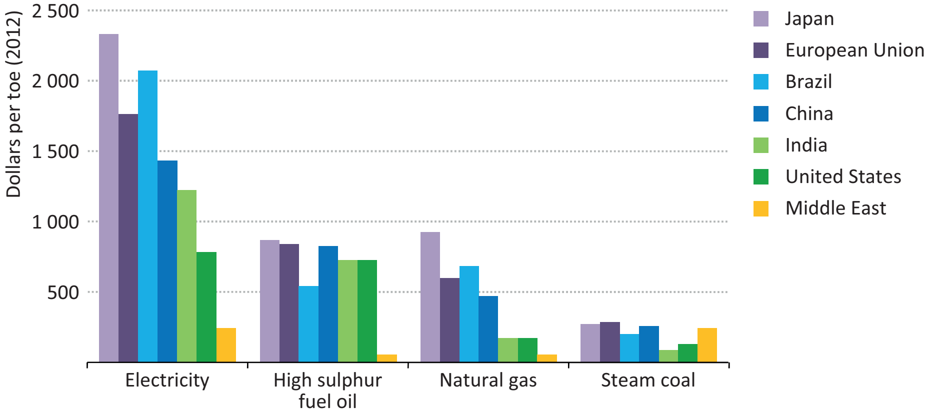
**Figure 8.4 ▷ Industrial energy prices including tax by fuel and region, 2012**

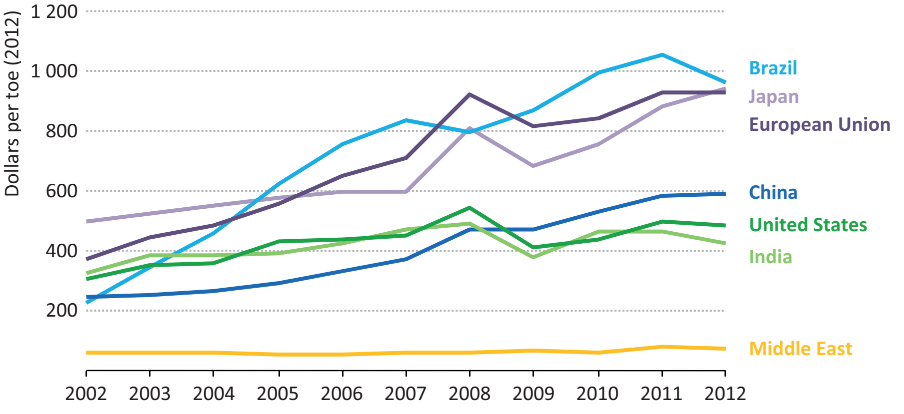



Note: toe = tonne of oil equivalent.

Sources: IEA databases and analysis.

The weighted average price of all fuels in industry, including tax, has increased in most regions in real terms over the past decade, but at different rates (Figure 8.5). India's industrial price has risen modestly, partly thanks to subsidies. By contrast in Brazil, the European Union and China, the industrial price more than doubled from 2002 to 2012. Over the same period, Japan's average industrial price increased less in percentage terms, by 90%, (partly because relatively high taxes dampened the impact of higher international energy prices) but it remains one of the highest among the leading economies. The US average industrial price rose by nearly 80% between 2002 and 2008, but it then fell 10% by 2012, and is now one of the lowest amongst the leading economies.

**Figure 8.5** ▷ **Average industrial energy prices including tax by region**




Note: Calculation based on the average price of each fuel (electricity, high sulphur fuel oil, natural gas and steam coal), weighted by the industrial consumption of these fuels.

Sources: IEA databases and analysis.

**Box 8.2** ▷ **Effect of taxes and subsidies on competitiveness**

Taxes on the sale of energy to industry affect the sector's international competitiveness, as taxes push up the effective price that industries have to pay. But this effect may be offset, to some degree, by other government interventions designed to improve industrial competitiveness, so the net effect can be positive or negative. For example, the revenues raised by those or other taxes may be used to pay for a range of other government measures and programmes, such as improvements to infrastructure and support for investment, that ultimately help industry to lower energy and other costs. Judicious use of revenues from relatively high taxes on energy can improve overall economic competitiveness, if it enhances the overall attractiveness of investing in the economy. For example, Switzerland has relatively high rates of energy taxation, yet has come out on top in each of the last five years in the World Economic Forum's annual survey of economic competitiveness among 148 countries (WEF, 2013a).

Energy consumption subsidies may make energy-intensive industries more competitive, but actually make the overall economy less competitive. This is because they create market distortions that are likely to lead to a misallocation of resources and a resulting loss of economic efficiency and social welfare. Subsidies also weaken prospects for energy efficiency, as they distort payback period calculations for investments. By encouraging over-consumption, energy subsidies can also give rise to large environmental costs, including emissions higher than would otherwise be the case.

One reason why industrial energy prices vary is because of differences in rates of taxation. Taxes can affect industrial competitiveness, but not necessarily economic competitiveness (Box 8.2). Sales of energy products to industry generally carry a lower rate of tax than products in the household sector, but they are nonetheless high in some countries –

notably in Europe. For example, tax accounts for one-third of the total industrial price of electricity in Germany, and 15% in France, while in the United States taxes levied by the states are lower, although the national average is unknown (Table 8.2). Generally taxes are highest on electricity. As in most cases value-added tax is refundable for industry, taxes reported for industry reflect mainly excise duties or other taxes. In some high-tax countries, especially in Europe, tax exemptions or reductions have been proposed, as a way of improving competitiveness.[3]

Energy consumption subsidies also contribute to regional energy price differences and they remain significant in some non-OECD countries, notably among oil exporters (see Chapter 2). For example, oil and gas prices to industry in most of the Middle East are far below international prices, giving industry in the region a big advantage, but at the same time they carry large net economic, social and environmental costs. There can also be large cross-subsidies between industrial and household consumers (for example in China), which generally result in higher prices to industry than would be the case if prices were determined according to supply costs.

**Table 8.2 ▷ Share of tax in industrial energy prices in selected countries, 2012**

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| | Electricity | Heavy fuel oil | Natural gas | Steam coal |
|---|---|---|---|---|
| Germany | 33 | 4 | 10 | 9 |
| Brazil | 26 | n.a. | 22 | n.a. |
| China | 15 | 20 | 15 | 18 |
| France | 15 | 3 | 4 | 6 |
| Japan | 7 | 8 | 6 | 11 |
| India | n.a. | 22 | n.a. | 16 |
| United States | n.a. | 5 | n.a. | n.a. |

Notes: In most cases value-added tax is refundable for EU industry; hence, taxes reported mainly reflect excise duties or other taxes. In Germany, most energy-intensive industries are exempt from the renewables levy and electricity tax, while coal and gas use is also exempt from taxes for most industries. In France and Germany, the tax shares on heavy fuel oil apply to low sulphur fuel oil. Data for China varies depending on product and sector specification. In the United States, taxes on gas and electricity mostly refer to general sales taxes levied by the states (between 2-6%), although their national average is unknown; similarly for coal the national average of various taxes is unknown.

Sources: Sistema Firjan (2013); IEA databases and analysis.

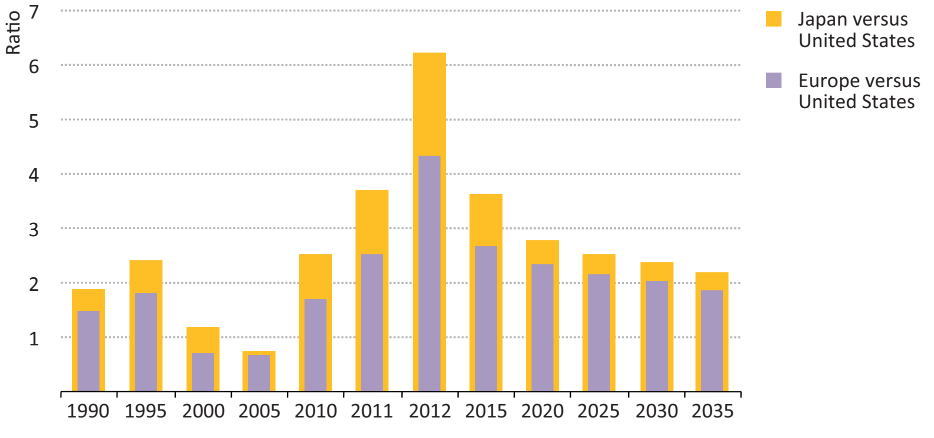
## *How are regional energy price disparities set to evolve?*

The *World Energy Outlook* derives energy price trajectories through an iterative modelling process, based on assumptions about production costs along the supply curve for each fuel and technology, as well as existing and future contractual terms and other factors that influence both energy supply and demand (see Chapter 1). The resulting regional fossil fuel prices determine the trajectory of end-user prices, taking into account taxes and subsidies (and their eventual phase-out), while electricity and heat prices are derived endogenously.

3. In Germany, energy-intensive industrial sectors benefit from exemptions from the renewables levy, and also some of them are exempt from additional taxes and surcharges. In total, around 15% of electricity sales to German industrial consumers are totally exempt from the renewable levy (BDEW, 2013).

The derived price levels in the New Policies Scenario imply some persistent, large disparities in import and retail prices between regions. These reflect assumptions about taxes and subsidies, as well as the market conditions expected to prevail in each region, transport costs between them and supply constraints. There is expected to be little change in the ratio of refined oil product prices across major regions, other than some convergence between regions that currently subsidise oil products and those that do not (on the assumption that subsidies are phased out within the next decade in net oil-importing countries and reduced in net oil-exporting countries that have announced plans to do so). Similarly, regional coal prices are expected to move broadly in parallel. By contrast, regional natural gas price differentials narrow in the New Policies Scenario, but nonetheless remain large in 2035, in part because of the high cost of transporting gas over long distances between exporting and importing regions. US gas prices in the New Policies Scenario are about half of those in Europe and Japan in 2035 (Figure 8.6).[4]

**Figure 8.6 ▷ Ratio of Japanese and European natural gas import prices to United States natural gas spot prices in the New Policies Scenario**




In absolute terms, industrial electricity prices[5] are projected to increase in most regions over the *Outlook* period. This is mainly the result of the evolution of wholesale prices, which increase in line with increasing fossil fuel prices, investment requirements and the eventual pricing of carbon dioxide ($CO_2$) in some countries.[6] Japan is an important exception to this trend, as industrial electricity prices are currently very high following the accident at Fukushima Daiichi. They stand at about three times those in the United States, 65% higher than in China and 35% higher than in the European Union (Figure 8.7). Over time, electricity prices in Japan are expected to move closer to the average of the last decade, falling in the period to the early 2020s and stabilising thereafter. This occurs as nuclear power plants gradually resume generating electricity, as assumed in the New

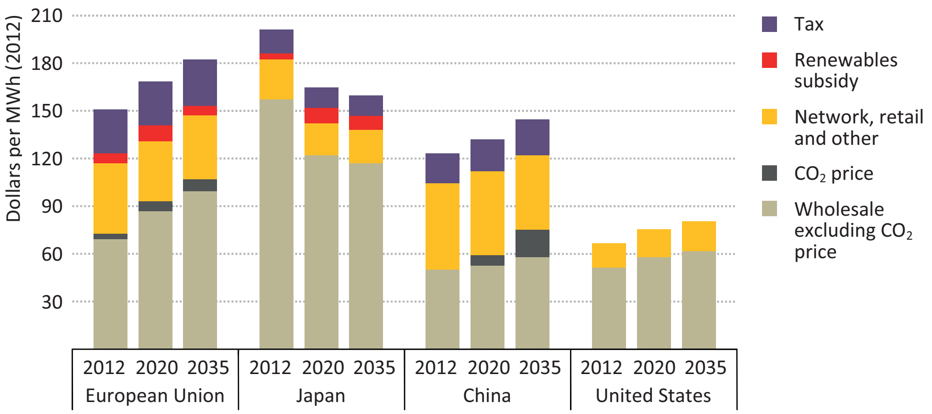
4. Gas price differentials are about 20% lower on average in a Gas Price Convergence Case (see Chapter 3).

5. Prices include costs for wholesale (including $CO_2$); network, retail and other; renewable subsidies; taxes.

6. Where end-user subsidies persist, they can play a significant role in keeping prices low, while their phase-out can lead to substantial price increases.

Policies Scenario, and renewable energy technologies are deployed, reducing the need for expensive oil- and gas-fired power generation. Lower demand for imported natural gas until around 2020 also puts downward pressure on international prices for these, contributing further to a reduction of wholesale electricity prices in Japan.

**Figure 8.7 ▷ Industrial electricity prices by region and cost component in the New Policies Scenario**



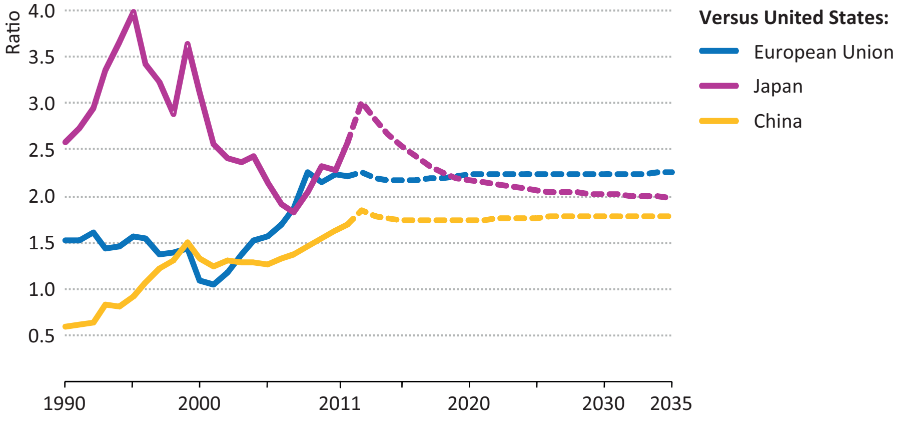

Notes: Network, retail and other costs are regulated and, in the case of China, reflect a cross-subsidy to households that raises the cost to industrial customers. While the United States and China have renewable subsidy schemes, they are partly or fully borne by tax payers rather than reflected in the electricity tariffs.

Sources: IEA analysis and data (including historical data from China's State Grid Energy Research Institute).

As a basis for comparison, industrial electricity prices in the United States increase throughout the projection period, but remain well below those in the European Union, Japan and China. The increase is due, in roughly equal parts, to rising fossil fuel prices, recovery of investment costs for new power plants, and network expansions and reinforcements (see Chapter 5). An expanding role for gas-fired generation and rising gas prices drives up the fuel component of the electricity price, though this is moderated by gains in power plant efficiencies. Strong deployment of renewables and the emphasis on more-efficient conventional technologies push up the investment cost component, which is partially offset by the shift towards less capital-intensive gas-fired capacity. On the other hand, the increasing share of renewable-based electricity generation reduces industrial electricity prices by lowering electricity wholesale prices through the merit order effect, while the costs of subsidies to renewables are partly or fully borne by tax-payers rather than reflected in the electricity tariffs (see Chapter 6).

Industrial end-user electricity prices in the European Union are currently more than twice those in the United States (Figure 8.8). The absolute difference between EU and US prices increases slightly in the New Policies Scenario mainly due to rising wholesale electricity prices in the European Union. The biggest driver of rising EU wholesale prices is investment cost recovery for new power plants. Currently, cost recovery is very low because of overcapacity in many European countries following the recent economic crisis, combined with a strong impetus (from support mechanisms) to build additional renewables capacity. In the New Policies Scenario, the low rate of investment cost recovery is resolved by around 2020, resulting in an increase in wholesale prices. This is partially offset by a marked reduction in fuel costs, as generation from renewables expands rapidly and displaces fossil-fuelled generation, and more efficient power plants are deployed. The $CO_2$ price also contributes (though less so) to increasing wholesale prices. Subsidies to renewables increase until around 2030, adding to rising electricity prices for industry, before falling below today's levels as the policies that support more expensive technologies expire.

**Figure 8.8 ▷ Ratio of European Union, Japanese and Chinese to US industrial electricity prices including tax in the New Policies Scenario**




In China, industrial electricity prices in 2012 were nearly double those in the United States. In absolute terms, this regional disparity grows slightly over time in the New Policies Scenario. While the wholesale price excluding the costs associated with a $CO_2$ price remains similar to that in the United States through to 2035, the anticipated introduction of $CO_2$ pricing in China underpins a widening difference in the end-user price. The costs associated with a $CO_2$ price are higher in China than elsewhere mainly because of coal's relatively large share of electricity generation. Conversely, the introduction of a $CO_2$ price incentivises investment in more efficient technologies, limiting the increase of the fuel cost component over the projection period and partially compensating for the costs associated with a $CO_2$ price. Additionally, China's industrial electricity price is kept at high levels by the assumed maintenance of a cross-subsidy from industrial to household customers. A reduction in network, retail and other costs also helps to mitigate the impact of growing costs associated with a $CO_2$ price. Similar to the United States, the costs of subsidies to renewables in China are partly or fully borne by tax-payers rather than reflected in electricity tariffs.

The increasing share of renewables in many countries affects energy competitiveness in several ways. The higher investment costs (as renewables are more capital-intensive than conventional power plants), increased network costs, and cost of subsidies to renewables (if passed on to end-users) can apply upward pressure on electricity prices. Renewables can also put downward pressure on end-user prices in the short run by reducing wholesale prices through the merit order effect. In the long run, they can help to reduce reliance on fossil fuels in power generation, cutting both total fuel costs and $CO_2$ costs (especially where limits on emissions exist). The net effect of higher shares of renewables can vary significantly across countries. It depends critically on whether renewables deployment occurs as part of the regular cycle of investment in new power plants and whether renewables subsidies are paid by end-users.

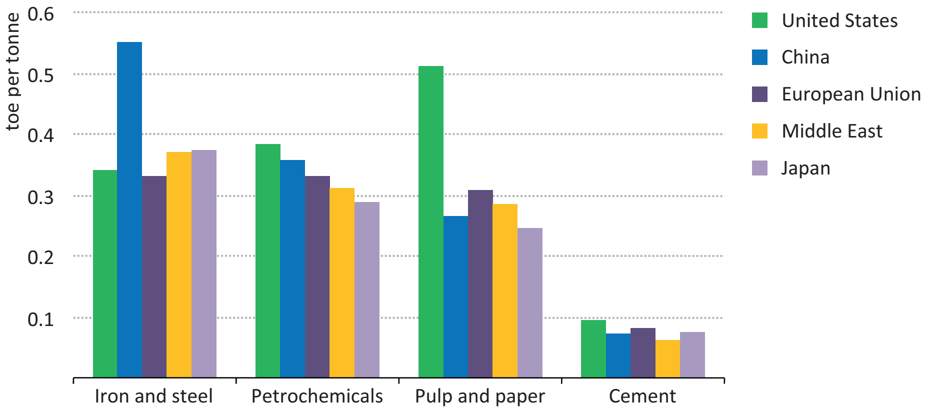
## Energy and industrial competitiveness

### *Why do energy price disparities affect industrial competitiveness?*

The extent to which current price disparities are affecting the competitiveness of industry across countries varies according to economic structure. The vulnerability of each sector to an increase in energy prices, relative to that in other regions, depends largely on its energy intensity and the degree to which the manufactured goods are tradable, which in turn depends on the ease and cost of transportation.



**Figure 8.9 ▷ Industrial energy intensity by sub-sector and region, 2011**

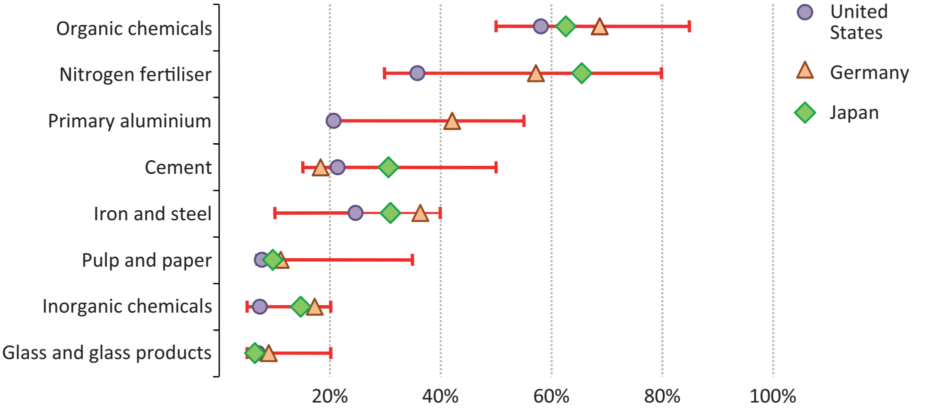



Note: Petrochemicals in this graph refers to ethylene production excluding feedstocks.
Source: IEA analysis.

On average, worldwide in 2011, each dollar of industrial value added involved the use of about 135 grammes of oil equivalent, with a value of \$0.07 or 7%. If industry in one region has to pay 50% more than the world average for its energy, its overall costs will be 3.5% higher (assuming all other production costs are equal). But for some important industrial sectors, energy is a major input to production. In those cases, high relative prices can be a major handicap, particularly where the goods in question can be transported over long distance easily and at low cost (Aldy and Pizer, 2009). The amount of energy needed per tonne of output is generally highest for iron and steel, petrochemicals, and pulp and paper, with variations across countries reflecting mainly differences in the processes deployed, the types of products produced and the variations in energy efficiency (Figure 8.9).

Worldwide, energy accounts on average for more than one-tenth of total production costs (including labour and capital) in only a handful of industrial sectors, but these sectors account for a relatively large share of total manufacturing value added. The major energy-intensive industries are chemicals; primary aluminium; cement; iron and steel; pulp and paper; glass and glass products; as well as refining.[7] Although energy intensity in some of these sectors, such as aluminium, can be high on average, they account for a relatively low share of overall energy use worldwide (Table 8.3). Together, these energy-intensive sectors account for some 20% of total value added by industry and 25% of industrial employment, but 70% of industrial energy use worldwide. The importance of energy in total production cost is greatest in the chemicals industry, where in some segments it accounts for around 80% (Figure 8.10). In activities such as ethylene and nitrogen fertiliser production, it is actually the fossil fuel used for feedstock that accounts for the bulk of energy costs. Across regions there are big differences in the share of energy in total production costs by sector, due to differences in energy prices, the cost of other materials, labour and capital, and process efficiencies. The share is generally highest in Europe and lowest in the Middle East, where energy prices are often heavily subsidised. We estimate that the lower price of gas and electricity in 2012 in the United States relative to Europe equated to total savings of around $130 billion for the US manufacturing industry.

**Figure 8.10 ▷ Share of energy in total production costs by sub-sector, 2011**




Notes: Red horizontal lines show typical ranges for the world. In chemical industries, energy is used both in the production process and as a feedstock. Pulp and paper excludes printing. There are no data for primary aluminium in Japan as production there is minimal.

Sources: US Department of Commerce (Census Bureau), Eurostat and Federal Statistical Office of Germany online databases; Eurostat databases; UNIDO (2010); OECD (2012b); Ecorys, *et al.* (2011); Morgan Stanley (2010); IEA estimates and analysis.

7. Some types of oil and gas exploration and production fall into this category as well, notably oil sands and shale oil and gas.

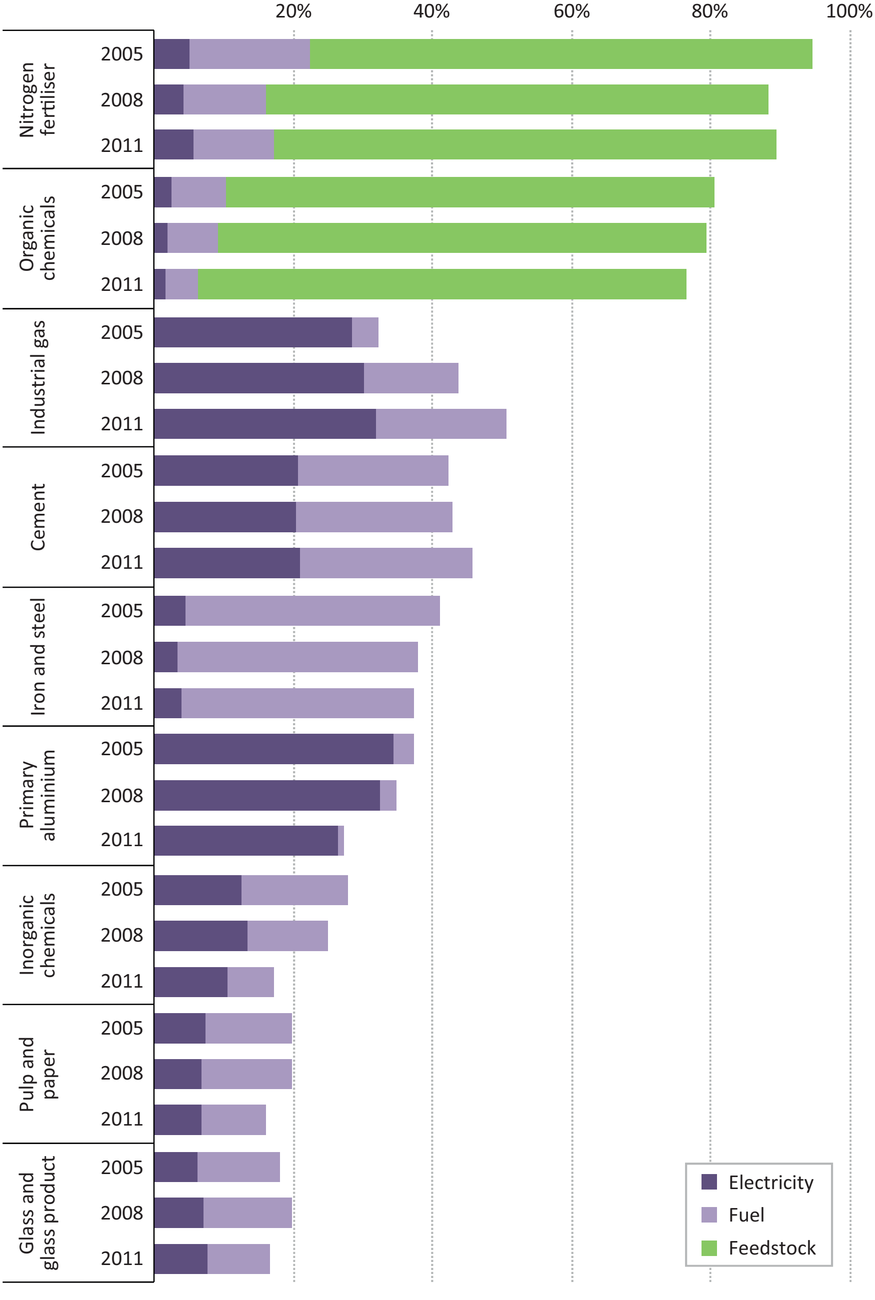
**Table 8.3 ▷ Indicators of significance of industry to the economy by subsector and region**

| | Region | Energy use as share of industry total (%) | Value added | | Net trade as % of value added | Employment | |
|---|---|---|---|---|---|---|---|
| | | | Share of GDP (%) | Share of industry total (%) | | People (thousand) | Share of industry total (%) |
| **Chemicals** | US | 36.3 | 2.3 | 11.2 | 14 | 700 | 6.6 |
| | Japan | 33.2 | 2.5 | 9.3 | 15 | 340 | 4.5 |
| | EU | 32.0 | 0.5 | 2.1 | 155 | 1 160 | 3.9 |
| | China | 19.6 | 2.4 | 5.2 | -7 | 25 810 | 12.9 |
| | World | 27.8 | 2.2 | 7.2 | -4 | 77 930 | 10.4 |
| **Aluminium** | US | 2.0 | 0.1 | 0.3 | -49 | 50 | 0.5 |
| | Japan | 0.2 | 0.1 | 0.3 | -146 | 10 | 0.1 |
| | EU | 2.3 | 0.1 | 0.2 | -611 | 90 | 0.3 |
| | China | 3.9 | n.a. | n.a. | n.a. | n.a. | n.a. |
| | World | 2.7 | 0.0 | 0.4 | 23 | n.a. | n.a. |
| **Cement** | US | 1.4 | 0.04 | 0.2 | -7 | 30 | 0.2 |
| | Japan | 2.7 | 0.2 | 0.9 | 3 | 90 | 1.1 |
| | EU | 4.1 | 0.04 | 0.1 | 139 | 70 | 0.2 |
| | China | 14.1 | 1.2 | 2.6 | n.a. | 14 810 | 7.4 |
| | World | 7.2 | 0.7 | 2.3 | n.a. | 31 940 | 4.3 |
| **Iron and steel** | US | 6.5 | 0.6 | 3.1 | -13 | 290 | 2.8 |
| | Japan | 27.5 | 0.9 | 3.3 | 80 | 220 | 2.9 |
| | EU | 13.9 | 0.2 | 0.6 | 46 | 560 | 1.9 |
| | China | 35.9 | 1.3 | 2.9 | 3 | 15 440 | 7.7 |
| | World | 20.0 | 0.7 | 2.2 | -1 | 29 720 | 4.0 |
| **Pulp and paper** | US | 8.5 | 0.5 | 2.5 | 12 | 350 | 3.3 |
| | Japan | 4.5 | 0.6 | 2.1 | 2 | 190 | 2.5 |
| | EU | 6.9 | 0.3 | 1.0 | 39 | 650 | 2.2 |
| | China | 2.5 | 0.5 | 1.2 | 10 | 6 790 | 3.4 |
| | World | 3.9 | 1.1 | 3.6 | 0 | 29 360 | 3.9 |
| **Glass and glass products** | US | 1.4 | 0.2 | 0.7 | -3 | 150 | 1.4 |
| | Japan | 0.3 | 0.3 | 1.0 | 39 | 50 | 0.7 |
| | EU | 1.3 | 0.1 | 0.3 | 25 | 310 | 1.0 |
| | China | 0.9 | n.a. | n.a. | n.a. | n.a. | n.a. |
| | World | 1.0 | 0.1 | 0.2 | -3 | n.a. | n.a. |
| **Refining** | US | 15.1 | 0.5 | 2.6 | -55 | 60 | 0.6 |
| | Japan | 6.2 | 0.2 | 0.9 | -142 | 10 | 0.2 |
| | EU | 11.1 | 0.1 | 0.6 | -1 247 | 120 | 0.4 |
| | China | 3.1 | 0.1 | 0.3 | n.a. | 1 630 | 0.8 |
| | World | 7.5 | 0.2 | 0.5 | n.a. | 4 810 | 0.6 |
| **Total industry** | US | 100 | 20.7 | 100 | -22 | 10 500 | 100 |
| | Japan | 100 | 27.3 | 100 | 7 | 7 700 | 100 |
| | EU | 100 | 25.4 | 100 | -5 | 30 000 | 100 |
| | China | 100 | 45.5 | 100 | 4 | 200 000 | 100 |
| | World | 100 | 31.2 | 100 | -1 | 750 000 | 100 |

Notes: Data for energy use are for 2011, while data for value added, net trade and employment are for 2010 due to data availability constraints. In addition to the sectors listed, the total industry category includes also data for all the less energy-intensive industries. US = United States. EU = European Union.

Sources: Databases (including Eurostat; International Labour Organization; World Bank and Global Trade Analysis Project; US Department of Commerce, Census Bureau, Annual surveys of manufacturers; National Bureau of Statistics of China; International Trade Center); US EIA (2013); MIC (2012, 2013); Eurostat (2011); Schmitz, *et al.* (2012); EAA (2010); ILO (2012); OECD ENV-Linkages model; and IEA analysis.

**Figure 8.11 ⊳ Share of energy in total material costs in the United States**




Sources: IEA estimates and analysis based on US Department of Commerce, Census Bureau databases; Morgan Stanley (2010); OECD (2012).

Relative to *total production costs*, the share of energy in *total material costs* (which make up most of the variable costs for energy-intensive industries) is generally much higher. While the share of energy in total production costs affects the attractiveness of investing in different regions, the share in total material costs is a more important factor for near-term production decisions. The wider global spread of best available technologies tends to reduce regional differences in efficiency. Largely due to diverging energy prices, the contribution of energy to total material costs has followed differing trends in recent years. In most sectors in the United States, including in organic chemicals, the share has fallen since 2005, and especially 2008, due to weaker gas and electricity prices (Figure 8.11). By contrast, the share of energy to total material costs has remained flat or has risen in most cases in Europe and Japan.

As differences in total production costs often more than offset the cost of shipping, most energy-intensive industries are characterised by a significant degree of international competition, though the extent to which particular products can be traded varies considerably (Table 8.4). Generally, chemicals (including organic chemicals and nitrogen fertiliser), iron and steel, aluminium, and pulp and paper are sectors particularly exposed to international competition, while cement is the main exception due to its relatively low value as a bulk product, which often renders long-distance transportation uneconomic. Importantly, the migration of steel and chemicals production away from high energy price regions can be limited by the fact that those activities are often vertically integrated with less energy-intensive and higher value parts of the value chain.

Although energy represents a small share of total production costs for most industries, regional variations in energy prices can be more marked than variations in costs of other factors. For example, capital costs tend to be similar across regions, as capital competes internationally. The cost of skilled labour can differ significantly across regions, but it has tended to converge in recent years as wage rates in the emerging economies have increased and labour markets have become more international. Exchange rate movements can also have a major impact on competitiveness. While a stronger currency against the dollar normally lowers the cost of imports of energy and other raw materials, it will raise the price of exported products, which can limit the ability of local firms to compete internationally. The decline in the value of the dollar against most other major currencies over the last decade or so has helped to boost the competitiveness of US manufacturing (Figure 8.12). On the other hand, the relative strength of the euro and yen has exacerbated the problems that Europe and Japan face in trying to improve their competitiveness, although the yen (like the Brazilian real and Indian rupee) has depreciated markedly in recent months.

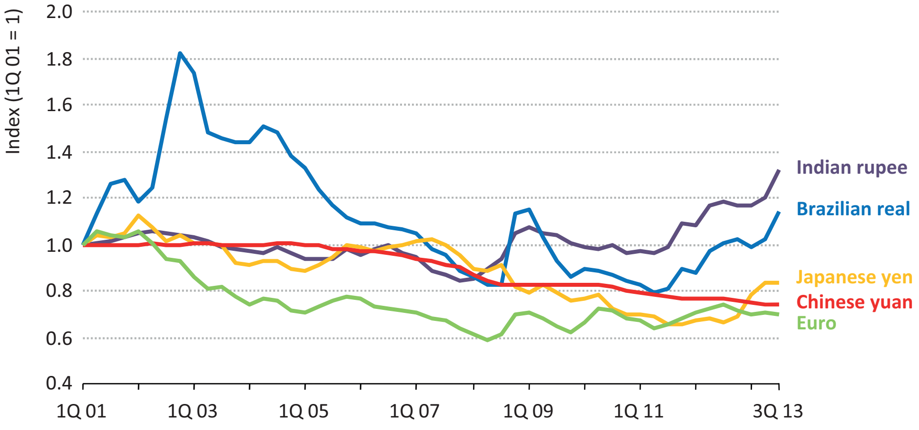
Several signs point to US industry becoming more competitive relative to the European Union, Japan and some other energy-importing countries (including China), at least in part due to low energy prices. But despite indications that investments into US manufacturing are starting to pickup, it is too early yet for recent global shifts in energy competitiveness to show up clearly in manufacturing output and employment statistics, because of the planning and investment lead times involved. Globally, both manufacturing output and related employment have declined recently in most regions, yet this is mainly because of the global economic downturn and depressed local demand. Views still differ as to whether a renaissance in US manufacturing is imminent as a result of low energy prices (Box 8.3).

**Table 8.4 ▷ Typology of main energy-intensive industries**

| | Product characteristics | Use of energy | Degree of international competition |
|---|---|---|---|
| **Chemicals** | Four main product categories: base chemicals (*e.g.* petrochemicals), speciality chemicals, pharmaceuticals and consumer chemicals. | Energy intensity varies enormously across products: generally extremely high for base chemicals (up to 80-85% including feedstock) but very low for pharmaceuticals. | Competitive global markets in most of the main chemicals, but trade of some products limited by technical difficulties and economies associated with the integration of processes. |
| **Aluminium** | Commodity product, but many different final uses after processing. | Electricity only; needs are about 20 times higher for primary production than recycling. | Strong competition and large traded market due to ease of transport and big regional differences in production costs; prices set internationally. |
| **Cement** | Standard commodity, with only a few classes of cement; products from different producers can generally be interchanged. | Requires large amounts of primary energy for process heat to produce clinker (from limestone and clay), which is processed into cement. Coal or municipal or industrial waste are often used. Electricity generally used for crushing, grinding, blowers and cooling. | Market is highly internationalised, dominated by a few large multinational firms, but competition is generally localised due to the relatively low value of the product by volume (which often renders long distance transport uneconomic). |
| **Iron and steel** | Diverse range, including cast iron, crude steel, hot-rolled finished products, cold-rolled sheets and plates. | Coking coal is the main fuel in blast furnaces, though use of gas in direct reduced iron is growing worldwide. Electricity used in electric arc furnaces to melt scrap steel and gas is mostly used in steel finishing. | Competitive global market, though most products are traded domestically or regionally, due to high transport costs. |
| **Pulp and paper** | Diverse range of raw materials (wood types and waste), products and manufacturing routes. | Highly energy intensive, due to need to heat raw materials and water to dry the pulp and for mechanical and electrical processes. Wood is usually a leading fuel, due to access. | Very competitive, particularly for newsprint and office paper, due to often large differences in raw material and energy costs. |
| **Glass and glass products** | Qualities and types of product vary; production processes are broadly similar across the world. | Large amounts of energy needed to heat kilns; gas is often the favoured fuel. | Raw materials are heavily traded internationally; trade restrictions can be large. |
| **Refining** | LPG, naphtha, gasoline, jet fuel, other kerosene, diesel, fuel oil, petroleum coke and other products. | Up to 10% in total material costs (including feedstock); over 50% excluding feedstock. The more complex the refinery (*i.e.* the more it produces high-quality fuels), the higher the energy requirements. | Extremely high, as unit transport costs per tonne are very low. |

Source: IEA analysis.

**Figure 8.12 ▷ Value of the US dollar *vis-à-vis* other major currencies**




Source: De Nederlandsche Bank exchange rate online database.

**Box 8.3 ▷ Reindustrialisation of the US economy: myth or reality?**

There have been a good many announcements by leading manufacturing firms (including General Electric, Ford, Dow, BASF, Voestalpine and Caterpillar) of plans to invest large sums in new plants in the United States, but the jury is still out on whether they signal the beginning of a renaissance for US manufacturing and, if they do, whether low energy prices are the main driver. Indeed the United States has enjoyed several years of relatively low natural gas prices, which has lowered costs for manufacturers. However, outside petrochemicals (and the shale gas industry itself), there is so far little evidence of any resurgence in investment or production. Relative to the six million jobs that disappeared between 2000 and 2009, the contribution to employment for the time being appears only modest. According to official government data, over half a million manufacturing jobs have been added since January 2010. But of those, only 50 000 have come from overseas firms moving to the United States (Morgan Stanley, 2013).

Yet the logic of a manufacturing renaissance remains compelling, when account is taken of factors beyond the direct boost to income and jobs from increased drilling and the low energy prices that the shale revolution has brought. These factors include the narrowing wage gap between the United States and China and the continuing rise in US productivity. In principle, these factors, combined, should help to make US manufacturing more competitive with other economies, encouraging a shift in production back to the United States, a phenomenon known as "reshoring". Thanks to the strong multiplier effect of manufacturing jobs, small- and medium-size domestically focused industrial suppliers would benefit too.

Recent analysis by the Boston Consulting Group points to an imminent surge in US exports of manufactured goods (in part thanks to low energy prices), which together with the effects of reshoring could add 2.5 to 5 million jobs by 2020.[8] By around 2015, the United States is expected to have an export cost advantage of 5-25% over Germany, Italy, France, the United Kingdom and Japan in a range of industries, including plastics and rubber, machinery, electrical equipment, computers and electronics. Another study estimates that one million manufacturing jobs may be created by 2025, solely due to the advantages of low gas prices and the demand for the products used to extract shale gas – with around one-third of these jobs resulting from lower feedstock and energy costs (PWC, 2011). These estimates are sensitive to underlying assumptions about the persistence of relatively low energy prices in the United States.

### *How does carbon pricing affect industrial competitiveness?*

Carbon pricing is not necessarily detrimental to industrial competitiveness: it all depends on how it is implemented and whether similar action is taken in competing economies. In principle, the introduction of a carbon price (whether in the form of a tax on fuel use according to its related $CO_2$ emissions or a cap-and-trade system) increases the cost of industrial production insofar as the industry in question uses fossil fuels. This leads to a risk that carbon-intensive industries in countries that introduce a carbon penalty migrate to other countries that do not, with no net saving in emissions, a phenomenon known as "carbon leakage". But, in practice, the extent of the increase in costs depends on the level of the carbon price, whether industry is required to pay the entire price and whether accompanying measures are introduced to compensate for the higher prices. For example, under the EU Emissions Trading System (ETS), certain energy-intensive industries have been granted free allowances.[9] In addition, part or all of the revenue from carbon pricing may be recycled back to energy users in the form of investments towards improved energy efficiency, or through other, broader supportive policies for industry; hence, this may actually increase industrial and energy competitiveness.

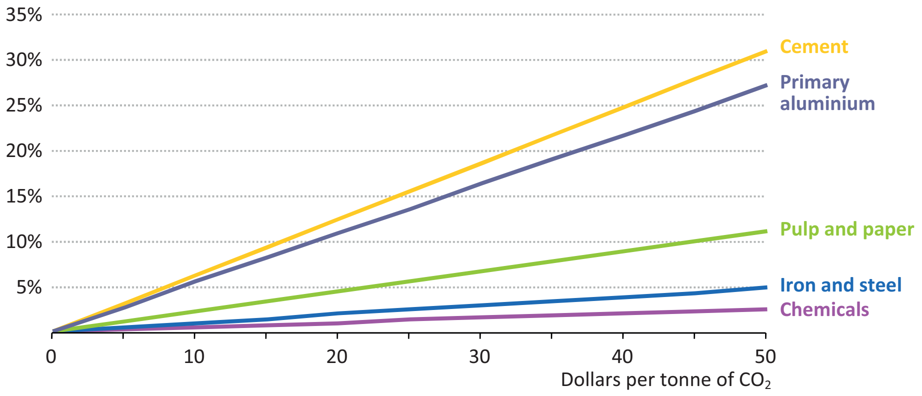
For a given level of carbon price (where there are no free allowances), the potential impact on total material costs is greatest for those industries most reliant on coal and carbon-intensive electricity, relative to the value of their output. In the case of the United States, a hypothetical $CO_2$ price of \$10/tonne would increase costs on average (over and above current levels) by about 6% for cement; 5% for primary aluminium (due to its heavy reliance on electricity); 2% for pulp and paper; and less than 1% for both iron and steel, and

8. *www.bcg.com/media/pressreleasedetails.aspx?id=tcm:12-116389.*

9. The EU ETS is the world's largest cap-and-trade system covering all 28 European Union member states plus Norway, Iceland and Liechtenstein. The $CO_2$ price under the system has fallen in recent years, largely because energy demand has fallen due to recession and there was a large influx of international credits. The price plummeted to less than €3/tonne in April 2013, following an inconclusive vote by the European Parliament on a plan to delay the introduction of 900 million of the 16 billion tonnes worth of allowances on the market for 2013-2020. It has recovered a little since with a new vote on an amended Commission proposal, which limits the extent to which allowances can be delayed. As of September 2013, the proposal awaits approval by the European Council.

chemicals (Figure 8.13). Total material costs could increase by significantly less or could even fall, were the carbon price to be accompanied by additional measures to encourage or mandate investments in more energy-efficient equipment or processes.

**Figure 8.13 ▷ Sensitivity of US industrial total material costs to $CO_2$ prices, 2011**




Note: A $CO_2$ price is not assumed on petrochemical feedstocks. Source: IEA analysis.

8

Enhancing industrial competitiveness does not require governments to relegate action to tackle climate change, since climate change poses a far greater threat to national economies than the adjustments associated with shifts between countries in relative energy costs. Properly designed climate change policies can go hand-in-hand with policies to enhance industrial and energy competitiveness. Yet the threat of carbon leakage is real and governments need to pursue climate change policies which ensure their domestic energy-intensive industries are not penalised by the absence of policy action in other markets. An international agreement on climate change, which for example puts a price on carbon, can help to ensure that energy-intensive industries in countries acting decisively to limit emissions do not face unequal competition from countries that do not.

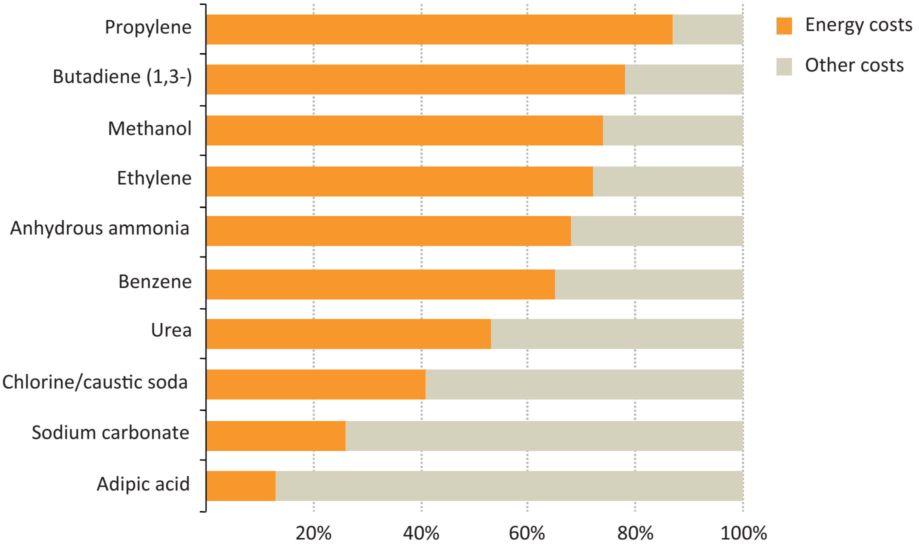
### *Focus on chemicals*[10]

The chemicals industry is the biggest industrial consumer of energy worldwide and the energy-intensity of this sector's various activities varies significantly. Basic petrochemicals (such as propylene and ethylene), as well as inorganic and agricultural chemicals and fertilisers, and certain specialty chemical segments (such as industrial gases), are sensitive to energy prices – with energy even accounting for up to 90% of total material costs in the United States (Figure 8.14). Production and investment decisions in these segments are therefore very sensitive to regional energy price differentials, contrary to other activities, such as pharmaceuticals, for which energy costs are of lower importance. The production of some chemicals, essentially bulk petrochemicals and fertilisers, in contrast to most other

10. See Chapter 15 for a discussion of prospects for oil demand in the petrochemical industry.

industries, relies on energy as both fuel and as feedstock. Most bulk chemicals can be transported economically over long distances, so regions with low energy prices can have a relative cost advantage in their exports. This has prompted concerns in Europe and Asia about the competitiveness of their respective petrochemical industries.

**Figure 8.14 ▷ Share of energy in total material costs for selected chemical products in the United States, 2012**




Note: Energy costs include feedstock use. Source: ACC (2013).

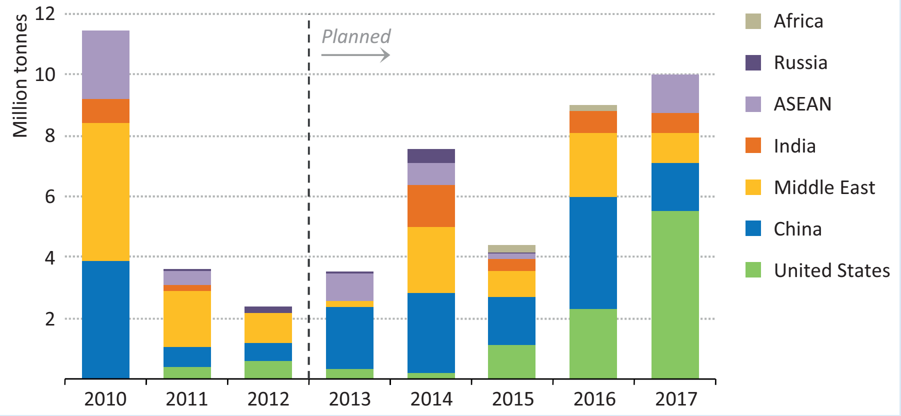
The surge in shale gas in the United States since 2005 has led not just to lower prices for natural gas (methane) but has also boosted the availability and lowered the prices for liquefied petroleum gas (LPG) and ethane contained in associated natural gas liquids. This has triggered a wave of planned new investment in US steam crackers and other downstream units in the ethylene supply chain, as well as other facilities for producing propylene, methanol, ammonia, chlorine and other chemical products (Box 8.4).

Low feedstock costs are continuing to underpin expansions in the Middle East – at $0.75/MBtu, gas prices in Saudi Arabia are among the lowest in the world. But in Europe, heavy reliance on relatively expensive naphtha is putting ethylene producers at a competitive disadvantage to both Middle East and US producers, and prompting them to consider modifications to their operations (CEFIC, 2013). For example, the company Total is considering a major upgrade of its refining and petrochemical complex in Antwerp, involving an increase of diesel production and using LPG as feedstock in the petrochemical unit. In China, which has large deposits of coal and which already produces large amounts of methanol using coal as feedstock, high oil and gas prices are leading companies to increase olefins production (including ethylene) using this process (see Chapter 15, Box 15.4).

### Box 8.4 ▷ The remarkable renaissance of US petrochemicals

The slump in gas, ethane and LPG prices in the United States due to the boom in shale gas has given US petrochemical producers a major advantage over many competitors in Europe and other parts of the world that rely primarily on naphtha, an oil-based alternative feedstock. This sharp improvement in the profitability of bulk petrochemicals production has boosted utilisation rates at existing US plants and led to a surge in plans for new production facilities (Figure 8.15). Between 2010 and the end of March 2013, almost 100 chemical industry projects valued at around $72 billion were announced (ACC, 2013). According to the American Chemistry Council, these investments, were they all to proceed, would boost production capacity by 40% in 2020; provide 1.2 million jobs during the construction phase (to 2020); create over half a million permanent jobs; and give rise to total output worth $200 billion per year in the longer term. The majority of the planned projects, many of them for export, involve expansions of capacity for ethylene, ethylene derivatives (such as polyethylene and polyvinyl chloride), ammonia, methanol, chlorine, and to some extent for propylene. Roughly half of the announced investments to date are by firms based outside the United States. Much of the investment is aimed at making use of the rapidly growing volume of ethane coming onto the US market. However, using solely ethane as feedstock in steam crackers produces just ethylene and almost no other by-products, such as propylene, which may lead to local imbalances in derivative product markets.

**Figure 8.15 ▷ Historical and planned ethylene capacity additions by region**




Sources: ICIS (2013); IHS (2013); METI (2013); Platts (2013); US EIA (2013); and IEA analysis.

## *Focus on iron and steel*

Iron and steel production requires large amounts of energy and in 2011 the sector accounted globally for 20% of industrial energy use and 8% of total final energy use. Energy typically makes up 10% to 40% of total production costs and therefore the economics of iron and steel production are highly sensitive to local energy prices (see EU example in

Box 8.5). However, the cost of long-distance transportation of finished steel products provides a cushion against competition from producers in low energy-price regions, and for some specialised products, high quality can compensate for differences in production cost.

### Box 8.5 ▷ Expensive energy adds to the steel woes of the European Union

High energy prices are contributing to the difficulties faced by steel producers in the European Union, where domestic demand has fallen due to the region's economic slowdown. EU producers have a strong competitive position in domestic markets, particularly in high value-added products, and have established strong technological links with their main client sectors (like the automotive, aerospace and high-performance engineering industries) to develop tailor-made products. Indeed, EU steel imports have fallen and exports risen since 2009. But several steel plants, in response to lower demand and cost pressures, have closed temporarily or permanently over the past year. According to the European Steel Association, EU steel consumption is expected to drop by 4.4% in 2013, before recovering slightly in 2014 (Eurofer, 2013).

Worryingly for EU steel producers, there appears to be only limited potential for lowering the energy intensity of production through the adoption of best available technologies, though innovative technologies under development could yield much bigger gains (Moya and Pardo, 2013). One such process is HIsarna, in which iron ore is processed almost directly into steel, promising much greater energy efficiency, as well as lower $CO_2$ emissions. A pilot unit for HIsarna is under construction at the Tata Steel plant in IJmuiden in the Netherlands. In June 2013, the European Commission released a plan for the steel industry, which proposes a number of actions to help alleviate the problems facing the EU steel industry (EC, 2013). These include moves to ensure EU steel producers have access to third-country markets through fair-trade practice; streamlining EU regulation; promoting innovation, energy efficiency and sustainable production processes; and targeted measures to support employment in the sector and during the restructuring to ensure that highly skilled labour is retained in Europe.

The way steel is made is changing in some parts of the world, in part due to shifts in the price differentials between the fuels that can be used in the production process. The standard blast furnace route to making steel involves the use of coking coal, along with iron ore and limestone to produce iron, which is then fed into a basic oxygen furnace (usually together with scrap steel) to produce crude steel. The other main route is the electric arc furnace, which relies on electricity to melt the steel (usually scrap) before further processing. Due to the rising cost of coking coal, some steel producers are turning to an alternative method for producing iron – direct reduced iron (DRI) – which involves the use of a gas (a mixture of hydrogen and carbon monoxide) as a reducing agent (usually derived from natural gas or coal). This process has the advantage of being less capital intensive than the blast furnace method and less carbon intensive, if based on gas. India and Iran (where gas prices are relatively low despite recent energy subsidy reforms) dominate DRI production today, but several plants are under construction in other countries. For example the US steel firm Nucor is expected to bring online a 2.5 million tonnes/year gas-based DRI plant in Louisiana at the end of 2013, while the Austrian steel producer, Voestalpine, announced in March 2013 that it would also build a similar 2 million tonnes/year plant in Texas (the produced iron will be shipped to Austria for processing into steel).

### *Focus on refining*[11]

The global refining industry is undergoing a profound transformation as a result of changes in regional demand trends for oil products and in feedstock composition, as well as diverging regional energy costs. Crude oil and part of natural gas liquids are mainly used as feedstock in refining and to provide fuel for the transformation process (up to 10% of the energy contained in the feedstock). Consequently, the cost of energy inputs has an impact on profitability. In general, it is more economical to ship crude oil to refineries located close to market than to transport refined products over long distances (as separate carriers are needed to ship "clean" and "dirty" products), which provides a degree of protection for refineries against distant competitors. Nonetheless, imbalances between local production and demand usually mean that significant volumes of specific products need to be imported or exported. Relatively high energy costs, alongside falling demand and overcapacity, are contributing to weak margins in some regions, notably Europe, where several refineries have already closed in recent years and further closures are likely.

The importance of low energy prices has risen in the refining industry, as the energy intensity of the sector has increased since the mid-2000s. Several factors are contributing to growing energy intensity, notably increasingly stringent oil-product standards (such as low-sulphur diesel) and a combination of increasing demand for middle distillates (diesel and kerosene) coupled with a growth of the share of both very heavy and light oil production, which, together, are forcing refiners to increase secondary processing. These factors are outweighing improvements in the energy efficiency of refining operations from new investment in energy-saving equipment and improved operating practices.

Worldwide, refinery gas and oil products (ordinarily produced by the refinery itself) are the principal sources of the energy consumed in the refining process, though natural gas is a key fuel in regions where gas prices are low, such as the United States. The fall in gas prices in the United States has given its refiners a competitive boost, especially relative to European refiners that are burdened with high imported gas costs, and refiners elsewhere that rely heavily on oil products to fuel their plants.

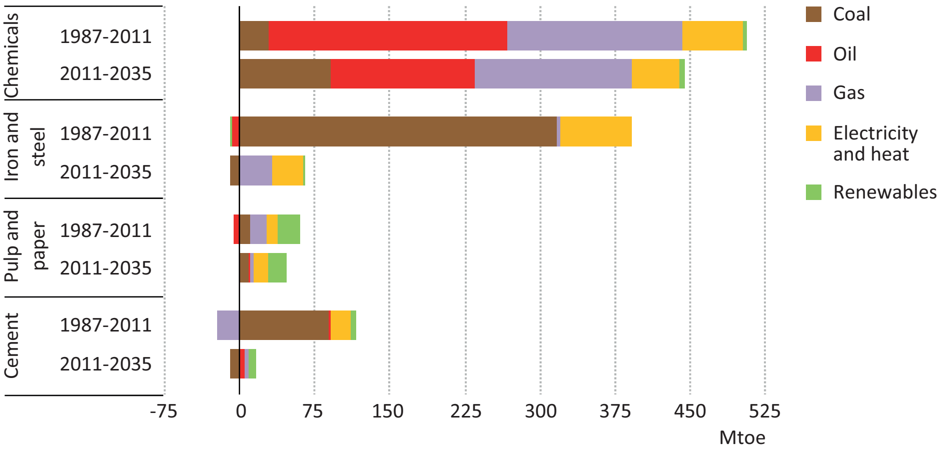
## The outlook for industrial energy and competitiveness

Industrial energy use over 1987-2011 expanded by almost 55%, and it is projected to increase a further 37% by 2035 in the New Policies Scenario. Gas, electricity and heat increase their combined share of the industrial fuel mix from 43% in 2011 to 50% in 2035, as these fuels account for nearly 70% of the incremental energy demand. Among the energy-

11. See Chapter 16 for a detailed analysis of the outlook for global refining.

intensive industries, some see a marked slowdown in the growth of energy use largely due to lower output growth, as well as process changes and energy efficiency improvement (Figure 8.16). The reduction is particularly marked in the case of cement, and iron and steel, as the construction boom slows in China. Conversely, energy use in the chemical, and pulp and paper industries expands in absolute terms similarly to historical trends. The chemical industry alone accounts for 40% of incremental industrial gas consumption. The increase in chemicals production is particularly driven by petrochemicals, where the demand for plastics increases strongly in China and other developing Asian countries as a result of their per capita consumption currently being about one-fourth of the OECD level. Overall the share of the four energy-intensive sectors in total industrial energy demand declines from 65% in 2011 to 58% in 2035. The combined energy use of all other industrial sectors almost doubles, driven by increasing production in sectors such as textiles, car manufacturing, machinery and mining.

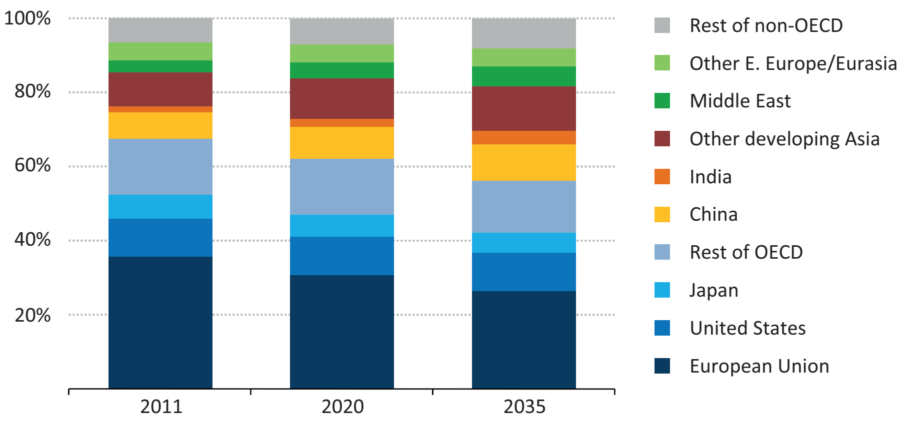
**Figure 8.16 ▷ World incremental energy demand by industrial sub-sector and fuel in the New Policies Scenario**




The energy use, production and export prospects for the energy-intensive industrial sectors differ markedly between regions. Their stage of economic development is the main determining factor, though energy prices also weigh in. The largest increases in energy demand in the chemical industry come from China, the Middle East and ASEAN countries, while in the iron and steel industry India sees the largest absolute growth. In many emerging economies, the strong growth in domestic demand for energy-intensive goods supports a swift rise in their production (accompanied by export expansion). But relative energy costs play a more decisive role in shaping developments elsewhere, particularly among the OECD countries. While regional differences in natural gas prices narrow in our central scenario, they nonetheless remain large through to 2035, and electricity price differentials largely persist.

OECD countries currently dominate the export market for energy-intensive goods, accounting for more than two-thirds of the export value. About half of those exports originate from within the European Union, which makes it the largest export region (Figure 8.17). In the New Policies Scenario, export growth rates among OECD countries are highest in the United States, which enables it to increase its export market share.[12] Despite a continuing slow expansion of export volumes, market shares fall in Japan and in the European Union – especially for chemicals. Next to high energy prices, relatively high wages in the European Union as well as longer shipment distances to the major consumption centres in Asia (which emerge in the long term), put European Union exports at a comparative disadvantage. Despite a reduced share in the global export market, which is particularly pronounced up to 2020, the European Union still remains the leading exporter of energy-intensive goods. In 2035 the European Union is exporting more than the United States, China and Japan combined.

**Figure 8.17 ▷ Regional shares of global export market value of energy-intensive industries in the New Policies Scenario**




Notes: Energy-intensive industries covers chemicals; iron and steel; pulp and paper; cement; and non-ferrous metals (aluminium, copper, lead, nickel, tin, titanium, zinc and alloys such as brass). Intra European Union trade flows are excluded.

Sources: OECD ENV-Linkages model and IEA analysis.

The growth in exports from developing Asian countries, including China and India, remains rapid in the New Policies Scenario on the back of rising production of chemicals, aluminium and steel (in some cases). As a consequence, developing Asia increases its export market share to a level equal to that of the European Union. In China, the increase in export market share occurs largely within this decade as steel production is anticipated to level off afterwards. Developments in the chemical and non-ferrous industries (where energy

12. These projections are sensitive to assumptions about real exchange rates, which remain constant through the projection period.

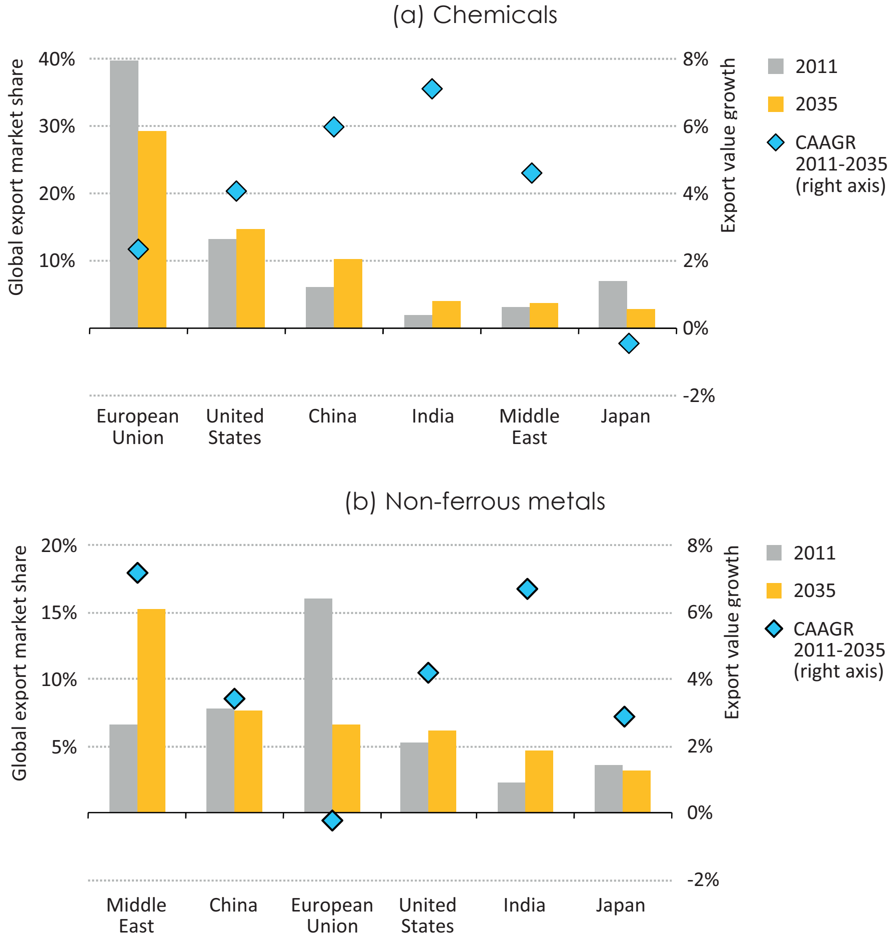
accounts for the largest share in total production costs) provide a clear indication of the link between relatively low energy prices and international competitiveness.

Chemicals production in most regions grows in the New Policies Scenario, but prospects for exports in major producing countries varies markedly (Figure 8.18a). By 2035 the European Union retains the largest share in the global export market for chemicals (as speciality chemicals, with lower energy-intensities, account for a growing share of global chemicals trade), but its dominance declines by ten percentage points over the projection period. Japan, where petrochemicals account today for around 60% of its chemical exports, sees a marked decline in export market share as petrochemicals production wanes. By contrast, the market shares of China, India and the Middle East increase, supported by strong growth in export values. In 2035, the United States maintains its position as the second-largest exporter of chemicals in the world, supported by relatively low gas prices and increasing production of bulk chemicals. The narrowing of gas price differentials in the later part of the projection period boosts the rate of growth in EU exports and tempers the decline in the region's global market share.

In the non-ferrous metals industry, the Middle East sees a strong growth in exports and by 2035 becomes the dominant exporter supported by relatively low electricity prices (Figure 8.18b). The European Union loses its leading trade role, experiencing a nine percentage points drop in global export market share, about equivalent to the gain in the Middle East. While China maintains its share in export markets (the rising production mainly satisfies domestic needs), the United States increases its share slightly and Japan's share decreases slightly. The non-ferrous metal sector is dominated by aluminium and other base metals, such as copper, zinc, and lead, with the rest being made up by precious metals (*e.g.* gold and sliver) and specialty metals (*e.g.* cobalt). Particularly for primary aluminium, energy costs far outweigh other costs, such as labour, capital or administrative costs. This puts regions with low electricity prices, such as the Middle East, Norway or Iceland, at a competitive advantage. Access to raw material plays a role in other segments: Chile, for example, is the leading exporter of copper thanks to its vast reserves.

In the iron and steel industry, the outlook for international trade is broadly similar to other energy-intensive sectors. Today, the industry is dominated by China, which represents almost half of current steel production, followed by the European Union with 12%, Japan with 7%, the United States with 6% and Russia and India with each 5%. The vast majority of Chinese steel is used in its domestic construction industry, driven by the need for housing in its rapidly developing cities. Only a small part of domestic production is currently shipped from China to other countries: China accounts for less than 10% of the global export market. With the domestic construction boom slowing notably down towards the end of this decade in the New Policies Scenario, China is able to increase its share in global export markets though from a low base. In light of the structural shifts in steel production in mature markets, the OECD sees a drop in market share, with Europe losing the most.

**Figure 8.18 ▷ Regional shares of global export market and growth in export values by selected sector in the New Policies Scenario**




Notes: CAAGR is compound average annual growth rate. Chemicals include base chemicals (*e.g.* petrochemicals), specialty chemicals, pharmaceuticals and consumer chemicals. Non-ferrous metals include aluminium, copper, lead, nickel, tin, titanium, zinc and alloys such as brass. Intra European Union trade flows are excluded. Sources: OECD ENV-Linkages model and IEA analysis.

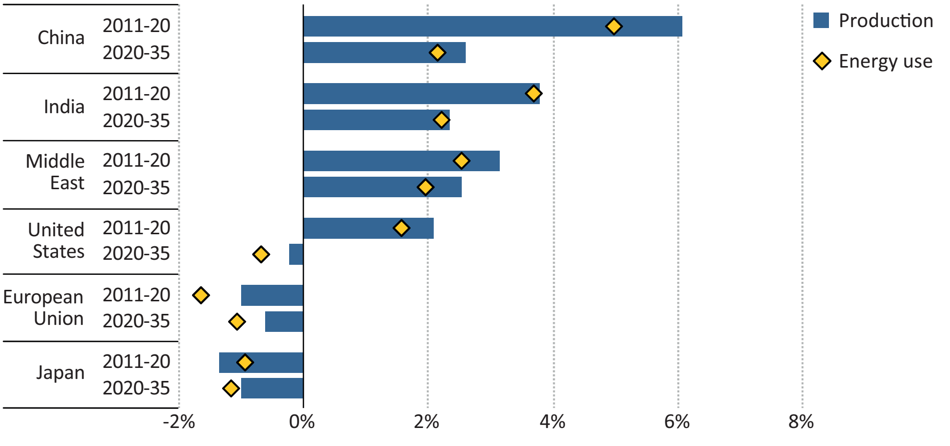
## *Focus on the outlook for chemicals*[13]

Chemicals are a key energy-intensive industrial sector in the economies of China, the European Union, Japan and the United States, many of which are net exporters of chemicals. The chemical industry is very diverse in terms of output, but energy consumption is dominated by a few large-volume products. Olefins production, including ethylene and propylene, and their derivatives (*e.g.* polyethylene and ethylene oxide),

13. See Chapter 15 for a discussion of prospects for oil demand in the petrochemical industry.

make up the largest share of fuel and feedstock use within the chemical industry. Other important intermediate products are aromatics, nitrogen fertiliser and methanol. Globally, energy use (including feedstock) in chemicals production grows on average 1.5% per year between 2011 and 2035 in the New Policies Scenario, with nearly 70% of the growth met by gas and oil. The chemical industry alone accounts for 35% of incremental industrial energy consumption. The projected increase in chemical energy use in absolute terms and growth rate varies markedly across regions, mainly according to the rate of increase in domestic demand, but also as a reflection of the international competitiveness of domestic production (Figure 8.19).

**Figure 8.19 ⊳ Compound average annual change in chemicals energy use and production by region in the New Policies Scenario**




China and the Middle East alone account for 70% of incremental energy use in the chemical industry to 2035. Energy use falls in the European Union and Japan, but grows in most other major regions, mainly as a result of different rates of growth in the production of chemicals. In the United States, energy needs grow relatively slowly over the entire projection period, but this hides a significant increase in production out to 2020 (supported by a surge in ethane availability), and a fall towards the end of the projection period. The contrast in chemical industry trends between the United States (where output and related energy use grow), and the European Union and Japan (where output and related energy needs decline) is particularly striking and illustrates the central role energy prices can play in industrial competitiveness (although other factors, such as weak domestic demand, are important too).

## Energy and economic competitiveness

A change in relative energy costs across countries not only affects industrial and energy competitiveness but also economic competitiveness. The extent to which an increase, relative to other economies, in the pre-tax price of energy (rather than simply higher prices) undermines economic competitiveness depends largely on the extent to which a given country relies on energy-intensive manufacturing, as well as the scope for higher prices to be offset by economically viable investments towards greater energy efficiency. A loss of economic competitiveness (to a greater or lesser degree due to a rise in relative energy costs) may result in a reallocation of resources away from energy-intensive industries towards less energy-intensive manufacturing or services. Conversely, a fall in relative energy costs boosts economic competitiveness.

While energy-intensive industries across regions are directly affected by any change in relative energy prices, this impact on industry also has knock-on effects more broadly. Competitively priced industrial goods (such as cement and steel) help to lower the cost of producing final products (such as housing and metal goods). Also, increasing domestic production of energy, often associated with lower energy prices, enhances economic activity indirectly through increased demand for equipment, materials and services (such as steel products, cement, haulage and engineering). In the United States, this effect may be greater than the benefit from lower industrial energy prices (Box 8.3). Conversely, a rise in the price of industrial goods, due to high energy prices, erodes indirectly the competitiveness of other sectors through the same mechanisms.



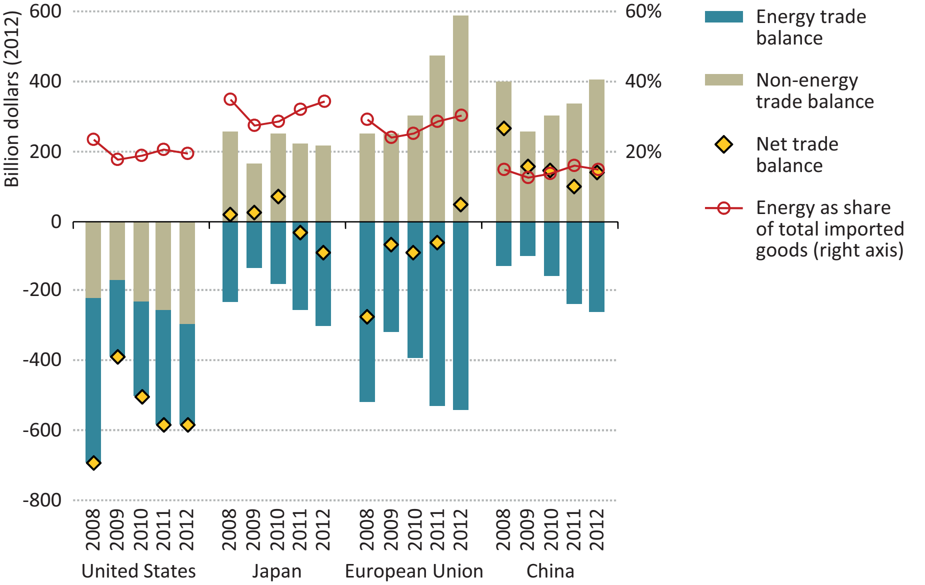
Economic restructuring that results from a change in industrial competitiveness and, therefore, economic competitiveness (whether resulting from higher energy costs or an increase in the cost of other inputs to production) is generally associated with medium-term adjustment effects (such as a change in employment levels, corporate profitability, real wages and the rate of inflation). Any loss of competitiveness is reflected in a relative decline in GDP when higher-value manufacturing shifts to lower energy-cost regions. Also as real disposable incomes falls due to the increase in the share of energy in total household spending, this reduces the amount of money available for spending on other goods and services. Multiplier effects accentuate these macroeconomic worries. Conversely, countries with relatively low energy prices enjoy a macroeconomic boost from increased investment, higher incomes and an improvement in their trade balance.

The global economic rebalancing that follows a shift in energy competitiveness also involves second-order effects that may temper the effects of the initial adjustments. For example, although low US gas prices are leading to a loss of energy competitiveness *vis-á-vis* the United States in higher cost regions, part of this negative impact is being offset by increased US imports of other products. The economic benefits of a fall in relative energy costs due to greater exploitation of domestic resources can be reduced by an accompanying sharp inflow of foreign currency – a phenomenon known as "Dutch disease". The currency inflows lead to currency appreciation, which makes the country's non-energy goods and services less price competitive on the export market. This can then lead to higher levels of cheaper imports, offsetting the impact of lower energy prices on energy competitiveness.

### *What is the impact of energy price disparities on overall trade balances?*

The divergence in energy prices across regions and fluctuations in international energy prices in recent years have manifested themselves in shifts in energy trade balances. Annual spending on energy imports in 2012 hit new records in dollar terms (by exceeding previous peaks in 2008) in many major energy-importing regions. The contrast between the United States and other major importers is striking; the United States saw its energy import bill fall by 40% since 2008, while that of the European Union slightly increased and that of many others continued to climb. Such fluctuations in energy trade balances have been an important driver of recent changes in overall trade balances of the major energy-importing regions (Figure 8.20). This is most evident in Japan, where a sharp increase in energy import costs was the primary cause of the country recording an overall trade deficit in 2011. Japan ran its fifteenth straight monthly trade deficit in September 2013, making it the longest period of deficit since the fourteen months between July 1979 and August 1980. Energy now accounts for one-third of Japan's total imports, which is a slightly lower share than at the previous peak in 2008. The overall trade deficit in the United States worsened steadily over 2009-2011, but a drop in the share of energy in total imports in 2012 helped to reverse this upward trend.[14] In the European Union the overall trade deficit turned positive in 2012, as strong growth in non-energy exports (particularly from Germany) outweighed the increase in the weight of energy in total imports.

**Figure 8.20 ▷ Overall trade balance including energy trade by region**

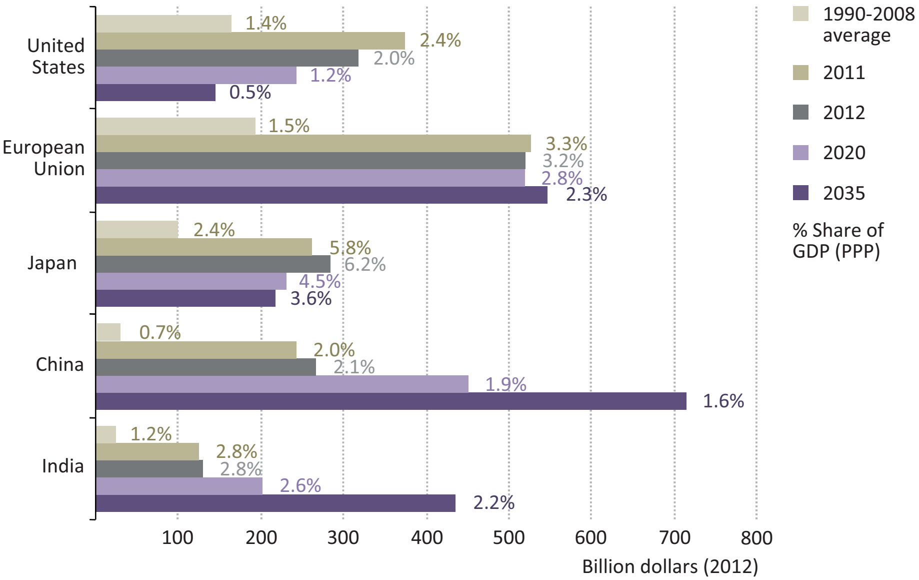



Sources: MIC (2012); WTO (2012) and WTO databases; and IEA analysis.

14. The US administration deems unhealthy a world economy that is too dependent on US consumption spending and aims to reduce further the US trade deficit. The US National Export Initiative is intended to increase US exports to help reduce worldwide trade imbalances (White House, 2013).

Generally, oil accounts for the majority of fossil-fuel import bills in energy-importing countries, though natural gas import bills can also be significant (with a share of around 25% in both Japan and the European Union), especially given regional gas price disparities. China in 2012 had a record high fossil fuel net import bill of $270 billion (or 2.1% of GDP) representing a four-fold increase over 2005 (Figure 8.21). Japan's fossil fuel net import bill rose to over 6% of GDP in 2012, mainly because of a combination of higher prices and higher imports of energy to replace the loss of nuclear power. In the New Policies Scenario, spending on fossil fuel net imports continues to rise strongly in China and India, resulting in China surpassing the European Union spending levels by 2035. The share of GDP spent on fossil fuel net imports declines progressively in all regions, mainly because of efficiency gains reducing the need for imports. The share falls most in Japan due to a gradual resumption of nuclear power generation and greater generation from renewables, coupled with a push for energy efficiency improvements.

**Figure 8.21 ▷ Fossil fuel net import bills by region in the New Policies Scenario**

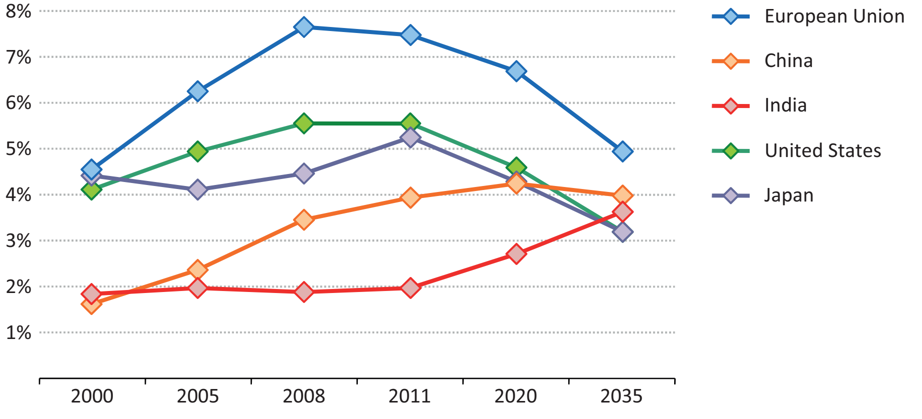



A persistent trade deficit can constitute a drag on economic growth, manufacturing activity and employment, as each dollar spent on imports that is not matched by a dollar of exports reduces overall demand within an economy. G-20 economies were particularly affected by the slowdown in international trade during the recent economic crisis (OECD/ILO/World Bank/WTO, 2010). In the longer term, deterioration in the terms of trade for energy would be expected to lead to currency depreciation, discouraging imports and encouraging exports of goods and services. This would lead towards a narrowing, if not elimination, of the overall trade deficit.

### *What is the impact of energy price disparities on household income?*

Rising energy prices in recent years, combined with the relatively low short-term price elasticity of household energy demand, have resulted in energy taking a growing share of household income in most regions (Figure 8.22). In general, the increased burden on household income is due to higher energy use and prices. The share of energy in EU household income reached a high of almost 8% in 2008, reflecting the important price increase of transport fuel and higher household prices for natural gas and electricity, partially driven by increasing taxes. The share is already slightly lower in 2011 and declines by another third to 2035, driven by significant efficiency improvements in personal transport, though it remains the highest among leading economies.

**Figure 8.22 ▷ Share of energy expenditures in household income by region in the New Policies Scenario**




Note: Excludes upfront energy investment costs (*e.g.* purchase of vehicle).

Sources: United Nations and Eurostat databases; and IEA analysis.

In the United States, the share of energy in household income is lower than in the European Union due to low taxes, lower prices for gas and electricity, and higher income levels. While residential energy expenditures (including for space heating, appliances or cooking) were higher than transport-related expenditures in 2000, rising costs for gasoline had reversed this situation by 2011. Personal transport plays an important role in US households' energy expenditures given the lower use of public transport and larger vehicles on average compared with most other OECD countries. In the New Policies Scenario, the adoption of more efficient cars in the United States leads to a significant reduction in energy expenditures relative to income by 2035, with Japan following a similar trajectory.

In non-OECD countries, including China and India, the share of energy spending is currently below the average of OECD countries as a consequence of the significantly lower level of cars per capita and lower ownership of household appliances. In China, the share of energy expenditures in household income increased rapidly over the past eleven years not only as a result of increasing fossil fuel prices but also improved living standards, accompanied by higher energy demand for electrical appliances and space cooling. The importance of energy in income of Chinese households remains roughly stable to 2035, with efficiency gains moderating the increase in energy demand. In India, the role of energy in household income increases as a consequence of the assumed subsidy phase-out for natural gas and electricity, increasing access to energy and higher use of personal transport.

## *Energy competitiveness and policy implications*

There is considerable scope for action to enhance energy competitiveness, both by minimising energy prices and by mitigating the impact of price increases. It is for businesses and households themselves to make the investments needed and to adjust their spending to respond to changes in the global energy landscape. But it is up to policymakers to create the conditions that encourage businesses and households to take the necessary action, so aiding firms to compete internationally and for households to obtain affordable energy services. For example, there has been considerable recent debate about the vulnerability of the European Union's industrial sector to relatively high energy prices (Box 8.6). The challenge for all governments is to identify win-win solutions that improve energy competitiveness (or at least mitigate part of the impact of energy price disparities), while at the same time addressing energy security and environmental concerns. Should it not be possible to find ways to compensate for the relative energy price disparities, it would be advisable for policymakers not to impede the economic restructuring that is necessary to respond to shifts in energy competitiveness. Without market distortions, it often makes economic sense for highly energy-intensive activities to migrate to countries that have low energy prices, and for relatively high energy-price countries to focus more on less energy-intensive and higher-value-added activities.

One way to cut energy prices to end-users is to lower taxes, but this is unlikely to make any difference to the overall burden of energy on the economy and would counteract efforts to curb energy imports and reduce emissions. Similarly, introducing subsidies might enhance industrial competitiveness in the near term but in the long term they create large economic, social and environmental costs. Hence other more economically and environmentally efficient ways to enhance energy competitiveness should be sought.

Improvements in energy efficiency are the most cost-effective way to deal with energy prices disparities, therefore mitigating high energy costs while addressing energy security and environmental concerns. The European Union has already demonstrated how much can be done in reducing the energy intensity of manufacturing processes: its twelve largest member countries have achieved a bigger reduction in the relative weight of energy inputs in their exports of manufactured goods than any of their external trade partners since 1995 (EC, 2012).

In the New Policies Scenario, which assumes cautious implementation of a raft of announced measures, 55% of the global economic potential for improving efficiency in industry (and two-thirds of total energy use) nonetheless remains untapped through to 2035 (see

Chapter 7). The potential for efficiency gains in industry varies across sector. The most energy-intensive industries generally already use relatively efficient technologies as they have a strong financial incentive to save energy and boost their profitability. Nonetheless, there is often still scope for significant energy savings in energy-intensive manufacturing by replacing older facilities or optimising processes and energy management practices. There is even greater potential for energy savings through the development and adoption of innovative production technologies.[15] Persistently large energy price disparities between regions can, in principle, drive more innovation (WEF, 2013b).

### Box 8.6 ▷ Energy competitiveness and the European Union

Industrial and energy competitiveness were key issues discussed by European Union leaders at their summit meeting in Brussels on 22 May 2013.[16] At this meeting the president of the European Commission acknowledged that there is no silver bullet to boost EU's competitiveness in response to changes in global energy markets, yet indicated that there are several avenues for mitigating the negative impact of persistently high energy price disparities. The president set out the European Commission's approach to a so-called "no regrets scenario", involving action in five areas:

- Completing the internal energy market.
- Investing in innovation and infrastructure.
- Promoting greater energy efficiency.
- Using renewable sources cost-effectively.
- Diversifying energy supplies.

But the remaining global economic potential for improving energy efficiency may not be fully realised without action by governments to encourage industry to make the necessary investments, even where they ultimately pay for themselves. Fiscal incentives and financing mechanisms, including tax breaks and extended payback periods, can be effective to overcome barriers to investment. Specific measures that have been shown to work well include efficiency targets and standards, benchmarking, energy audits and energy management requirements, complemented by training, capacity-building, information provision and awareness raising campaigns. Public support for research, demonstration and deployment of energy and process technologies can also deliver significant efficiency gains.

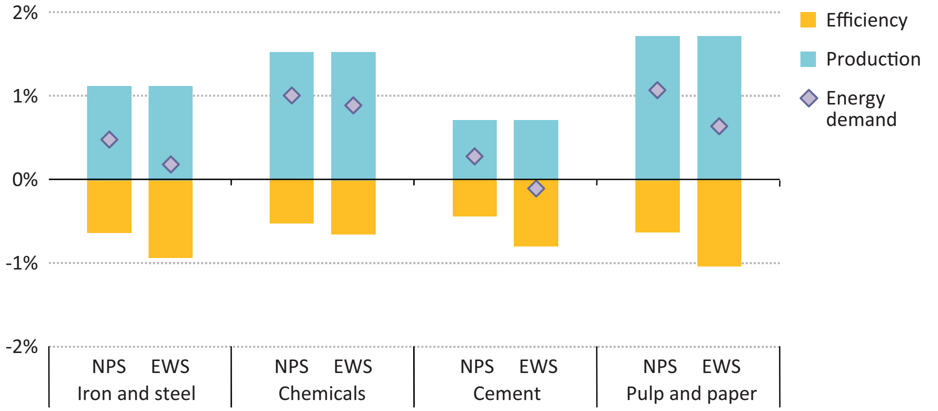
15. Recycling could also provide a means of saving energy and effectively lowering energy costs. For example, each year the European Union disposes of €5.25 billion worth of recyclable goods such as paper, glass, plastics, aluminium and steel, despite having some of the highest recycling rates in the world. In theory, if all of these goods were recycled, an estimated 148 million tonnes of $CO_2$ emissions could be avoided annually (EC, 2011).

16. The European Council discussed energy and taxation in the context of the European Union's efforts to promote growth, jobs and competitiveness.

In the World Energy Outlook 2012 Efficient World Scenario[17] (in which efficiency investments that are economically viable are adopted systematically due to stronger government measures) industrial energy demand growth falls to 0.8% per year on average in 2011-2035 compared with 1.2% in the New Policies Scenario. Despite an increase of around 115% in industrial sector activity, energy use in the Efficient World Scenario increases by only 22% over the period due to energy efficiency gains (Figure 8.23). Most of the cumulative energy savings, with respect to the New Policies Scenario, come from reduced use of electricity (37%), followed by lower use of coal (27%) and gas (18%). Emerging economies account for the majority of the cumulative energy savings (China alone for 39% and India for 13%), while only 15% of savings arise in OECD countries. The potential for further energy efficiency savings is lower in OECD countries since little new capacity is added over the projection period and their energy intensity is in general lower than in non-OECD countries. Energy use in the Efficient World Scenario in 2035 is cut by 10% in pulp and paper, 8% in cement, 7% in iron and steel, and 3% in chemicals, relative to the New Policies Scenario. Since significant efficiency improvements are already part of the New Policies Scenario, additional savings from efficiency are limited in the Efficient World Scenario, particularly in the chemical industry where no efficiency savings are possible for the part of the energy used as feedstock.

8

**Figure 8.23 ▷ Compound average annual change in industrial production, efficiency and energy demand by scenario, 2011-2035**




Notes: Negative values for efficiency represent improvements. NPS = New Policies Scenario; EWS = Efficient World Scenario. Source: IEA (2012b).

Investments toward energy efficiency in all end-use sectors in the Efficient World Scenario more than pay for themselves, boosting global GDP by an estimated 0.4% by 2035, as production and consumption of less energy-intensive goods and services free up resources

17. The additional investment in energy efficiency is in all cases economically viable. In transport, for example, the average payback period is seven years. See *WEO-2012* for further details on the methodology used to develop the Efficient World Scenario, and results by sector, region and fuel (IEA, 2012b).

to be allocated more efficiently elsewhere. But there are winners and losers: the energy-importing countries see the biggest gains, with GDP expanding by 1.1% in 2035 compared with the New Policies Scenario in OECD Europe, 1.7% in the United States, 2.1% in China and 3% in India. By contrast, GDP falls by 4.5% in Russia, as its oil and gas exports are lower.

Another avenue boosting energy competitiveness is encouraging the development of indigenous sources of energy with the potential to meet domestic demand at lower cost. In several regions (including parts of Europe, China and Latin America) there is the potential to replicate, at least in part, the US success in developing its unconventional gas and oil resources, but considerable uncertainty remains over the quality of the resources and the cost of producing them. Moreover, a number of technical and regulatory hurdles will need to be overcome for large-scale production. What can be done to achieve this, while allaying legitimate public concerns about the potential environmental impact, is encapsulated in the IEA's Golden Rules (IEA, 2012c). Additionally, in terms of natural gas, renegotiation of pricing terms in both existing and future import contracts can be another possible avenue towards improving energy competitiveness. Promoting gas production can be compatible with climate goals, insofar as gas displaces more carbon-intensive coal or oil. In the longer term, even gas use will need to fall, or it will need to be used with carbon capture and storage, in order for climate goals to be met.

Other low-carbon sources of energy, such as renewables and nuclear power, can contribute both to enhancing energy competitiveness and achieving climate change goals. However when renewables continue to receive subsidies, government support measures need to be adjusted for new capacity as technology costs and electricity prices evolve. Such efforts will ensure that associated costs are kept to a minimum, consequently reducing the impacts on electricity prices and the burden on industries, particularly for those exposed to international competition.

Regardless of the make-up of energy supply, efficient, competitive markets are crucial to minimising the cost of energy to an economy. In many countries, market reforms aimed at liberalising energy supply and increasing competition in wholesale and retail markets for gas and electricity are far from complete, and therefore result in an inefficient allocation of resources and higher prices to end-users than would otherwise be the case.

PART B
# BRAZIL ENERGY OUTLOOK

## PREFACE

Part B of this *WEO* (Chapters 9-12) continues the past practice of examining in depth the prospects of a country of special significance to the global energy outlook. The spotlight falls this time on Brazil.

Chapter 9 surveys the situation as it is today, and how historical developments have brought Brazil to this point. It also explains the analytical approach for the projections that follow.

Chapter 10 provides a detailed analysis of Brazil's future energy needs, projecting energy demand growth across all sectors and fuels, including the development of the power sector, the future role of renewables, the utilisation of domestic gas supplies and the role of oil and biofuels in transport.

Chapter 11 provides a detailed analysis of Brazil's energy resources, covering the spectrum of fossil fuels, renewables and nuclear. It assesses the scale of these resources and what will be involved in their future exploitation, including the potential challenges and risks. The scale of necessary investment is assessed.

Chapter 12 brings the analysis of the previous chapters together, examining the implications of Brazil's supply and demand trends for the country itself and for the region, but also putting Brazilian developments in a global context. It does this by considering three dimensions of Brazilian energy: its links with economic development, energy trade and security, and the environment.

# The Brazilian energy sector today

## Building on green foundations

### Highlights

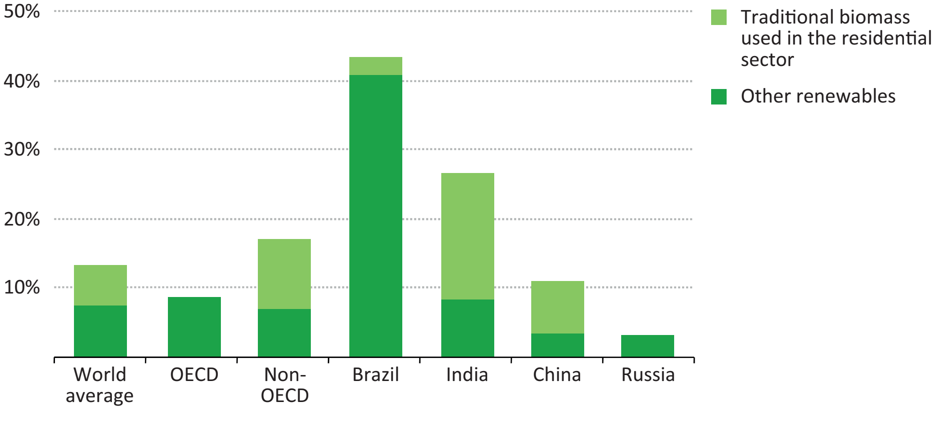
- Brazil's energy policy choices and achievements measure up well against some of the world's most urgent energy challenges. A concerted policy effort has meant that access to electricity is now almost universal across the country. Almost 45% of the country's primary energy demand is met by renewable energy, making Brazil's energy sector one of the least carbon-intensive in the world. Total primary energy demand has doubled in Brazil since 1990 on the back of strong economic growth and the emergence of a new middle class. Strong growth in electricity consumption and in demand for transport fuels has led the way.
- Large hydropower plants account for around 80% of domestic electricity generation, giving the electricity system a great deal of operational flexibility. Continued expansion of hydropower is increasingly constrained by the remoteness and environmental sensitivity of a large part of the remaining resource, although 20 GW of hydropower capacity is under construction in the Amazon region.
- Reliance on other sources for power generation is growing, notably natural gas, wind and bioenergy. A system of contract auctions provides a mechanism to bring forward investment in new generation and transmission capacity, as well as to diversify the power mix.
- Biofuels, primarily sugarcane ethanol, currently meet around 15% of demand in the transport sector, where flex-fuel technologies account for around 90% of new passenger vehicle sales. A combination of poor harvests, rising costs, under-investment and, since 2010, a weakened competitive position versus gasoline have held the ethanol sector back, although current market conditions look more promising. Biodiesel production is growing and the use of bioenergy is extensive in power generation and industry.
- Large offshore oil and gas discoveries have confirmed Brazil's status as one of the world's foremost oil and gas provinces. The "pre-salt" discoveries also prompted a change in upstream regulation, granting Petrobras – the national oil company – a strengthened role in areas deemed strategic. After a five-year hiatus, the resumption of licensing rounds in 2013 opened up new opportunities to explore Brazil's offshore and onshore potential.
- Production from the deepwater pre-salt fields in the Santos basin has started, but has not yet gained sufficient momentum to offset declining output from mature fields elsewhere. Brazil's oil output has levelled off at just above 2 mb/d since 2010, and pre-salt growth will be essential to re-attain the objective of net self-sufficiency in oil and to pave the way for Brazil to become a major oil exporter.

## Introducing Brazil's energy sector[1]

Brazil occupies, in many ways, an enviable position in the global energy system. Its endowment of energy resources is vast, varied and more than sufficient to meet the country's needs. Brazil has confronted head-on some of today's most pressing energy challenges: almost all Brazilian households now have access to electricity and the expansion of the energy system to support a rapidly-growing economy has been achieved, to an impressive degree, through renewable energy resources. These are two of the most urgent challenges facing energy policymakers, in a world in which almost 1.3 billion people lack access to electricity (see Chapter 2) and continued reliance on fossil fuels comes at an increasingly high price, which is not yet fully reflected in the price of fuel.

Brazil's early determination to press ahead with alternatives to fossil fuels was a natural choice, given the country's large hydropower potential and agricultural base, but it was also driven by concerns over energy security. Domestic discoveries of oil and gas were initially relatively modest, at least until the late 1970s, and the desire to minimise reliance on imported fuels was reinforced by the oil shocks of that decade. The result of the choices made to address those challenges is that, as of 2012, around 85% of Brazil's electricity comes from renewable sources, mainly hydropower, and in the transport sector, a stronghold of oil consumption around the world, around 15% of consumption is domestically produced biofuels. Overall, the share of modern renewable energy in total primary energy demand in Brazil is far above the global average, making Brazil's energy sector among the least carbon-intensive in the world (Figure 9.1).

**Figure 9.1 ▷ Share of renewables in total primary energy demand in selected regions, 2011**




Brazil is now emerging as a leading force in the oil sector. Over the last three decades, Petrobras – the national oil company – has made a series of large offshore discoveries, initially in the Campos basin, becoming a world leader in deepwater technology in the

1. This analysis has benefited greatly from discussions with Brazilian officials, industry representatives and experts, notably during a high-level *WEO* workshop held in Rio de Janeiro on 11 April 2013.

process (Figure 9.2). With the huge "pre-salt" finds in the Santos basin since 2006, Brazil's ambition in the oil sector has risen once again.[2] The development of these fields by Petrobras and its partners will be complex and costly, but it has the potential to turn Brazil into a major exporter of oil as well as a significant producer of natural gas.

### Figure 9.2 ▷ Energy map of Brazil


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.

2. These huge resources are called "pre-salt" because they predate the formation of a thick salt layer, which reaches up to 2 000 metres in places and overlays the hydrocarbons, trapping them in place (see Chapter 11).

Despite Brazil's pre-eminent position on issues of energy security, sustainability and near universal access to electricity, the challenges facing its policymakers remain considerable. Self-sufficiency in energy resources, although mitigating external risks, does not guarantee reliable supply at affordable cost: the energy sector has already strained, on occasion, to keep up with the demands of a rapidly expanding middle class and a burgeoning economy. Although renewable resources are plentiful, there are potential limitations – including social and environmental constraints – on whether their share of total energy supply can be maintained or increased. Efforts to conserve Brazil's biodiversity, policies on land use and water-resource management are all closely intertwined with the outlook for the energy sector. Risks to the resilience of the Brazilian power system, such as those arising from the variability of rainfall patterns and hydropower inflows, could be exacerbated by a decreasing role for large storage reservoirs or by changes to the climate. And the promise of rapid growth in Brazilian oil and gas production, if realised, will demand consideration of new trade-offs between economic, environmental, social and energy security objectives. How Brazil meets the challenges ahead will have implications not just for its own economy, but for the world at large.

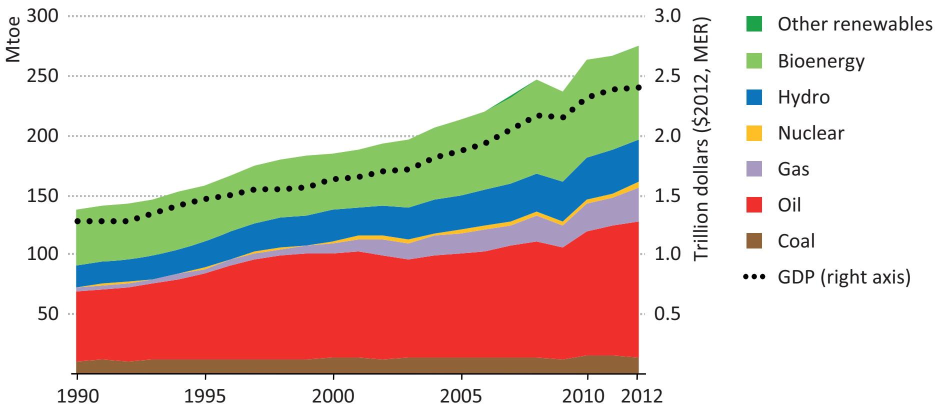
## Domestic energy trends

Energy demand in Brazil has followed closely the trajectory of gross domestic product (GDP) growth over the past two decades (Figure 9.3).[3] Since 1990, energy demand has doubled, reaching nearly 270 million tonnes of oil equivalent (Mtoe) in 2011. The pace of growth in both economic activity and energy demand has picked up noticeably since the turn of the century: from 2000-2011, average annual GDP growth was a full percentage point higher than in the previous decade (3.5% versus 2.5%). Oil and renewables (mainly bioenergy and hydropower) have remained dominant in the primary energy mix, the only significant change over the last two decades being the growth in demand for natural gas, which increased its share from 2% in 1990 to over 10% today.

The aim of successive administrations to ensure that economic development goes hand-in-hand with social inclusion has been an important determinant of energy trends. Improving access to modern energy services has been a policy priority, reflected in targeted initiatives such as the Luz Para Todos (Light for All) programme, which was launched in 2003 with the aim of achieving universal access to electricity in Brazil by 2014. By early 2013, the programme had provided access to 14.8 million people, bringing overall electrification rates to around 99%. The programme provides an electricity connection free of charge, together with three lamps and the installation of two outlets in each residence, and discounts the price for up to 220 kilowatt-hours (kWh) of consumption per month. This programme has been an important part of Brazil's campaign to reduce the numbers living in extreme poverty, which fell from 17% of the population in 1990 to 6% in 2009 (UNDP, 2013).

3. The energy statistics for Brazil used here, unless otherwise specified, come from IEA databases. They may differ slightly from national statistics due to variations in methodology. We use 2011 as the base year for projections, as this is the most recent year for which a full IEA energy balance was available at the time of writing. We have incorporated 2012 data from the Brazilian government where possible.

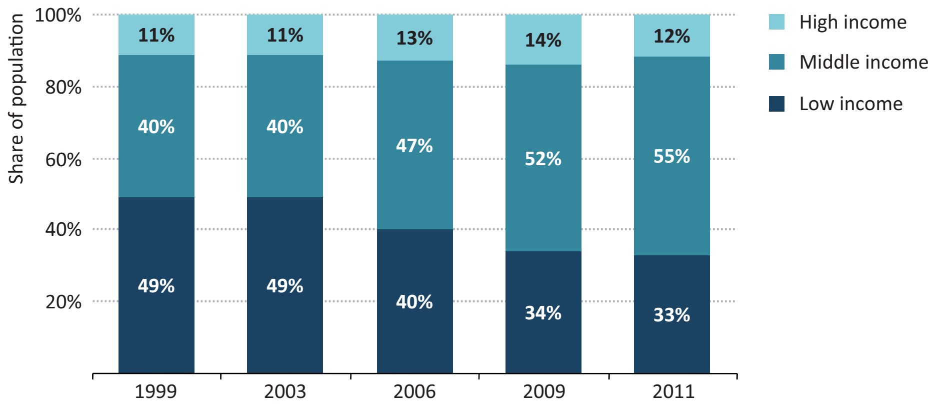
**Figure 9.3** ▷ **Brazil primary energy demand and GDP growth**




Note: MER = market exchange rate.

Broader shifts in Brazil's income distribution have been achieved through increased employment, improved education, income transfer policies (such as the Bolsa Familia [Family Allowance] programme) and growth in the minimum wage, which rose by 75% in real terms over 2003-2013 (Ministry of Finance, 2013). As a result, from 2003 to 2009 alone, around 25 million people entered the middle-income group (as defined by the government), bringing the share of this group to above 50% for the first time (Figure 9.4). The rise of a Brazilian middle class has been a key driver of growth in energy consumption. It is reflected in the rate of passenger vehicle ownership, which has tripled since 1990. Purchases of new appliances have driven up household energy consumption, with electricity use in the residential and commercial sectors increasing by more than 4% per year.

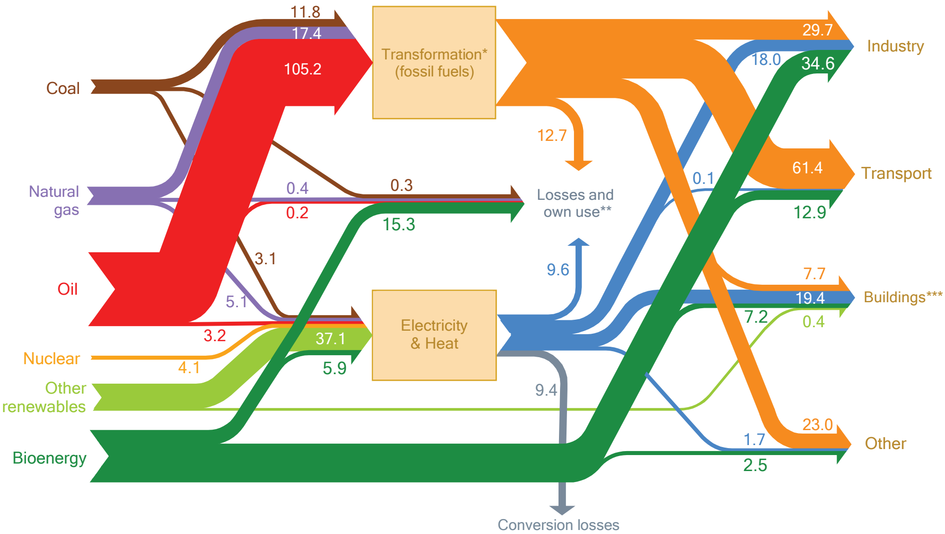
**Figure 9.4** ▷ **Changes in income distribution in Brazil**




Notes: This figure is based on the definition of middle income used by the Government of Brazil, equating to a monthly household income in 2011 of between 291 Brazilian reals (BRL) ($174) and BRL 1 019 ($608). The minimum monthly income for the middle class, as defined by the United Nations, is higher at around $300. Source: SAE (2013).

A snapshot of energy use in 2011 shows how the different fuels work their way through the Brazilian energy system (Figure 9.5). Compared with patterns of energy consumption elsewhere in the world, the dominance of renewables (mainly hydropower) in power generation stands out, as does the relatively high penetration of bioenergy in industrial energy consumption and transport. Fossil fuel demand in Brazil is heavily concentrated on oil products, most of which are consumed in the transport sector; natural gas (though growing fast) and coal play relatively minor roles.

**Figure 9.5 ▷ Brazil domestic energy balance, 2011** (Mtoe)

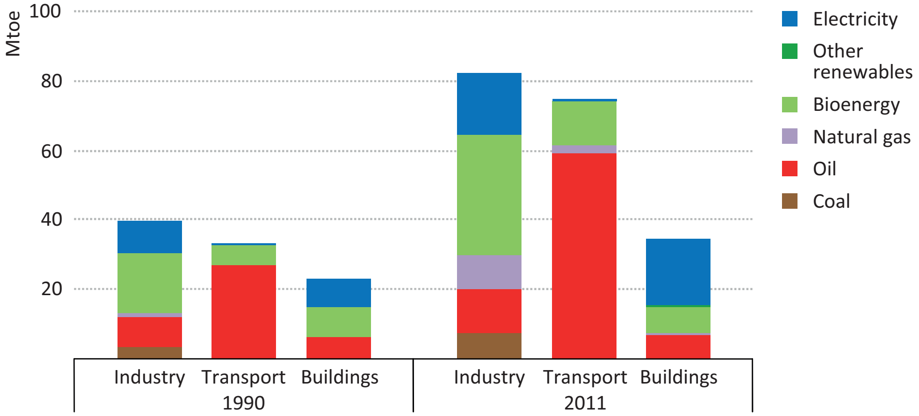



* Transformation of fossil fuels (*e.g.* oil refining) into a form that can be used in the final consuming sectors. ** Includes fuel consumed in oil and gas production, transformation losses and own use, generation lost or consumed in the process of electricity production, and transmission and distribution losses. *** Includes energy use in residential, commercial and public buildings.

Looking more closely at the evolution of demand in the end-use sectors since 1990, energy use for transport has increased most rapidly, at an average rate of almost 4% per year (Figure 9.6). The share of biofuels in transport demand has remained around 15%, with oil ceding a small part of its share to compressed natural gas, which has made inroads as a transport fuel in specific markets, such as taxi fleets in São Paulo and Rio de Janeiro. With the domestic rail network relatively under-developed, road freight has absorbed the expansion in goods traffic generated by the growing economy.

Industry is the largest of the main energy end-use sectors, its demand increasing at an average annual rate of around 3.5% from 1990 to 2011. The iron and steel industry accounts for more than one-fifth of final energy consumption in the industrial sector, using domestically produced charcoal, as well as imported coking coal. Pulp and paper processing also relies on bioenergy for a large share of its energy needs. Energy consumption in the buildings sector has grown much more slowly, at just under 2% per year, in part because of a switch away from inefficient use of traditional biomass towards electricity. Within this sector, increased consumption of electricity accounted for almost all of the growth in energy demand.

**Figure 9.6 ▷ Brazil final energy consumption by fuel in selected sectors**




## *Power sector*

Since 1990, electricity supply in Brazil has more than doubled (Figure 9.7). Hydropower remains the bedrock of the power system, accounting for over 70% of total installed generation capacity in 2011. Depending on hydrological conditions, its share of total domestic generation has typically been higher, at 80-90%. Contributions from other sources are small by comparison, but have grown quickly. Two nuclear power plants started operation in 1985 and 2000. Output from bioenergy (primarily from the combustion of bagasse, a by-product of sugarcane processing) has increased to account for 6% of electricity generation. Wind power has also been increasing its role in electricity production rapidly, albeit from a very low base. The share of generation from fossil-fuel power plants grew to just under 10% of the total in 2011, but this capacity was called upon much more frequently in 2012 because of concerns over hydro reservoir levels, pushing its share in total generation up to 13%. Electricity imports currently meet around 6% of total demand, with the largest amounts of imported electricity coming from the Paraguayan share of output from the bi-national Itaipu hydropower plant, which straddles the border between the two countries. This 14 gigawatt (GW) facility is the world's second-largest hydropower plant, generating almost 100 terawatt-hours (TWh) in 2012.

Brazil's hydropower plants are spread across various hydrological basins and their operation is co-ordinated countrywide via a large interconnected transmission network.[4] The large hydro reservoirs give the electricity system a significant degree of flexibility, as the associated plants can be called upon to respond at relatively short notice to changes in

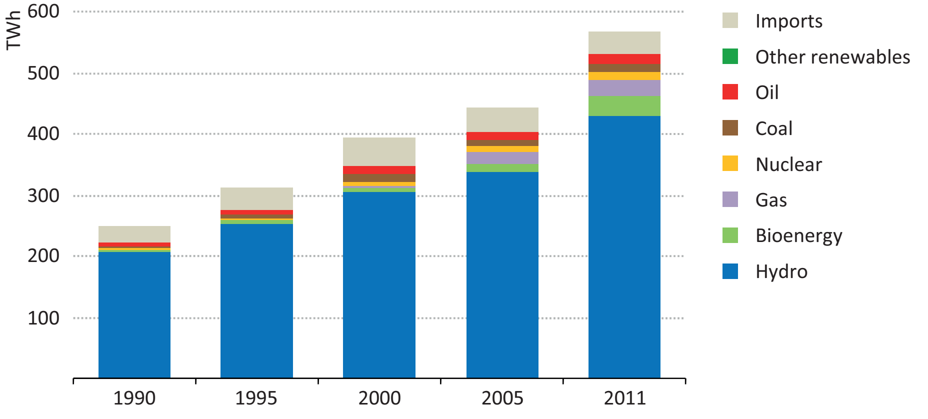
4. This co-ordination of output from the different hydrological basins with generation from other renewable and thermal sources is done using a chain of optimisation models representing the operation of the power system. These models are also used as a planning tool for capacity and network expansion (Maceira, *et al.*, 2002 and 2008).



9

power demand or in the availability of supply from other sources. This makes it relatively straight-forward to deal with the seasonal variations that are associated with bioenergy co-generation, as well as the variability of other renewable sources, such as wind. This dual role of hydropower, both as a renewable source in its own right and as an enabler of other renewables, is fundamental to the Brazilian power sector's low-carbon credentials and prospects.

**Figure 9.7 ▷ Brazil electricity supply by source**




Electricity consumption has grown at just under 4% per year since 1990 – a faster rate than that of the economy as a whole. Yet even though power consumption has more than doubled over the last two decades, electricity use per capita is still relatively low by international standards. The average Brazilian consumed around 2 300 kWh of electricity in 2011, 40% below the equivalent figure for South Africa (even though GDP per capita in the two countries is very similar) and 20% below the figure for China (despite Brazil's higher per capita income). Indicators such as these help to underpin the expectation of continued strong growth in power demand in the years to come and the importance for Brazil, as for many emerging economies, of timely and adequate investment in both new capacity and in energy efficiency. The risks of failing to invest adequately were highlighted in 2001-2002, when Brazil's tight supply and demand coincided with a prolonged period of lower-than-average rainfall and a consequent reduction in hydropower output, causing a major power crisis (Box 9.1).

The scope for new hydropower facilities is far from exhausted: Brazil has developed only one-third of its estimated 245 GW of total hydro potential. But while hydropower is set to retain its primary position in the power mix for decades to come, there are factors constraining its growth. Chief among these is the location of the remaining hydro potential, which is concentrated in the Amazon region, far from the main centres of demand.[5] Closely related issues are the environmental and social sensitivities of new projects, which find

5. Around 20 GW of hydropower capacity is under construction in the Amazon region, including the 11.2 GW Belo Monte plant and the Jirau and Santo Antônio dams on the Madeira River (for another combined 6.9 GW).

expression in difficulties and delays with environmental licensing and resolute opposition from parts of civil society. The Brazilian authorities are seeking ways to assuage public concerns and minimise social and environmental impacts, for example through the concept of "platform" hydropower development that minimises the footprint of a new project on the surrounding area (see Chapter 11, Box 11.5). The planning process for new hydropower projects is also resulting in a change in the type of projects that move forward (MME/CEPEL, 2007). Given the topography of the Amazon region, and seeking a balance between power output, environmental and social impacts, and considerations of water-resource management, most of the new hydropower plants are "run-of-river" type. These projects avoid flooding very extensive areas, but – as a result – have little or no water storage, meaning that their power output is subject to large seasonal variations.

**Box 9.1 ▷ Electricity crisis in Brazil, 2001-2002**

The roots of the 2001-2002 Brazilian power crisis can be traced to the previous decade, during which demand for electricity rose more quickly than generation capacity. A far-reaching reform process launched in the 1990s introduced many of the fundamentals of a competitive market, but regulatory uncertainty and weak incentives for distributors and large consumers to enter into long-term power supply arrangements with generators led to difficulties obtaining financing for new power plants. This meant that the power sector became progressively more vulnerable to the impact of adverse hydrological conditions. This came to a peak in the unusually dry summer of 2001: water reservoir levels in many parts of the country fell to critical levels, compromising the ability to ensure reliable power supply.

Short-term options to increase electricity generation were relatively limited and so the brunt of the crisis response fell on the demand side, where the government implemented a quota programme that imposed on all residential, industrial and commercial consumers a monthly ceiling, set at 80% of their consumption for the previous year, and penalised excess consumption. This reduced electricity use by 20%, allowing Brazil to avoid the rolling blackouts that otherwise would have ensued.

The crisis had major repercussions for the Brazilian power sector. It generated new debate about how to ensure adequate investment, leading to a revised power sector model that gave the state, within a continued commitment to market competition, a more proactive role in planning and financing new capacity. The new model obliges distributors and large consumers to cover all of their expected long-term electricity needs with long-term power purchasing agreements, providing an anchor for the system of capacity auctions (described below) and a more stable investment environment for new generation capacity. The crisis also had a prolonged impact on demand, with higher public awareness about energy use and efficiency meaning that total residential electricity demand returned to 2000 levels only in 2005.

Energy policy in Brazil since the mid-2000s has sought to foster other sources of generation. The main mechanism has been a system of contract auctions, in which total long-term demand from the various distribution companies is matched, in a bidding process, to different combinations of potential supply, with the most competitive bids then receiving long-term power supply contracts.[6] Since 2005, 24 auctions for new power generation projects have been held, organised in some cases by technology, *e.g*. renewables-only, or exclusively large hydropower (and, in some cases, only for reserve capacity). The system provides a mechanism for the authorities to exert a degree of control over the evolution of the power mix.

Contracts for more than 500 new generation projects have been concluded since 2005, promising to deliver around 65 GW of capacity from a range of sources at specified future dates (typically starting either three or five years after the date of the auction, for a period of 15 to 35 years). The auctions have contributed to a significant build-up of new thermal generation, with the main attraction of gas-fired power, in particular, being the ease with which it can be brought online to provide back-up in case of shortfalls elsewhere in the system. Auctions are also used to develop the transmission and distribution network.

A second notable outcome of the auctions has been the success of wind power projects, which have competed successfully with gas-fired power projects in some auctions on an (unsubsidised) cost basis. Early indications are that new wind projects are operating at capacity factors in excess of 50%, high levels by international standards. Nonetheless, there remain concerns that the intense competition for contracts has introduced some new elements of risk, as suppliers commit to a level of long-term performance that they may be unable, in practice, to deliver. In other cases, implementation of new power projects or transmission lines has fallen behind schedule. As examined in more detail in Chapter 10, the contract auction system has reduced, but not completely removed, uncertainty over future supply.

### Bioenergy

Brazil's use of bioenergy is distinctive, widespread and a largely successful example of government policy shaping trends in energy production and use. The initial spur was a national initiative (Pró-Álcool), borne of the first oil shock in the 1970s, that aimed to incentivise the replacement of oil as a transport fuel by ethanol produced from sugarcane. Both through the introduction of mandatory blending levels of ethanol with gasoline and through its sole use as a transport fuel, domestically produced ethanol has regularly met between 13-21% of Brazil's demand for road transport fuel since 1990. Overall, bioenergy accounts for more than one-quarter of primary energy demand (Box 9.2).

6. This system provides a contrast with the operation of power markets in many OECD countries (and the initial attempt at power sector reform in Brazil), where competition between suppliers is based on short-run marginal costs. In the Brazilian context, an emphasis on short-run marginal costs turned out to be too volatile, primarily because of the large share of hydro in the system (which is either available at very low marginal cost or, in the event of a shortfall, potentially unavailable in very large volumes), hence the preference for a system that provides more stable cash flows over time, easing project financing and investment.

### Box 9.2 ▷ Bioenergy in Brazil: more than ethanol

Ethanol consumption in the transport sector is the most widely known example of bioenergy use in Brazil, but it is by no means the only one. Brazil's climate, size and the importance of its agriculture industry mean that it is well-placed to develop bioenergy, four categories of which feature in Brazil:

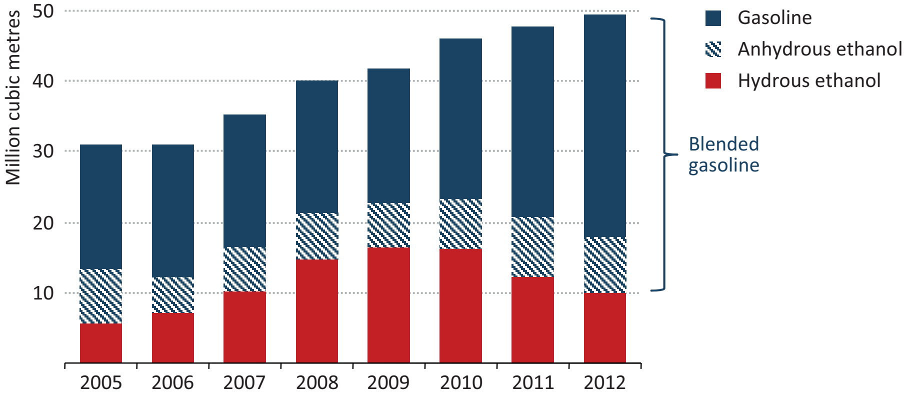
- Firewood and charcoal. The share of wood in the Brazilian energy balance has been declining, but still accounted for some 9% of primary energy demand in 2011. Brazil has a large forestry industry and around 35% of harvested wood is transformed into charcoal, mainly for use in steel mills. Almost 40% is consumed directly in a variety of industrial and agricultural processes while the remaining 25% is used in households, primarily for cooking.
- Steam turbine generation systems fired primarily by agricultural residues, such as bagasse from sugarcane processing, and also by black liquor, a by-product from the manufacture of pulp and paper. These are often co-generation systems, providing on-site heat and electricity, with surplus power being sold to the grid. In 2011, 6% of the electricity used in Brazil was produced using bioenergy, half of which was sold to the market.
- Ethanol for the transport sector, distilled from sugarcane.[7] This is blended with gasoline (at a mandated level of between 18% and 25%) or used directly in flex-fuel or ethanol-only vehicles. Ethanol production in 2012 averaged around 405 thousand barrels per day (kb/d).
- Biodiesel for transportation. Biodiesel is produced primarily from soybean oil, with smaller amounts from animal fats and other vegetable oils. It has grown rapidly since the launch of a state support programme in 2004 and the introduction of a blending mandate, which has risen to 5%. In 2012, 47 kb/d of biodiesel was produced.

The development of bioenergy at relatively low cost in Brazil has brought a range of associated economic and energy security benefits (especially where it displaces fossil fuel imports). The balance of environmental benefits is more nuanced: the $CO_2$ released with the combustion of bioenergy is equivalent to the $CO_2$ absorbed during its growth, meaning that the use of oil products during production and transport is the only source of net emissions — but there is also a vigorous debate over the broader environmental impact of bioenergy, once direct and indirect changes to land use are taken into account (see Chapter 11).

7. Around 60% of ethanol production in 2011 was hydrous ethanol; the rest was anhydrous. Hydrous (or wet) ethanol is produced by simple distillation and has a water content of between 4-7%. This is typically used directly as a transport fuel. The anhydrous ethanol that is blended with gasoline undergoes additional dehydration to reduce the water content to below 1%.

Brazil's energy system is generally well-adapted to bioenergy use, an essential component being the rapid growth over the last ten years of a "flex-fuel" vehicle fleet capable of running either on gasoline, ethanol or any mixture of the two. The popularity of a previous generation of ethanol-only vehicles plummeted in the 1990s because of shortfalls in ethanol supply and the flex-fuel option has since become dominant in new passenger vehicle sales. Even though the technology was only introduced to the market in 2003, it already accounts for around 90% of new passenger vehicle sales and over 50% of the passenger vehicle stock is now flex-fuel. As drivers are able to use both gasoline and ethanol (and in some cases, also compressed natural gas), demand for these fuels has become very sensitive to their relative prices.

**Figure 9.8 ▷ Brazil consumption of gasoline and ethanol in road transport**



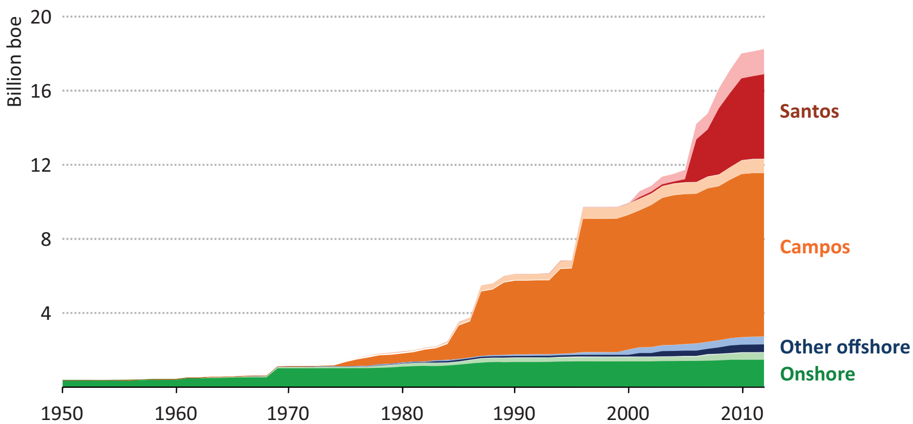

Source: UNICA (2013).

In recent years, this competition has not worked to ethanol's advantage (Figure 9.8). Domestic gasoline prices have lagged behind international prices since the end of 2010 (as part of efforts to diminish the impact of volatile international prices and to contain inflation), boosting gasoline demand. This has come at a significant cost to Petrobras, which has had to import fuel at a loss to cover the gasoline balance. But factors on the supply side have also contributed to difficult years for the ethanol industry. Many sugarcane producers have a degree of flexibility in choosing whether to produce ethanol or sugar, with the proportions varying according to market opportunities. High international sugar prices meant a preference for sugar production, which – allied to a poor sugarcane harvest in 2011 – resulted in ethanol output falling, leading the government to temporarily lower the ethanol blending mandate to 20% at the end of 2011. Market conditions currently look more promising, due to: a stronger harvest in 2013; more favourable economics for ethanol versus sugar production; a 6.6% increase in early 2013 in the ex-refinery gasoline price (narrowing the gap with international prices); a temporary reduction in the level of most federal taxes paid by ethanol mills and distributors; and, given expectations of improved supply, a decision to restore the ethanol blending mandate to 25%. But the industry also needs to tackle more deep-rooted issues if it is to expand in the future, notably the renewal rate of sugarcane, which is currently low, and rising input, labour and land costs that are deterring new investment.[8]

## *Oil and gas*

After many years in which production languished well behind domestic consumption, Brazil is now recognised as a major hydrocarbons resource-holder and producer, and has become a major destination for international upstream investment (following the end of Petrobras' monopoly in 1997). This process has taken time: Brazil had to look harder for its resources than most other oil-rich countries, as the search over the years moved to ever deeper waters offshore. But the resources are there and a series of discoveries – initially concentrated in the Campos basin but then extending into the Santos basin – have confirmed Brazil's status as one of the world's foremost oil and gas provinces.

**Figure 9.9 ▷ Evolution of Brazil's proven oil and gas reserves**



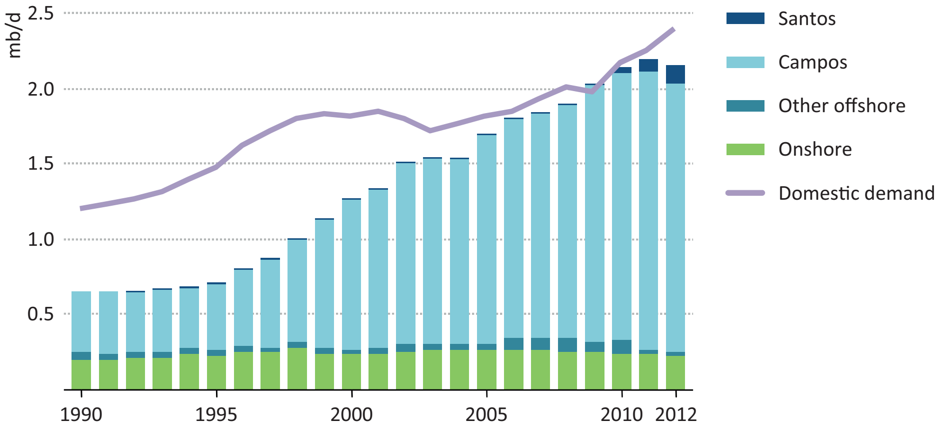

Note: The lighter-shaded areas in each category are gas reserves, in billion barrels of oil equivalent.
Sources: ANP (2012); Rystad Energy AS; IEA databases and analysis.

As of 2012, Brazil's proven oil and gas reserves amount to 18.2 billion barrels of oil equivalent (boe) (15.3 billion barrels of oil and 2.9 billion barrels of oil equivalent – or 460 billion cubic metres [bcm] of natural gas) (Figure 9.9). Over 90% of these reserves are offshore, of which the majority is categorised as deepwater. Brazil's promotion into the highest league of resource-holders started in 2006, with the discovery of what is now called the Lula field in the Santos basin. This was an eye-catching find for the global oil industry, not only because of its size – the largest discovery worldwide since Kashagan in Kazakhstan in 2000 – but because it confirmed the scale of oil-bearing formations in the deep pre-salt layers, with potential implications for discoveries elsewhere.

8. To maintain high levels of productivity, sugarcane needs to be replanted (or renewed) every five to seven years, with the land typically lying fallow for a year before re-planting.

While the new pre-salt finds concentrated in the Santos basin underlie Brazil's hopes of becoming a world-class oil producer and exporter, actual output is only just beginning.[9] In the meantime, the shallower deposits of the Campos basin in the waters off Rio de Janeiro state remain the mainstay of Brazilian production (Figure 9.10). The challenge that is felt most strongly by Petrobras, Brazil's dominant upstream player, has been that while the enormous Santos pre-salt projects are in their heaviest investment period, the Campos basin is facing its own problems, including declining production from some of the more mature fields. This explains the flattening of Brazil's production curve since 2010 and the slight fall in output in 2012. Alongside strong domestic oil demand growth, this also explains why re-gaining net self-sufficiency in oil, a goal effectively reached for five years from 2006, is now dependent on the build-up of production from the pre-salt fields.

**Figure 9.10 ▷ Brazil oil production and domestic demand**




Drilling into and producing from pre-salt reservoirs requires Petrobras and its partners to overcome several formidable technical and environmental challenges. The ocean at the location of the pre-salt fields (200-300 kilometres offshore) is often more than 2 000 metres deep (a depth often classified as ultra-deepwater) and the well needs to extend through another 5 000 metres of rock, including up to 2 000 metres of salt layers that provide a high-pressure, corrosive environment exerting considerable stress on the wellbore. Production above 300 kb/d from pre-salt fields (as of mid-2013) indicates that key technical and geological challenges are being overcome. But scaling up production remains a huge task, necessitating a step-change in investment levels over the coming years. The requirement that a large part of the construction and supplies for all the wells, facilities and infrastructure be sourced locally within Brazil is stimulating local industrial development, but adds potentially important strain to the supply chain in the coming years.

The oil in the pre-salt fields is of sweet, light quality and contains significant amounts of dissolved gas (including $CO_2$), raising expectations in some quarters that Brazil will become

9. Pre-salt fields have also been found in the Campos basin, although the accumulations are smaller than those discovered in Santos.

a major producer of natural gas. In 2012, domestic production of natural gas reached 18 bcm (net of reinjection and flaring) and the remaining share of domestic consumption was met either by pipeline imports from Bolivia, or, to a lesser extent, by imported liquefied natural gas (LNG). Future production growth could come in part from onshore, where there are signs of renewed interest in exploring and developing Brazil's gas potential, including its unconventional gas resources. But the greatest uncertainty surrounds the volumes of associated gas that may become available from the deep offshore, with a critical and as yet unknown variable being the volumes of gas that may be required for reinjection to maintain reservoir pressure (see Chapter 11).

**Box 9.3 ▷ Brazil's upstream regulatory framework**

There are now three systems governing upstream hydrocarbon activity in Brazil: the concessionary system; a special production-sharing regime for new developments in the main pre-salt area (which could be extended in the future to other areas identified as being of strategic importance); and a system which grants deposits to Petrobras under a "transfer of rights" programme from the government (also known as the Onerous Assignment Law).

- Under the existing concessionary system, any company can participate in the various licensing rounds and there is no obligatory state participation in projects (although, in practice, Petrobras has remained the dominant player, with interests in many of the most prospective areas). After payment of royalties and taxes, the oil produced belongs to the concession-holder.
- For any new blocks opened up in the designated area of pre-salt potential (see map in Chapter 11, Figure 11.7), Petrobras has to be the operator and hold a minimum 30% interest. The concession-based system is replaced by a production-sharing mechanism, with the share of profit oil[10] offered to the state the key parameter in the contract award.
- In some pre-salt areas that have not been offered for external investment, the government has capitalised Petrobras with a direct right to develop up to 5 billion barrels of reserves. The reserves involved are commonly known as "transfer of rights".

As part of a strategy to encourage development of the Brazilian oil and gas service sector, the requirement to source a certain share of goods and services from within Brazil has become increasingly important. Local content requirements have been stipulated in each licensing round and have been raised over time. Interested companies in many cases committed to a level of local content in excess of the basic requirement in order to increase their chances in the assessment of bids.

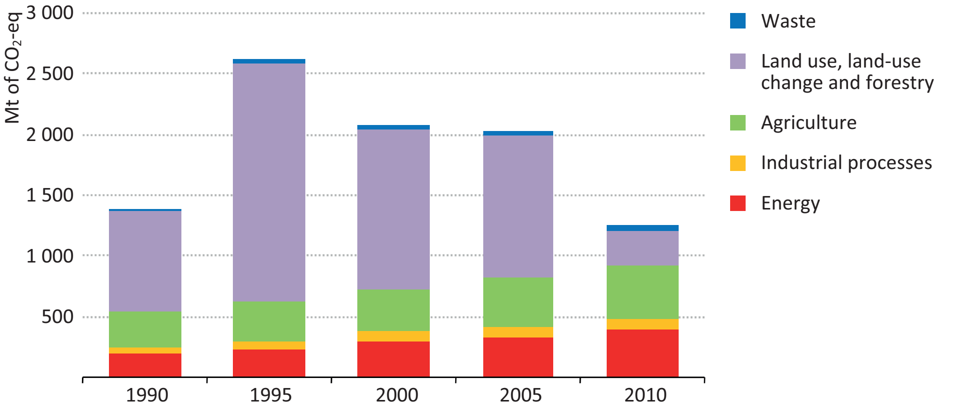
10. Profit oil is the amount of production, after deducting production allocated to costs and expenses ("cost oil"), which is divided between the parties and the host government under the production-sharing contract.

The Santos basin discoveries have not only changed the outlook for Brazilian production, but also the overall approach to the exploitation of Brazil's upstream resources. In the second-half of the 1990s, Brazil's regulatory system underwent a major overhaul, with the decision to end Petrobras' monopoly in the oil and gas sectors and to open the upstream to international investment. A series of ten licensing rounds from 1999 to 2008 saw acreage awarded to 78 companies, Brazilian and international. But the scale and success rate of pre-salt discoveries led the Brazilian authorities to conclude that, for these resources, the concession-based system had to change. As a result, in a designated geographical area that covers the parts of the Campos and Santos basins with pre-salt potential, the pendulum has swung back towards a guaranteed role for Petrobras and a different system of resource management, involving a higher government take (Box 9.3). After a five-year gap, a further concession-based licensing round — the eleventh — saw 142 blocks awarded (87 onshore, 55 offshore) in May 2013 and a twelfth round, focusing on onshore gas, is scheduled for November. A first licensing round under the production-sharing system, for the right to develop the huge Libra pre-salt prospect in the Santos basin, was held in October 2013.

## *Energy-related $CO_2$ emissions and energy efficiency*

Brazil's high share of low-carbon energy in its energy mix yields a low figure for energy-related carbon-dioxide ($CO_2$) emissions, 409 million tonnes (Mt) in 2011. This is one-quarter of the energy-related emissions in Russia, even though the Brazilian economy is one-fifth larger. Brazil is unusual in that historically its energy sector has not been the largest source of national greenhouse-gas emissions (Figure 9.11). In 2005, the energy sector was responsible for just 16% of total greenhouse-gas emissions, with the largest contribution coming from land use, land-use change and forestry (LULUCF). Since 2005, Brazil has embarked on a large-scale campaign to slow deforestation. As greenhouse-gas emissions from LULUCF have declined, the share of the energy sector in total emissions has doubled, to 32% in 2010, second only to emissions from agriculture (35%).

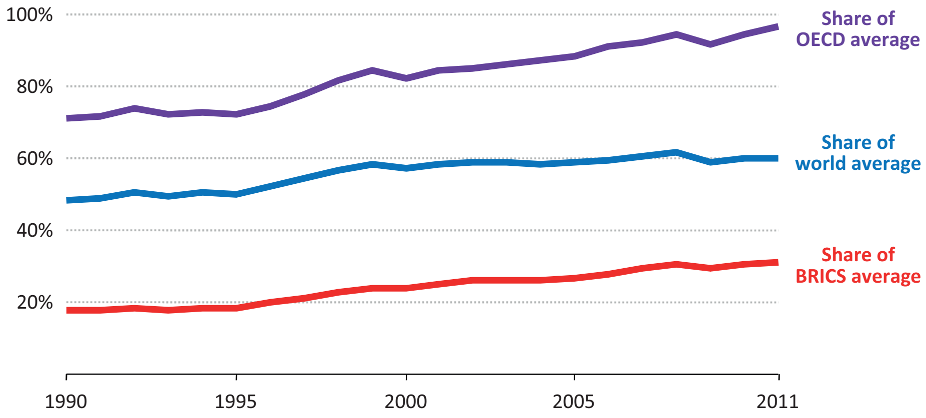
**Figure 9.11 ▻ Brazil greenhouse-gas emissions by source**




Source: Ministry of Science and Technology (2013).

Brazil's energy intensity (primary energy demand per unit of GDP), an indicator that is sometimes used as a proxy for the overall efficiency of energy use (see Chapter 7, Box 7.2), is comparable to the OECD average. Based on data for 2011, it takes 0.11 tonnes of oil equivalent (toe) on average to create $1 000 of GDP (at market exchange rates) in Brazil, compared with 0.12 toe in OECD countries. By contrast, the global average was 0.19 toe and the average for the other BRICS[11] (excluding Brazil) was 0.36 toe. Among the factors that contribute to Brazil's low energy intensity, two stand out: the relatively small amount of energy used for heating (and cooling) and the large share of hydropower in the energy system. There are no, or only very limited, conversion losses from hydropower so it is a highly efficient form of power generation compared with electricity generated from fossil fuels. While the absolute indicators for energy intensity in Brazil are impressive, the trends are less so. Brazil's energy intensity has remained at roughly the same level for the last two decades, while there has been a slow but steady improvement in many other countries and regions. As a result, Brazil is moving steadily closer to global and regional averages (Figure 9.12).

**Figure 9.12 ▷ Energy intensity of GDP in Brazil as a share of selected regional and global averages**




## *Regional and global interactions*

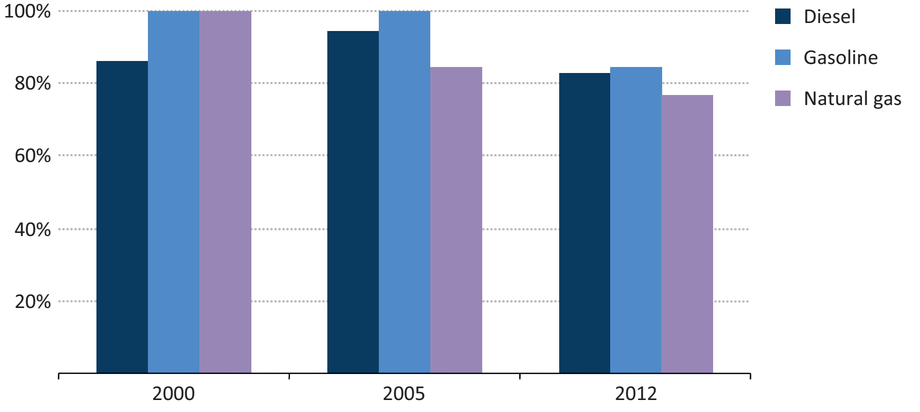
Brazil's large and growing domestic market limits to some degree its reliance on international trade and its exposure to international markets. Total trade accounts for only around one-quarter of GDP, around half the average in the other BRICS. Nonetheless, by virtue of its size and economic weight, Brazil remains crucial to the well-being of its region and to the prospects for its continued integration. The Brazilian economy is five times the size of the next largest in South America (Argentina) and is an important driver of regional trade. Around 10% of the region's exports in 2011 were destined for the

11. Brazil, Russia, India, China and South Africa.

Brazilian market. Energy plays an important role in this trade relationship, with Argentina, Uruguay, Venezuela, Colombia and Peru exporting petroleum products and coal to Brazil. Particularly important for Brazil are its agreement with Paraguay to purchase electricity from the Itaipu hydropower plant that is jointly owned by the two countries and the 1999 gas trade agreement with Bolivia that provides Brazil with some 10 bcm of natural gas per year. Highlighting Brazil's value to its neighbours, gas exports to Brazil from Bolivia were worth more than $3 billion in 2012, over 30% of total Bolivian export earnings.

The completion of the Bolivia-Brazil natural gas pipeline in 1999 helped to push more gas into the Brazilian energy mix and the share of imported gas in total demand has risen steadily since then. The Bolivia pipeline remains the main source of imports but, since 2009, these have been supplemented by LNG imported via two regasification terminals located in the northeast and southeast of Brazil. And despite the rise in Brazil's oil output over the last ten years, a shortage of refining capacity has meant a continued reliance on imported diesel, naphtha and liquefied petroleum gas (LPG) and, since 2011, a switch from net exports to net imports of gasoline (Figure 9.13).[12]

**Figure 9.13 ▷ Brazil self-sufficiency in natural gas and selected oil products**




Source: EPE (2010 and 2013a); IEA databases.

Brazil has a diverse set of international relationships that bear on the energy sector, among which the growing partnership with China stands out. Over 2000-2011, total bilateral trade between China and Brazil increased 33-fold, reaching $77 billion, making China Brazil's most important trade partner. China's demand has even shifted the overall balance of Brazil's exports away from manufactured and semi-manufactured goods towards primary commodities (the latter's share in Brazilian exports has risen to 50%), leading to concerns

12. The nameplate capacity of Brazil's refineries is around 2 mb/d, with several additional projects underway or planned. Although current oil output is close to this level, Brazil currently produces mostly heavier crudes, not all of which can be processed in the domestic refining system. Some light sweet crude from West Africa is imported to boost output of the lighter products.

about potential "de-industrialisation" and increased exposure to international commodity prices. Chinese companies have also become important investors in Brazil, both in the power sector, and in oil and gas.[13] In all, between 2005 and 2012, China invested $18.2 billion in Brazil's energy sector, accounting for 70% of total Chinese investment in the country, with deepwater expertise and technology a particular point of attraction.

A second set of important external relationships is with African countries, where Brazil has generated substantial interest as a model for sustainable growth in the developing world. Brazil has made considerable efforts to improve ties with Africa over the last decade, doubling its number of embassies across the continent. Although Brazil's trade with Africa accounted for only around 5% of Brazil's total trade in 2012, it has increased four-fold since 2002. Energy linkages, in particular, are expanding rapidly, based on a desire to emulate Brazilian successes in biofuels production, deepwater drilling and mining. Examples of recent Brazilian companies' involvement in Africa include Odebrecht's joint venture with Sonangol and Damer Industria to produce ethanol; Petrobras' deepwater activities in Angola; and Vale's recent opening of a coal mine in Mozambique.[14]

## Projecting future developments

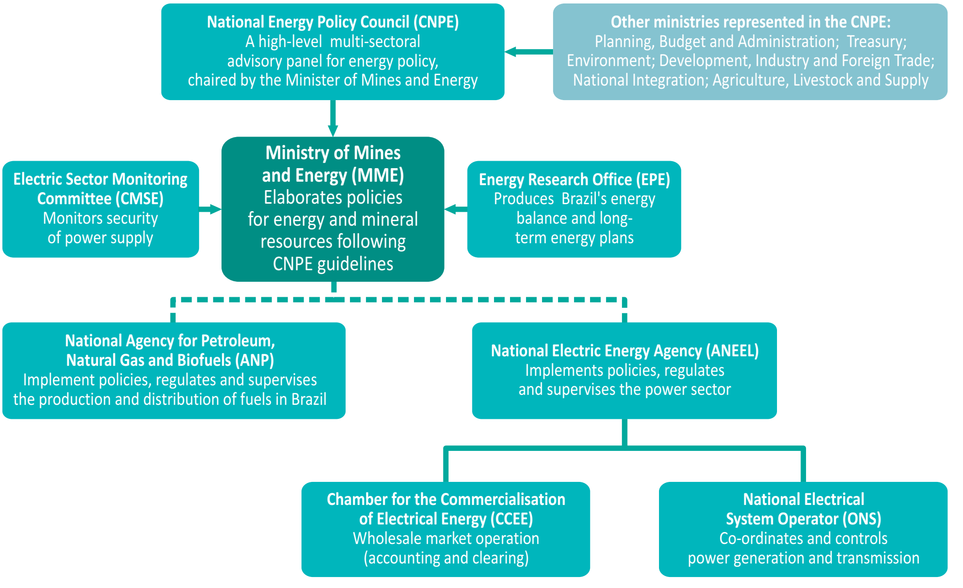
The projections for Brazil, developed in subsequent chapters, follow the overall analytical approach that is taken elsewhere in this *Outlook*. The primary focus for analysis is the New Policies Scenario, which takes into account both existing policies and modest realisation of Brazil's policy intentions. Around the projections for the New Policies Scenario, we include some case studies assessing specific variations in policy or circumstance, notably the potential impact of stronger action on energy efficiency and the possibility that the contribution from the hydropower sector might be held back by regulatory or climatic factors. In relation to oil, we consider a case in which Brazil's production increases more quickly than we project in the New Policies Scenario.

The projections for Brazil are naturally subject to a range of uncertainties relating to economic development, demographics, prices and policies. Baseline factual information for the analysis, though, is commendably clear, thanks to the availability and quality of the energy data collected by the Brazilian government, which helps to inform policymaking across a range of institutions (Figure 9.14). Differences in methodology mean that the IEA energy data for Brazil, used in this report, in some respects vary from the data published by the Brazilian authorities.

13. Investments include State Grid Corporation's acquisition of seven Brazilian power companies, Sinochem's acquisition of Statoil's stake in the Peregrino field, and Sinopec's acquisition of a 30% stake in Galp Energia's Brazilian assets and a 40% stake in Repsol YPF (the second-largest holder of exploratory rights after Petrobras in the Santos, Campos and Espirito Santo basins)

14. Portuguese-speaking parts of Africa are natural target markets for Brazilian energy and engineering companies. African members of the Community of Portuguese Language Countries (CPLP) include Angola, Mozambique, Cape Verde, Guinea-Bissau, São Tomé and Príncipe and Equatorial Guinea (associate observer).

**Figure 9.14 ▷ Brazil's energy policy and regulatory institutions**




## *The building blocks*

### *Economic and population growth*

With GDP of $2.3 trillion in 2011 (year-2012 dollars in purchasing power parity terms) Brazil's economy is among the ten largest in the world. It has grown by nearly 50% in real terms since 2000, with growth averaging 3.5% per year to 2011, and continued to perform relatively well in the period immediately following the global economic crisis. However, Brazil has not been immune to the crisis and has taken policy action in response to strong capital inflows and currency appreciation (which have since moderated), above-target inflation and weak global demand. GDP growth of 7.5% in 2010 and 2.7% in 2011 was followed by lower than expected growth of 0.9% in 2012.

Domestic demand has been central to continued economic expansion, underpinned by moderate credit expansion, job creation and income growth (Central Bank of Brazil, 2013a). The unemployment rate has generally been on a declining trend, with the national rate standing at 5.6% in July 2013 and even lower rates in some important energy producing areas, *e.g.* 4.7% in Rio de Janeiro State (Central Bank of Brazil, 2013b). The services sector has been performing strongly and now accounts for more than two-thirds of Brazil's GDP. Industry makes up 27% of the economy and Brazil's is the second-largest industrial sector in the Americas. While Brazil is a heavyweight in terms of natural resources and has one of the world's largest oil and gas companies in Petrobras, its economy is not heavily dependent on the energy sector.

Among the factors that may limit Brazil's growth prospects in the medium to long term are the state of the country's infrastructure, the availability of a sufficiently skilled workforce and the set of constraints arising from a generally complex business and regulatory environment, often known collectively as the *custo Brasil* (Brazil cost). The government is seeking to address these issues. On infrastructure, for example, the 2011-2014 Growth Acceleration Programme allocated over $57 billion to improving transport infrastructure and a further $255 billion to a wide-ranging energy plan that covers power generation and transmission, oil and gas exploration, production and research. The economic rationale for these investments is clear, but the scale and pace at which Brazil is seeking to upgrade its infrastructure carries with it the risk of delay.

In line with the assumptions used elsewhere in this *Outlook*, the medium-term GDP growth outlook for Brazil is based on the projections of the International Monetary Fund (see Chapter 1). The average growth rate for 2011-2020 is held back by the low growth recorded in 2012. However, the longer-term GDP assumptions move slightly higher than in *WEO-2012*, reflecting the view that the prospects for growth and productivity gains remain robust even if, in some sectors, these will be deferred to a later period. We assume Brazil's GDP grows by an average of 3.7% per year over the period 2011-2035, slightly higher than the global average (Table 9.1). GDP per capita increases by 3% per year on average, rising from around the world average in 2011 to 13% above it in 2035.

**Table 9.1 ▷ GDP and population indicators and assumptions**

| | GDP | | | | Population | | | |
|---|---|---|---|---|---|---|---|---|
| | 2011 ($ billion) | 2011-2020* (%) | 2021-2035* (%) | 2011-2035* (%) | 2011 (million) | 2011-2020* (%) | 2021-2035* (%) | 2011-2035* (%) |
| Brazil | 2 375 | 4.1% | 3.6% | 3.7% | 197 | 0.8% | 0.5% | 0.6% |
| World | 69 937 | 4.0% | 2.9% | 3.1% | 6 960 | 1.1% | 0.8% | 0.9% |
| BRICS** | 11 976 | 8.0% | 4.4% | 5.4% | 2 785 | 0.8% | 0.4% | 0.5% |

* Compound average annual growth rate. ** BRICS excluding Brazil. Notes: Population estimates and projections in the *WEO* are based on those of the United Nations Population Division. The latest UN estimate of Brazil's population in 2011 differs from Brazil's official data (193 million).

Brazil is the fifth-most populous country in the world, with around 195 million people in 2011. Since 2000, the population has grown by just over 1% per year on average, but the rate of increase has been slowing gradually. About 166 million Brazilians live in urban areas: this is a relatively large share for the country's stage of development, explained by historically high rates of population growth in towns and cities, rural to urban migration and the urbanisation of former rural areas. The vast size of the country results in a relatively low population density (23 people per square kilometre) but, in reality, a large share of the population is concentrated in urban areas along the coast. More than 40% of the population lives in the southeast of the country and more than one-quarter lives in the northeast (IBGE, 2011).

Population growth is an important driver of energy use, directly through its impact on the size and composition of energy demand and indirectly through its effect on economic growth and development. The population assumptions are based on the medium variant of the latest United Nations projections (see Chapter 1), which see Brazil's population growing to 226 million in 2035, increasing by 0.6% per year, on average, compared with world population growth of 0.9% per year. The rate of population growth slows over time, from around 0.8% per year, on average, before 2020 to around 0.5% per year afterwards. The urbanisation rate in Brazil continues to increase, going from 85% in 2011 to 89% by 2035 and the median age also rises from 29 years in 2010 (in line with the world average at that time) to 39 years in 2035. The proportion of the population that is of working age (15-64 years) is projected to peak near 70% around 2020-2025, but the absolute size of the working age population continues to grow until near the end of the *Outlook* period.

### *Energy prices*

Energy prices in the *World Energy Outlook* are determined as a product of the World Energy Model, rather than imposed as assumptions (see Chapter 1). But, in this analysis, particular account needs to be taken of the conditions in Brazil. As a large and rapidly growing economy, Brazil has had to balance significant growth in demand with ensuring economic conditions that bring forth the necessary increase in supply. In line with a gradual process of liberalisation that started in the 1990s, most energy prices in Brazil move either directly or indirectly in response to market signals, but there have nonetheless been regular instances of government intervention to keep prices in check, motivated by public policy objectives, such as the desire to maintain industrial competitiveness or efforts to keep inflation down. If such interventions on energy prices were to be reinforced over the longer term, there would be a material impact on the evolution of the Brazilian energy system, encouraging more rapid growth in demand while limiting the incentive to invest in supply and energy efficiency.

For oil products, the core assumption is that price movements in Brazil will be entirely aligned with international market dynamics. This implies, for example, an end to the current under-pricing of gasoline. A partial exception to this assumption is policy in relation to LPG, which is priced to encourage the use of this fuel in the residential sector. High oil product prices imply a boost to the competitive position of ethanol in the transport sector and of natural gas in the industrial, commercial and residential sectors, as long as the cost pressures on ethanol and natural gas are manageable.

Future natural gas prices in Brazil are subject to a wide range of uncertainties related to international market conditions, the evolution of the Brazilian supply and demand balance and the possible changes to the current market structure, which has Petrobras in a dominant position in all areas of the gas supply chain. As of 2012, prices on the domestic market are typically pegged at 90% of the cost of fuel oil (for the same energy content), which meant \$8-10 per million British thermal units (MBtu) in 2012.[15] These prices have risen substantially since the mid-2000s, helping Petrobras to cover the costs of new gas production and related infrastructure. Over the projection period, we assume that domestically produced gas, which becomes available in much larger quantities in the projections, will continue to be priced in a way that allows for its absorption on the domestic market, notably for power generation and industrial uses.

As for imported sources of gas, the average price of LNG imported to Brazil in 2012 was above \$12/MBtu (this has risen further in the first half of 2013), while pipeline imports from Bolivia cost around \$10-11/MBtu. In the New Policies Scenario, the natural gas import price, reflecting the average cost of gas imports, remains within the range of \$11-13/MBtu over the period to 2035 (in year-2012 dollars). As to end-user prices, these vary widely in different parts of the country, but the current average price paid by industry is around \$17/MBtu; this is above the OECD average and four times more than the price paid by industrial consumers in North America in 2012. We discuss the market and regulatory factors that could influence the evolution of domestic gas prices in subsequent chapters.

Electricity prices in Brazil have risen in recent years and, by 2012, the average price paid by industry had reached \$178 per megawatt-hour (MWh). This was at the upper range of prices paid in OECD countries and well above the level of other BRICS. The average prices paid by residential users, at around \$237/MWh, were at the middle of an OECD range, but were high by comparison with other emerging economies. Concern about the impact of these higher prices on the Brazilian economy led the government to renew around 20 large power generation concessions that were due to expire between 2015 and 2017, in exchange for reduced power costs. Together with a reduction in some taxes, this allowed for a lower power price for industry of up to 28% and 16% for households. This new (2013) price structure is taken as the baseline for the evolution of electricity prices.



### *Policies*

The breadth and quality of Brazil's endowment of energy resources have allowed policymakers to chart a distinctive path as they pursue the traditional trinity of energy policy concerns: security, affordability and sustainability. In the Brazilian case, large-scale deployment of indigenous bioenergy and hydropower has enabled the country to limit its reliance on imported fossil fuels, benefit from relatively low-cost energy (at least until quite recently), expand access to modern energy services and become a world leader in low-carbon energy development.

This virtuous circle has served Brazil well and remains at the heart of Brazilian energy policymaking; but there are signs that the traditional alignment of energy goals is shifting. The energy needs of the economy are expanding fast, bringing new sources of energy (both renewable and non-renewable) into the energy mix.  Large oil and gas discoveries mean the

15. Excluding local distribution company tariffs and taxes.

**Table 9.2 ▷ Main policy assumptions for Brazil in the New Policies Scenario**

| Cross-cutting: climate and emissions |
|---|
| ■ 36% reduction in greenhouse-gas emissions compared with business-as-usual by 2020 (the lower end of the range specified in the National Climate Change Policy). |
| ■ Emissions trading scheme for Rio de Janeiro state from 2014, incorporating major sectors for industrial emissions. |
| **Cross-cutting: energy efficiency** |
| ■ Further implementation of the measures in the National Plan for Energy Efficiency, including an extension and tightening of the Brazilian Labelling Programme (PBE), the National Programme for Energy Conservation (PROCEL), the National Programme for Rational Use of Oil Products and Natural Gas (CONPET), and an extension of the scope of efficiency standards for equipment and machinery. |
| ■ A continuation of the Energy Efficiency Programme (PEE) under which utilities must spend at least 0.5% of their operating revenues on energy efficiency. |
| **Cross-cutting: other** |
| ■ Policies for increasing natural gas supply, restricting gas flaring and expanding gas pipeline infrastructure (Ten-Year Plan for Expansion of Gas Pipelines – PEMAT). |
| **Power sector** |
| ■ Targeted auctions to maintain a strong renewables-based share in the power sector. |
| ■ Reduction of non-technical losses in the power sector. |
| ■ Special funding conditions to promote network metering; support (through the Inova Empresa programme) for smart grid technology and its deployment. |
| **Transport** |
| ■ Ethanol blending mandate at the upper limit of an 18-25% range, plus flex-fuel passenger light-duty vehicle (PLDV) fleet consuming ethanol. |
| ■ Voluntary fuel efficiency labelling for PLDVs; support (through the Inovar-Auto programme) for vehicle energy efficiency and hybrid technologies; vehicle pollution control measures through the PROCONVE programme. |
| ■ Biodiesel blending mandate of 5% (at present), with a gradual rise in the mandated share over the projection period. |
| ■ Concessions to improve port, road, rail and air infrastructure, as per the Accelerated Growth Programme 2011-2014. |
| ■ Long-term plan for freight transport (PNLT), developed by the Ministry of Transport. |
| ■ National urban mobility plan (PNMU), developed by the Ministry of Cities. |
| **Industry** |
| ■ Local content requirements in the oil, gas and power sectors. |
| ■ Enhanced efficiency measures in line with the National Energy Efficiency Plan. |
| ■ Funding from the National Climate Fund and from the Brazilian Development Bank's PROESCO programme for energy efficiency projects. |
| **Buildings** |
| ■ Enhanced efficiency measures in line with the National Energy Efficiency Plan. |
| ■ Measures to encourage the deployment of end-use solar photovoltaic applications. |
| ■ Network metering. |

concerns over import dependence are no longer as prominent as they once were: the central rationale for continued large-scale renewable deployment is, instead, to sustain an important area of national industrial expertise and to mitigate the rise in $CO_2$ emissions. The social and environmental dimensions of energy development, including water and land-use issues, are gaining in importance, particularly for projects that have direct or indirect impacts on the Amazon region. The links between energy and economic development are also being recast. Policymakers are increasingly concerned about the impact of sharply higher energy prices on the national economy. They are also keen to ensure, via local content requirements, that the investment in new energy fields, notably the pre-salt hydrocarbon resources but also non-hydro renewables, brings direct local economic benefits.

Against this increasingly complex backdrop, the policy commitments, announcements and intentions of the Brazilian authorities – and the extent to which these are implemented successfully – are of fundamental importance in shaping the outlook for the energy sector. Brazil has a well-developed institutional and policy framework for the sector (Figure 9.14), as well as a system of detailed operational planning for its expansion, based on Brazil's expected energy needs as well as consideration of social and environmental aspects. The resulting long-term and ten-year expansion plans are key points of reference for the energy policy outlook in Brazil. The long-term expansion plan, often referred to as PNE-2030 (EPE, 2007) is in the process of being updated (and its horizon extended from 2030 to 2050) but, even in its present form, provides some important guidance on long-term policy objectives. The ten-year expansion plan, which is updated every year and currently looks out to 2021 (EPE, 2013b) provides a detailed sector-by-sector analysis of the anticipated development of the energy system and builds on engineering and environmental studies of specific projects scheduled for implementation (for example, via the system of auctions for new generation and transmission capacity).

The National Policy on Climate Change (Interministerial Committee on Climate Change, 2008), adopted in 2009, identifies specific actions and measures that can mitigate greenhouse-gas emissions, including a specific target for emissions to 2020. In addition, there are documents dealing with specific policy areas, notably the National Action Plan for Energy Efficiency (PNEF) (MME, 2010), and policy documents related to other issues – water, biodiversity, land use, deforestation, conservation units, societal consent, etc. – that require integration into coherent energy policymaking. Some key measures from these and other policy documents that are considered in the New Policies Scenario are listed in Table 9.2.

# Prospects for Brazil's domestic energy consumption

## Going with the flow

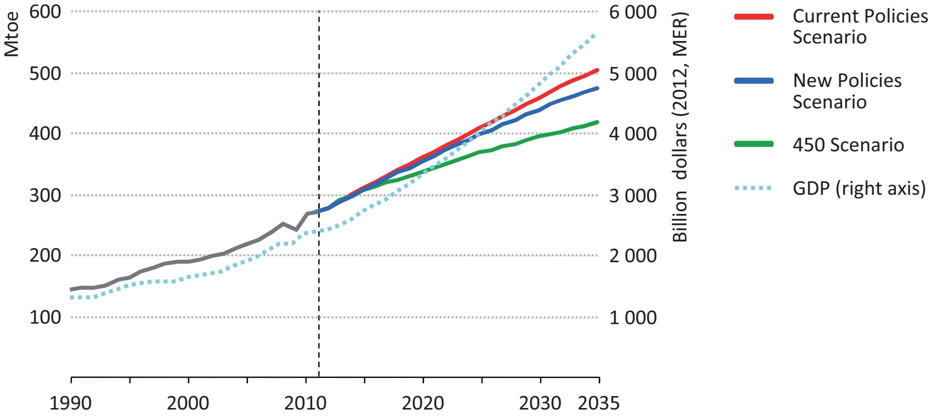
### Highlights

- Brazil's primary energy demand rises by 80% in the New Policies Scenario to reach 480 Mtoe in 2035, spurring and accompanying steady growth in economic output. Growth in electricity demand is particularly strong, doubling to reach 940 TWh. Brazil achieves its goal of providing universal energy access early in the projection period.
- Despite increasing availability of domestic oil and gas, renewable sources of energy retain their distinctive position in Brazil's primary energy mix, their share remaining firm at 43% in 2035. Among the other fuels, the share of oil in energy demand declines from 41% to 34%, while the share of natural gas increases from 9% to 16%. The rise in gas use hinges critically on the establishment of a long-term framework for the sector that is attractive to new suppliers and consumers.
- Hydropower capacity increases by almost 70 GW in the New Policies Scenario, but this expansion depends on sufficient social consent for the licensing and implementation of new projects. If hydropower expands more slowly, then it is likely that all other technologies would be called upon to fill the gap, meaning accelerated growth for other renewables but also the likelihood of additional nuclear and fossil-fuel capacity, the latter pushing up $CO_2$ emissions.
- Most of the anticipated growth in hydropower capacity is expected to come from run-of-river projects, which increases the contingency of power output on natural and seasonal variations. The flexibility afforded by existing reservoirs and the seasonal supply patterns of wind and bioenergy help to balance this, but gas-fired capacity remains prized as a reliable complementary source of power. Overall, the power sector needs more than $555 billion in investment through to 2035 ($24 billion per year on average), of which 45% is on transmission and distribution.
- Electricity demand growth is strongest in residential and commercial buildings through to 2035, highlighting the role of appliance standards and other efficiency policies in relieving potential stress on the power sector. Industrial energy use rises by 2.5% per year, but the relatively high cost of electricity and natural gas in Brazil is a factor holding back the growth of energy-intensive industry in our projections.
- Biofuels account for nearly one-third of the energy used in road transport by 2035. The energy performance of the transport sector is enhanced by new fuel efficiency policies for passenger vehicles and a shift away from today's heavy reliance on road transport for freight. With these factors combining to slow the growth in demand for oil products, particularly for gasoline, new refinery construction allows Brazil to meet all of its domestic oil product needs by around 2020.

## Domestic energy consumption trends

Rising energy consumption in Brazil is set to accompany and spur growth in national income over the *Outlook* period. In our projections, primary energy use increases to 2035 by between 56% and 88%, depending on the scenario (Figure 10.1). In all of our scenarios, the percentage increase in energy demand is bigger than the equivalent projection for China and second only to that for India among the BRICS (Brazil, Russia, India, China and South Africa). The eventual trajectory will depend on a range of factors, particularly the rate of gross domestic product (GDP) growth and the policy choices that Brazil makes over the coming decades (see Chapter 9). The gradual weakening of the correlation between rates of GDP growth and energy demand growth is a phenomenon that has been observed in many countries and regions; the extent to which it occurs in Brazil will be conditioned by the way that economic activity changes over time, with shifts in productivity and in the composition of GDP, and by the way that energy is used to fuel economic activity, as more efficient technologies are adopted.[1]

**Figure 10.1 ▷ Brazil GDP and primary energy demand by scenario**




Note: GDP is expressed in year-2012 dollars in market exchange rate (MER) terms. Mtoe = million tonnes of oil equivalent.

The implication of these projections is that Brazil's energy consumption per capita, which is currently around three-quarters of the global average, rises above world average levels in 2035 in each of the three scenarios. Where these scenarios differ, though, is in the way that government policies affect the trajectory of energy demand growth. The fairly limited variation between the Current Policies and New Policies scenarios reflects the strong dynamics underpinning the rise in energy demand in Brazil and our guarded assessment of

1. The weakening relationship between GDP growth and energy demand growth projected in our scenarios is a point of divergence with Brazilian energy planning scenarios, where long-term growth rates for the economy and the energy sector are more closely correlated. This is less visible over the Brazilian ten-year planning horizon, but is one factor (alongside different GDP assumptions and other parameters) that leads to divergent projections in the longer term.

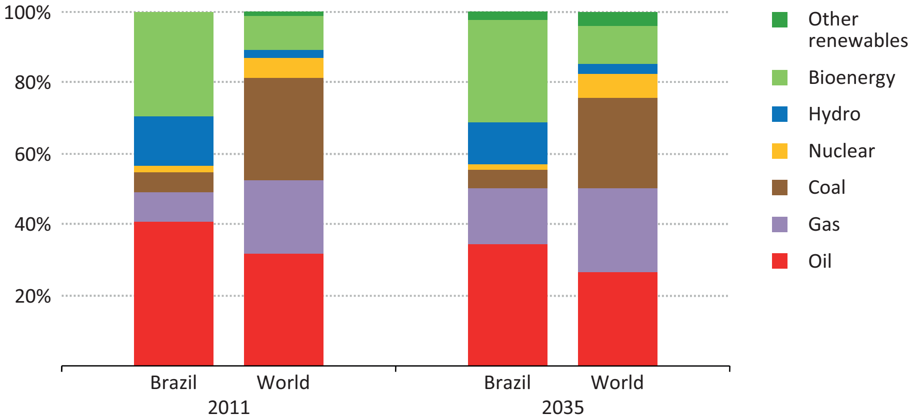
the likely impact of the policies so far announced to curb this growth. There remains scope for stronger policy action in some important areas, notably energy efficiency, which could result in energy demand growing more slowly than in the New Policies Scenario. This is reflected in an Efficient Brazil Case (see Chapter 12) and also in the 450 Scenario, in which consumption increases by less than 2% per year on average, 0.6 percentage points lower than the rate seen in the New Policies Scenario (Table 10.1).

**Table 10.1 ▷ Brazil total primary energy demand by fuel and scenario** (Mtoe)

| | | | New Policies Scenario | | Current Policies Scenario | | 450 Scenario | |
|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2035 | 2020 | 2035 | 2020 | 2035 |
| Oil | 59 | 109 | 141 | 165 | 143 | 174 | 129 | 112 |
| Natural gas | 3 | 23 | 38 | 77 | 42 | 88 | 32 | 51 |
| Coal | 10 | 15 | 19 | 24 | 19 | 28 | 17 | 17 |
| Nuclear | 1 | 4 | 6 | 8 | 6 | 8 | 6 | 11 |
| Renewables | 66 | 116 | 148 | 207 | 146 | 204 | 150 | 225 |
| Hydropower | 18 | 37 | 44 | 58 | 44 | 60 | 44 | 58 |
| Bioenergy* | 48 | 78 | 99 | 138 | 97 | 134 | 102 | 156 |
| Other renewables | 0 | 1 | 5 | 11 | 5 | 10 | 5 | 11 |
| **Total** | **138** | **267** | **352** | **480** | **356** | **502** | **334** | **416** |
| *Fossil fuel share* | *52%* | *55%* | *56%* | *55%* | *57%* | *58%* | *53%* | *43%* |

* Includes traditional and modern biomass uses.

**Figure 10.2 ▷ Primary energy mix in Brazil and the world in the New Policies Scenario**




The Brazilian energy mix retains its distinctive character in the New Policies Scenario, with the overall shares of fossil fuels and of renewable sources of energy remaining largely unchanged in 2035, compared with 2011 (Figure 10.2).[2] Among the fossil fuels, the share

2. The remainder of this chapter focuses on the projections for the New Policies Scenario.

of oil in Brazil's primary demand declines (from 41% to 34%), while that of natural gas increases (from 9% to 16%). Coal continues to play only a very small role in Brazil's energy sector, the share of around 5% being a fraction of the global average. Among the renewable sources of energy, the share of bioenergy remains at just under 30% and hydropower falls slightly (from 14% to 12%) while the share of wind and solar, taken together, increases from a very low base to reach 2%. The 43% share in primary energy demand held by renewables in 2035 means that Brazil remains a global leader in low-carbon energy development, well ahead of the world average.

## Outlook for the power sector

### *Electricity demand*

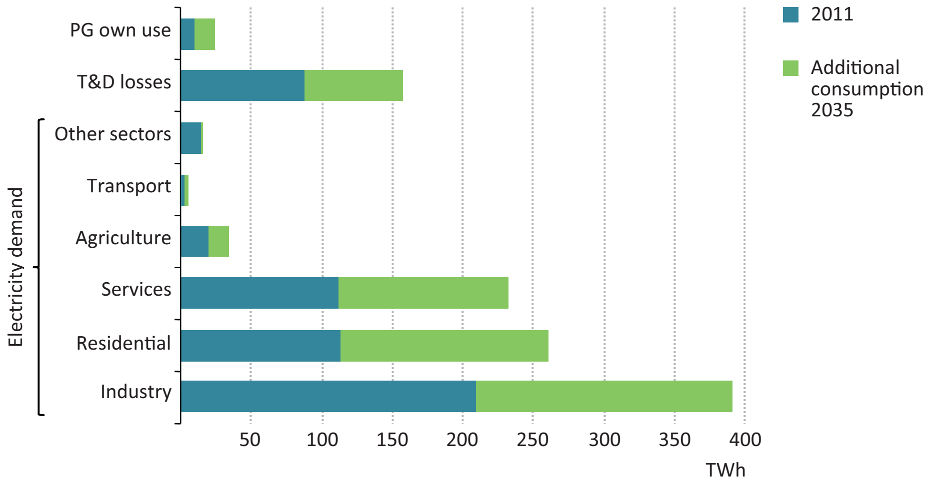
In the New Policies Scenario, electricity demand continues the steep upward trajectory seen in recent years, rising by nearly 3% per year on average over the period from 2011 to 2035, doubling from 471 terawatt-hours (TWh) to 940 TWh.[3] This strong increase in demand flows from the growth of Brazil's economy and the rise in average income levels, driving up electricity consumption in appliances and for cooling. By sector, the largest increase in demand in absolute terms comes from buildings, where residential and services consumption both more than double (Figure 10.3); buildings represent more than half of electricity consumption by 2035. Electricity use also grows strongly in industry, by 180 TWh (see the sector-by-sector discussion for more details).

Transmission and distribution (T&D) losses are relatively high in Brazil, including not only the electricity that is dissipated during transmission and distribution (technical losses) but also a share of losses attributable to non-technical factors, including energy theft and measurement errors. The latter has been on the rise in parts of Brazil in recent years, particularly in densely populated urban areas, prompting the regulatory agency, ANEEL, to target the reduction of these losses in annual tariff reviews. Through these efforts, broader adoption of smart meters and other T&D grid upgrades, the share of both non-technical and technical T&D losses falls over time in the New Policies Scenario.

Geographically, electricity demand remains concentrated in the southeast region of Brazil (including Rio de Janeiro and São Paulo). As of 2012, this region has the highest population and highest income per capita and accounts for over 60% of total electricity demand (EPE, 2013). Over the period to 2021, EPE estimates that electricity demand in the southeast region will grow more than in the rest of Brazil combined. But demand growth elsewhere is also expected to be buoyant; the northeast, north and centre-west regions will also experience strong growth (as they have in recent years), but starting from a much lower base. For the country as a whole, electricity demand per capita increases by nearly three-quarters over the *Outlook* period, reaching 4 150 kilowatt-hours (kWh), and moves from being significantly below the world average level in 2011 to 12% above it in 2035.

3. In the Current Policies Scenario, demand growth is 60 TWh higher in 2035, reaching 1 000 TWh.

**Figure 10.3 ▷ Brazil electricity supply* and demand by sector in the New Policies Scenario**




* Electricity supply refers to imported electricity and gross domestic generation including own use by power generators (PG). This then covers demand in final uses (industry, residential, services, agriculture, transport and other) and losses through T&D grids.

Brazil is set to accomplish, in the next few years, the objective of providing electricity to all its citizens. More than 99% of Brazilians already have access to electricity, one of the highest electrification rates among developing countries, and we expect Brazil to attain its stated goal of universal access early in the *Outlook* period. The last stage in this process is, though, potentially the most difficult, as the remaining population without access is hardest to reach, in many cases being located in remote communities (such as in the Amazon) or comprising the poorest households, making the issue of affordability particularly acute.[4] Overcoming this final challenge is likely to require greater focus on decentralised solutions, such as small-hydro and solar, potentially supported by some form of back-up generation. The shift towards decentralised, renewables-based solutions raises unresolved questions about the most appropriate business model to fund and recoup the investment needed to provide access and to fund ongoing maintenance. The impact on overall consumption of providing electricity to the remaining households is initially very small, but there is also evidence that, once electricity is available, low initial levels of consumption give way to higher levels after only a few years, even in relatively poor parts of Brazil (Obermaier, *et al.,* 2012). This is a positive signal of the role that electricity plays in social welfare, although electricity can be only one part of broader development strategies for the poorest parts of the country.

4. The tariff structure provides a 65% discount for monthly consumption below 30 kWh, a 40% discount from 31-100 kWh, 10% discount from 101-220 kWh and no discount above this level. Indigenous populations earning less than half the minimum wage are provided with free electricity up to 50 kWh.

**Box 10.1 ▹ End-user energy efficiency policies in Brazil**

Brazil's efforts to increase end-user energy efficiency date back to the 1980s, having initially been part of policy action to rein in energy demand and limit, where possible, dependence on imported fuels. Over time, Brazil has accumulated an array of energy efficiency initiatives and programmes, many of which are focused on the power sector. The priority given to this sector reflects recurrent concerns about the possibility of power shortages, driven either by shortfalls in investment or hydrological variations (Box 10.2). The main initiatives are:

- The Brazil Labelling Programme (PBE) which informs energy consumers about the energy efficiency performance of many different types of equipment (mostly residential energy appliances).
- The National Programme of Electrical Energy Conservation (PROCEL), which involves a range of campaigns and studies promoting efficiency. It is also a major funding source for efficiency research and development. PROCEL also has a labelling component, an endorsement label for the most efficient products.
- Since 2000, all electricity distribution companies are obliged to spend at least 0.5% of their net operating revenue on energy efficiency actions (a commitment monitored by the regulator). Typical activities might be installing more efficient public lighting or providing energy audits for large consumers. Since 2005, half of the spending is mandated to promote efficient energy use among low-income residential consumers.
- Since 2001, minimum energy performance standards have been introduced for various appliances and equipment, including electric motors, refrigerators, air conditioners and ovens. Unlike the labelling schemes, these minimum standards are compulsory and must be met by all manufacturers and importers, although there has been criticism that, in some cases, the standards are too low to have a big impact (Box 10.5).

On occasion, Brazil's ambitions in end-user energy efficiency have proven difficult to realise, with implementation falling short of expectations. For instance, a plan to install smart meters for all consumers was scaled back in 2012 on grounds of cost, and instead new basic meters allowing consumers to tailor their consumption to off-peak hours will be installed on request. In 2009, Brazil produced an inventory of all current initiatives as part of a National Energy Efficiency Plan, which includes the objective to reduce electricity consumption by 10% in 2030 compared with a business-as-usual case, an estimated saving of 106 TWh. In our projections, the gains in the New Policies Scenario are smaller in 2030, at around 40 TWh, compared with our Current Policies Scenario (close to a business-as-usual case, but incorporating some gains from energy efficiency policies that are already in place). As examined in Chapter 12, there remain powerful social, environmental, economic and energy security reasons for Brazil to boost, and then maintain, its efforts on energy efficiency.

For the country as a whole, the rate of electricity demand growth is projected to slow somewhat over the projection period. Over the years to 2020, it is closer to the assumed rate of growth in GDP (3.4% per year on average, versus 3.6% for the economy as a whole). After 2020, the divergence becomes more pronounced as economic growth continues at a similar pace, while power demand grows by an average of 2.6% per year. One reason for this divergence is the gradual progress we assume in implementing some of Brazil's energy efficiency initiatives and programmes (Box 10.1), though its potential for efficiency gains is far from exhausted in the New Policies Scenario (see Chapter 12).

## *Electricity generation*

### *Generation capacity*

Keeping up with the growth in electricity demand will be a constant challenge for the Brazilian power sector. The implication of our demand projections is that the country has to increase installed generation capacity by, on average, around 6 000 megawatts (MW) every year until 2035, more than doubling the size of its power system in just over two decades. There is no shortage of competitive generation options for Brazil to provide for such an increase in electricity production, including hydropower, wind power, bioenergy, plus nuclear and fossil fuel-fired power plants (see Chapter 11). The uncertainty lies in how rapidly these can be mobilised, both in terms of the necessary investment and also in addressing the related social and environmental issues. A further question, given the geographical distribution of the hydropower and other renewable resources across a vast country, is whether the power mix and the transmission system can evolve so as to allow Brazil to take optimal advantage of the potential complementarities between the various resources at its disposal.



In the New Policies Scenario, total generating capacity increases from 118 gigawatts (GW) in 2012 to 260 GW in 2035 (Figure 10.4). Hydropower, the traditional mainstay of the Brazilian power system, provides by far the largest source of additional capacity: almost 70 GW out of the total increase of 142 GW (this is about 10% of the worldwide hydropower capacity additions projected in the New Policies Scenario). An expansion at this rate cannot, though, be taken for granted. Large hydropower projects have become increasingly controversial in Brazil, as elsewhere, and, where projects go ahead, they are often subject to delays and cost overruns. The nature and location of Brazil's remaining hydropower resources — heavily concentrated in the Amazon region — is such that the environmental and social sensitivities are expected to increase over time. One response being considered by the Brazilian authorities to assuage these concerns is the platform hydropower concept (described in Chapter 11, Box 11.5). Our projection for hydropower in the New Policies Scenario rests on the assumption that sufficient social consent will be obtained to allow the various projects to proceed. An alternative case, examined in Box 10.2, considers the situation should the growth in hydropower fall short of the levels anticipated in the New Policies Scenario.

### Box 10.2 ▹ What if hydropower falls short?

The development of any large hydropower project in Brazil is necessarily preceded by a lengthy period of planning, evaluation and consultation, with the potential impact on the environment and on local communities being important aspects of this process. But, if and when projects are authorised, they typically remain contentious, with their planning and construction subject to legal challenges and obstruction. In the New Policies Scenario, we are projecting an increase of almost 70 GW in hydropower capacity over the decades to 2035, on the assumption that a way is found for these projects to gain the necessary degree of social and environmental acceptability.

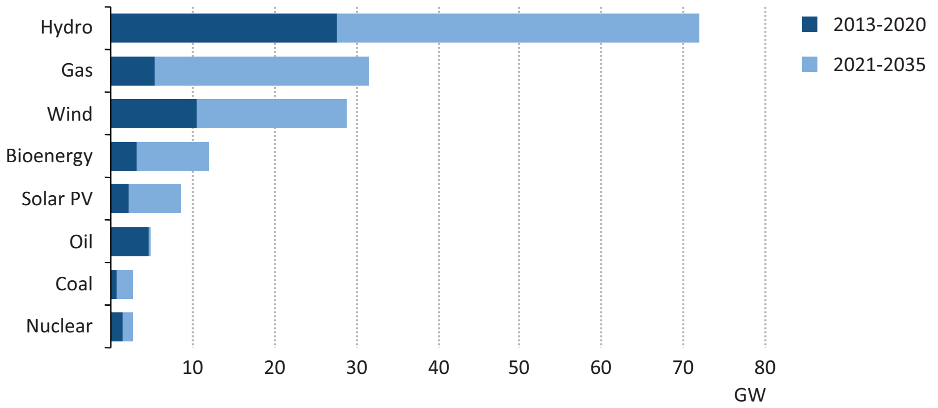
But if this assumption is mistaken, then a combination of persistent opposition, delays and higher project costs could result in a significantly slower pace of hydropower expansion. To examine this alternative, we have examined a Low-Hydro Case for Brazil, in which the growth of hydropower capacity is limited to 50 GW. The loss of generation compared with the New Policies Scenario reaches 72 TWh by 2035 and other technologies have to compensate for this shortfall.[5] We assume that the Brazilian authorities would then need to take action to allow all the available alternatives to grow more quickly. So, in the Low-Hydro Case, wind power capacity expands almost 40% more than in the New Policies Scenario (where it already grows rapidly), generating an additional 26 TWh. Bioenergy and solar PV also fill part of the gap; by 2035, an additional 4 GW of capacity from these sources contributes an extra 13 TWh.

Given the ready availability of domestic resources, contributions from fossil fuels and nuclear also step up. New coal-fired capacity and an additional nuclear plant are added, pushing the combined capacity of nuclear and coal generation to above 11 GW by 2035 (compared with 9 GW in the New Policies Scenario). To make up the remaining difference, gas-fired generation is 12 TWh higher, consuming an extra 2 billion cubic metres (bcm) of gas by 2035.

The net result by 2035 is that the share of renewables in Brazil's power mix is 77% in the Low-Hydro Case, down from 79% in the New Policies Scenario. Investment costs are lower (hydropower is very capital-intensive, compared with most of the alternatives, though it has a longer operating life), but the increase in fossil fuel generation means that fuel costs for the sector would be higher by a cumulative $27 billion. There is also an additional increase in carbon-dioxide ($CO_2$) emissions by over 170 million tonnes (Mt) over the projection period, with the average emissions per unit of electricity produced rising above 100 grams of $CO_2$ per kWh (g $CO_2$/kWh), compared with less than 90 g $CO_2$/kWh in the New Policies Scenario.

5. We kept all other assumptions constant from the New Policies Scenario so electricity demand grows at the same rate.

**Figure 10.4 ▷ Brazil power generation capacity additions in the New Policies Scenario**

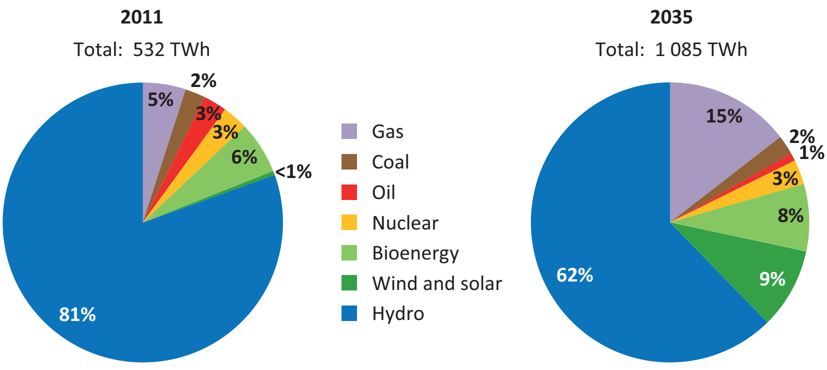



Beyond hydropower, natural gas-fired power plants add the largest amount of generation capacity to 2035 in the New Policies Scenario (more than 30 GW). As electricity supply grows, so gas is increasingly called upon to ensure continuity of supply. Most gas-fired power plants are located along the coastal areas, where they have easier access to gas delivered from the offshore (or as liquefied natural gas [LNG]), although, increasingly, gas-fired power also provides a way to monetise onshore gas discoveries that may be isolated from the existing gas network. Additions of wind power are similar in scale to those of gas, harnessing the high-quality wind resources found in the northeast and south of the country. Installed capacity for generating electricity from bioenergy nearly doubles over the projection period, consuming a part of the increasing amounts of bagasse made available as a by-product of sugarcane processing. In addition, biomass co-firing with coal increases over the *Outlook* period. Deployment of solar photovoltaics (PV) picks up momentum over the projection period as technology costs continue to fall and advantage is taken of the relatively high rates of insolation throughout the country (see Chapter 11). Coal, oil and nuclear power continue to play smaller roles in Brazil, with capacity additions for each totalling less than 5 GW to 2035.

### *Generation by fuel*

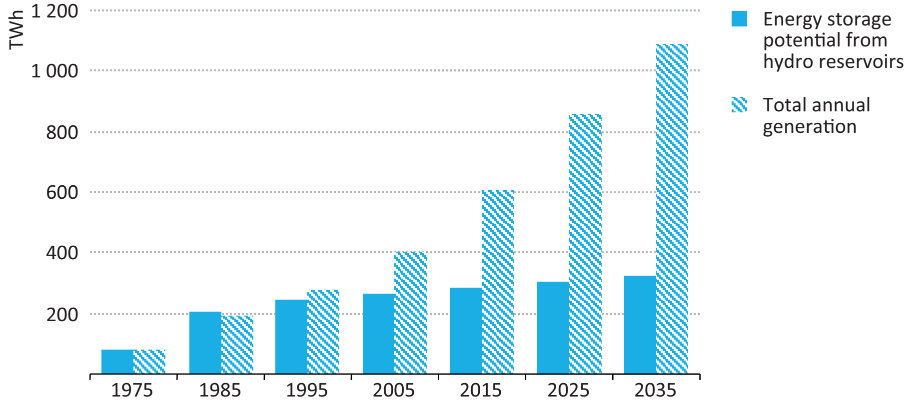
In the New Policies Scenario, renewables account for 80% of power generation in Brazil throughout the *Outlook,* maintaining one of the highest shares in the world. Hydropower remains the predominant source of power, but its share in total generation nonetheless falls from 81% in 2011 to 62% in 2035 (Figure 10.5). Among the other renewable resources, wind power and, later in the projection period, solar PV generation increase at the fastest rates, gaining a significant foothold in the market. The electricity generated from bioenergy more than doubles over the projection period but, despite the continued expansion of hydropower and other renewables, the difference between renewables-based generation and demand continues to widen, and thermal generation – primarily fuelled by natural gas – steps in to fill this gap.

**Figure 10.5** ▷ **Brazil power generation by source in the New Policies Scenario**



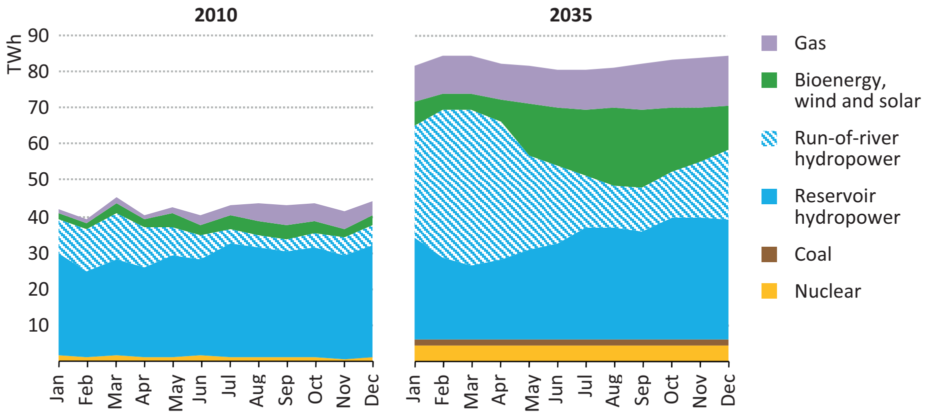

Hydropower continues to be central to the operation of Brazil's power system, but an important variable in our projections is not only the volume of hydropower capacity added, but also the type of capacity. Most of the additions over the period to 2035 are run-of-river hydropower, not involving the expansive reservoirs of many existing hydropower projects in Brazil. The volume of water stored in hydropower reservoirs is at present a key (and closely watched) indicator for the Brazilian power sector, as it represents a massive amount of stored energy, to be used as needed by the system. When reservoir levels start to fall below the seasonal norms, typically because of unusually low rainfall, this is a signal to reduce output from the hydropower system and increase the volumes demanded from other sources. The volume of stored water/energy has been declining in relation to the overall size of the Brazilian power sector since the mid-1980s and the addition of run-of-river hydropower would continue this trend. The relative storage capacity of Brazil's hydropower system is expected to continue to decline from about half of total generation in 2011 to less than one-third of total generation in 2035, as domestic demand increases but hydro storage does not expand to match it (Figure 10.6).

**Figure 10.6** ▷ **Brazil energy storage potential from hydropower reservoirs in compared with total generation in the New Policies Scenario**



The addition of mainly run-of-river hydropower has significant impacts on the evolution of the power system in Brazil by making the system more subject to variations in rainfall and river flows over the course of the year (Figure 10.7). The massive run-of-river Belo Monte plant, currently under construction, is a good example: the natural water inflow to the plant (as opposed to the regulated inflow which would be possible with a reservoir) varies by a factor of twenty between the greatest and lowest monthly values (EPE, 2010). Run-of-river hydropower generally has a lower capacity factor than hydropower with large reservoirs; generating, on average, less electricity per unit of installed capacity over the year. The Belo Monte hydropower plant is expected to have a capacity factor of about 40%, compared with an average capacity factor of 77% from 2000-2012 for the massive Itaipu hydropower project, and an average capacity factor across the hydro system of around 55% over the same period. The shift towards more run-of-river capacity is also expected to result in wider variations in transmission needs throughout the year, reducing average line-utilisation rates and potentially placing greater stress on the system.

**Figure 10.7 ▷ Brazil indicative monthly variations in power generation by source**




Note: Calculations of bioenergy, wind and solar generation in 2035 are based on projected installed capacity, biomass harvest cycles and historical generation profiles, while those for run-of-river generation are based on projected installed capacity and river flow variations at the sites of planned hydropower projects.

To a degree, the seasonal variations introduced by run-of-river hydropower can be absorbed by existing hydro reservoirs, which can be replenished during periods when run-of-river output is at its highest. They can also be compensated by the seasonal supply patterns of other renewable resources, notably bioenergy in the southeast and wind in the northeast (see Chapter 12). But an essential role is played by gas-fired power generation, which is increasingly prized for its reliability during dry months or seasons. This balancing role underpins the expansion of gas-fired power in our projections, although there is also a trend for some gas-fired power plants to run at higher load factors as they provide a more significant share of power throughout the year.

## *Transmission and distribution*

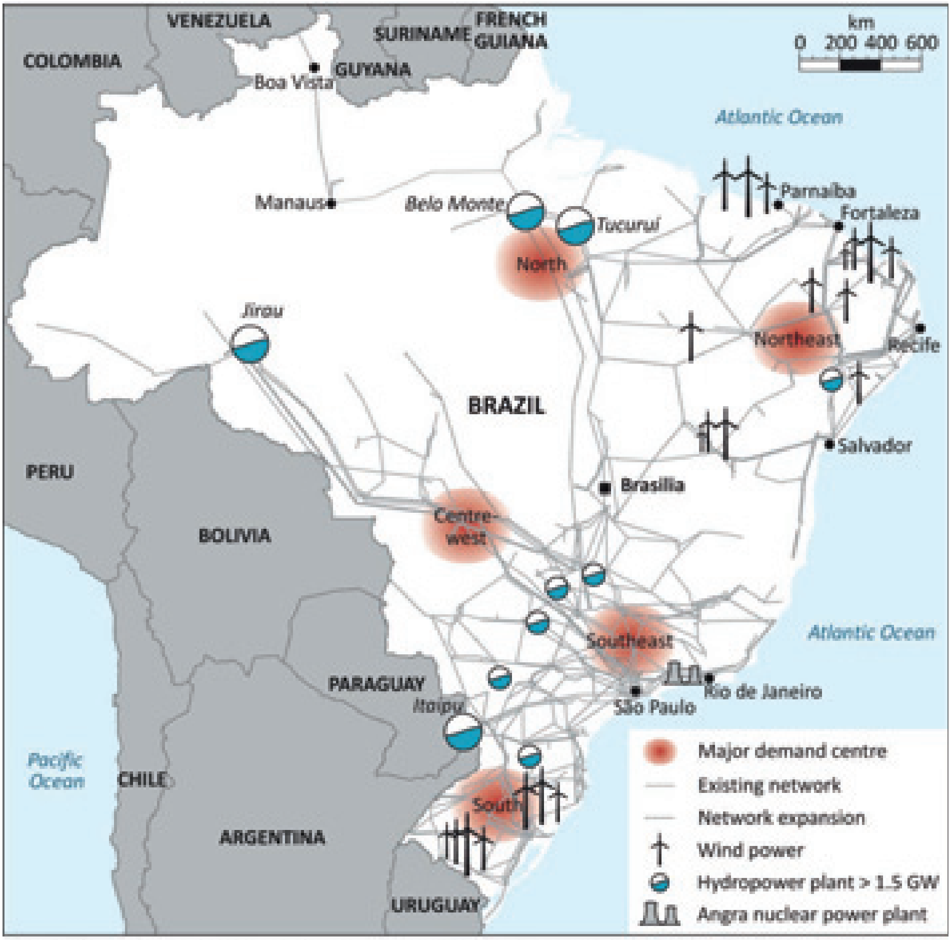
Timely expansion of the transmission and distribution network in Brazil is critical to meet the continued growth in the power demand and to ensure the reliability of power supply. Currently, there are 107 000 kilometres (km) of transmission lines (ranging from 230 kilovolt [kV] up to 750 kV) that span most of Brazil and are considered part of the Brazilian National Interconnected System (SIN) (Figure 10.8). The system serves to transfer energy generated from power plants (such as large hydropower projects) to the demand centres, to integrate the various components of the power system (including the multiple hydrological basins) and to provide for integration with neighbouring countries. Currently, all the Brazilian states and their capitals are connected to the national system (with the sole exception of Boa Vista, capital of Roraima state in the north of Brazil, whose connection is anticipated in 2015). The transmission system is predominantly controlled by companies in which the government has a stake, though, between 1999 and 2010, nearly 75% of bids for transmission expansion (through a competitive auction system) have come from the private sector, rather than government-owned utilities. The distribution system is composed of a greater mix of private companies and government (federal, state and municipal) utilities, and is regulated, based on the cost of service, by the National Electrical Energy Regulatory Agency (ANEEL).

The interconnected nature of the Brazilian grid provides a number of benefits, allowing supply and demand to be balanced over a very large area and providing multiple transmission corridors to the main demand centres, improving reliability. Moreover, by connecting several subsystems and hydrological basins, system operators are able to take advantage of differing hydrological conditions in different parts of the country to help maintain overall hydropower reservoir levels and to enable more optimal generation profiles for hydropower and thermal power plants.

As in all power systems, the risk of disruption remains. Indeed, while the cause of the 2001-2002 electricity crisis was rooted in under-investment in generation capacity (see Chapter 9, Box 9.1), more recent power interruptions have often been related to transmission issues. The Brazilian interconnected system is generally able to keep incidents isolated, without interrupting power to consumers. However, on occasion, incidents have caused more widespread contagion. An example of this occurred in 2009, when a short circuit in transmission lines, due to heavy rains, caused the shutdown of the Itaipu hydropower plant. Even with a relatively quick recovery (over the course of a few hours), the resulting power cut affected around 90 million people across the country.

To address this issue and meet growing power demand, the ten-year transmission plan, "Transmission Expansion Programme" (PET), for the period 2013-2022, aims to add over 50 000 km of new transmission lines and related equipment. In order to tap the expansive hydropower potential in the Amazon, some 2 500 km of new transmission corridors are planned. For the new transmission corridors, ultra-high voltage transmission lines are being considered and the Electrical Energy Research Centre (CEPEL) is currently testing this technology, as it would be its first use in the Americas. In total, the investments needed for the PET are estimated at $36 billion, with almost 60% of this being for transmission lines and the remaining 40% for substations. In addition to expansion of the transmission system within its borders, Brazil is actively seeking to increase interconnections with neighbouring countries. To the north, Brazil is pursuing agreements with Venezuela, Guyana, French Guiana and Suriname. To the south and west, Brazil is looking to strengthen interconnections with Argentina, Bolivia, Paraguay, Peru and Uruguay.

**Figure 10.8 ▷ Brazil's electricity sector**

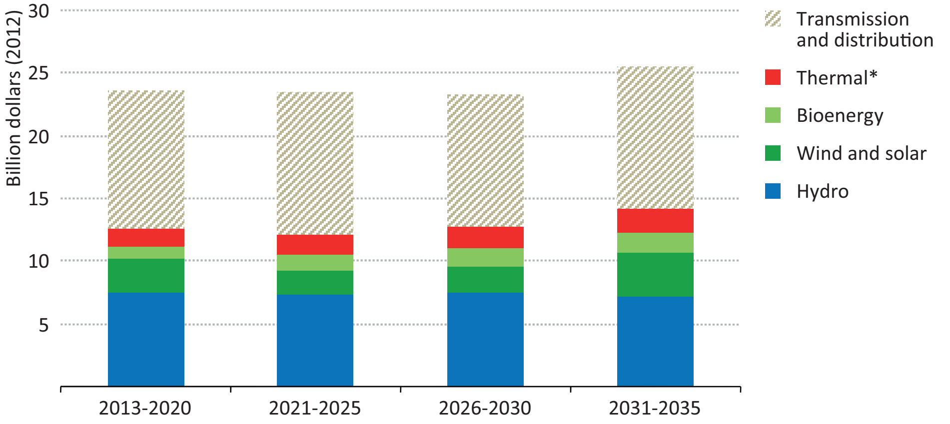



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

### *Investment*

Efficient investment, operation and end-use are required to enable the power sector to support Brazil's social and economic development. Given the projected increase in demand, the first of these considerations – investment – is clearly critical: to meet projected electricity consumption in the New Policies Scenario, we estimate that over $300 billion in cumulative investment in power generation capacity is required from 2013 to 2035, as well as $250 billion in transmission and distribution.[6] The average annual investment requirement is around $24 billion to 2035 (Figure 10.9).

**Figure 10.9 ▷ Brazil average annual investment in the power sector in the New Policies Scenario**




* Includes fossil fuel-fired and nuclear plants.

For power generation, investment needs are concentrated in hydropower (the largest projected source of additional capacity), although these tail away somewhat after 2030, as the accessible resource potential starts to run up against increased social and environmental constraints. Investments in wind power edge higher, although this upward trend is mitigated by a gradual reduction in assumed unit costs. Investment in thermal capacity is around $1.7 billion per year on average, with the majority required for the expansion of gas-fired generation capacity.

Given the political priority attached to the reliability and security of supply after the experience of power shortages in 2001-2002, Brazil's electricity market model puts a very strong emphasis on ensuring that adequate investment is forthcoming. As described in Chapter 9, Brazil seeks to achieve this on the generation side by contracting energy on a long-term basis (either the delivery of a fixed amount of energy, or the availability of a certain amount of capacity, to be called upon if required), and by requiring potential generators to compete for these contracts through the auction system.

The 24 auctions held since 2005 (for large hydropower and also for other selected technologies or a mix of technologies) have resulted in a cumulative investment commitment of almost $120 billion (for around 65 GW of capacity). Transmission projects are similarly contracted on a long-term basis, with investors competing to offer the most favourable terms for construction and operating rights. Not all of these projects are likely to

6. Our transmission and distribution investment projections include a wider range of line voltages (110 kV-800 kV) than analysed in Brazil's Transmission Expansion Plan, particularly at the low end of the range, where a large portion of the investments take place.

be delivered on time and, as mentioned in Chapter 9, some contractors may have difficulty in fulfilling their commitments. That said, the Brazilian choice of market design eliminates most of the long-term investment uncertainty that, for example, currently characterises the European power market. The new market design has already demonstrated enhanced resilience in the power system, as electricity supply in 2013 was not compromised, despite hydrological conditions worse than those during the crisis in 2001. The trade-off is that this approach loses some responsiveness to short-term fluctuations in market conditions, such as fuel prices. For example, if natural gas became available at lower prices in Brazil, it would take several months or years for this to be reflected in the generation mix through the auction process whereas, in the United States, the recent decline in gas prices caused a rapid shift from coal-fired to gas-fired generation.

### Box 10.3 ▷ Brazil's high tolerance for variable renewables

The contribution of variable renewables (including generation from wind, solar and small hydropower, but excluding large hydropower[7]) to the Brazilian energy mix increases ten-fold from 14 TWh in 2011 to over 140 TWh in 2035 in the New Policies Scenario. By the end of our *Outlook* period, variable renewables account for 13% of total generation. Accommodating variable renewables into the power system normally involves additional costs to accommodate the variable nature of the output generated from these sources, but our analysis suggests that, in Brazil, these costs are likely to be limited. Integration costs, which generally range from $5-25 per megawatt-hour (MWh) of variable renewable generation, are likely to be at the low end of (or even below) this range in Brazil for the foreseeable future (IEA, 2011).

There are several reasons for this, the most important of which is the amount of energy storage in the Brazilian power system, in the form of reservoir hydropower, which provides significant scope to balance short-term variations in supply and demand. The size of the interconnected transmission and distribution system, spanning thousands of kilometres and the major demand centres, also lowers integration costs, as the variations in generation are small, compared with regular fluctuations in demand. The nature of Brazil's wind resource also helps to reduce integration costs below their average levels elsewhere as wind capacity factors are high relative to many other countries, reducing (but not eliminating) variability and the need for its accommodation by flexible capacity. In addition, the seasonal wind patterns in the northeast make wind generation there complementary to the seasonal variations in output from run-of-river hydropower plants in the north, making more wind power in this area a positive contribution to constant supply, rather than a cost to the system.

Our estimate of $250 billion in cumulative investments in the transmission and distribution network for the period to 2035 covers the cost of expanding the system in line with the projected increase in capacity, as well as the cost of tackling current vulnerabilities and the (relatively modest) expenditure required to integrate a larger share of variable renewables

7. Run-of-river hydropower is not included as its variability is on a seasonal basis rather than short term.

into the power mix (Box 10.3). Of this total, investment in the distribution network, whose length increases by 80% by 2035, makes up more than two-thirds, an average of more than $7 billion per year.

## Outlook for other energy-consuming sectors

In the New Policies Scenario, final energy consumption rises by an average of 2.4% per year over the period to 2035, with the shares by sector remaining broadly comparable to those seen today (Table 10.2).[8] This implies that the more rapid growth seen in recent years in industrial and transport energy use slows, while demand in the buildings sector– particularly residential – steps up. The mix of energies used in final consumption mirrors some of the trends seen for primary energy consumption as a whole: the share of oil falls from 46% in 2011 to 40% in 2035, as it is substituted by gas in some industrial applications and by biofuels in transport. The share of bioenergy declines somewhat, as rising use in the transport and industrial sectors is accompanied by a fall in residential consumption, where the use of traditional biomass all but disappears. Coal consumption remains at low levels, its 3% share in final consumption in 2035 largely attributable to its use in iron and steel manufacturing. The share of electricity rises to 20%, from 18%, because of rising demand for appliances in the residential sector. The share of natural gas also grows strongly, from 6% to 11%, primarily because of its increased use in industry.

**Table 10.2 ▷ Brazil final energy consumption by sector in the New Policies Scenario** (Mtoe)

| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|---|
| Industry | 40 | 82 | 105 | 119 | 133 | 148 |
| Transport | 33 | 74 | 105 | 115 | 124 | 132 |
| Buildings | 23 | 35 | 41 | 47 | 52 | 57 |
| Other sectors* | 15 | 27 | 36 | 41 | 46 | 51 |
| **Total** | **111** | **219** | **287** | **322** | **356** | **388** |

* Includes agriculture and non-energy use. Note: Final consumption does not include energy used in power generation, oil and gas extraction, the refining sector or other processes that create products consumed in the end-use sectors.

### *Industry*

Industrial energy consumption grows by nearly 80%, from 82 million tonnes of oil equivalent (Mtoe) in 2011 to 148 Mtoe in 2035, and, with growing energy needs, comes a shift in the composition of demand. The share of bioenergy in Brazilian industrial use is among the highest in the world, although this share declines from 42% to 38% over the period to 2035. The share of oil use in industry also decreases (from 15% to 11%), but there is a substantial projected increase in the share of natural gas (which almost doubles, from

8. Our projections of final energy consumption in Brazil categorises demand by sector for industry, transport, buildings (including both residential and services) and other uses, the latter including agriculture as well as non-energy uses for gas such as feedstocks used for the manufacture of fertilisers or petrochemicals.

12% to 20%). The future level of gas demand in industry hinges on domestic gas supply and the long-term strategy for gas use throughout Brazil's economy (see natural gas section below).

The growth in industrial energy consumption to 2035 is less than the anticipated rise in the value of overall industrial output (which more than doubles), indicating an improvement in the energy intensity of industrial production.[9] The change in energy intensity is linked to two factors: efficiency improvements in individual sectors[10] and an assumed shift among industrial sectors away from the most energy intensive. There are good reasons for large energy-consuming industries to operate in Brazil, including the size of the domestic market and the availability of other key inputs for the manufacturing process, such as iron ore for the iron and steel industry, wood for paper and pulp production, or bauxite and alumina resources for aluminium. But it cannot be taken for granted that these industries will grow in Brazil, with one of the factors in play being the relatively high costs of energy (Spotlight).

Looking in more detail at the composition of energy demand, four energy-intensive industrial sectors – iron and steel, chemicals, cement and pulp and paper – accounted for half of Brazil's industrial energy consumption in 2011. By 2035, this figure is projected to fall to around 43%, in part because these sectors' share of overall manufacturing output declines, but also because they implement measures to improve efficiency (Figure 10.10). In iron and steel making, for example, where steel output is anticipated to rise from 35 Mt in 2011 to 65 Mt in 2035, efficiency improvements of the order of 10-15% in energy consumption per unit of output are realised through increasing heat and gas recovery in blast furnaces and basic oxygen furnaces. In the pulp and paper industry, where output grows the fastest among the energy-intensive sectors at 3.6% per year on average, there are efficiency gains in chemical pulp production in the range of 15-20%, with pulp exports expected to double. In paper production, efficient refiners, new drying techniques and heat integration further reduce electricity and fuel consumption. Yet significant potential remains in these and other energy-intensive manufacturing to improve efficiency further.



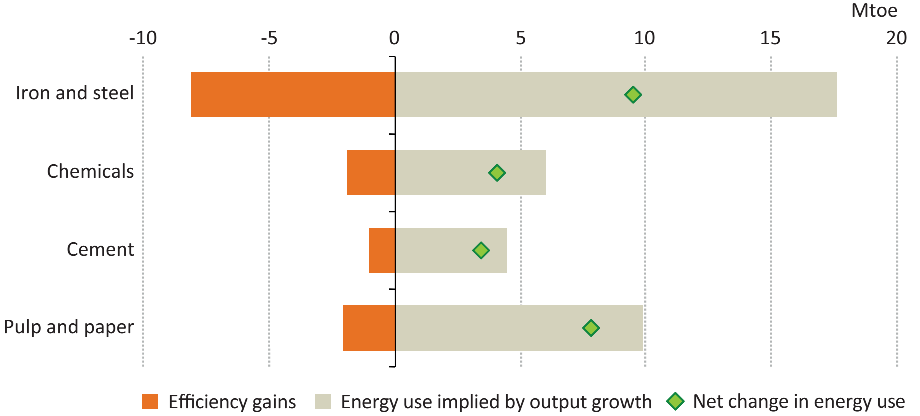
South America is not a major force in global petrochemicals, but Brazil is by far the largest regional player. It has 70% of the region's ethylene capacity and has ambitions to expand this, based in part on the possibility of lower-cost petrochemical feedstocks, once oil and natural gas production start to rise later in this decade. Brazil is also a pioneer in the production of bio-plastics, using sugarcane ethanol instead of petroleum feedstocks to produce bio-ethylene. The first such plant was built in 2010, with a capacity of 200 thousand tonnes per year, and other projects are in the pipeline (although a large

9. Energy intensity, in general defined as demand in primary energy terms per unit of economic output, is not an exact indicator of energy efficiency as it is influenced by the structure of an economy and climatic conditions. For analysis of past trends, however, energy intensity is often used as a proxy for energy efficiency, given the lack of more detailed data; but it is sub-optimal to the extent that it is influenced by structural factors in each sub-sector of the economy (see Chapter 7).

10. These are related to assumed progress with implementation of measures included in the National Energy Efficiency Plan, such as capacity-building for energy efficiency and the introduction of energy management systems.

bio-polymer project was postponed in early 2013, on the grounds of cost escalations). Bio-plastics are not yet commercially competitive but, before the end of the *Outlook* period, they are expected to contribute to the anticipated growth in ethylene output, which grows by almost 2% annually to 2035.

**Figure 10.10 ▷ Brazil change in energy demand in selected energy-intensive manufacturing in the New Policies Scenario, 2011-2035**




Note: The net change in energy consumption is the difference between the energy consumption implied only by growth in output and the energy savings due to efficiency improvements.

S P O T L I G H T

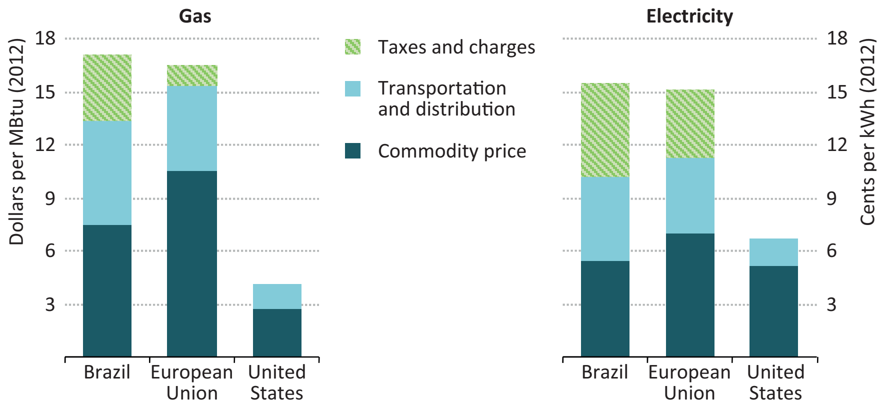
## Are high energy prices hurting Brazil's industrial competitiveness?

Despite an enviable endowment of energy resources, the prices that final consumers in Brazil have to pay for energy services – with the notable exception of bioenergy – are generally high, compared with most other countries. Prices paid by various end-users vary in different parts of Brazil, but the average price of natural gas to Brazilian industry is higher than in Europe and about four times higher than in North America. Even after the reductions in electricity prices introduced in early 2013, and despite the large share of low-cost hydropower in the power mix, the average electricity price paid by industry remains comparable with the average in the European Union and more than twice the level in the United States (Figure 10.11).

There are different components to the price paid by energy end-users. Beyond the wholesale price of the commodity itself, there are also the charges for transmission and distribution, and taxes. Transmission costs in Brazil will tend to be higher because of the size of the country but, even so, these additional cost components are relatively high when compared internationally. The Brazilian tax rate on gas (22%), for example, is also well above the rates applied in most other countries: it is zero in the United States, 4%

in France and 5% in Japan. These costs have an impact on company strategies and investment decisions, particularly for sectors where energy forms a high percentage of total production costs (see Chapter 8). Allied to other elements of a generally complex business environment, known as the *custo Brasil* (Brazil cost), they can counter-balance some of Brazil's advantages for energy-intensive industrial sectors in terms of market size and raw materials.

**Figure 10.11 ▷ Average natural gas and electricity prices to industry by component**




Note: The Brazil electricity price is for 2013 (expressed in year-2012 US dollars) to reflect the impact of the electricity price reduction introduced in early 2013. All other prices are averages for 2012.

Sources: Sistema Firjan (2013); IEA databases and analysis.

Between 2002 and 2006, Brazil was a net exporter of six important energy-intensive products – chemicals, iron and steel, ceramics, glass, aluminium, and pulp and paper. Since 2007, the trade balance in these sectors taken together has reversed and the value of Brazil's imports of these products has been higher than its exports. There are a number of factors that explain this turn-around, including the appreciation in the Brazilian currency, but rising energy costs have played a role. The government has taken several policy initiatives to address the issue of industrial competitiveness, including the lowering of electricity prices in early 2013; some targeted tax reductions; efforts to ensure a favourable macroeconomic climate and exchange rate; and access to financing for new projects through the Brazilian Development Bank (BNDES). For the longer term, though, another key issue for Brazilian industry will be developments in the gas sector: the timing of the availability of new supplies from offshore and onshore; their volume; their suppliers; and, crucially, their price.

Outside energy-intensive manufacturing, the major industrial consumers of energy in Brazil are the food and tobacco industries. Brazil is the world's largest producer of sugar and of coffee and the second-largest producer of beef and of tobacco. The sugar industry's use of bagasse as a source of process heat and also of electricity is a main reason why the share of bioenergy in industrial energy consumption is so high.[11] In other parts of the food industry, harvested wood makes a large contribution to energy consumption, although this is expected to decline. The extractive industries are also expected to rise in importance as energy consumers, with the supply chain needs of the upstream oil and gas industry becoming a prominent driver for industrial development and increasingly large gas consumers in their own right (Box 10.4).

**Box 10.4 ▷ The upstream oil and gas industry – a major consumer of its own products**

Brazil's upstream oil and gas industry is a large consumer, as well as producer, of energy. Oil and gas production requires energy to operate pumps, compressors and other equipment and this energy is typically generated on site, using some of the produced fuel (usually the less-valuable gas). As a general rule, around 5% of energy production is consumed as "own-use" in this way.[12] In Brazil, production platforms in the Campos basin might typically have the capacity to produce 20 MW of power, while the huge floating production vessels that are expected to contribute most of the anticipated increase in offshore output over the coming decades can have up to 70 MW of gas-fired turbines operating on board. Drilling rigs do not have the ready supply of gas that production units have and so rely on diesel-generated power: around 10 thousand barrels per day (kb/d) of diesel are used in drilling operations every day.

With the expansion of offshore production operations anticipated in the New Policies Scenario, we estimate that some 4 GW of electricity generation capacity will be contained within the various offshore production units by the mid-2020s. The amount of gas consumed to support offshore operations triples in our projections, from 2 bcm to 6 bcm in 2035, although it declines as a share of total gas production, from more than 10% in 2012 to around 6% by the end of the *Outlook* period.

### *Transport*

The transport sector in Brazil has been the fastest growing of all the end-use sectors (at an average of 4.2% per year from 2000-2011) and, at 74 Mtoe in 2011, accounts for 34% of final energy consumption. Energy demand for transport is heavily concentrated in road transport, which accounts for more than 90% of the total and more than 90% of the increase in demand over the last decade. In the New Policies Scenario, transport energy

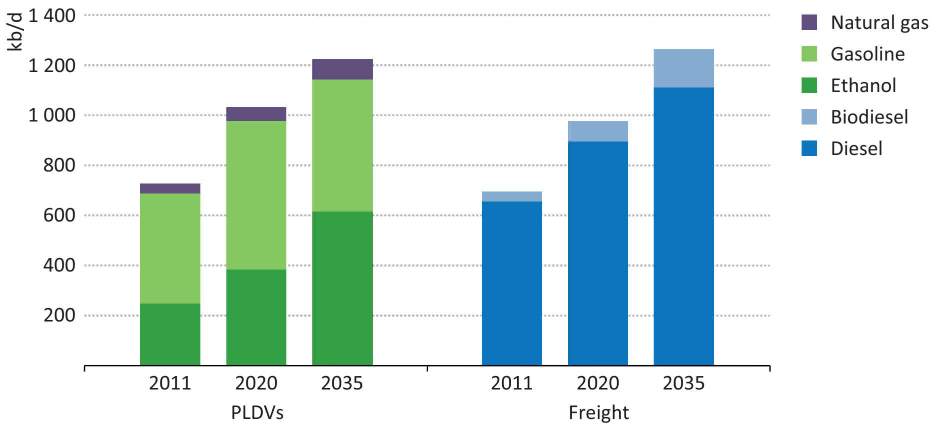
11. "Auto-production" of heat and electricity is widespread in the Brazilian industrial sector, although this is an area where data are often difficult to collect. Most of the output is used on site (appearing as bioenergy consumption in the industrial energy balance, not as heat or electricity); but surplus bio-electricity, sold to the grid by auto-producers, is an important element in Brazil's power mix.

12. This is classified as "energy own use" in the energy balance (alongside the energy used in the refining sector and other energy transformation processes), rather than industrial energy consumption.

consumption grows by 2.4% per year, on average, between 2011 and 2035, the rate of increase gradually slowing over the projection period. In absolute terms, road transport is the main source of demand growth, but the fastest rates of growth come from domestic aviation (3.6%) and railways (2.5%).

The distinguishing feature of the Brazilian road-transport sector is the significant penetration of non-oil based fuels. Biofuels, predominantly ethanol from sugarcane, account for around just under one-fifth of road-transport demand today, and natural gas a further 2%. This though, represents a low ebb for the ethanol industry, because recent years have been marked by poor harvests, under-investment and a poor competitive position against gasoline priced below international market levels (see Chapter 9). It will take time for growth in ethanol consumption to regain momentum, but the shave of ethanol in an expanding road-transport market rises towards one-quarter, a new high. Ethanol will then contribute as much as gasoline to satisfying road liquid-fuel demand, but less than diesel.

**Figure 10.12 ▷ Brazil road-transport fuel demand by type in the New Policies Scenario**




Note: PLDVs = passenger light-duty vehicles.

The growth in mobility and in road-freight services in Brazil in the earlier part of the projection period is largely satisfied by oil-based fuels, which meet almost 70% of the total growth in road-fuel consumption to 2020. After 2020, however, further expansion of biofuels use in road transport sees the share of biofuels rising to almost one-third of total demand for road-transport fuel by 2035. This is based on the positive underlying economics of Brazilian sugarcane ethanol supply in a high oil-price environment, on continued government backing for the sector and on the industry successfully managing to overcome some of the cost pressures and logistical problems that could hold back growth (see Chapter 11). Other fuels, such as natural gas (3% of transport fuels in 2035) or electricity (less than 1%), make only minor in-roads into the Brazilian transport sector due to the need for additional infrastructure investments and the dominant role of oil and biofuels.

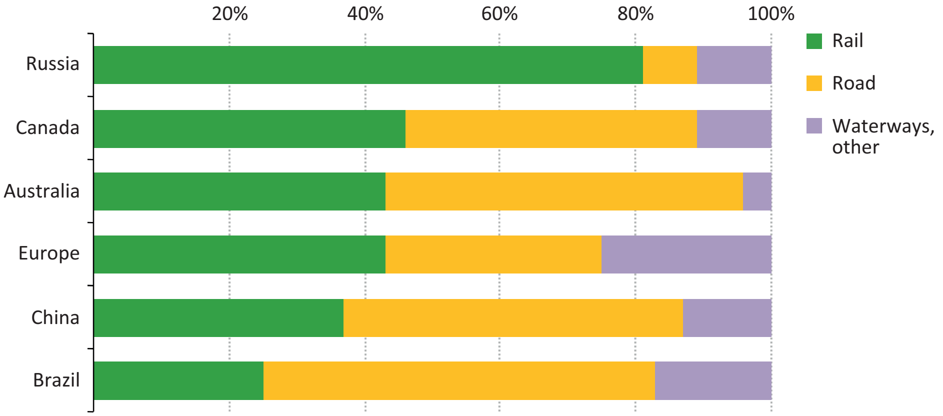
The Brazilian car market is the fourth-largest single-country market in the world after China, the United States, and Japan, with passenger light-duty vehicle (PLDV) sales reaching a record high of 3.6 million in 2012, partly incentivised by government tax breaks. Car ownership levels have surged, alongside the expansion of the Brazilian middle class. Brazil has also become a major car manufacturer, with most of the major international companies producing for the domestic market and for export. European and US manufacturers have traditionally held a strong position, but their market share has been shrinking as companies from Japan, Korea and China have increased levels of local production and imports.

In our projections, the rate of car ownership rises steadily at 3.2% per year, a rate only slightly below underlying GDP growth, to reach almost 290 vehicles per 1 000 people in 2035, implying a total fleet of around 65 million PLDVs. This rate per 1 000 people compares with around 110 vehicles per 1 000 people in the rest of Latin America in 2035. But growth on the scale projected in Brazil is dependent on adequate investment in road infrastructure: traffic congestion is already a major problem in large cities. The impact of traffic growth on demand for transport fuel is expected to be dampened by efforts to improve fuel economy. By and large, Brazil's efficiency policies have not focused on transport in the past, but the recent Inovar-Auto initiative is targeting a fuel efficiency improvement for PLDVs of at least 12% in 2017 (measured as the average efficiency of the product portfolio of each manufacturer). The target can be achieved by new, more efficient technologies as well as by introducing smaller and less powerful vehicles. Though the targets are voluntary, they are linked to tax breaks for manufacturers so there is a strong incentive for them to be achieved, making this initiative an important first step to improve vehicle fuel efficiency.

An important policy concern in the transport sector is the high share of freight carried by road. For a country of Brazil's size this indicator is very high, at around 60%, with only one-quarter of freight carried by rail, much of it being bulk commodities (Figure 10.13). Over the *Outlook* period, road-freight activity, measured as billion vehicle-kilometres, is projected to increase by 3.1% per year (at 80% elasticity to the growth in value added in the industrial sector). Road-freight transport depends heavily on the use of diesel and the share of diesel in oil-based road transport fuels in Brazil is projected to increase from around 60% today to nearly 70% in 2035, as fuel-economy policies for PLDVs and increasing use of ethanol suppress gasoline demand.

There are only a few alternatives to the use of petroleum-based diesel in road freight transport on a large scale, the most important of which are natural gas and biodiesel. The use of gas is an alternative that has so far remained relatively unexplored in road freight in Brazil, unlike the United States and some other countries (see Chapter 16). But the Brazilian government is exploring the possibility of expanding the current 5% blending mandate for biodiesel. Brazil has the capacity to produce more biodiesel but, for the moment, biodiesel depends, for its market share, entirely on the blending mandate. We assume that biodiesel quality, adequacy and competitiveness all gradually improve in a way that allows for an extension of the biodiesel mandate in the longer term. In the New Policies Scenario, biodiesel use reaches 7 Mtoe in 2035, its share in total diesel fuel demand rising to 10% by the mid-2020s and slightly more by the end of the projection period.

**Figure 10.13 ▷ Share of domestic freight transport by mode in selected regions**




Source: Ministry of Transport of Brazil (2012).

A key ambition of Brazil's National Transportation Plan, which outlines a large-scale investment programme in railways and water-borne transport (both inland waterways and sea-borne along the coast), is to switch some road freight to other modes of transport in order to relieve the pressure on Brazil's road infrastructure and increase the efficiency of freight transport. Transport infrastructure initiatives have been included in the Accelerated Growth Programmes (Programa de Aceleração do Crescimento), related in part to Brazil's preparation for the Football World Cup in 2014 and the Olympic Games in 2016.

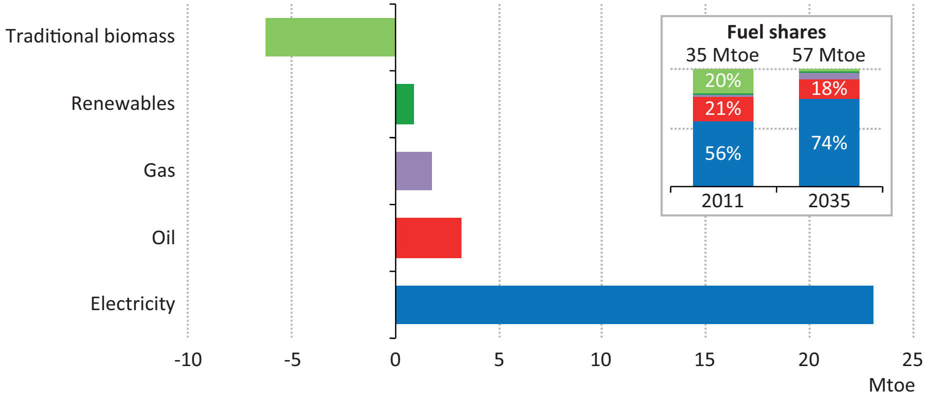
As a consequence of such investments, which are expected to continue throughout the projection period, by 2025 around 200 billion tonne-kilometres of freight are projected to move away from roads to other modes of transport, bringing the share of freight moved by road down from 60% in 2011 to 45% in 2025. This is well short of the objective included in the National Transportation Plan (which aims to bring this indicator down to 30% by 2025), but it nonetheless makes a significant impact on energy consumption. Since the other ways of moving goods are all much more efficient, the result is a net saving of 8 Mtoe in energy use in 2025, with multiple other beneficial spillovers, such as improved industrial efficiency and safety, reduced local pollution and congestion on Brazil's roads.

### *Buildings*

The buildings sector (residential and services) in Brazil consumed some 35 Mtoe of energy in 2011. Although this represents only around 15% of total final energy consumption from all sources, the buildings sector consumes almost half of Brazil's final consumption of electricity. Growth in this sector will, accordingly, be important in determining how quickly the electricity supply system needs to expand during the coming decades. Another important feature of the outlook for the buildings sector is the declining share of traditional biomass in residential energy consumption. In 1990, this was the largest source of energy in households but, by 2011, its share had fallen to 20% of the total, mostly firewood for cooking and water heating.

Over the period to 2035, energy demand in the buildings sector is projected to rise to 57 Mtoe, some two-thirds higher than in 2011 (Figure 10.14). The increase comes primarily in the form of electricity, the use of which rises by an average of 3.3% per year to reach three-quarters of all energy use in the sector by the end of the projection period. The share of energy used for appliances grows from one-quarter to almost half of total energy consumption in the residential sector, reflecting the expansion in the number of households (which is assumed to almost double) and rising average incomes. Energy use for cooling increases particularly quickly, albeit from a low base (Box 10.5). The share of water heating in electricity consumption drops, due to strong growth in the use of solar water heating after 2020.

**Figure 10.14 ▷ Brazil change in energy demand in the buildings sector in Brazil in the New Policies Scenario, 2011-2035**




Among the fuels used in the buildings sector, the most noticeable evolution is the large-scale displacement of traditional biomass, whose share in residential energy consumption declines rapidly to 2% in 2035. We estimate that around 12 million people in Brazil currently rely on traditional biomass for cooking, with major impacts on the health of people, mainly women and children, exposed to the high levels of household air pollution from combustion. Over the projection period, this biomass is largely displaced by liquefied petroleum gas (LPG) or, in some cases, by electricity or natural gas (in areas where it becomes available). The instances of "fuel stacking", where biomass is used as a secondary fuel for cooking when households cannot afford LPG or other modern fuels, are also set to decline.[13] While a relatively small number of households can still be expected to use biomass for cooking in 2035, both for cultural as well as affordability reasons, it is expected that those who do so will use more efficient cookstoves that reduce indoor pollution.

Energy efficiency policies targeted specifically at the buildings sector have been fairly limited in scope and achievement. The programme Procel Edifica (part of the wider National Programme of Electric Energy Conservation called Procel) encourages energy efficient concepts in building design, but has only a voluntary system of energy performance ratings for buildings. There is also a specific programme called Procel EPP supporting energy efficiency in public buildings. The policy that is likely to have the most substantial impact on efficiency in buildings is the decision to phase out incandescent light bulbs; as of mid-2014, bulbs above 60 Watts that do not meet a performance standard can no longer be sold in Brazil. This policy means that lighting plays only a marginal role in the overall increase in electricity demand, saving an estimated 11 TWh per year by 2035. The policy on incandescent bulbs provides a good illustration of the sort of gains that efficiency policies can deliver, were Brazil to consider more stringent performance standards and labelling for a wider variety of appliances, such as air conditioning, as well as mandatory labelling of buildings, and the implementation of building codes (probably on a regional basis given the climatic variations across the huge country (IEA, 2013).

### Box 10.5 ▻ Keeping Brazil cool

With high temperatures for much of the year in the most populated areas of the country and a growing middle class with rising incomes, Brazil has the ingredients for a continued rapid increase in ownership of air conditioners and energy used for cooling. In 2012, there were 22 air conditioning units per 100 households in Brazil (EPE, 2013), accounting for some 5% of total residential electricity demand. As ownership of air conditioning units increases and their average use grows, the amount of electricity used for cooling is projected to rise five-fold to almost 30 TWh in 2035 (more than one-tenth of all residential power consumption). Allowing for the potential impacts of a changing climate, such as a rise in the number of cooling-degree days, we estimate that cooling demand could be noticeably higher than this projection, by as much as 7% in 2035.

Energy efficiency policies and measures could hold back this trend: air conditioners are subject to labelling (the PROCEL endorsement label, which aims to identify the best-performing models) and also to a minimum energy performance standard (Box 10.1). But there is considerable scope to tighten the current standards. An efficiency level lower than the average observed in other markets, such as the United States, Japan and China, is enough to qualify for the PROCEL endorsement. Likewise, the performance standard is lower than that established by China for its domestic market (Cardoso, *et al.*, 2012).

13. The price of fuel continues to be an important factor in whether the poorest households can afford to cook using modern fuels, or revert to traditional means.

### *Other sectors (agriculture, non-energy use)*

Energy demand in the agriculture sector is projected to increase by around 90% to reach 19 Mtoe in 2035, accounting for 5% of total final consumption. Oil demand, mainly diesel use for agricultural machinery, rises by an average of 1.7% per year, reaching 170 kb/d in 2035. However, the share of oil in total agricultural energy demand declines from 58% in 2011 to 46% by the end of the *Outlook* period, in part because consumption of biodiesel increases.

Energy products are also used for non-energy purposes, notably oil (naphtha and LPG) and natural gas as a feedstock for the production of fertilisers and petrochemicals, and oil (mainly asphalt and lubricants) in a variety of other industrial applications. In our projections, oil consumption for petrochemical products increases by 2% per year: ethylene production, for example, increases by about 2 Mt, which corresponds to an increase of more than 50%. Natural gas consumption in non-energy applications sees an even bigger boost, with an annual growth rate of 4.5% as a result of increasing output of fertilisers (natural gas is used as a feedstock for the production of ammonia, which is used in turn to produce urea, an important fertiliser). Brazil is the fifth-largest consumer of nitrogen-based fertilisers in the world, but currently relies on imports to satisfy domestic demand – a trade flow that we expect to be reduced as more domestic natural gas becomes available. Oil consumption for non-feedstock related purposes (mainly asphalt and lubricants) nearly doubles from 2012 to 2035, driven by robust industrial growth and Brazil's ambitious plans to upgrade the country's infrastructure.

## Outlook by fuel[14]

### *Oil products*

Demand for oil in Brazil increases by 1 million barrels per day (mb/d) over the period to 2035, reaching 3.4 mb/d. In contrast to the situation in many other countries around the world, oil demand does not become more concentrated in the transport sector. Over the *Outlook* period, the share of transport in total oil demand remains at around 55%. Growth in oil-product use in transport is held back by rising consumption of ethanol and biodiesel, which contribute a further 780 thousand barrels of oil equivalent per day (kboe/d) to total liquids demand by 2035 (Table 10.3).

Considered by product, the largest growth in absolute terms is in diesel consumption, with most of it used for freight transport and smaller volumes of off-road use in agriculture. Consumption of gasoline in passenger vehicles levels off at just under 600 kb/d, before declining in the second part of the projection period, as ethanol takes a larger share of this market. Kerosene sees the most rapid growth among oil products, reflecting the anticipated expansion of domestic aviation. The rise in naphtha is almost entirely accounted for by its expanded use as a feedstock, mainly in the petrochemicals sector. LPG consumption is concentrated in the residential sector for cooking and heating.

14. The outlook for the nuclear industry is covered in Chapter 11.

**Table 10.3 ▷ Brazil oil demand by product in the New Policies Scenario** (kb/d)

| | 2012 | 2020 | 2025 | 2030 | 2035 | 2012-2035 | |
|---|---|---|---|---|---|---|---|
| | | | | | | Delta | CAAGR* |
| LPG | 228 | 265 | 283 | 300 | 317 | 89 | 1.4% |
| Naphtha | 174 | 224 | 245 | 261 | 271 | 97 | 1.9% |
| Gasoline | 529 | 590 | 551 | 536 | 525 | -4 | -0.0% |
| Kerosene | 77 | 115 | 133 | 151 | 171 | 95 | 3.6% |
| Diesel | 923 | 1 165 | 1 267 | 1 349 | 1 423 | 500 | 1.9% |
| Fuel oil | 88 | 93 | 97 | 101 | 103 | 15 | 0.7% |
| **Total oil demand**** | **2 394** | **2 928** | **3 107** | **3 279** | **3 426** | **1 032** | **1.6%** |
| Ethanol | 259 | 382 | 496 | 578 | 620 | 361 | 3.9% |
| Biodiesel | 43 | 76 | 105 | 132 | 155 | 113 | 5.8% |
| **Total liquids demand** | **2 695** | **3 386** | **3 708** | **3 989** | **4 201** | **1 506** | **1.9%** |

* Compound average annual growth rate. ** Total includes other products such as asphalt, waxes and lubricants.

### *Refining sector*

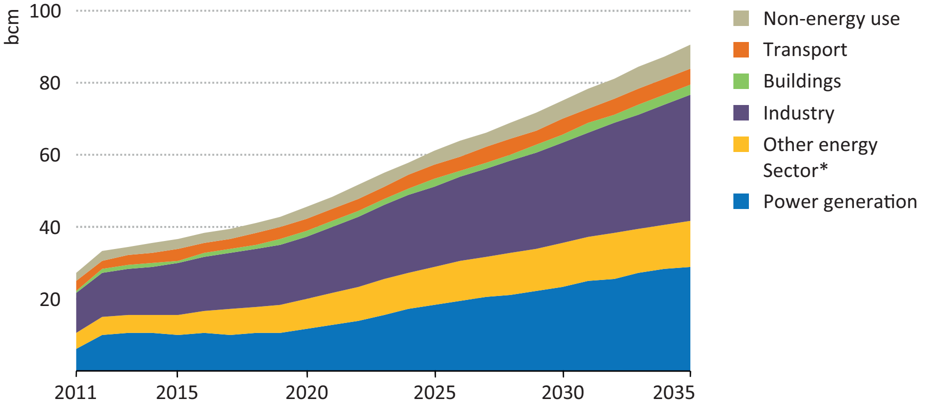
Brazil has made efforts in recent years to maximise throughput at its existing refineries and current refinery runs are slightly above nameplate capacity of 2 mb/d, but this still falls short of the amount required to meet the country's demand for oil products in full. The target to reach self-sufficiency in oil products therefore depends on a new cycle of refinery expansion. Two refineries are under construction: the Abreu e Lima refinery, known as Rnest, being built in the northeast state of Pernambuco (two phases adding a total of 230 kb/d of capacity) and the large Comperj refinery and petrochemical complex being built near Rio de Janeiro (two phases adding a further 330 kb/d). A further two, also foreseen for the northeast of the country, are at the planning stage, Premium I (in Maranhão, with two phases totalling 600 kb/d) and Premium II (in Ceara, 300 kb/d).

These capacity additions would bring the country's refinery capacity up towards 3.5 mb/d, sufficient to cover our projections of Brazil's oil product needs fully through to 2035. An initial expansion in capacity (of 860 kb/d) is sufficient to cover Brazil's projected oil product needs in full by around 2020, with subsequent expansions synchronised approximately with increases in product demand, so as to avoid or minimise product imports. We assume that Brazil exports its oil surplus in the form of crude oil rather than becoming a significant exporter of oil products.

## *Natural gas*

The evolution of demand for natural gas in Brazil over the coming years is subject to multiple uncertainties. Gas consumption is low by international standards, suggesting there is room for an increase. But the speed at which this happens will depend to a significant extent on what happens upstream and on how the market develops, *i.e.* whether gas enjoys advantages in terms of availability and affordability, compared with other fuels (see Chapter 11). The projections see clear potential for gas to expand its role in the Brazilian energy system, with demand growing to 90 bcm by 2035, an increase of more than 60 bcm compared with 2011 and an average annual rate of increase of 5.2%. Three-quarters of this growth comes from power generation and industry; gas use in the buildings sector and in transport increases, but accounts for less than 10% of gas demand in 2035 (Figure 10.15).

**Figure 10.15 ▷ Brazil natural gas demand by sector in the New Policies Scenario**




* Includes gas used in oil and gas extraction (largely for on-site power generation) and in refineries.

### *Gas market development*

Natural gas in Brazil is dominated by Petrobras, at all points along the value chain. From a legal standpoint, the absolute hold of Petrobras over the sector was abolished in 1997 and private operators are entitled to participate in the upstream, mid-stream and downstream. In practice, however, Petrobras is responsible for the bulk of the country's gas output and controls the national gas transmission network. It has a 51% stake in the company owning and operating the pipeline importing Bolivian gas and a 100% share in existing LNG import facilities. Petrobras has a stake in 21 of the 27 regional gas distribution companies in Brazil and is the largest single gas consumer, mainly for power generation and petrochemicals.

There are some signs of change on the horizon: there is fresh momentum behind onshore gas development, with some private players already producing and the 11th and 12th licensing rounds opening new acreage for exploration (see Chapter 11). There is also considerable pressure from energy-intensive industries, often with an eye on the gas prices paid by their counterparts in the United States and Mexico, for a more competitive market that could bring down their gas prices (Spotlight). The sheer volumes of associated gas set to become available offshore, starting in the latter part of this decade, could also become a force for change, as they imply a considerable expansion of the Brazilian gas market and an effort to find and develop new outlets for gas consumption. These gathering pressures have already resulted in some changes to the regulatory structure of the gas market, aimed at encouraging infrastructure investment and new market entrants (Box 10.7). But our assumption in the New Policies Scenario is that the process of implementing a more open natural gas market in Brazil is likely to occur only gradually, as it has elsewhere.

### Box 10.6 ▹ A long and winding road to a competitive Brazilian gas market

The Brazilian natural gas transportation network has been expanding quickly over the last decade but it still, as of 2012, covers only a relatively small part of the country, mainly the densely populated areas of Rio de Janeiro and São Paulo, and the coastal states in the northeast. A natural gas law, passed in 2009, was intended to speed up investment in new gas transport routes by opening the process to new actors and sources of capital, and to encourage the development of a more competitive market.

Under this legislation, either the Ministry of Mines and Energy (supported by the energy research body, the EPE) or any private operator can bring forward new transportation proposals, with ANP (the regulator) then holding an open season process to identify potential shippers and the effective demand for the new capacity. If the demand is there, ANP holds an auction to award concessions for the construction and operation of the pipeline. New pipelines to be constructed under the legislation will be open to any party wishing to transport gas, after a period of exclusivity, granted to the initial shippers, of up to ten years.

Implementation of the new system has proceeded slowly. The first ten-year blueprint for extending the country's pipeline network (a network expansion plan with the acronym PEMAT) was not ready at the time of writing and not all the secondary regulations required by the law, for instance on third-party access, had been finalised. Reliable access to market is a necessary condition for the emergence of new players in the gas market. Until this condition is met, owners of surplus gas are more likely to sell to Petrobras (if possible), or reinject it, and the objective of opening up the market is unlikely to be realised.



A key issue for the natural gas sector is how to manage uncertainty over demand from gas-fired power plants, whose role in providing back-up to the power sector can vary widely, depending on hydrological conditions. Most gas production in Brazil is unsuited to respond flexibly to changes in demand, as it consists primarily of associated gas that is produced offshore along with oil; the start of pre-salt production will exacerbate this situation. Today it falls to Petrobras to address this dilemma, since it controls most of the gas production and is, at the same time, committed to providing large amounts of gas-fired power to the electricity system on a flexible basis. It has done so by constructing two (soon to be three) LNG import terminals, as well as taking advantage of the limited flexibility of a contract with Bolivia and modulating, as necessary, its own use of gas in refineries and fertiliser plants.[15] However, high costs are involved, as demonstrated in the last part of 2012 and first half of 2013, when Petrobras was forced to call on expensive spot-market LNG imports to make up the gas balance.

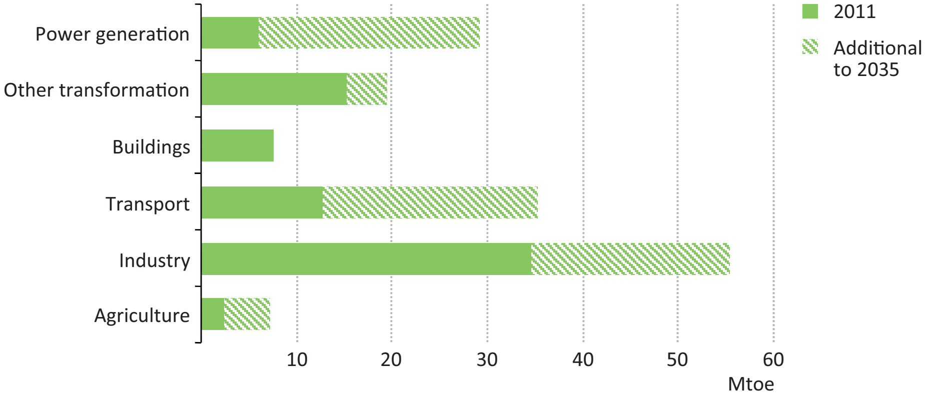
15. There is a degree of contractual flexibility in the gas import contract with Bolivia as Petrobras can vary its daily off-take within a range of 24-30 million cubic metres, but this is not enough to cover the swings in demand. Gas trade issues are discussed in Chapter 12.

In addition to the major demand centres served by offshore supplies, the exploration activity that is underway onshore (in many cases, far from existing pipelines) could result in a series of local or regional gas-consuming areas, each based on their own onshore gas discoveries. Unless there is a major onshore discovery, linking these emerging pockets of gas consumption to the existing coastal grid is unlikely to be cost effective; but they could be stepping stones on the way to a more integrated gas system in the future. Whichever way things unfold, it is clear that the Brazilian gas market is set to enter a new phase of expansion and development. So far, demand growth has largely been managed by Petrobras to absorb, first, the gas available from the Campos basin and then the gas from Bolivia. But it is not clear that this managed approach will survive the next wave of offshore gas and the interest by other companies in developing gas business opportunities onshore. Ultimately, how this plays out will depend on two key variables: whether there will be a concerted government effort to facilitate the arrival of competing suppliers to the market; and gas availability, a topic covered in the Chapter 11.

### Renewables

Consumption of renewable energy excluding hydropower is projected to rise by almost 90% between 2011 and 2035. In contrast to the rise in renewables consumption in many countries, this increase, though guided by policy, is driven in most cases by the strong competitive position of renewable energy within Brazil. The composition of this element of supply changes over time, with the share of traditional biomass, charcoal and harvested wood declining and the contribution growing from other sources, notably wind, solar, biofuels and bagasse (used for heat and power generation).

**Figure 10.16** ▷ **Brazil consumption of non-hydro renewable energy by sector in the New Policies Scenario**




Note: Consumption of renewables in the buildings sector falls by 5.2 Mtoe between 2011 and 2035.

Analysing the increase by the different sectors of energy use, the rise in renewables use in the power sector is driven in part by the growth in electricity produced from bioenergy (mainly bagasse), which more than doubles over the projection period, and, in the second part of the projection period, an increase in generation from wind and solar. The growth of bioenergy use in "other transformation" (Figure 10.16) consists of the energy used for transformation of wood into charcoal (for iron production) and the residues that provide heat and power for the transformation of sugarcane into ethanol.

In the final consumption sectors, the largest increase in renewables consumption comes in the transport sector, with the projected rise of ethanol and biodiesel use. In industry, there are different trends at work. Charcoal use in the steel industry is projected to be steady, as new blast furnaces revert mainly to the use of coke oven coke as a reduction agent (charcoal is unsuitable for use in large units). In other sectors, notably in food production and processing, the use of vegetal and forestry residues as a source of auto-produced heat and power increases substantially.

### *Coal*

Coal consumption in Brazil increases from 22 million tonnes of coal equivalent (Mtce) to 34 Mtce over the period to 2035, with two main sources of demand, the power sector and the iron and steel industry. The power sector is the outlet for domestically produced coal, but demand in the iron and steel industry is primarily for coking coal, which has to be imported. Coal demand in the power sector has been fairly static since 2000, but the potential for an increase over the next decade has risen as a result of a government decision to allow coal generation into the electricity auction system. With new thermal generation being encouraged (but questions in the short term about the availability and price of natural gas), a reversal of the previous prohibition on coal was a logical step. However, coal-fired projects were unsuccessful in an August 2013 auction and their inclusion has drawn criticism as a step towards carbonisation of the Brazilian energy mix. We do not expect coal to increase its share in the power mix (except in a Low-Hydro Case, [Box 10.2]), given the increased availability of natural gas and the increasing competitiveness of non-hydro renewables. In our projections, coal use for power generation increases to 8 Mtce in 2035 from 4 Mtce today. Iron and steel manufacturing is the largest single consumer of coal in Brazil and, with the use of domestically produced charcoal levelling off, imported coking coal meets the bulk of the increase in demand over the projection period. Coal use in iron and steel production (including consumption in blast furnaces and coke ovens) increases from 14 Mtce in 2011 to almost 20 Mtce in 2035.

# Brazilian resources and supply potential

## Setting a course for deepwater

### Highlights

- Brazil's resources are abundant and diverse; their development over the coming decades moves the country into the top ranks of global energy producers. Deepwater oil production leads the way, bringing with it large volumes of associated gas. Brazil is also set to almost double its output from renewable resources, with hydropower, bioenergy and wind energy at the fore.

- In the New Policies Scenario, oil production rises from 2.2 mb/d in 2012 to 4.1 mb/d in 2020 and to 6 mb/d in 2035. These projections are based on the huge size of Brazil's deepwater pre-salt deposits, the complexity of their development and the scale of the investment required. They also reflect a judgement that commitments made to source goods and services locally in Brazil, which have risen in recent years, are likely to contribute to a tightening of the supply chain. We also model a High Brazil Case, in which output exceeds 5 mb/d already by 2020.

- Natural gas production grows strongly in the New Policies Scenario, rising to more than 90 bcm by 2035. This growth is dependent on decisions as to how much of the offshore associated gas is reinjected to maintain reservoir pressure for oil production and whether incentives are in place to develop Brazil's onshore potential, including its significant shale gas resources.

- Only one-third of Brazil's estimated hydropower potential has been developed, but a large share of the remainder is in the Amazon region and is subject to a range of social and environmental concerns, which the Brazilian authorities are trying to address through concepts such as the "platform hydropower plant". If the Amazon were to prove to be off-limits for new projects, then the 70 GW expansion of hydropower foreseen in the New Policies Scenario would largely exhaust the country's remaining hydropower potential by 2035.

- Brazil's production of biofuels expands more than three-fold to 1 mboe/d in 2035; suitable cultivation zones are more than sufficient to achieve this expansion in supply without impinging upon environmentally sensitive areas. Sugarcane ethanol continues to dominate biofuels supply, with over 80% of the total. Advanced biofuels account for a growing share of investment and output by 2035.

- Wind resources are already being harnessed on a competitive basis and continue to be developed, particularly in the northeast of Brazil where recently-built wind projects are operating at very high capacity factors by international standards. Solar resources are widespread but are used mainly in decentralised applications, including electricity supply and water heating.

## Oil and gas

### *Resources and reserves*

Since the 1980s, the waters off Brazil's Atlantic coast have become one of the leading areas of interest worldwide for oil and gas exploration. What companies, led by Petrobras, are uncovering dates back to an era some 150 million years ago, when the original Gondwana super-continent (which contained most of the land mass now found in the southern hemisphere) started to break up. As the rift slowly grew between South America and Africa and sea levels fluctuated, alternate periods of flooding and evaporation created thick marine deposits, before the continents eventually became separated by a growing expanse of ocean. These deposits produced not only hydrocarbon-rich shale source rocks and fine-grained sandstones (such as the reservoir rock found in the Campos basin) but also carbonate hydrocarbon reservoirs covered by large deposits of salt (Figure 11.1).

**Figure 11.1 ▷ Main hydrocarbon basins in Brazil**


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.

These giant salt layers, some of which are 200 kilometres (km) wide and more than 2 000 metres thick in places, extend northwards from the Santos basin and provide an effective cap to keep hydrocarbons in place. The scale of the resources trapped underneath the salt is still poorly understood, but advances in technology, such as improvements in three-dimensional seismic imaging, are making it increasingly possible to test and verify the geological concepts and to overcome the operational difficulties experienced in trying to reach pre-salt reservoirs.[1]

The main areas for exploration onshore are the gas-prone Amazonian sedimentary basins of Solimões and Amazonas, the Paraná basin in the south and the basins of Parnaíba and São Francisco (which are thought to have unconventional potential). These five basins alone extend across 3.8 million km$^2$, around half of Brazil's landmass. The first oil production in Brazil was from the coastal basin of Recôncavo in 1939. Inland discoveries have generally been more modest than those in coastal and offshore areas: only the Solimões basin has significant onshore production today, but there are large areas that are relatively unexplored. Access is often hampered by thick basalt layers (in the case of Paraná) or by extensive wetlands and rainforests. The most prospective basins are also, typically, a long way from markets. Nonetheless, there are signs of renewed interest, with 87 onshore blocks covering nearly 70 000 km$^2$ awarded during the 11th licensing round in May 2013. Of these, 47 blocks are located in the coastal basins of Sergipe-Alagoas, Recôncavo and its inland neighbour, the frontier basin of Tucano. Much of the area awarded is expected to be gas-prone.

### *Oil*

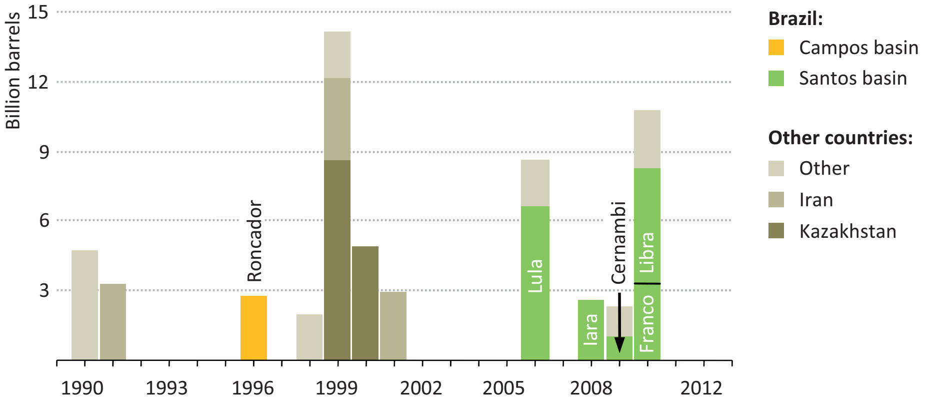
Estimates of Brazil's conventional hydrocarbon resources have risen as the scale of the pre-salt resources became clearer. Over the last ten years, more super-giant oil fields (fields with more than 1 billion barrels of reserves) have been discovered in Brazil than in any other country in the world (Figure 11.2). The proliferation of huge discoveries in the pre-salt reservoirs of Brazil – more than 80% of the exploration wells drilled by Petrobras in the Santos basin over the last five years made discoveries – has led many to judge that current estimates of undiscovered resources may be modest.

The figures for conventional oil resources presented in Table 11.1 are derived from analysis provided by the United States Geological Survey (USGS). An updated USGS assessment of undiscovered conventional oil that covered the main Brazilian basins, published in 2012, almost doubled the previous recoverable resource estimate for Brazil, primarily because of a large upgrade in the estimate for the Santos basin (USGS, 2012). On this basis, we estimate ultimately recoverable conventional resources in Brazil at around 120 billion barrels (crude oil and natural gas liquids), of which just over 14 billion barrels had already been produced by the end of 2012 (see Chapter 13 for definitions). This leaves remaining

1. In turn, many of the technical breakthroughs pioneered in this area in Brazil are now being put to use in West Africa to explore known pre-salt accumulations off the coasts of Gabon and Angola, as well as prospects off Cameroon, Congo, Equatorial Guinea and Namibia.

recoverable resources of 106 billion barrels, of which only 14% consists of proven reserves (Brazil's 15 billion barrels of proven reserves nonetheless make it the twelfth-largest holder of proven conventional reserves). In Brazil, almost 90% of ultimately recoverable resources remain to be produced. This compares with a figure of around 75% for the Middle East, 65% in Russia and 40% in the United States.

**Figure 11.2 ▷ Global discoveries of super-giant oil fields**




Note: Super-giant fields are those with estimated ultimate recovery greater than one billion barrels. Sources: Rystad Energy AS; and IEA analysis.

**Table 11.1 ▷ Brazil conventional oil resources by region** (billion barrels)

| | Proven reserves end-2012 | Ultimately recoverable resources | Cumulative production end-2012 | Remaining recoverable resources | Remaining % of ultimately recoverable resources |
|---|---|---|---|---|---|
| Campos Basin | 8.5 | 37 | 9.6 | 27 | 73% |
| Santos Basin | 5.4 | 49 | 0.1 | 49 | 100% |
| Other offshore | 0.5 | 24 | 0.8 | 23 | 96% |
| Onshore | 0.9 | 10 | 3.7 | 6 | 60% |
| **Total Brazil** | **15.3** | **120** | **14.1** | **106** | **88%** |
| of which deepwater | 11.5 | 96 | 6.8 | 89 | 93% |

Sources: USGS (2012); ANP (2012); Rystad Energy AS; IEA databases and analysis.

In addition to its conventional oil resource base, Brazil also has potential in unconventional oil, including kerogen oil and light tight oil (LTO).[2] An estimated 3 billion barrels of recoverable kerogen oil resources are present in the Iratí formation in the Paraná basin in the south of the country, which have been exploited since the 1960s. According to a

2. Certain offshore fields in Brazil contain extra-heavy oil, the largest concentration of which is in the Marlim field in the Campos Basin. We consider this as conventional oil, since it is produced by conventional means. It amounts to just over 1 billion barrels of the proven reserves in Table 11.1 (largely in the Campos Basin).

recent assessment by the US Energy Information Administration (US EIA) of three large onshore basins (Solimões, Amazonas and Paraná), technically recoverable LTO resources are estimated at 5.4 billion barrels of oil (US EIA, 2013).

### *Natural gas*

Understanding of Brazil's natural gas potential has grown alongside that of its oil resources. In practice, the two are closely linked, as a large part of Brazil's gas resources is associated gas. Based on USGS analysis, remaining recoverable conventional gas resources are estimated at just over 12 trillion cubic metres (tcm) (USGS, 2012), (Table 11.2). Most of these resources are located offshore, with just over half of the total concentrated in the Santos basin (52%). Estimates of onshore conventional resources are considerably smaller, at just 1.2 billion cubic metres (bcm), with much of this expected to be non-associated gas, containing some light condensates.

**Table 11.2 ▻ Brazil gas resources by region** (bcm)

| | Proven reserves end-2012 | Ultimately recoverable resources | Cumulative production end-2012 | Remaining recoverable resources | Remaining % of ultimately recoverable resources |
|---|---|---|---|---|---|
| Campos basin | 102 | 2 360 | 85 | 2 275 | 96% |
| Santos basin | 222 | 6 360 | 16 | 6 344 | 99% |
| Other offshore | 65 | 2 420 | 77 | 2 343 | 97% |
| Onshore | 71 | 1 290 | 52 | 1 238 | 92% |
| Total conventional | 459 | 12 430 | 230 | 12 200 | 98% |
| Unconventional (onshore) | 0 | 7 800 | 0 | 7 800 | 100% |
| **Total Brazil** | **459** | **20 230** | **230** | **20 000** | **99%** |
| of which associated gas | 278 | 9 480 | 143 | 9 337 | 98% |

Sources: USGS (2012); ANP (2012); US EIA (2013); Rystad Energy AS; IEA databases and analysis.

Brazil is also thought to have considerable potential for unconventional gas production. The recent US Energy Information Administration (EIA) assessment put Brazil's technically recoverable shale gas resources for three onshore basins at 6.9 tcm – the tenth-largest in the world (US EIA, 2013).[3] The Brazilian National Agency for Oil, Gas and Biofuels (ANP) has conducted exploration surveys on the Parnaíba basin and the São Francisco basin and considered these sufficiently prospective, both for conventional and unconventional gas, to be included in earlier bid rounds. Further blocks in both basins are expected to be offered in a 12th licensing round, scheduled for November 2013, alongside acreage in the remote Parecis and Acre basins in the Amazon, the Paraná basin in the south and the more mature Recôncavo and Sergipe-Alagoas coastal basins in the east of Brazil.

3. The US EIA assessment covered the three basins for which sufficient data were available, *i.e.* Paraná, Solimões and Amazonas.

*Production costs*

The largest uncertainty over production costs relates to the new deepwater projects that are concentrated in the Santos basin, where exploration risks may be low, but the risks related to developing the resources are considerably higher. Frontier developments in deepwater are among the most complex projects undertaken by the global industry. They require new floating drilling platforms, able to handle the extreme weight of the pipes between the surface and the reservoir. Remotely operated underwater vehicles perform the operations required on the seafloor. Increasing distance from shore means limitations in helicopter capacities and the need for larger supply boats. The thick salt layer above the hydrocarbon reservoirs can slowly creep and deform the wellbore. Some of the equipment required is highly specialised and only a relatively small number of suppliers is capable of building it to the required specifications, which can result in tight supply markets. Overall, as in the case of Brazil, development of such resources can be undertaken only where the fields are of sufficient size to produce enough hydrocarbons to reward the substantial upfront investments.[4]

**Table 11.3 ▷ Indicative oil development and production costs in selected regions**

| Country or region | Type of project | Scale (mb/d) | Capital cost per barrel per day of capacity ($ thousand) | Operating costs ($/bbl) |
|---|---|---|---|---|
| Brazil | Deepwater pre-salt | 1.0 | 45-55 | 15-20 |
| Canada | Canadian oil sands with upgrading | 0.25 | 100-120 | 25-30 |
| Iraq | Onshore super-giant | 1.0 | 10-15 | 2 |
| Kazakhstan | North Caspian offshore | 0.25 | 70-80 | 15-20 |
| Saudi Arabia | Onshore generic expansion | 0.5 | 15 | 2-3 |
| United States | Light tight oil | 0.25 | 90-100 | 8 |
| West Africa | Deepwater | 0.25 | 70-80 | 25-30 |

Notes: All costs are in year-2012 dollars. Capital cost per barrel per day of plateau rate production capacity (or maximum production in the case of LTO). Operating costs include all expenses incurred by the operator during day-to-day production operations, but exclude taxes or royalties that might be levied by the government, as well as payments due to the operator, such as remuneration fees.

Source: IEA analysis.

We estimate that to bring a barrel of oil production capacity onstream in Brazil in the coming years will cost between $45 000-55 000 in the large fields of the pre-salt complex (Table 11.3).[5] This is at the low end of the range for deepwater operations globally, mainly

4. For sufficiently large offshore developments, as in Brazil, there is a point at which economies of scale start to kick in: helicopters and boats can be re-used to serve multiple projects; production from new projects can be connected to established sub-sea pipelines; and as regional geology becomes better known, wells can be drilled faster. As a result, the development of smaller and smaller fields becomes economic.

5. This can be expressed as about $7 billion capital expenditure to put in place 150 thousand barrels per day of capacity, *i.e.* roughly the output to a single floating production storage and offloading vessel (FPSO). Of this investment, the cost of the well represents around 50%, the FPSO itself about another 20% and the sub-sea equipment the remaining 30%.

because of the large size and high productivity of the fields in Brazil. Operating costs, averaged over the lifetime of a project, are estimated at $15-20/barrel.[6] One unknown element, which could push costs towards the higher end of this range, is the provision to be made for future repair or maintenance work on wells. Such work can be challenging and expensive in the deepwater pre-salt: unlike shallower locations, with more conventional geology, pre-salt wells require the same high-cost drilling rigs for well repairs and maintenance as are used for exploration and well construction.

Costs for natural gas production depend to a large extent on whether the gas is associated or non-associated. In cases where project economics are driven entirely by oil, gas is essentially available as a free by-product at the wellhead, but, in all cases, there is a cost associated with separating out and treating the gas and transporting it to shore (around $1-$2 per million British thermal units (MBtu) in the case of gas from the Santos basin). We estimate that the current delivered cost of non-associated offshore gas from the Mexilhão field to the onshore gas processing facilities is around $2-3/MBtu, but expect future non-associated offshore gas to cost up to twice these levels. The costs of onshore gas production depend on the nature of the resource and its location: where gas can be produced conventionally (that is to say without costly hydraulic fracturing), operators are expecting wellhead gas costs of $2-5/MBtu, but, where the gas is in tight formations which need to be fractured, the costs could be as high as $9/MBtu (a level at which the resources would be unlikely to be produced), depending on the scale of this type of operation in the region and the availability of the necessary services.

### *Oil production*

The Brazilian authorities and Petrobras have set impressive oil production goals for the upcoming ten-year period. The current ten-year plan for the energy sector (EPE, 2013) forecasts production of 5.3 million barrels per day (mb/d) by 2020, two-and-a-half times the 2.16 mb/d seen in 2012. The anticipated increase in production, 3 mb/d over eight years, is expected to come overwhelmingly from deepwater developments, in which Petrobras is a world leader (Box 11.1). Petrobras' own business plan sees the company's output reach 4.2 mb/d by 2020, highlighting the extent to which the achievement of national ambitions in Brazil rests on the shoulders of its national oil company. Both the company figures and the national figures represent feasible scenarios for Brazil, but they (self-evidently) require many things to go according to plan, with almost no room for slippage.

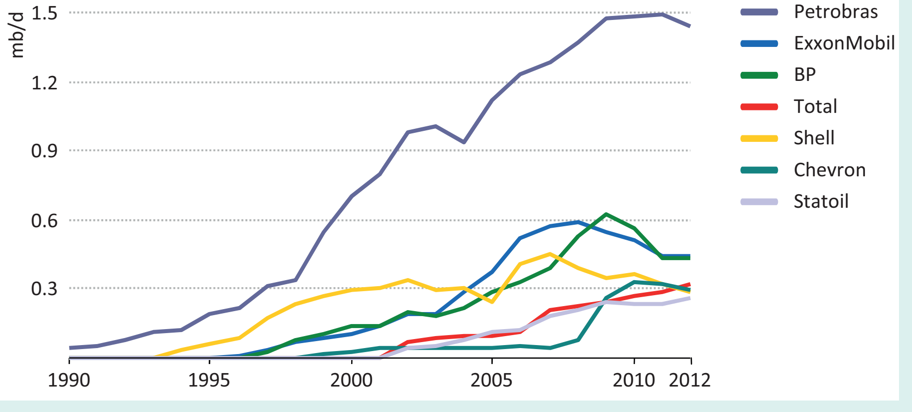


6. Operating costs include all expenses incurred during day-to-day production operations, but exclude taxes or royalties as well as other compensation to the operator, such as remuneration fees. Petrobras and its partners are currently indicating operating costs of between $4-13/barrel, but these costs are averaged against production rates that are likely to fall over time (while the operational cost of an FPSO remains constant).

**Box 11.1 ▷ Petrobras and global deepwater oil production**[7]

Global deepwater crude oil production has risen dramatically over the last twenty years, from a marginal 60 thousand barrels per day (kb/d) in 1990 to 6% of conventional crude output by 2012 (4.6 mb/d). Initially an activity mostly confined to the Gulf of Mexico, deepwater exploration extended first to Brazil and West Africa, and then, more recently to Australia, the Mediterranean, the South China Sea, India and East Africa. Petrobras has been at the forefront of this process and is, by a distance, the largest deepwater operator (Figure 11.3). The pace of development of the necessary deepwater technologies has been nothing short of phenomenal but, while recent years have confirmed deepwater potential, the extremes of deepwater continue to test the technological limits of the industry.[8]

**Figure 11.3 ▷ Global deepwater oil output by company**




Sources: Rystad Energy AS; IEA analysis.

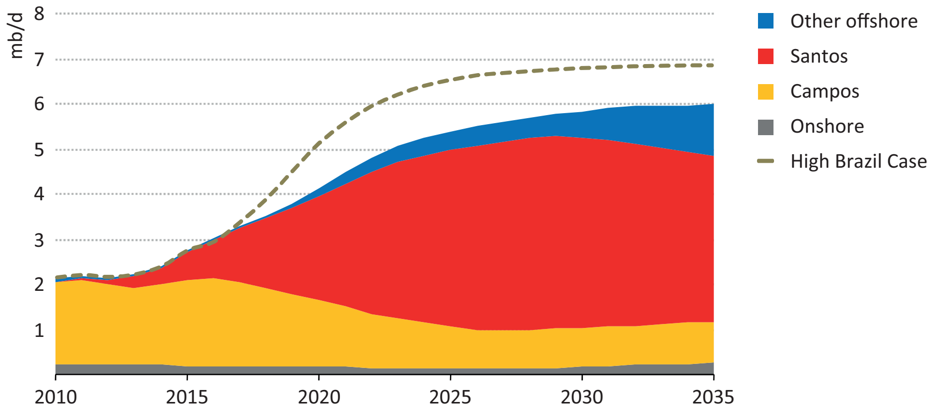
With the development of the pre-salt, Brazil and Petrobras are set to consolidate their positions of leadership in global deepwater production. The history of the oil industry offers few parallels for what Brazil is aiming to achieve over the coming years. The largest and most rapid growth in offshore production thus far came during the early development of the North Sea, with the efforts of the United Kingdom and Norway adding around 3 mb/d to production in eight years from the mid-1970s. At the time, the North Sea (with an average water depth of around 100 metres) represented the technology frontier for the offshore industry; the frontier today, in Brazil and elsewhere, is some twenty times deeper.

7. In this analysis, as in the *Outlook* as a whole, deepwater is defined as water depths in excess of 400 metres.

8. Highly relevant to this technical achievement is the fact that most of the deepwater acreage is open to international companies. We estimate that offshore resources represent about 60% of the remaining recoverable conventional resources currently accessible to international companies (excluding the Arctic).

The projections in the New Policies Scenario are more conservative than Brazilian national projections, but nonetheless see Brazil taking a seat at the top table of international oil producers and a leading place among offshore players. Production in our projections increases rapidly over the period to 2020, reaching just over 4 mb/d, and then expands to nearly 6 mb/d by 2035 (Figure 11.4). Set against the official outlooks, the anticipated pace of growth in the New Policies Scenario reflects the more cautious view that the vast and very capital-intensive process of developing the pre-salt is likely to experience some delays along the way. Given the challenges involved, there are downside risks beyond potential issues in the supply chain. For example, although Petrobras has been assiduous in its extended well testing and pilot schemes in the Santos basin, there are still inevitable uncertainties over how the reservoirs will perform during full development, the required level of well maintenance and whether the proposed recovery mechanism will function as anticipated (see the natural gas section).

**Figure 11.4 ▹ Brazil oil production by basin in the New Policies Scenario**




In this *Outlook*, we also present the outcome of a High Brazil Case in which the various offshore production units come on-stream at a pace that secures very rapid output growth in the medium term, with production reaching 5 mb/d by 2020 (just below the EPE target), before growth slows in the latter part of the projection period to reach 6.8 mb/d in 2035.

### *Pathways for Brazil's deepwater development*

The outlook for Brazil's oil output is almost entirely contingent on what happens with deepwater production, keeping in mind the tightened regulatory picture for Brazilian industry following the Macondo blowout the Gulf of Mexico in 2010 (Box 11.2). In the New Policies Scenario, the deepwater share in Brazil's total production rises from three-quarters in 2012 to nearly 90% in 2035. This includes all the output from the Santos basin and almost 90% from other offshore basins, including Campos. A key link in the deepwater supply chain is a series of floating production storage and offloading units (FPSOs), huge ships whose deployment in deepwater operations has grown rapidly over the last ten years.

With long distances from the main producing areas to the shore, the advantages of FPSOs in a Brazilian context are reinforced by their ability to store and then offload oil directly to tankers, avoiding the need for pipelines. Brazil has made a particularly strong commitment to this type of production unit as the means to develop its deepwater resources. There are currently around 160 FPSOs in operation worldwide, of which 34 are in Brazil, but Brazil is set to become the main area of growth in FPSO deployment: our projections imply that over 70 FPSOs will be producing in the Brazilian offshore by 2020, either built from scratch or converted from other large vessels.[9]

FPSOs are supplied via wellheads located on the ocean floor and sub-sea technologies are another important area for innovation in deepwater production. In certain circumstances, it is viable to install processing equipment such as separators and compressors on the sea-bed, where space is plentiful and where the operating conditions are also relatively stable, compared with the waves, winds and sea currents at the surface.[10] However, the challenges with sub-sea technologies are significant, including more difficult access and maintenance and the need for all equipment to be resistant to high pressure and the cold temperatures that can limit the flow of fluids.

With the start of pre-salt production, Petrobras and other companies operating in the deep Brazilian offshore have proven that the associated technological challenges are surmountable (although it is too early to assess all of the risks that may arise). What is open to question is the speed at which all of the necessary equipment, including FPSOs, can be built, commissioned and start operation. We focus here on FPSOs as a key link in this chain, but this analysis of FPSOs can serve as a proxy for other issues that may arise at different points along a complex manufacturing and production process.

The first half of 2013 has seen a significant increase of FPSO numbers in the Santos basin, with the addition of three units that were partially constructed in yards outside Brazil. In the period to 2016, about half of the units that we expect to be delivered will have been predominantly "made in Brazil", that is to say all the topsides, hull and integration work will have been carried out in Brazilian shipyards. The other half of the delivered units will have been (at least partially) built overseas. From 2017 onwards, the commitments already made on local content mean that these floating production units are predominantly produced in Brazil, in many cases involving the construction of the hull, rather than the conversion of an existing vessel. In our judgement, the timescale of this transition to Brazilian-built FPSOs creates uncertainty over the pace at which Brazil's oil production will grow, particularly given the large number of FPSOs that have been ordered or planned for the latter part of this decade. At present, Brazil has twelve hull conversions under order (of which six are being carried out in Brazil) as well as ten new-builds contracted (of which eight are being

9. In recent years the global shipping market has been somewhat over-supplied and a number of suitably large vessels have been available at reasonable cost for conversion to floating production vessels.

10. This type of installation is currently limited to cases where it would be difficult to pump the fluids to the surface without prior separation, or in locations, such as parts of the Norwegian sector of the North Sea, where hydrocarbons can be taken straight from sub-sea processing to onshore terminals without requiring an FPSO.

undertaken in Brazil). These 22 contracted vessels (twenty ordered by Petrobras) represent over half of the FPSOs currently under construction around the world. There are plans for a further fourteen vessels.

### Box 11.2 ▷ Brazil and deepwater regulation after Macondo

All deepwater developments operate in the shadow of the Macondo blow-out and spill in the Gulf of Mexico in 2010 and the knowledge that another serious accident or spill, anywhere in the world, would affect the prospects and pace of projects everywhere. The Macondo accident triggered a temporary moratorium on deepwater drilling in the Gulf of Mexico, and major reviews of safety regulations in the United States and other countries. Production from the Gulf of Mexico dropped from 1.6 mb/d in March 2010 to 1.1 mb/d in September 2011; in mid-2013 it had still not reached its pre-disaster level.[11]

Brazil has seen its own incidents in offshore operations, the most dramatic being the sinking of the Petrobras-36 floating production semi-submersible rig in 1 300 metres of water in 2001. The previous year had seen 11 000 barrels of fuel oil released into the bay of Guanabara due to a pipeline rupture. More recently, a rig drilling for Chevron had a well control incident on the Frade field in 2011, which resulted in 3 700 barrels of oil being released and an operational shut-down lasting almost eighteen months.

The Agência Nacional do Petróleo Gás Natural e Biocombustíveis (ANP) is the regulatory body responsible for operational safety on offshore installations, while regulatory authorities at state level within Brazil are responsible for environmental protection. The ANP has developed an Operational Safety Management System, SGSO, which includes seventeen management practices relating to leadership and personnel, facilities and technology and operational practices, observation of which must be demonstrated by all concession-holders. States require individual emergency plans for all installations to deal with environmental threats. The National Council for the Environment (CONAMA) requires co-ordination between the various plans in the same geographical area.

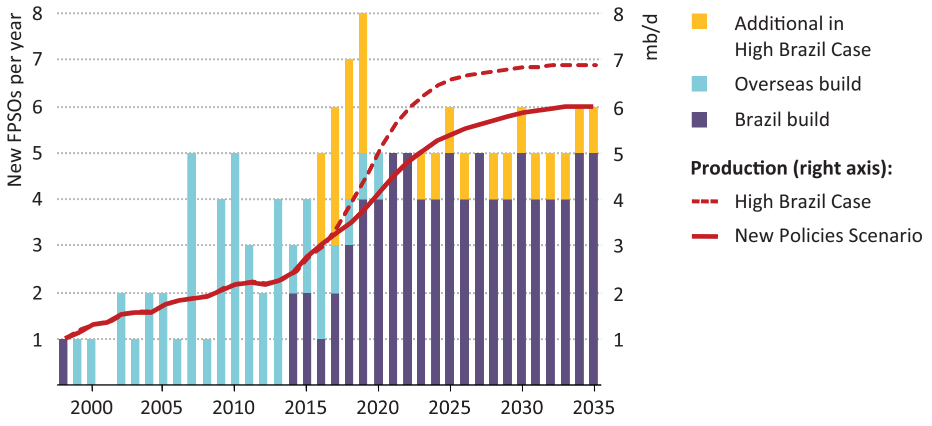
In reviewing lessons learned from Macondo, the Brazilian authorities revived the idea – considered at the time of the P-36 and Guanabara bay incidents in the early 2000s – of implementing a national contingency plan to deal with such emergencies and this is now in the last stages of adoption. The Brazilian environmental agency, IBAMA, has also tightened its scrutiny of contingency measures and increased its requirement for operators to maintain dedicated spill-response vessels offshore at all times. There are currently 40 such vessels covering Brazil's offshore operations.



11. Although production remains below the pre-disaster level, upstream activity levels in the Gulf of Mexico have already exceeded earlier highs, with 37 deepwater rigs in operation, compared to 30 at the time of the accident. Two new lease sales were held in 2012 and a further one in August 2013, attracting strong interest from the industry.

In the New Policies Scenario, the total number of new FPSO deployments averages around four per year in the second half of the decade, remaining roughly at this level for the rest of the projection period (Figure 11.5). This is enough to deliver a striking increase in output but, in the High Brazil Case, the delivery and commissioning of FPSOs proceeds more quickly. The key period – and the one that explains the difference in production between the High Brazil Case and the New Policies Scenario – is from 2017 to 2020, when the requirement for additional FPSOs in the High Brazil Case rises to a peak of eight in 2019 before dropping back to five per year thereafter. In terms of oil production, this higher rate of delivery translates into an additional 1 mb/d of oil production by 2020.

**Figure 11.5 ▷ FPSO deployment in the New Policies Scenario and in the High Brazil Case**




Notes: For the purposes of this figure a vessel is considered as built in Brazil if the hull is constructed or converted in Brazil. For many of the vessels built overseas, the fabrication of the process equipment (or topsides) and the integration of topsides and hull are carried out in Brazil. In the latter part of the projection period, some "new" FPSOs may be re-furbished vessels that have come out of service from other Brazil offshore locations.

Sources: Offshore Magazine (2012); press reports; IEA analysis.

In calibrating our New Policies Scenario, we looked to Asian shipyards as the international benchmarks for FPSO construction. Singapore dominates the market for converting existing hulls into FPSOs, performing two-thirds of all such conversions. There have been around sixty new FPSOs built globally to date, twenty-four of them in Korea and fifteen in China. The world's leading shipyard in FPSO construction (the Samsung shipyard in Korea) can deliver one to two units per year. The Brazilian shipbuilding industry is expanding rapidly, now employing more than 60 000 people, three times the number it employed in 2006 and 50% more than its previous historical peak of 40 000 in 1979 (SINAVAL, 2012a). Nonetheless, its relative lack of maturity makes it a potential bottleneck.[12] Of the eleven Brazilian shipyards that have been awarded contracts for FPSOs, seven of the shipyards

12. There is a large pipeline of orders with Brazilian shipyards (predominantly from the oil and gas industry) with over 386 ship works in progress in 2012, totalling 6.9 million deadweight tonnes (dwt) – a measure of the total weight carrying capacity of the ships (SINAVAL, 2012b).

themselves are under construction. Contracts for eight new-build FPSOs has been awarded to a new Brazilian shipyard in Rio Grande do Sul; the vessels are all due for delivery by the end of 2018, a schedule that requires a relative newcomer to produce FPSOs more quickly than the current market leader in Korea.

Thus far, Petrobras has taken a pragmatic approach to the risk of delay. In 2013, the company turned to a Chinese shipyard to perform part of the work for one vessel that was to have been carried out in Brazil. It has also chosen to lease two units for the pre-salt fields to ensure that production capacity is not wholly dependent on delivery of the Brazilian-built units. Since these projects resulted from earlier bidding rounds the local content commitments are not as strict, as those now applying, and similarly pragmatic approaches in the future could well fall foul of these commitments (Spotlight).

**S P O T L I G H T**

### Local content in Brazil; short-term costs, long-term value?

Commitments to use locally-sourced goods and services for Brazilian oil and gas developments have become an increasingly important element in the selection of upstream licensees since Brazil started its licensing rounds in the late 1990s.[13] The minimum requirements for local content in the exploration and development phases of projects have been raised and the procedures to verify compliance have become more extensive and detailed. Companies have also regularly committed themselves to meet local content levels in excess of the minimum requirements, as this commitment was an important assessment criterion for the award of licences (Figure 11.6).[14] The oil industry is now spending in excess of $30 billion per year in the Brazilian upstream, ten times the amount at the time of the initial rounds. For the projection period as a whole, we estimate that the requirement for upstream oil and gas spending in Brazil averages $60 billion per year, an amount similar to the figure for Russian investment (an average of $59 billion per year) and higher than that of the Middle East ($49 billion per year).

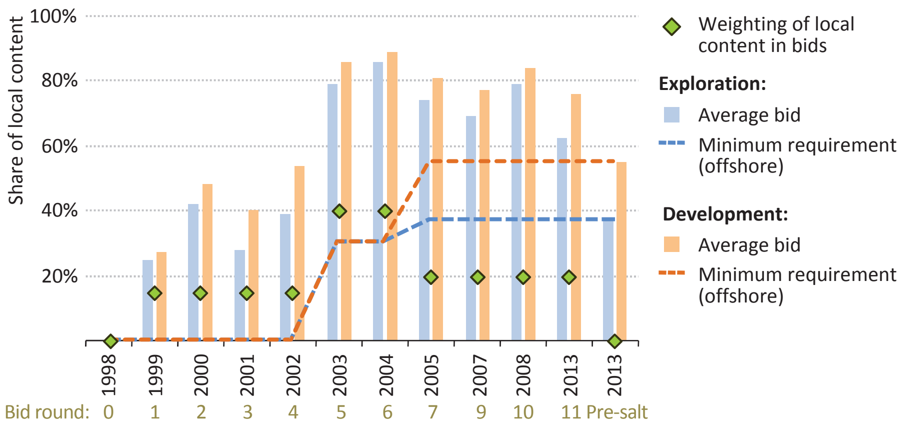
The guiding principle of these local content requirements is that operators should buy Brazilian goods and services wherever they are competitive in terms of cost and quality. With its experience in oil and gas production, Brazil already has over two hundred suppliers of capital goods to the industry (such as valves and pressure vessels) and local providers are major and regular contractors for drilling services, sub-sea installation and

13. Regulatory provisions favouring local goods and services over imported ones can raise questions about their compatibility with disciplines arising from membership in the World Trade Organization (WTO). Concerns have been expressed regarding Brazil's regulatory framework in this respect (WTO, 2013) but, since there has been no opinion or ruling on this from the WTO, and no process launched that would lead to such a ruling, we assume that the regulatory framework retains its current form.

14. There is scope for flexibility in implementing the rules, if it can be shown that suppliers within Brazil are unable to supply on competitive terms. ANP, the regulator, has some discretion in this area, but this is ultimately limited by the fact that many of the requirements have been taken on voluntarily by operators in the licensing rounds (at levels above the minimum requirements) and the authorities are reluctant to review parameters that may have determined the success of the various bids.

equipment maintenance. The Brazilian authorities and Petrobras have also made strenuous efforts to facilitate the emergence of Brazilian suppliers, through programmes such as PROMIMP, which maps out in detail the anticipated needs of the industry for different categories of equipment and then directs training and investment finance towards companies looking to supply these needs locally. Rising demand may nonetheless reveal shortfalls in areas such as sub-sea equipment, the construction of support vessels and the manufacture of FPSOs.

**Figure 11.6 ▷ Evolution of local content requirements in Brazil**




Notes: Offshore requirements indicated are for water depths >100m. Onshore projects are subject to a higher minimum local content requirement. Bid round 10 was exclusively for onshore blocks with a minimum local content requirement of 70% during the exploration phase.

Sources: ANP; IEA analysis.

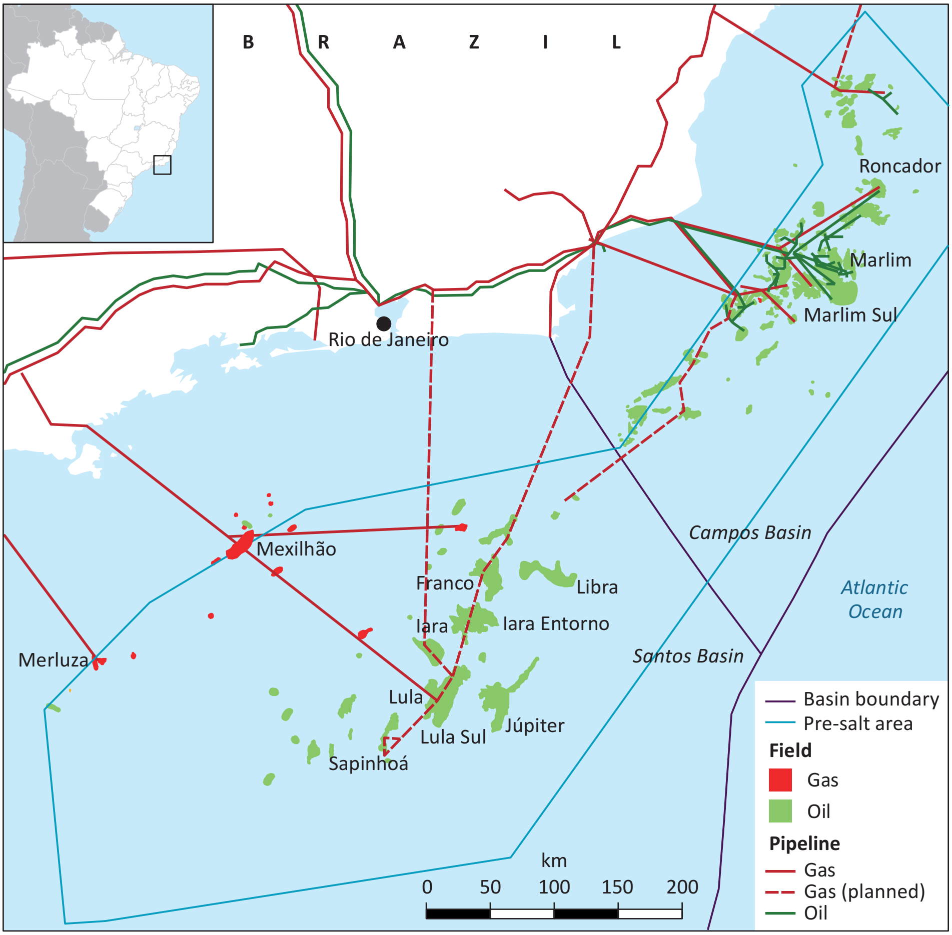
Over the period to 2035, the volume of investment required in the Brazilian upstream is on a scale sufficient to generate long-term value and employment within the country. But the risk involved in a local content policy is that local suppliers develop in a way that is not internationally competitive, with a resulting increase in costs and delays. In one sign of a tight market, the International Monetary Fund has estimated that, since 2009, the unit cost of labour in Brazil's manufacturing sector (the ratio of the wage bill to the value added of the sector) has risen by 20%, compared with that of Brazil's main trade partners (IMF, 2012). In another, Petrobras itself requested, in advance of the 11th licensing round in 2013, a reduction in the minimum percentages of local content required for 34 specific items and sub-items, stating that the requirements as they stood could not be met by the local supply chain (a request that was turned down by the regulator). Although a strong supporter of local content policies, Petrobras is the company most affected: with a business plan promising almost $240 billion in expenditure over the period to 2017, the company will be investing at levels beyond any other oil company (at home and internationally).[15]

15. Petrobras has 4 500 projects with budgets over $100 000 planned in the next twenty years. Of these, 3 600 projects are in exploration and production.

### *Santos basin*

The Santos basin is by far the largest source of projected supply growth in Brazil to 2035. In the New Policies Scenario, we project output from this basin to rise from 200 kb/d today to 2.3 mb/d in 2020 and to reach a plateau above 4 mb/d from the late 2020s, before declining to 3.7 mb/d in 2035. The prolific super-giant Lula field underpins this growth in the period to 2020. A growing contribution then comes in the 2020s from other areas of Santos, such as Iara and Franco (Figure 11.7) and from the huge Libra prospect, tendered in the first licensing round dedicated to pre-salt in October 2013 and awarded to a consortium including Petrobras (40% stake), Shell, Total, CNOOC and CNPC. Overall, growth from Santos accounts for 90% of total production growth over the projection period, implying the deployment of more than seventy FPSOs to different parts of the basin.

**Figure 11.7 ▷ Main oil and gas fields and infrastructure in the Santos and Campos basins**




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.

Petrobras is set to remain the dominant producer from the Santos basin in our *Outlook*, either because it is the existing concession-holder, or because the prospects (such as Franco) were part of the transfer of rights agreement reached with the government in 2010, or because of legislation governing the development of new fields within the pre-salt area (see Chapter 9, Box 9.3). The pre-salt area covers part of the Santos and part of the Campos basins and any new blocks offered within this limit (regardless of whether accumulations are geologically above or below salt layers) must be operated by Petrobras, which must hold at least a 30% stake in the asset (Figure 11.7).[16] However, the contribution from other companies is set to grow over time, either because they are partners with Petrobras (notably BG Group, Galp Energia and Repsol Sinopec[17]) or because they have existing concessions. Queiroz Galvão, an independent Brazilian oil and gas company, is one of the companies operating fields in the Santos basin and expects to see first oil from its twin heavy oil fields of Atlanta and Oliva, in the Santos post-salt, in 2015. A potential concern for companies operating in the Santos (and Campos) basins is some residual uncertainty over aspects of the regulatory and fiscal regime (Box 11.3).

### Box 11.3 ▻ Could oil suffer from divided royalties?

The division within Brazil of royalties paid by upstream companies has been a point of contention in recent years, pitting the states whose jurisdiction covers the main offshore deposits – Rio de Janeiro, São Paulo and Espirito Santo – against regional representatives from elsewhere. A compromise reached in 2012, covering all new oil production contracts, specifies that from the 11th licensing round onwards royalties are to be split evenly between all states. This issue has, however, been reopened in 2013, with legislation extending the scope of the arrangement, to cover not only new contracts but also earlier ones. The issue is before the Brazilian Supreme Court and prior to a decision the application of the legislation has been suspended. In theory, the outcome of the case would have no impact on the upstream companies: their payments would remain the same and it is only the beneficiaries that would change. In practice, though, if the states that currently receive revenue from the upstream were to lose all or part of it, they might want to exercise their own tax-raising powers to make-up any shortfall. If this happened, it would impact on the economics of projects that companies are undertaking.

#### *Campos basin*

The Campos basin has already been producing for 35 years and many of its current fields (and their equipment) are approaching the end of their productive life. But estimated remaining recoverable resources of 27 billion barrels do not suggest an area in terminal

16. In some offshore exploration blocks within the defined pre-salt area, which were offered in earlier licensing rounds, companies, other than Petrobras, have development rights for any deposits found. Pre-salt discoveries outside the defined area would likewise be open to development by the concession-holder.

17. Repsol Sinopec is a joint venture in Brazil between the Spanish oil company Repsol and China's Sinopec.

decline and, alongside Petrobras' efforts to maintain production from existing fields, new prospects are emerging for Campos from several recent discoveries in the deeper pre-salt. Our projections for the Campos basin anticipate oil production remaining at or above current levels until the latter part of the decade, before dropping to 1.5 mb/d in 2020 and 900 kb/d in 2035.

For the existing fields, the cost and difficulty of recovering the remaining oil has been increasing: the giant Marlim field, for example, has seen production fall from 615 kb/d in 2002 to less than 200 kb/d in 2012. Petrobras has been pursuing two initiatives to slow this trend. The first is a $5 billion programme, called PROEF, that focuses on maximising operational efficiency, in large part by ensuring that sufficient equipment and replacement parts are available in a timely manner, so as to maintain older platforms, sub-sea systems and wells in good working order. The second initiative is a programme called Varredura that aims to identify accumulations in both the Campos and Espirito Santo basins that could be tied in to existing infrastructure.

The most notable new discovery in the Campos basin was made at the Pão de Açucar prospect in the Campos pre-salt by Repsol Sinopec in 2012: resources there are estimated by the company at 700 million barrels of light oil and 85 billion cubic metres (bcm) of gas. Outside the Santos basin, this would be the largest field discovered in Brazil since the 1990s. Petrobras is also developing new fields in the area, including a pre-salt development at Parque das Baleias, the Papa-Terra heavy oil field and additional phases at Roncador. In all, we project that, in the period to 2016, more FPSOs will be brought into service on Campos than on Santos and that, by 2020, fields not currently producing contribute nearly 300 kb/d to Campos output.

### *Other offshore*



There are a number of promising basins beyond Campos and Santos, one of which is the neighbouring coastal basin of Espirito Santo, to the north of Campos. In 2012, this basin produced 2% of Brazil's oil output, less than 50 kb/d (although more than 10% of the country's gas) and, with the addition of a second FPSO around the end of the current decade, we expect production to increase. Production growth towards 2020 is also likely from the deepwater of the Sergipe-Alagoas basin.

In the 2020s, output from other offshore areas should start to reflect the fruits of the 11th licensing round, which offered extensive exploration opportunities along Brazil's equatorial margin and provisionally awarded 55 offshore blocks, 42 of which in deepwater. All of the six blocks on offer in the Espirito Santo basin were awarded, confirming the promise of this area. There was also strong competition for acreage in the Foz do Amazonas in the north, close to French Guiana (where an offshore discovery was made in 2011) and in the Barreirinhas basin, further along the coast. Alongside Petrobras, Total, Statoil, BG Group and BP were awarded some of the most promising offshore blocks. By 2035, we expect offshore basins other than Santos and Campos to contribute just over 1 mb/d to oil production.

### *Onshore*

In 2012, onshore production made up just 8% (180 kb/d) of Brazil's oil production, a percentage that has been falling steadily as offshore production has picked up. Petrobras has invested significantly over the last five years to maintain onshore production, and other onshore players have increased their activity. In all, nearly 3 300 new wells have been drilled for onshore oil or gas in the last five years, 75% more than the figure for the previous five-year period. But the return on these efforts has been comparatively slight and we do not expect onshore oil production to rise beyond 250 kb/d during the projection period. Brazil has also been a long-standing, if relatively small-scale, producer of unconventional oil from its kerogen oil resources in the south.[18] There is also some LTO onshore, although in the New Policies Scenario we do not anticipate that unconventional oil will play a large role in the Brazil supply picture.

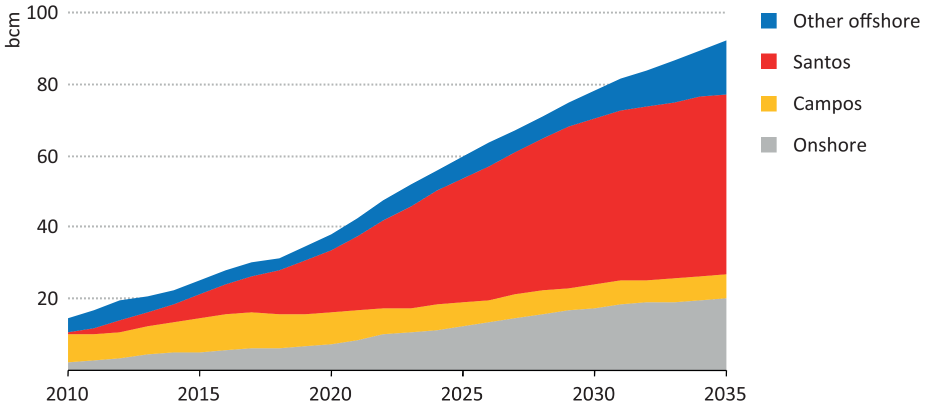
## Gas production

Natural gas has long remained in the shadow of oil production in Brazil's upstream priorities. The incentives to develop gas were initially muted by the limited domestic market for the gas, meaning that offshore associated gas was more of an encumbrance than an opportunity. But this situation is gradually changing and, since the early 2000s, natural gas has assumed a more important role in the Brazilian energy mix. While oil production still remains a priority, the government has come to view domestic gas resources as an important strategic asset, providing a means of increasing the reliability of electricity supply and to improving the competitive position of Brazilian industry. The shale gas phenomenon in the United States has reinforced this notion. There is huge potential to bring additional associated gas onshore from the Santos basin, (although still some major uncertainties over how much of this gas will immediately be reinjected back into the fields). There are also signs of a new dynamism onshore, with companies looking for productive opportunities to bring gas to market – or, where this is feasible, to create local gas markets on the back of future discoveries. In our New Policies Scenario, Brazil puts itself firmly on the map as a major gas producer, with output rising from 18 bcm in 2012 to 38 bcm in 2020, and 92 bcm in 2035 (Figure 11.8).[19]

18. Kerogen oil is produced from fine shale sediments containing kerogen, the geological precursor to oil and gas. Liquid oil is produced from these sediments by "retorting", *i.e*. an industrial heating process, carried out either in-situ or after mining the rock. Petrobras started production from the extensive Irati shale formation in the 1960s; its gas combustion retort is the world's largest single operational processor of kerogen shale, heating crushed rock fragments to high temperatures to release the organic matter in the form of oil and gas. This facility can process more than 6 000 tonnes of mined rock a day, generating 3 100 barrels of oil, 75 thousand cubic metres per day of gas and 45 tonnes of liquefied petroleum gas.

19. These figures are for marketed gas production. They differ from Brazilian official data which typically give gross gas production figures, including gas which is flared and reinjected into the field.

**Figure 11.8** ▷ **Brazil gas production in the New Policies Scenario**




Notes: Our projections present Brazil's marketed gas production, net of flaring, venting and reinjection, but including gas consumed in production. They consequently differ from the figures presented by ANP, which include gas that is flared and reinjected.

### *Offshore*

The key to Brazil's offshore gas production lies in the Santos basin. It is here that the largest expansion of oil output is envisaged and we estimate that each barrel of oil brought to the surface will, on average, be accompanied by some 40 cubic metres of gas (of which 10-20% is typically carbon dioxide [$CO_2$], although this varies widely by field). The options for dealing with this gas are constrained by the firm commitment of the Brazilian authorities that the $CO_2$ should not be released into the atmosphere and that gas flaring should be minimised. The share of gas flared in offshore production has been consistently diminishing, from 21% in 2002 to 6% in 2012 and we anticipate a continuation of this downward trend over the *Outlook* period.

11

Over the last ten years, only around 3% of the gas produced offshore in the Campos basin has typically been used for reinjection, as water injection has been the preferred way to improve the amount of oil recovered from the reservoir. For the Santos pre-salt fields, however, gas is provisionally expected to be a much more important part of the oil recovery process. In the Lula field, Petrobras is testing a scheme whereby a water injection cycle is followed by a gas injection cycle (known as a water-alternating-gas, or WAG, injection).[20] This form of oil recovery has been chosen in part because of the reservoir and fluid characteristics, which appear to favour this approach, but also to make use of the relatively high concentrations of $CO_2$ produced with the gas.

20. See Chapter 13, Box 13.5 for a discussion on recovery techniques for oil reservoirs. WAG injection is a combination of two standard secondary recovery techniques, water and gas injection. In this case, the gas is expected to partially dissolve in the oil and change its fluid properties. This is the first time that WAG injection has taken place in carbonate rocks at these depth and pressure conditions. Indeed, less than a dozen offshore WAG projects have ever been undertaken globally and never before on this scale.

How much gas is made available to market will depend on the oil output, on the success of the WAG pilot scheme, which is still in its early days, and on the extent to which it is then implemented across the pre-salt fields (where reinjection rates will be field specific). The direction that Petrobras takes on this issue will also be contingent on the pace of gas demand growth (some of which will result from the company's own investments in gas-consuming sectors), the amounts that are consumed to support upstream operations and the availability of infrastructure to bring gas to shore and process it.

These demand considerations mean that, in the initial phase when oil production rises quickly (and wellhead volumes of associated gas likewise), our assumed reinjection rate needs to be relatively high, but this rate declines over time as market opportunities expand. Volumes of marketed gas production from Santos (net of reinjection) rise from 3 bcm in 2012 to 51 bcm in 2035. This projection is subject to a wide degree of uncertainty. In the New Policies Scenario, the average reinjection rate over the next ten years is around 50%; if the average volumes reinjected were to vary by twenty percentage points either side of this figure, then already by 2025 the variation in terms of marketed gas output from the Santos Basin would be substantial: compared with the 34 bcm produced in 2025, the range would be from 27 bcm, with higher average gas reinjection, to 44 bcm with lower average gas reinjection (Figure 11.9).

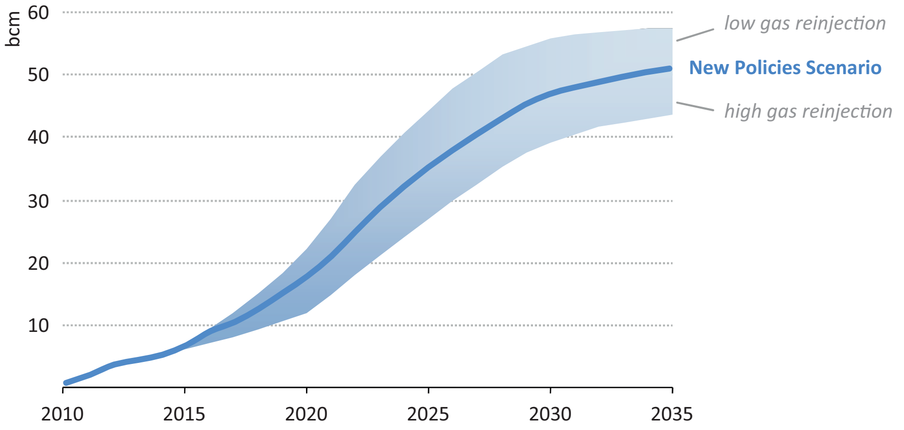
There is also a possibility that gas could emerge as a constraint on the oil production profile. If gas injection proves to be ineffective as a recovery mechanism (for example, if it fails to push the oil, but rather flows directly to the production well) and other disposal options (including flaring) are limited, or if the infrastructure to take gas to shore is not available on schedule, then Petrobras could have a surfeit of gas, with no obvious evacuation possibilities.[21] The only option under these circumstances would be to throttle back on oil output until such time as a workable transport or other disposal option is found. One option that might be considered is floating liquefied natural gas (FLNG) off-take from the offshore fields. Although FLNG is generally a more expensive option than transport by pipeline, it does give increased flexibility.

In our projections, the Santos basin emerges as the major source of offshore gas, while gas from Campos (where the oil is less rich in associated gas) makes a more modest contribution, picking up in the early part of the projection period from its 2012 level of 7 bcm to almost 10 bcm in 2017 and then dropping to between 6 and 7 bcm for the latter part of the projection period. This contribution is overtaken before 2030 by gas from other offshore basins, which reaches 15 bcm by 2035. Offshore production outside Santos and Campos at present comes primarily from the Espirito Santo basin and this is expected to

21. Our projections for gas production from the Santos basin in the New Policies Scenario are a reasonable match with the envisaged expansion of pipeline capacity to shore. Petrobras foresees two additional pipeline connections from the producing fields to the mainland, coming on stream in 2015 and 2016 (Figure 11.7). In addition to the link via the non-associated gas fields of Mexilhão and Merluza (constrained until later 2013 by onshore gas processing limitations), this would bring total capacity to around 20 bcm per year. This is sufficient to account for the basin's projected gas transportation needs (net of gas use in upstream operations) until 2020. After this point, operators would need to expand or add pipeline capacity, or consider other options, such as floating LNG liquefaction facilities.

increase in the early part of the projection period, as is production from the non-associated Manati field, located in shallow water in Bahia state. We also anticipate supply after 2020 from other offshore basins, notably those that were the subject of interest in the 11th licensing round in 2013.

**Figure 11.9 ▷ Santos Basin gas production for different gas reinjection rates**




### *Onshore*

There is new interest in Brazil in onshore gas exploration opportunities, but it remains to be seen whether this results in a new wave of potentially commercial discoveries and, if so, whether the location of these discoveries and Brazil's evolving gas market structure will be conducive to their development. In our projections, onshore production does gain ground, from 3 bcm in 2012 to 8 bcm in 2020 and 20 bcm in 2035 (including both conventional and unconventional production, Box 11.4). Anticipated supply comes mainly from the Solimões basin, which currently accounts for more than half of onshore gas production, and the Parnaíba basin, where commercial gas production began in early 2013 (this is an area that generated significant interest in the 11th bid round in 2013). The Tucano and Reconcavo basins, in the state of Bahia, which have been producing for more than 50 years, remain steady contributors. There are also smaller volumes expected from the Paraná and São Francisco basins.

The constraints on the onshore gas outlook are related in part to geology, but also to factors above the ground. The onshore supply chains and services required to support the upstream industry need time to develop. Even more importantly, areas that appear promising in terms of resources are often distant from markets and from the existing gas transportation network. The latter implies that many onshore discoveries will need to be accompanied by an active process of developing local or regional infrastructure and demand for gas.

This was the case in the Solimões basin, a particularly isolated area near the source of the Amazon River, where Petrobras discovered the gas condensate field, Urucu, in 1986 but – in the absence of a local market – had to reinject around 80% of production (the economics of the projects were driven almost entirely by the liquids content of the gas). This changed in 2009 with the completion of a 660 km pipeline to Manaus (a city whose 2 million inhabitants make up half of the population of Amazonas state). With this outlet, 1.7 bcm of gas is now consumed in this region and the share of reinjected gas has fallen substantially, to 50% in 2012. Similar development of local demand is evident in the Parnaíba basin, where the operators have achieved value from their gas output by developing local gas-fired power generation. Based on these examples, future onshore gas production is most likely where a high-quality resource is located within relatively easy reach of potential demand centres (such as industrial capacity, that could convert to use natural gas) or where there are specific projects that could be developed such as gas-fired power or fertiliser plants.

**Box 11.4 ▷ Unconventional gas outlook for Brazil**

The experience of North America has generated a lot of interest around the world in unconventional gas. Brazil is one of many countries that are now investigating this opportunity.[22] The 12th licensing round is offering onshore exploration assets in seven basins – São Francisco, Parnaíba, Paraná, Acre, Parecis, Recôncavo and Sergipe-Alagoas – with both conventional and unconventional gas potential. Unconventional gas (both in shale rocks and other low permeability or tight rocks) has the potential to make a major difference to the Brazilian gas outlook: the assessed resources in three Brazilian basins evaluated by the US EIA are equivalent to the gas resources estimated for the Santos basin and many times larger than estimated onshore conventional resources (US EIA, 2013). Unconventional gas currently is not subject to any distinct regulatory treatment: the conditions for bidding in the licensing round are uniform, with all bids being judged on the basis of the minimum exploration programme, signature bonus and local content proposals. Well specifications and environmental regulations are likewise uniform for the upstream as a whole, although the regulator, ANP, has indicated that it will scrutinise unconventional activities carefully to ensure that the associated social and environmental concerns are satisfactorily addressed.

In our projections, unconventional gas production starts to gather pace in the early 2020s, adding some 6 bcm to supply by 2035, The costs of multistage hydraulic fracturing make shale gas wells generally more expensive than conventional gas wells, in Brazil as elsewhere: extraction costs are estimated at between $4-9 per MBtu. This can nonetheless be an attractive prospect in areas where economies of scale can be expected to bring costs to the lower end of this range and – as with conventional gas – where resources are advantageously placed in relation to markets or infrastructure. Brazil is also a significant producer of ceramic proppant, a key component of the hydraulic fracturing process, supplying 10% of the world market in 2012.

22. The US EIA indicated that Brazil may have the tenth-largest technically recoverable shale gas resource base in the world, around 7 tcm: this is around 100 times larger than current proven reserves of onshore gas (US EIA, 2013).

## Renewables

Brazil's renewable resources are abundant, diverse and spread throughout the country. The use of renewable energy resources is firmly embedded in different sectors of Brazil's economy. The technical potential of Brazil's hydropower, bioenergy, wind, solar and other renewable resources could deliver levels of supply well in excess of projected domestic consumption long into the future. The extent to which this potential has already been tapped varies by source. In the case of hydropower, around one-third of the mapped potential has been developed, compared with only a small fraction of the country's solar and wind resources. In many countries, sources of modern renewable supply are not yet cost-competitive with fossil fuels but, in the case of Brazil, hydropower, some bioenergy technologies and wind are considered economically attractive energy supply options on their own terms.

### *Hydropower*

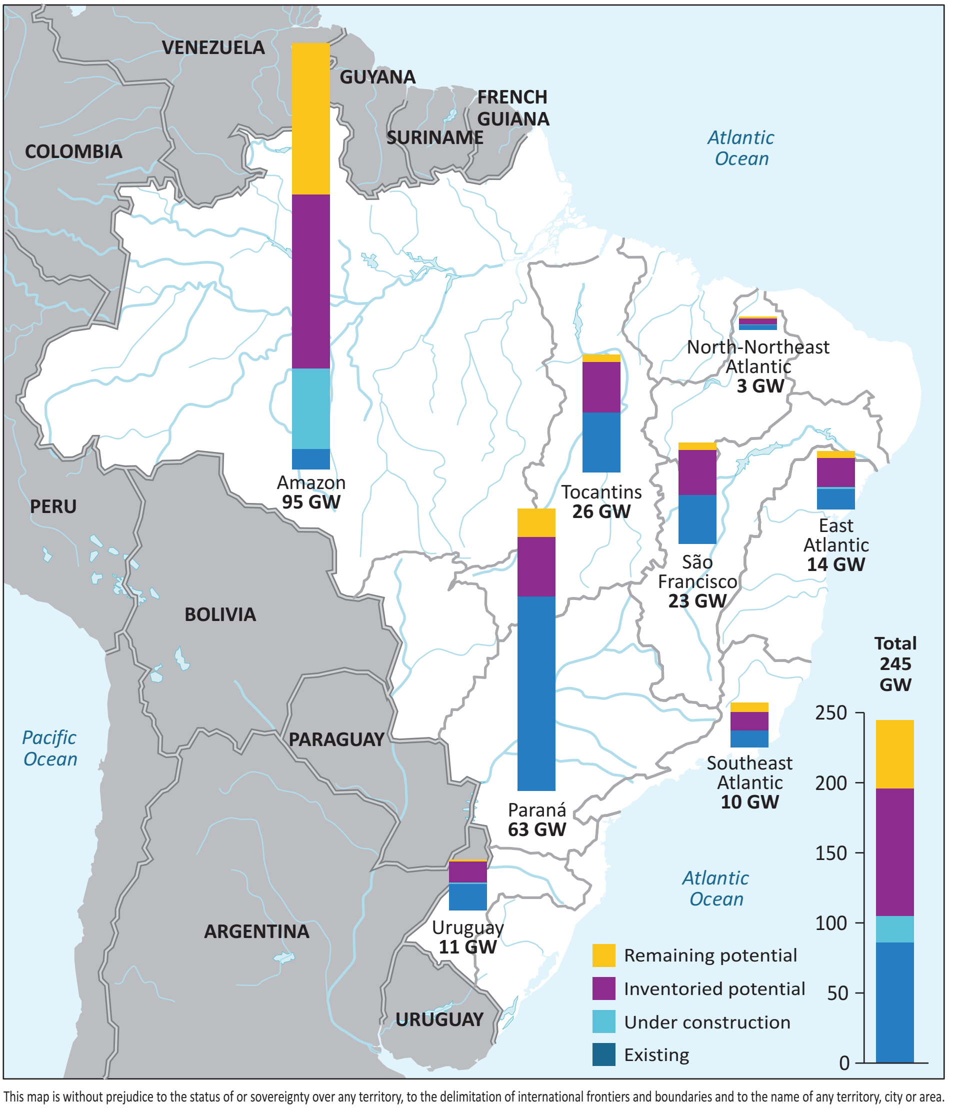
#### *Resources*

Hydropower has long been the cornerstone of the power sector in Brazil, but there remains significant potential to expand. In 2012, installed hydropower capacity was 83 gigawatts (GW), around one-third of the estimated 245 GW of potential in Brazil. Much of the remaining potential has been inventoried, meaning that the water resources have been officially assessed, an important first step toward developing a hydropower project in Brazil. The remaining hydropower potential in Brazil is concentrated in two river basins – the Amazon and Paraná – together accounting for more than three-quarters of the total (Figure 11.10).

**Box 11.5 ▷ A platform for Amazon hydropower development**

The concept of a "platform hydropower plant" has been developed for use in areas with low or no local population, especially in the Amazon region, where much of Brazil's untapped hydropower potential is located (Zimmermann, 2007; Melo, *et al.*, 2012). The stated objective is to limit the impact of the development to the site itself, minimising implications for the surrounding area and allowing "platform hydropower plants" to become enablers of permanent environmental conservation. This means avoiding the creation of large, permanent settlements for workers during the construction phase, reducing auxiliary access and roads to a strict minimum, and re-foresting any affected areas and avoiding the development of villages or towns once construction is complete. Once operational, it is intended that the plant functions with a high degree of automation and a relatively small number of staff working on periods of rotation, as in the case of offshore oil and gas platforms. High-capacity transmission lines still though would be needed to make the link between the plant and the main power grid, with vigilance from the authorities needed to ensure that the required rights of way in remote areas do not lead to illegal agricultural or logging activities. Brazil's first hydropower platform project will reportedly be tendered in late 2013 or early 2014 (Government of Brazil, 2012).

**Figure 11.10 ▷ Brazil hydropower resources by river basin**




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.

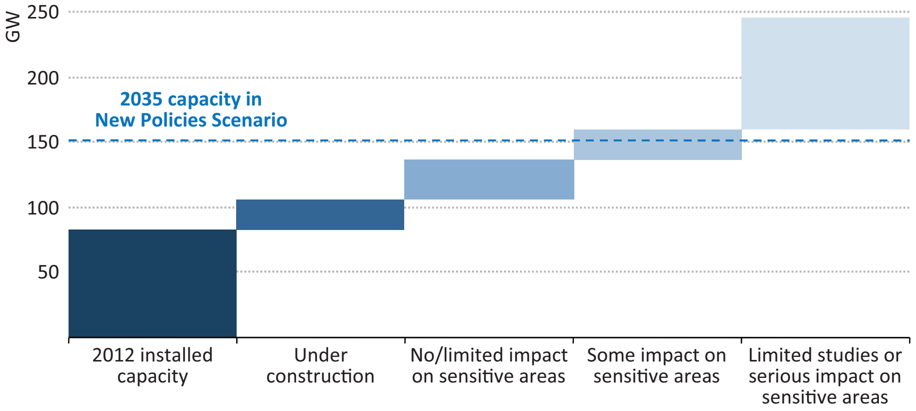
The Amazon River basin in the northwest of Brazil has a total estimated potential of 95 GW, representing around 40% of the country's total potential. Less than 5 GW of hydropower capacity has been built in this region, although a further 20 GW are under construction. Hydropower development in this area has been constrained for a number of reasons, including concerns about displacement and disruption of the indigenous population, damaging rainforest ecosystems and the means of connecting remote resources to distant demand centres. Efforts are currently being made to develop the hydropower potential in the Amazon region using new techniques, such as "platform hydropower", which would limit the impact of development on the surrounding area (Box 11.5).

The search for a model for Amazon hydropower that can command social acceptance is important for Brazil. If the potential in the Amazon River basin proves to be off-limits (beyond those projects already under construction), then the hydropower resource picture changes considerably. Without the Amazon, over 50% of the total hydropower potential in Brazil (including operational and under construction) has already been harnessed, leaving less than 70 GW untapped. In this case, the focus for hydropower expansion would fall more strongly on other areas, notably the Paraná River basin (which already supplies the Itaipu hydropower project), whose large resource is made more attractive by its relative proximity to Brazil's densely populated southeast.

### *Outlook*

In the New Policies Scenario, installed capacity of hydropower increases more than any other type of capacity over the *Outlook* period (67 GW), with hydropower capacity reaching 110 GW in 2020 and 151 GW in 2035. This is enough for hydropower to remain the predominant source of power generation in Brazil, even if its share of total capacity declines from 71% in 2012 to 58% in 2035. Close to two-thirds of the increase in hydropower capacity occurs before 2025 (41 GW), playing an important role in providing secure supply as electricity demand rapidly increases. Capacity additions slow after 2025, but installed capacity still increases a further 26 GW by 2035. The capacity additions in the New Policies Scenario can be achieved without developing hydropower potential considered to be of high social or environmental sensitivity, such as projects affecting inhabited or conservation areas in the Amazon region, but does not alter the imperative to find project development models that can win local acceptance and support (Figure 11.11).

**Figure 11.11 ▷ Brazil hydropower potential by classification of suitability**



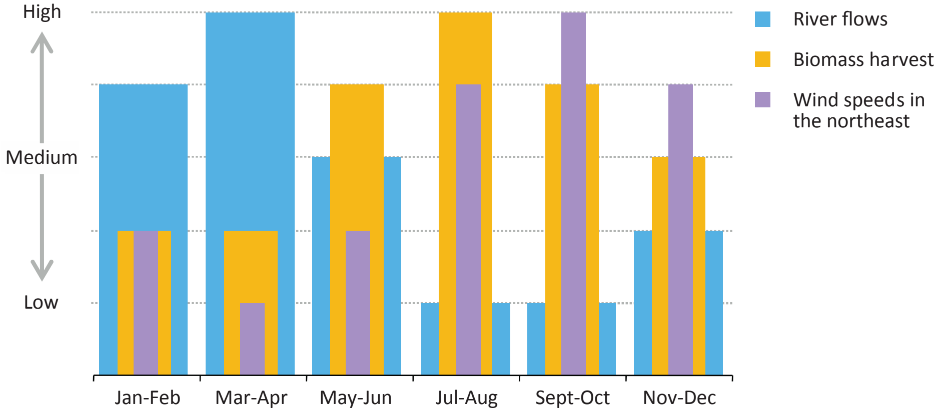

Note: Sensitive areas include indigenous lands or conservation areas.

Sources: EPE (2007); IEA analysis.

As described in Chapter 10, new hydropower capacity in Brazil is expected to focus on run-of-river projects, rather than those incorporating expansive reservoirs. The nature of the remaining hydropower resource is a factor that helps to explain this shift: some of the potential sites for new large hydropower projects are less suited for large reservoirs, as the flatter surrounding terrain would mean the flooding of very large surface areas. This though has implications for the character of the Brazilian power system, with the huge Belo Monte hydropower project providing a case in point. Once it is completed (expected to be in 2015), the power output of the 11.2 GW project will be much more dependent on the flow of the Xingu river over relatively short periods (days or weeks, rather than months or years) than hydropower developments that have reservoirs.

While rainfall patterns in Brazil vary considerably by region, seasonal supply from run-of-river hydropower projects is expected to be complemented (to an extent) by supply from some other seasonal forms of renewable electricity supply (Figure 11.12).[23] In the southeast of Brazil, the biomass (sugarcane) harvest begins before the onset of the dry season and extends beyond its end. The timing of the biomass harvest likewise assists in mitigating the variations in hydropower output in the north. Though wind power plays a minor role today, the seasonal pattern of winds in the northeast, where the majority of wind power is expected to be developed, complements low run-of-river hydropower during the dry season. Reservoir hydropower also helps to offset the strong seasonality of run-of-river hydropower, as reservoirs can be replenished during periods when run-of-river hydropower output is at its highest.

**Figure 11.12 ▹ Seasonal variation of selected renewable resources in Brazil**




Sources: ONS (2012); MAPA (2010); CEPEL (2001); IEA analysis.

Small-scale hydropower projects (*i.e.* those with capacity below 30 megawatts [MW]) currently account for less than 6% of total hydropower capacity and they are expected to continue to play only a supporting role to larger hydropower projects over the *Outlook* period. By 2020, there is projected to be around 7 GW of installed small hydropower capacity, with a further increase of 5 GW by 2035. Small hydropower projects are, in a number of circumstances, an attractive option because they are generally faster to build,

23. See also Chapter 10, Figure 10.7 for implications for the indicative power mix throughout the year.

require less capital and can often be located near demand centres, helping reduce stress and expenditure on transmission systems. However, such projects can sometimes be overlooked by investors, due to their limited scale. The development and application of alternative hydropower technologies for small-scale use (such as hydrokinetic designs) could expand the resource base in the future.

## Biofuels

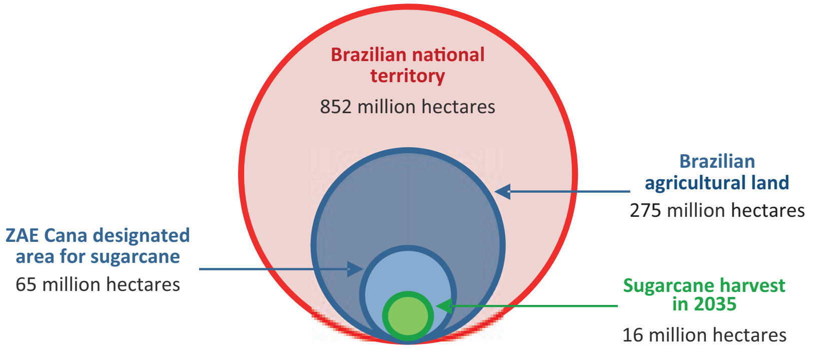
### Resources

The primary energy crops to produce biofuels in Brazil are sugarcane for ethanol and soybeans for biodiesel and much of the country provides good growing conditions for these crops. In 2012, 8.4 million hectares (around 1% of Brazil's national territory) of sugarcane were harvested (CONAB, 2013), with around 90% of Brazilian sugarcane production taking place in south-central Brazil, particularly São Paulo state, and the remainder grown in the northeast of the country. In 2012, about half of the sugarcane harvest was used to produce some 405 kb/d (0.3 million barrels of oil equivalent per day [mboe/d]) of ethanol. In the same year, 25 million hectares were dedicated to soybeans, with about one-quarter of the harvest used to produce around 50 kboe/d of biodiesel (EPE, 2013).

In response to concerns over the way that increased biofuels production could displace other agricultural activities and contribute to deforestation, the government's "ZAE Cana" programme has mapped suitable zones for the expansion of sugarcane in Brazil establishing that, under its guiding criteria, 7.5% of Brazil's national territory could be suitable for sugarcane production (Figure 11.13). While not all zones are equally well-suited to growing sugarcane, this assessment indicates sufficient suitable land remains to expand the harvest in Brazil. There is also scope to improve crop yields, which are expected to continue to increase, as a result of new crop varieties and further adoption of mechanised harvesting. Making more land in Brazil available for biofuels production (beyond that in the ZAE Cana programme) is limited by the need to protect the Amazonian forests and other environmentally sensitive regions: expansion at the expense of protected areas could threaten two of the three largest international markets for Brazilian biofuels. For example, serious concerns about the environmental aspects of Brazilian biofuels development could affect the classification of Brazil's sugarcane ethanol as an "advanced" biofuel under the United States' Renewable Fuel Standard. Likewise, in the European Union, sustainability conditions and greenhouse-gas balances for biofuels are critical in evaluating potential supply to meet mandatory targets. The way that Brazilian biofuels production is managed is therefore closely linked to the availability of export markets for Brazilian ethanol production.

While the land resources and climatic conditions are suitable for a significant increase in biofuels production, a number of factors may still serve to limit future development, including possible increases in the costs of production, competition for use of the best available agricultural land with other crops (or with other uses of the resulting crop harvest), or lower demand for Brazil's biofuels (either domestically or internationally) as a result of policy changes or lower fossil fuel prices.

**Figure 11.13 ▷ Brazil agricultural land assessed as suitable for sugarcane production**



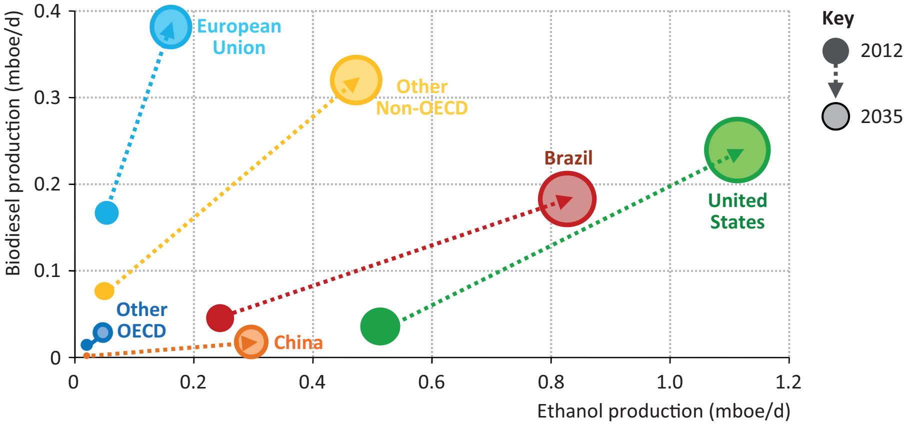

Notes: The ZAE Cana designated area is restricted to the total characterised by medium to high productivity. The sugarcane harvest includes both sugarcane for ethanol, based on IEA analysis, and sugarcane for sugar production, increasing by 1.7% per year.

Sources: MAPA (2009); OECD/UN FAO (2013); IEA analysis.

## *Outlook*

Biofuels represent the third-largest category of renewable energy in Brazil, after solid biomass and hydropower. Brazil is also the world's second-largest biofuels producer (after the United States), producing 0.3 mboe/d in 2012, more than 20% of global supply. In the New Policies Scenario, biofuels production in Brazil increases to about 1.0 mboe/day in 2035, a level more than sufficient to cover projected domestic demand of 0.8 mboe/day (Figure 11.14). The remainder goes to the international market, where demand is driven by increased use in road transport and some inroads into aviation. Ethanol continues to dominate biofuels supply over the *Outlook* period, accounting for over 80% of biofuels production in Brazil in 2035.

**Figure 11.14 ▷ Biofuels production in selected regions in the New Policies Scenario**



The level of ethanol production in Brazil in the New Policies Scenario is estimated to require over 800 million tonnes (Mt) of harvested feedstock from over 9 million hectares of cultivated land in 2035 (based on cautious assumptions relating to productivity improvements and feedstock composition). This level of cultivated land equates to less than one-sixth of the suitable land identified under ZAE Cana. In addition, 20 million hectares of land are used to produce soybeans for biodiesel production in 2035. Advanced biofuels, mainly cellulosic ethanol and biodiesel from palm oil, have the potential to limit the growth in land requirements and contribute to supply from early in the projection period, but they play only a supporting role in Brazil's overall production, contributing about 5% of biofuels production in 2035 (Box 11.6). Biodiesel derived from palm oil gains a small share of the market, displacing a marginal amount of soybean-based biodiesel.

Sugarcane-based ethanol is typically the lowest cost conventional biofuel, as the conversion process is relatively simple and the productivity of sugarcane is very high. In a high oil-price environment, such as that modelled in the New Policies Scenario, this is an important consideration – alongside continued government backing for the industry – that underpins the projected expansion of Brazilian ethanol production. But the outlook is also contingent on the industry successfully managing cost pressures on the production side. In south-central Brazil, close to half the sugarcane feedstock costs are associated directly with growing the crop and reconditioning the land, around one-third is related to collection costs and the rest is absorbed by administrative and other capital costs (PECEGE, 2012).[24] Continuation of the current trend of rising land and labour costs would point to higher feedstock prices in the future, which could undercut the competitive position of ethanol on the Brazilian market.

The risk of higher feedstock prices could though be offset completely or in part by changes to the structure of the sugarcane ethanol sector. Some less efficient mills are going out of business: companies accounting for about 2% of the total crushing capacity (40 mills) have recently filed for bankruptcy (tending to be smaller operations) (IEA, 2013). Over the projection period, the sector is likely to be increasingly characterised by a smaller number of larger players (including international companies) relying more heavily on mechanisation. This promises to bring progressively increased efficiency and scale to agricultural production and bio-refinery operations, reducing costs, and greatly improved logistics to ethanol transportation (away from the road network). There are already examples of co-operation between various producers on logistics, with a privately financed 200 km pipeline from the major sugarcane growing area of Ribeirão Preto in São Paulo state to the Petrobras refinery in Paulinia starting operation in 2013. Enhanced investment would also lower the risk (as currently witnessed) of a productivity decrease due to failure to renew crops. Over the longer term, these trends might help to reduce some of the volatility that has characterised ethanol output over recent years.



24. In the case of biodiesel, feedstock costs represent a larger share of the final price (upwards of 80%). Soybean oil, the main feedstock, is a tradable commodity, and so the price/cost for biofuels producers depends on the market price.

The prospect of reduced volatility in ethanol output is, though, far from guaranteed. Larger players in the sugarcane ethanol sector may be better placed to take advantage of arbitrage opportunities in sugar and ethanol markets, potentially shifting larger amounts of production from sugar to ethanol, or vice versa (which could in turn invite regulatory interventions from the authorities to guarantee ethanol supply). And while better farm management may lower some of the risk of crop failures and low harvests, irrigation is usually non-economic in the case of sugarcane, which leaves the activity more sensitive to variations in the weather.

### Box 11.6 ▷ Prospects for a new generation of biofuels in Brazil

Interest in advanced biofuels is increasing in Brazil. As productivity improvements in first generation biofuels show signs of diminishing, advanced (second generation) ethanol has the potential to generate another leap in output without expanding the harvested area. The existence of an established biofuels industry, the availability of low cost cellulosic feedstocks such as bagasse, a move towards mechanised harvesting (and a ban on field burning) and a desire to move into higher value-add sectors all contribute to making advanced ethanol production an attractive proposition in Brazil. Another form of advanced biofuels is biodiesel from palm oil, with potential yields per land area that are an order of magnitude higher than soybean-based biodiesel, potentially reducing the future land demand for biodiesel by millions of hectares.

International companies are becoming increasingly visible in Brazil's ethanol business and some have clear plans relating to advanced biofuels, drawing on international expertise and technology to build demonstration and commercial plants. In parallel, BNDES (Brazil's development bank) and FINEP (the federal government's research and development funding agency) have launched the PAISS programme, intended to provide supportive investment to the development of an advanced ethanol sector in Brazil, together with complementary sectors such as biochemicals and bio-refineries. The programme has allocated $733 million to eighteen advanced ethanol projects and is providing a strong signal of intent to the private sector (BNDES, 2013).

Advanced biofuels production costs are currently well above those of other fuels, due to the early stage of technology development and small scale of production. Efforts to develop the sector are expected to focus on building capacity and reducing investment costs (through pilot/demonstration projects), reducing the costs and enhancing the productivity of the enzymes and improving the efficiency of feedstock collection. With significant support from BNDES, the first commercial-scale advanced ethanol plant is scheduled to be operational in 2014. Given the supportive growing conditions, policy environment and funding programmes, several more commercial-scale production facilities can reasonably be expected by the end of this decade. In the New Policies Scenario, production of advanced biofuels gains momentum through to 2035 and accounts for a growing share of total biofuels investment in Brazil.

## Other bioenergy

### Resources

Other than biofuels, bioenergy produced in Brazil includes bagasse, wood and charcoal, biogas and other forms of both modern and traditional biomass. From the total sugarcane harvest, on average, around 30% ends up as residual bagasse, equivalent to around 150 Mt in 2011. The expected growth in sugarcane harvests and moves to reduce the unproductive burning of residues and increase the mechanisation of harvesting are expected to boost the availability of bagasse in the future. Bagasse contains around one-third of the energy potential of the original sugarcane. In practice, the first use of this bagasse is to provide power to Brazil's sugar mills, but around one-quarter of these mills also supply electricity to the grid. There is significant remaining potential to produce energy from bagasse, either in the form of second-generation biofuels or heat and electricity generation.

### Outlook

In the New Policies Scenario, power generation capacity utilising biomass increases by 2.4% per year on average, going from 9.6 GW in 2012 to 16 GW in 2035. This compares with 8 GW of installed capacity in the rest of Latin America combined in 2035. Power generation from bioenergy is overtaken by wind-based generation in our projections, but continues to be a substantial source of renewables-based electricity throughout the *Outlook* period. In 2035, around one-quarter of the electricity generated from bioenergy is in the form of distributed generation. Bioenergy also continues to meet a significant share of energy demand in industry, mainly charcoal that is used in iron and steel production (although this does not increase in absolute terms) and forestry residues for heat and power in the paper and pulp sectors. The role of bioenergy in energy supply in the buildings sector declines gradually as a share of overall energy use, but is expected to remain more prominent in rural communities. Important factors influencing the *Outlook* include the availability of financing to upgrade harvesting and boiler equipment, and to connect this power generation capacity to the local grid.



## Wind

### Resources

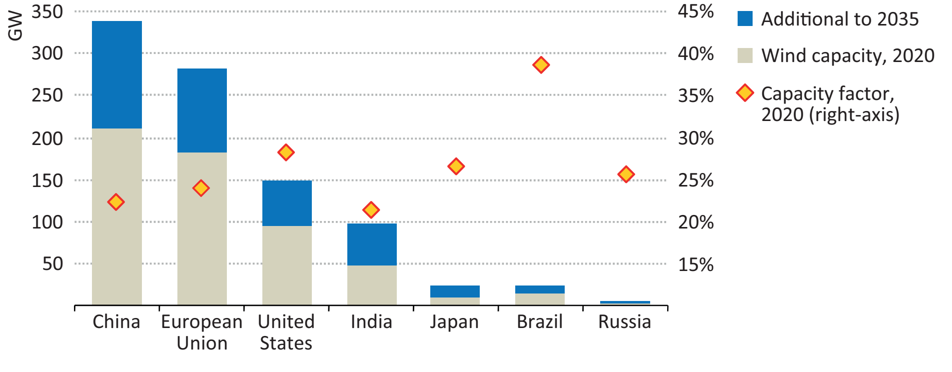
The wind power potential in Brazil was estimated at 143 GW in 2001 (CEPEL, 2001), but with technological advances since then, including larger wind turbines capturing stronger wind resources at higher elevations, the actual potential today may be closer to 350 GW (GWEC, 2011). Brazil has very favourable conditions for wind power generation, with the current focus being on the country's onshore wind resources, which are plentiful and cheaper to develop than offshore wind. The beneficial conditions include a coastline stretching about 7 500 km that provides many opportunities to harness the fairly constant easterly trade winds, with the most attractive possibilities concentrated along Brazil's coastline in the northeast and southeast. In the northeast alone, the estimated wind power potential is more than 50% of the potential for the whole of Brazil. There are also significant wind resources slightly inland of the eastern coast, in the states of Bahia and Minas Gerais.

At an average annual capacity factor of 40%, Brazil's wind resources could provide over 1 200 terawatt-hours (TWh) of electricity per year, more than double the country's total power generation from all sources in 2011. In a 2012 power auction, wind farms based their bids on estimated capacity factors of near 50%, which, if realised, would provide nearly twice the power generation per unit of capacity of the installed wind capacity in Europe. These expectations are supported by measured annual capacity factors around 50% in 2012 for recently built wind farms (although it will take some years of operation for capacity factors to be reliably established). Local content requirements have become an important condition to qualify for project financing from BNDES and could contribute to the growth of local manufacturing of turbines and other equipment. As in other sectors, it will be important that these requirements do not lead to the erosions of the competitiveness of wind power in relation to other sources of power.

### *Outlook*

In the New Policies Scenario, almost 30 GW of wind power capacity is added over the period to 2035, continuing wind's record of securing contracts in recent power auctions and promising measurements of its performance in practice (Figure 11.15).[25] More than three-quarters of the capacity additions expected in the period to 2020 have already been contracted through auctions. Based on capacity factors of above 40% for new projects, wind power grows from being 2% of Brazil's power generation capacity in 2012 to about 9% in 2035. Based on the higher range of estimates for Brazil's wind potential, less than 10% has been developed by 2035, with a focus on the sites with the best wind resources, such as the northeast coast. As wind power continues to be developed in this region, connection points and spare transmission capacity become limited, creating some resistance to more rapid growth in the medium to long term. Brazil continues to be the largest producer of wind-based electricity in Latin America and sees its share of global wind capacity increase to around 2% in 2035.

**Figure 11.15 ▷ Wind power capacity and capacity factors by country, 2020 and 2035**




25. Wind projects are assumed to have a 20-year economic lifetime in our modelling and so capacity installed before 2015 is retired before the end of the projection period.

The success of wind power when competing with thermal plants in Brazil's power supply auctions has received a lot of attention inside and outside the country. This success poses both an opportunity and a risk for the future of wind power in Brazil. There is an opportunity to prove that wind power is an economically viable option for meeting rising demand from the power sector, while holding down $CO_2$ emissions. The challenge lies in building the contracted wind projects on time and delivering performance in line with the contractual commitments. Although the costs of integrating wind power into the grid have not been considered in auctions to date (which have not included location criteria as part of the assessment of bids), the longer term prospects for wind power are helped by relatively low integration costs. As noted in Chapter 10, the large share of hydropower in the system provides a degree of flexibility that can accommodate a substantial expansion in the contribution of variable renewables. There are also planned upgrades to the transmission system that will help with the integration of more wind energy, notably the improved interconnections between the north and the southeast.

## Solar

### Resources

Brazil has strong and widespread solar resources. The annual mean of daily horizontal solar irradiation in any region of Brazil (in the range of 4 200-6 700 kilowatt-hours per square metre) is greater than that of many other countries already harnessing their solar resources (Pereira, *et al.*, 2006). While there are regional and climatic variations, solar irradiance is relatively constant across Brazil, the northeast region having the largest energy resource, followed by the midwest and southeast regions. The north of Brazil receives lower solar irradiation during the summer (December to January) than the south, with the opposite occurring during the winter (June to August). The variation of solar irradiation between winter and summer is smaller in the north, as it is closer to the Equator. Wide availability of the resource, at a "usable" level, opens up the possibility of off-grid applications, as well as centralised, on-grid development of solar power.



### Outlook

Solar power in Brazil continues to gain momentum throughout the projection period in the New Policies Scenario, despite other sources of energy supply remaining favoured to meet most of growing needs to 2035. Becoming more competitive as costs fall, solar capacity increases to 2 GW in 2020 and 8 GW in 2035, with the majority being solar photovoltaics (PV) and a much smaller share being concentrating solar power (CSP). Brazil continues to have the largest solar capacity of any country in Latin America, but it is about one-twentieth of the level projected in Europe for 2035.

Within Brazil's energy mix, solar is expected to find its place mainly in relatively niche roles: as a source of distributed electricity generation, especially as net metering is implemented; as part of the strategy to provide electricity access to remote rural communities (potentially in conjunction with back-up generation); and as a water heating solution in buildings (where domestic production capacity has developed). Of the installed solar capacity in the New Policies Scenario in 2035, the great majority (more than 7 GW) relates to distributed PV capacity installed on buildings as technology cost reductions make it increasingly attractive to consumers. In addition, the use of solar water heaters steadily increases throughout the *Outlook*.

The abundance of other sources of energy supply helps explain the relatively slow development of solar resources in Brazil over the *Outlook* period. Also, while capital costs for solar PV capacity decline by around 45% over the projection period in real terms, it still struggles to compete with other energy sources in many applications. However, there are regions where the use of PV technology is the best technical and economic solution, including areas with low local consumption, a dispersed consumer base, problems of access and environmental restrictions. This helps explain the deployment of solar as distributed generation, where it becomes competitive with alternatives such as small hydropower and biogas. To date, government programmes have been important in determining how and where solar solutions are deployed in Brazil's energy system and it is likely that this will continue. Solar PV is a viable option for communities targeted by the Luz para Todos (Light for All) programme and PRODEEM (Programme of Energy Development of States and Municipalities).

## Other fuels

### *Coal*

Brazil has sizeable coal reserves and resources, estimated to be on the order of 23.8 billion tonnes. Around three-quarters of this amount is low-grade lignite and the rest is hard coal (BGR, 2012). Proven reserves amount to about 6.6 billion tonnes, of which more than three-quarters is lignite. All of the commercially extractable coal in Brazil is located in the Paraná Basin, which extends across the states of Paraná, Santa Catarina and Rio Grande do Sul in the south. The high ash yield and sulphur values of Brazilian coal make it unsuitable for coking – a main source of coal demand in Brazil for iron and steel production.

Coal production has been in steady decline since the mid-1980s, when it peaked at 5.1 million tonnes of coal equivalent (Mtce), and it took a particularly strong hit at the start of the 1990s with the revocation of a long-standing law, introduced by the government in 1931, which stipulated that 10% of coal used in industrial production must be mined locally. Most of Brazil's current coal-fired generation was built in the period from the 1960s until the early 1970s, following which there was an extended hiatus in new plant commissioning that lasted until 2008, but the upturn in coal capacity and demand has not been matched by an upturn in domestic production. Coal output in 2011 (2.2 Mtce) dipped to its lowest level since 1977.

Coal-fired generation occupies only a small role in Brazil's power mix and the outcome of a power auction in August 2013 (in which coal-fired projects competed without winning any capacity contracts) suggests that this role is unlikely to change significantly. In the New Policies Scenario, we do see a gradual increase in installed coal capacity from 3.3 GW in

2012 to 4.8 GW in 2035, but this is only 2% of total generation (a very low share, when compared internationally). Power generation from coal-fired plants doubles to 25 TWh in 2035. New coal-fired capacity is assumed to be located in the south of Brazil, so as to take advantage of domestic resources in an area that is close to the largest demand centres, a feature that helps to alleviate potential electricity transmission bottlenecks.

### *Nuclear*

The Brazilian nuclear power industry, developed as part of the national strategy to diversify the energy mix and decrease reliance on imported fuel, currently plays only a small role in the overall supply picture. Government plans for the longer term suggest that nuclear will continue to be seen as being one of a number of options for additional capacity that can meet the government's preference for indigenous sources of low and zero-carbon energy. All nuclear generation capacity is operated by Eletronuclear, a subsidiary of Eletrobras.

Current generation capacity comes from two nuclear power reactors, Angra I (640 MW, commissioned in 1985) and Angra II (1.35 GW, commissioned in 2000), which have been operating at a site in Rio de Janeiro state, near the main Brazilian electricity demand centres. Preliminary work on a third reactor, Angra III, began in the 1980s, but was suspended after the Chernobyl disaster and re-started only in 2010. Construction to an upgraded design has been delayed by wrangles over tendering procedures and also by stricter regulatory demands put in place following the 2011 Fukushima Daiichi accident in Japan. We assume that Angra III's 1.35 GW of capacity comes online before 2020. Beyond 2020, expansion of nuclear capacity is expected to remain limited and gradual, with total installed capacity reaching 4 GW by 2035 in the New Policies Scenario, compared with 2 GW in 2012. Nuclear generation increases to 31 TWh in 2035, maintaining its share of total generation at 3%. The availability of other low carbon technologies at lower costs, including hydropower and wind power, limit the prospects for nuclear, particularly when combined with potential financing challenges, very long project lead times and the risk of public opposition. The relative inflexibility of nuclear power can also work against it in those parts of Brazil, such as the northeast, where more flexible types of generation might be preferred to work alongside variable renewables. Financing for new projects will be an important challenge for the further expansion of nuclear capacity, with the authorities seeking a way to involve private capital, while retaining government control over the sector as a whole.

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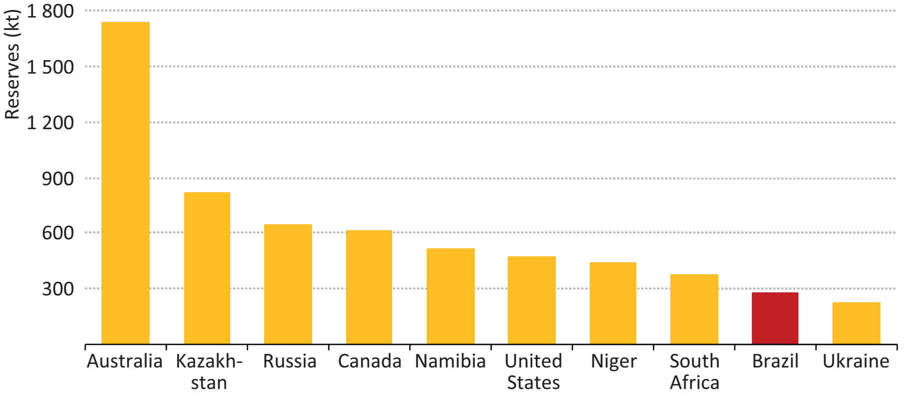
The availability of domestically produced nuclear fuel is one reason to suppose that a modest expansion in nuclear capacity will go ahead. Brazil has significant uranium resources to support its nuclear power ambitions: these are estimated at almost 277 thousand tonnes (kt), of which some 155 kt is considered as "reasonable assured resources", 3.5% of the global total (NEA/IAEA, 2012) (Figure 11.6). Most of these resources lie in two regions, Lagoa Real in Bahia State and Santa Quitéria in Ceará State. Caetité, at Lagoa Real, is Brazil's only producing uranium mine. It has the capacity to produce 400 tonnes per year, although current upgrade works are expected to raise the nominal capacity to 800 tonnes per year in 2015, by which time a second mine, with a capacity of 1 500 tonnes per year, is due to come online in Santa Quitéria. These projects would bring uranium production to around 2 300 tonnes per year. Currently, Brazil's nuclear plants require around 450 tonnes per year of uranium, a number that will increase to about 750 tonnes per year once Angra III comes online.

**Figure 11.16 ▷ Top ten holders of uranium resources**



# Implications of Brazil's energy development

## What does it mean for Brazil and for the world?

### Highlights

- Brazil's energy sector undergoes a huge expansion between now and 2035. It has a wealth of energy resources to draw on, but faces stern challenges to develop them effectively. The country's emergence as a major exporter of oil, the tightening constraints on the expansion of domestic hydropower and the continued strong growth in energy demand create a new context for policymaking.
- Brazil plays a central role in meeting the world's oil needs through to 2035, accounting for one-third of the net growth in global supply. Such an increase in supply is heavily dependent on highly complex and capital-intensive deepwater developments, where Brazil is set to consolidate its position as the global leader. Brazil's rise means that it joins the ranks of the ten largest global oil producers around 2015 and is the sixth-largest in 2035.
- Brazil is a key player in any scenario for regional energy trade and integration. Although our projections do not suggest a large surplus for Brazil in either commodity, both natural gas and electricity offer promising perspectives to expand cross-border energy trade. In biofuels, Brazil is already a global player and its net exports grow to account for about 40% of global biofuels trade by 2035. This increase is contingent on policies favourable to biofuels trade being in place in the United States and Europe, the two largest export markets for Brazil.
- A pivotal factor in shaping Brazil's energy outlook will be the country's success in maintaining high levels of investment, with $90 billion needed per year to 2035. Almost two-thirds of this is required in the oil sector and more than a quarter to expand power generation and the transmission network. The heaviest burden lies with Petrobras, the world's largest deepwater operator, placing an emphasis on its ability to deploy resources effectively across a huge and varied investment programme.
- Brazil's energy sector remains one of the least carbon-intensive in the world, although the absolute level of energy-related $CO_2$ emissions grows by more than two-thirds to 2035, elevating the importance of this policy consideration. The high dependence of Brazil's energy system on climatic conditions, due to its continued high share of renewables, could increase vulnerability to the impacts of climate change, although the nature of these impacts remains uncertain.
- Opportunities exist to realise significant additional energy efficiency gains, sufficient to reduce final energy consumption in 2035 by 11% compared with the New Policies Scenario. This helps to relieve pressure on the power sector (a reduction of 100 TWh in 2035 power consumption, equivalent to 2012 output from the massive Itaipu hydropower plant), increase export earnings and mitigate the rise in emissions.

## Context for Brazilian energy development

The Brazilian energy sector is changing, opening up a new landscape of choices, opportunities and potential vulnerabilities. Brazil has successfully developed over many years a range of policies aimed at limiting domestic reliance on oil and has very strong credentials on carbon-dioxide ($CO_2$) emissions, sustained in our projections by a low-carbon development strategy over the coming decades. Yet, within a few years, Brazil is also set to become one of the foremost international oil and gas producers, and a major net oil exporter, a development that redefines its place in the energy world.

Brazil also has to contemplate the implications of declining reliance on hydropower to meet its rapidly-growing demand for electricity. Unless satisfactory ways can be found to address social and environmental concerns about developing the hydropower potential of the Amazon region, limits to the further expansion of hydropower will come into view before 2035. A trend towards greater reliance on other technologies or fuels for new power generation is already visible in our projections and will develop further after 2035. Brazil will have to decide whether this need is to be filled primarily by renewable sources of energy, fossil fuels, nuclear, energy efficiency – or by a combination of all of the above.

A further shift in the context for Brazilian energy development comes from broader economic and social trends. As Brazil's economy more than doubles over the coming decades, the country will be making choices on mobility, infrastructure, social inclusion and economic development that will determine the relationship between rising incomes and energy consumption. The quality of energy services provided in Brazil, and the cost of these services, will also play a role in dictating the nature and speed of economic growth. The evident prospect of an oil and gas boom creates expectations of enhanced public services and economic opportunities, which may be difficult to fulfil. Beyond its own borders, Brazil will respond to, but also shape regional and global trends in both the energy sector and the broader economy (see Chapter 2).

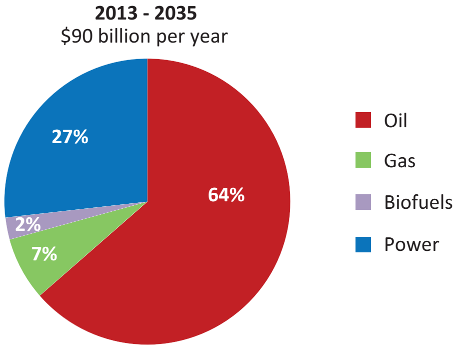
Against this shifting background, the focus of this chapter is to examine the implications of Brazil's supply and demand trends for the country itself, and for Latin America, but also to put Brazilian developments in a global energy and environmental context. We do this by considering three dimensions of Brazilian energy: its links with economic development, energy trade and security, and the environment.

## Energy and the Brazilian economy

Brazil's need for energy at home and its ambitions to export oil and biofuels all require massive capital investment. To meet the energy supply projections in the New Policies Scenario, we estimate that Brazil requires a cumulative \$2.1 trillion in investment across the different energy sectors, or \$90 billion per year on average (Figure 12.1). The oil sector accounts for 64% of the total and an average of \$57 billion per year, followed by the power sector (27% of the total), natural gas (7%) and biofuels (2%). As a component of overall

GDP, the share of investment in Brazil (in all sectors of the economy) is currently relatively low by international standards, at less than 20%, so an increase in capital spending in the energy sector would help to meet a broader policy priority. At the same time, Brazil will need to be wary of the risk that too high a concentration of investment in the oil sector may divert funds away from other productive sectors of its economy.

**Figure 12.1 ▷ Average annual investment in Brazil's energy supply infrastructure in the New Policies Scenario**




There are a number of mechanisms in place to bring the necessary capital investment into the energy sector, such as the bidding rounds for oil and gas licences, whether on a concession basis (as in the eleventh and twelfth rounds in 2013) or as production-sharing agreements (as in the first pre-salt round), and the auctions in the power sector for generation and transmission capacity. Concession-based schemes are also proposed to stimulate private investment in the transportation sector at large: the 2012 Logistics Investment Programme aims to bring private investment to a range of infrastructure projects, including highways, railways, and air and sea ports. More broadly, although direct allocations of public funds to the energy sector are limited (with health and education at the forefront of public spending plans), the government retains a major presence in shaping the environment for investment through the Brazilian Development Bank (BNDES). BNDES is the pre-eminent source of low-cost debt financing for energy projects and its lending criteria can be critical in determining the types of investment that are made. In all of these areas, there are ways to channel investment towards areas that serve government policy objectives but, to sustain a thriving mixed energy economy, it will be important that this does not occur at the expense of transparent conditions for the sector as a whole.

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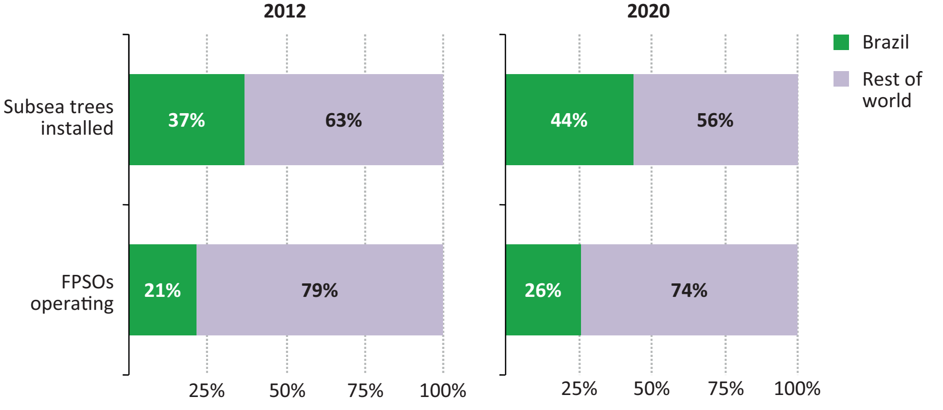
Our projections imply that Brazil becomes an important focal point for global spending on energy, deepwater production in particular. Brazil has the greatest impact on the global deepwater market in the early part of the projection period, when growth of deepwater production is quickest. By 2020, we estimate that 44% of all the subsea trees[1] installed in

1. A subsea tree (or "Christmas tree" as it is often called) is an assembly of valves which controls the flow from an oil or gas well situated on the sea bed.

the world in water depths more than 400 metres will be in Brazil (Figure 12.2). This implies that one in every two deepwater subsea trees produced between now and the end of the decade will be destined for Brazil. The story is similar for floating production, storage and offloading vessels (FPSOs): one in every three FPSOs brought into service between now and 2020 will be destined for Brazilian waters. A clear understanding of the plans of the government and of Petrobras, the national oil company, (including local content policy) is thus a critical input to business planning for the suppliers of such capital equipment.

**Figure 12.2 ▹ Brazil share of installed deepwater subsea equipment and FPSOs in the New Policies Scenario, 2012 and 2020**




Sources: Petrobras (2012); Offshore Magazine database (2013); Quest Offshore Resources (2013); McQuilling Partners (2012); IEA databases and analysis.

Over the projection period, a range of Brazilian and international players is set to increase their presence in the upstream (a development that increases the resilience of the sector); but the bulk of the anticipated investment will still be the responsibility of a single company, Petrobras. This is a function both of its traditional preponderance in the Brazilian upstream and also of the responsibilities reserved by legislation to Petrobras (a minimum 30% stake and role as operator) in areas deemed strategic, such as the new pre-salt developments. The company's business plan for the years to 2017 includes an investment programme of $237 billion, just over 60% of which is in the upstream. Annual upstream spending of $30 billion by Petrobras would represent around 5% of the anticipated global total, a massive commitment that would keep Petrobras in the highest echelon of companies committing capital to oil and gas production. The strain on resources that this implies (in terms of financing, skills and management capabilities) is amplified by the need for Petrobras, as a national oil company, to maintain a large and diverse portfolio of oil and gas sector activities upstream, midstream and downstream. Whereas international oil companies might typically sell off marginal assets in order to focus resources, Petrobras must allocate staff and spending across a very wide range of projects and is not necessarily free to focus on the most profitable. Upstream, Petrobras retains operatorship of a very high percentage of fields in its overall portfolio, compared with other similar size oil and gas companies, creating heavier staff needs. Downstream, the structure of the market and the uncertainties over pricing mean that Petrobras is the only company investing in new refining capacity, but, as this is a capital-intensive business, it raises the question of whether new refineries can be built on the scale required at the same time as the company is developing Brazil's pre-salt resources (a similar point can be made in relation to the midstream and downstream gas sectors). Petrobras has thus far managed to raise money on domestic and international markets without difficulty, but this borrowing has occurred against fairly tough expectations for future oil production and revenue. A slippage relative to these targets could raise the cost of capital for the continued high investments required.

The scale of energy sector investment will ultimately be determined by the speed at which the Brazilian authorities choose to deplete their resources (Box 12.1). How this investment then affects the Brazilian economy will depend, to an extent, on how much of it is spent on domestically-sourced goods and services. As noted in the previous chapter, the government is seeking to secure spillover effects from the growth of the energy sector through local content requirements that are intended to stimulate the domestic supply chain, generating multiplier effects on employment and demand in the wider economy. However, the evidence from other countries on the benefits of such policies is mixed – they can result in a tighter and less competitive supply chain, especially while the necessary industrial capacity and skilled expertise is being developed. In Brazil's case, the possibility of labour shortages, and related inflationary and cost pressures, is already evident. Unemployment is low and energy projects are competing for skilled labour, not only with other industrial sectors, but also with the large-scale spending foreseen under the 2011-2014 Accelerated Growth Programmes (Programa de Aceleração do Crescimento), which includes the construction of major new transport infrastructure. The ultimate tests of the success of local content policies are whether they create domestic supply industries that can both meet local demand during the expansion phase and compete internationally after their domestic opportunities level off.

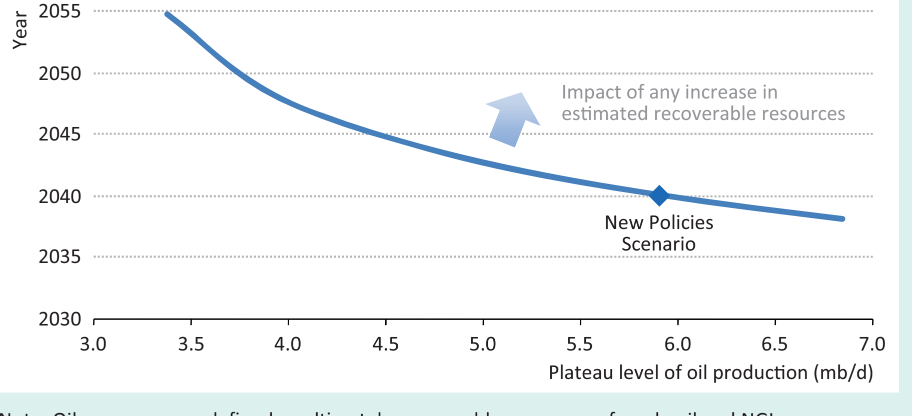
An additional way for investments in the domestic supply chain to bring broader economic benefits is via research and innovation. With this in mind, the government has introduced a levy on oil companies with concessions in Brazil's upstream that is earmarked for spending on research and development (R&D). The levy amounts to 1% of gross revenues, half of which goes to academic and research institutions. This has already borne some fruit, with a research hub now forming around Rio de Janeiro, involving a Petrobras technology centre and research units from leading international upstream, services and technology companies. ANP, the regulator, estimates that nearly $1 billion per year will be invested over the next decade as a result of the R&D provision included in oil and gas concessions.

### Box 12.1 ▷ Choices for oil production beyond self-sufficiency

For a long time, the goal of self-sufficiency defined the limits of Brazil's ambitions for oil output. The most recent official long-term outlook (to 2030) for the energy sector dates from 2007 (EPE, 2007) and anticipates production rising to 3 mb/d during the current decade and then remaining at these levels for the rest of the period – enough to turn Brazil into a relatively small net exporter for much of the 2020s, before domestic demand catches up with supply. This forecast has been overtaken by higher medium-term prospects: the latest ten-year plan from the government sees oil production reaching 5.4 mb/d already by 2021 (EPE, 2013). This is broadly consistent with Petrobras' latest production forecast, which sees its own output reaching 4.2 mb/d in 2020. The level of ambition beyond 2021 has yet to be redefined.

Different considerations affect the choices Brazil has to make to maximise the value of its hydrocarbon resources. These involve longer-term assessments of market conditions and policies that may have an impact on demand for oil, the desire to maintain a steady flow of revenues and how best to develop and sustain domestic supply industries and employment. A key factor in these choices is the size of the resource base and the speed at which it is depleted. To illustrate this, we took the current estimate for Brazil's ultimately recoverable conventional resources (120 billion barrels) and calculated how soon different levels of plateau production might deplete 50% of these resources, the point at which it would be reasonable to assume that production starts to decline (see Chapter 13). These points can be shifted further into the future by increases in the size of the estimated resources (as has already happened in Brazil over the last ten years), or by technologies allowing higher recovery rates in discovered fields, but, in general, the higher the targeted level of production, the shorter the period for which this can be maintained. In the New Policies Scenario, production settles at between 5.5 mb/d and 6 mb/d and, at this rate of output, half of the Brazilian resource base (as currently estimated) will have been produced by 2040 (Figure 12.3).

**Figure 12.3 ▷ Implications of different plateau production levels for the year in which 50% of Brazil's oil resources are depleted**




Note: Oil resources are defined as ultimately recoverable resources of crude oil and NGLs.

## *Pricing*

A key determinant of the interaction between the energy sector and the wider economy is the way that energy is priced. In the New Policies Scenario, the evolution of oil product demand (with the exception of liquefied petroleum gas [LPG]) and the competitiveness of ethanol relative to gasoline are based on the assumption that oil product prices in Brazil are aligned with international prices. Continuation of the current practice of holding gasoline prices below their international value would push up demand for this fuel at the expense of biofuels, compared with our projections, and continue to erode the financial resources of Petrobras, limiting its investment options.

For natural gas, the range of uncertainty over gas market development is substantial. We assume that domestic gas production will be priced in a way that finds and develops the domestic market, supplemented by imports at an average price of between $11-13 per million British thermal units (MBtu). There is clearly some momentum from national and regional policymakers, and from gas-consuming industry, to move to more open market models that would allow new, more transparent ways of pricing gas to emerge (see Chapter 10). With a well-functioning gas market, domestic production from a variety of sources, and imports via both pipeline and liquefied natural gas (LNG) (and, possibly, LNG export facilities), Brazil would be well placed to introduce open and efficient gas trading, allowing pricing signals to emerge that reflect the real supply-demand balance for gas (which is not the case today).

Counteracting pressures result in electricity prices remaining around current levels in real terms over the projection period. On one hand, the cost of renewable energy technologies, such as wind and solar photovoltaics (PV), are expected to decrease over time, transmission and distribution losses are expected to be reduced, and future growth in domestic gas supply could lead to lower average fuel costs for gas-fired power plants. On the other hand, concession rates for power from new hydropower projects will be higher than for existing hydropower to accommodate run-of-river designs and the requirement to repay capital costs. In addition, gas-fired power plants make up a growing share of the power mix in the New Policies Scenario and the cost of generating electricity from these plants is likely to be higher than from most other sources, even if average fuel costs come down.



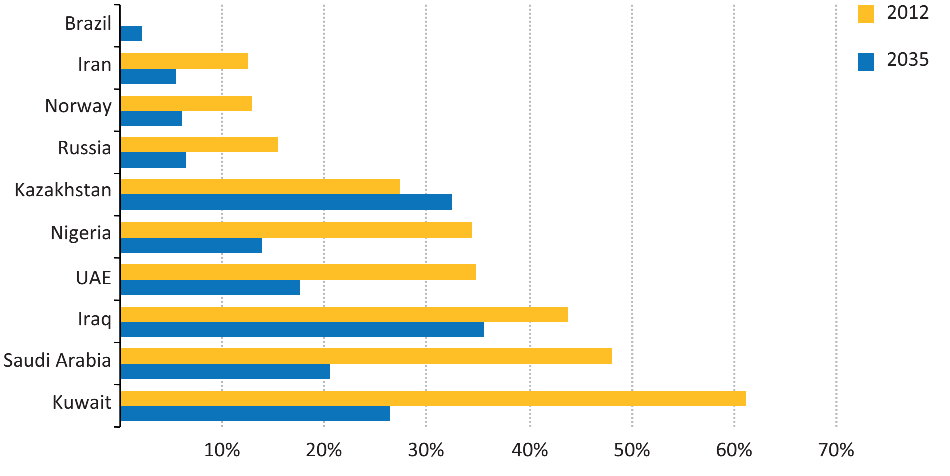
## *Revenues*

The emergence of net oil exports post-2015 brings with it a notable boost to Brazil's export earnings, with oil export revenues estimated at close to $50 billion in 2020 and $120 billion in 2035 in the New Policies Scenario. This is an important source of national wealth, but needs to be seen in the context of the large and diversified Brazilian economy.[2] This export revenue amounts, at its peak, to around 2.5% of national gross domestic product (GDP), a level considerably below that of other leading exporters (Figure 12.4). One could conclude

2. Oil is the most important source of energy-related export earnings in 2035, supplemented by revenue from exports of biofuels (around one-tenth of the value of oil exports) and smaller amounts from natural gas.

from this that Brazil's oil exports do not, in themselves, create a major risk of "Dutch disease", *i.e.* of inflating the value of the currency in a way that harms other sectors, an ailment to which some resource-rich countries have succumbed. But the risk is higher if oil is considered in concert with Brazil's other commodity-based exports, particularly if energy commodities follow the same price cycles as other important export groups, such as mineral ores. This possibility is not to be excluded, given that the prospects for many commodities are tied closely to prospects in China and are highly correlated with global economic activity. A slowdown in demand and a dip in primary commodity prices could therefore be detrimental and indeed has been identified by the International Monetary Fund as a key economic risk for Brazil (IMF, 2012).

**Figure 12.4 ▷ Oil export revenue as a share of GDP in selected countries in the New Policies Scenario**




The oil and gas sectors represent a valuable source of fiscal revenue for Brazil, including signature bonuses, royalties, direct taxes and a complicated system of indirect taxes and social contributions levied by different levels of government. The expected increase in revenues has already made their allocation a hot topic in Brazilian politics, increasing the likelihood that a larger share of the revenues may be folded into current spending (with royalties earmarked specifically for education and healthcare), rather than to mitigate the effects of economic cycles.[3] Experience from other resource-rich countries offers some cautionary notes about the way that the promise of oil wealth can detract from the need to tackle structural economic problems, even though these are, in many cases, important determinants of the level of long-term welfare and economic growth.

3. The Brazilian authorities set up a sovereign wealth fund (Fundo Soberano do Brasil) in 2008 as a vehicle for saving a part of oil revenue. However, no money has been added to the fund since 2009 and its long-term role remains under discussion. Similarly, the Fundo Social was announced in 2009 as a sovereign wealth fund for the revenues that will come specifically from the pre-salt area.

## Energy trade and security

In this section, we turn to Brazil's interactions with the wider world, how these might evolve over the projection period and how they might affect regional and international energy security. The focus is Brazil's net trade position in the various fuels, primarily oil, where net exports rise to 2.6 million barrels per day (mb/d) by 2035 from close to zero today, and biofuels, where net exports rise to 0.2 million barrels of oil equivalent per day (mboe/d) (Table 12.1).

**Table 12.1 ▷ Brazil supply-demand balance by fuel in the New Policies Scenario**

| | | 2011 | 2020 | 2025 | 2030 | 2035 | 2011-2035 Delta | 2011-2035 CAAGR* |
|---|---|---|---|---|---|---|---|---|
| **Oil** (mb/d) | Production | 2.2 | 4.1 | 5.4 | 5.8 | 6.0 | 3.8 | 4.3% |
| | Demand | 2.3 | 2.9 | 3.1 | 3.3 | 3.4 | 1.2 | 1.8% |
| | Net trade | -0.1 | 1.2 | 2.3 | 2.6 | 2.6 | 2.6 | n.a. |
| **Gas** (bcm) | Production | 17 | 38 | 60 | 78 | 92 | 76 | 7.4% |
| | Demand | 27 | 45 | 61 | 75 | 90 | 63 | 5.2% |
| | Net trade | -10 | -7 | -1 | 3 | 2 | 12 | n.a. |
| **Biofuels** (mboe/d) | Production | 0.4 | 0.6 | 0.8 | 0.9 | 1.0 | 0.7 | 4.4% |
| | Demand | 0.3 | 0.5 | 0.6 | 0.7 | 0.8 | 0.5 | 4.2% |
| | Net exports | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | n.a. |

* Compound average annual growth rate.

### *Regional co-operation*

As in many parts of the world (Europe is an exception), there has been a large and persistent gap in Latin America between the potential for regional energy co-operation and actual progress on the ground. This is not due to lack of political efforts to foster energy integration, nor to a lack of complementarities between the different energy systems. At a political level, for example, a Council of Ministers on Energy was created in 2007, under the Union of South American Nations (UNASUR in Spanish, UNASUL in Portuguese), which was followed in 2009 by the creation of a Council of Ministers on Infrastructure and Planning. A UNASUR energy treaty is also currently being prepared.[4] There are also examples of co-operation on specific projects, notably between Brazil and Paraguay on the huge bi-national Itaipu hydropower plant. But, overall, the amount of energy traded across borders in Latin America remains very small, relative to the size of the region's energy sector.

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4. Other regional initiatives with an energy dimension or a specific energy focus include the Latin American Energy Organization (OLADE), South American Common Market (MERCOSUR) and the Andean Pact; there are also initiatives bringing together regional authorities and the private sector, such as the Commission of Regional Energy Integration (CIER), focusing on the power sector, as well as industry fora such as the Regional Association of Oil, Gas and Biofuels companies of Latin American and the Caribbean (ARPEL).

As the largest regional economy, Brazil is a key player in any Latin American energy integration scenario. One avenue for this could be the power sector, where – in addition to purchasing part of Paraguay's share of Itaipu output – Brazil already has transmission connections with Argentina, Uruguay and Venezuela. Further potential exists for cooperation on hydropower, where Brazil has been in discussions about new bi-national projects with Argentina, Bolivia and Peru. Another possibility is the natural gas sector, where an early wave of enthusiasm for integration in the 1990s led to the construction of the "Gasbol" pipeline from Bolivia to Brazil, along with several other pipelines across the Andes between Argentina and Chile. In addition, there are some joint initiatives in the oil sector, for example the commitment by Venezuela in 2005 to take a 40% stake in Brazil's Abreu e Lima oil refinery.

In each of these areas, though, there are questions over the prospects for deepening co-operation. The electricity sector is perhaps the most promising area for an expansion of cross-border ties, but the prospects for deeper integration are diminished by the disproportionate size of Brazil's power sector compared with any of its neighbours, meaning that the operation of any integrated network would be largely driven by the dynamics of the Brazilian system. Large new bi-national hydropower projects would be subject to the same public acceptance hurdles as purely domestic projects, but with added layers of political complexity arising from the need to negotiate and implement the projects in concert with a neighbour. Enthusiasm for cross-border gas pipeline projects faded significantly after the nationalisation of the upstream gas sector in Bolivia in 2006 and the failure of Argentina to fulfil its gas supply commitments to Chile since 2005. Experience in the oil sector has also been mixed. In the case of the joint refinery project, Venezuela has yet to provide financing for its stake, although Petrobras is committed to complete the project.

Over the *Outlook* period, it is projected that Brazil remains a modest net importer of electricity (at around 30-40 terawatt-hours [TWh] per year) and assumed that gas imports from Bolivia continue beyond the expiration of the current contract (in 2019), albeit with steadily decreasing volumes as Brazil moves to a position in which its own production can cover all of its domestic needs. Coal imports are likewise predominantly sourced from within the continent. But we do not assume a political breakthrough that would push forward the prospects for thorough top-down regional energy integration.

The prospects for increased trade, in Brazil's case, come in our judgement from a gradual process of expanding cross-border power links and also from a possible expansion in gas trade, notably LNG, which can be managed flexibly and without the political risk associated with fixed cross-border pipeline projects. In the power sector, Brazil's plans for expanding the electricity transmission network include new international interconnections with Bolivia, Guyana and Suriname and the expansion of existing interconnections with Argentina and Peru. Projects being considered or implemented under the Initiative for

Integration of the Regional Infrastructure of South America (IIRSA) include transmission projects with Paraguay and Uruguay.[5]

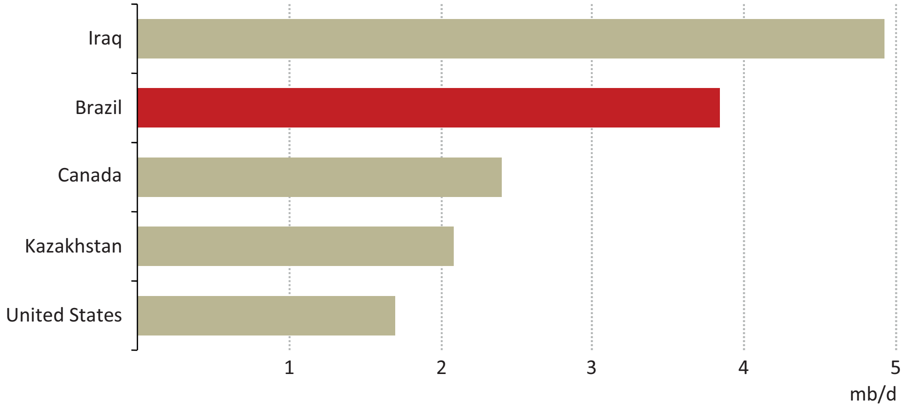
LNG trade can play an important role to fill in gaps in the regional gas infrastructure and could, with time, help to bring a degree of connectivity to the different gas markets in the region. Much will depend, though, on whether new regional trading and pricing hubs evolve to guide investment and gas flows (an issue in which Brazil can play an important role) and whether unconventional gas development in Argentina allows a restart of gas flows to Chile and also, potentially, the opening of a reversible link to Brazil that would provide for further balancing between the region's two largest gas markets.

## *Brazil and international oil and gas markets*

### *Oil*

In the period to 2035, Brazil becomes a major source of growth in global oil supply, with the highest anticipated rate of output growth among all oil producers. The 3.8 mb/d increase in production to 2035 is higher than that of global light tight oil, second only to Iraq among all oil producers and by far the largest among non-OPEC countries (Figure 12.5). The combined growth in output from Brazil and Iraq is equal to around 80% of the net increase in global production. Brazil's rise means that it joins the ranks of the ten largest global oil producers (crude oil plus natural gas liquids [NGLs]) around 2015 and becomes the sixth-largest producer by the end of the projection period, behind only Saudi Arabia, the United States, Russia, Iraq and Canada.

**Figure 12.5 ▷ Major contributors to global oil supply growth in the New Policies Scenario, 2012-2035**



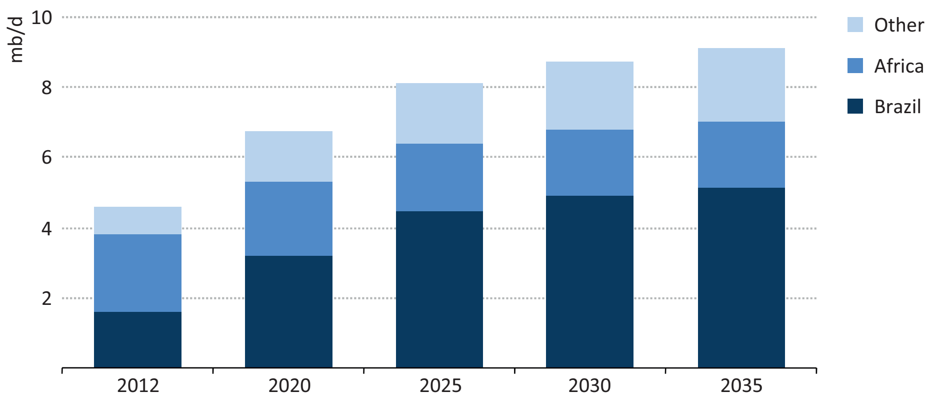

Growth of the magnitude projected for Brazil is not unprecedented for a single oil province. What makes this case stand out is the extent to which this growth relies on the performance of a single player: fields operated by Petrobras account for more than 80 % of Brazil's current

5. IIRSA is a technical forum under the Union of South American Nations Council of Ministers on Infrastructure and Planning.

oil production and, even though there were signs in the eleventh licensing round that the company was ready to take on non-operating roles in partnership with other companies, its position as operator of the main producing fields in the pre-salt is enshrined in legislation. We estimate that fields operated by Petrobras are responsible for around three-quarters of the increase in Brazilian output over the period to 2035.

Another distinguishing feature of Brazil's strong position in the global outlook is that it is almost entirely dependent on increases in deepwater production. The importance of deepwater is growing in the overall oil supply picture, its share of conventional crude output rising from 6% in 2012 to 11% in 2035, and Brazil accounts for more than 3.5 mb/d (nearly 80%) of the overall 4.4 mb/d increase from this source (Figure 12.6). This means that Brazil becomes the unrivalled leader in deepwater output and by far the largest market for all types of deepwater suppliers, a factor that is set to underpin a migration of deepwater suppliers to Brazil. It also suggests that, if Brazil can take on a position as technology leader in this area and develop a competitive local supply base, then there may be opportunities to export equipment and expertise in the second half of the projection period, when growth in deepwater output is expected to be spread more evenly across the various global basins. A second implication of our projections is that Brazil will be taking on the greatest share of deepwater risk. This type of oil production, it should not be forgotten, is consistently pushing at the frontiers of what the industry can undertake, and represents a relatively expensive source of oil. The repercussions of any serious accident or spill would be felt in Brazil, regardless of where it took place.

**Figure 12.6 ▷ Global deepwater* oil production by region in the New Policies Scenario**

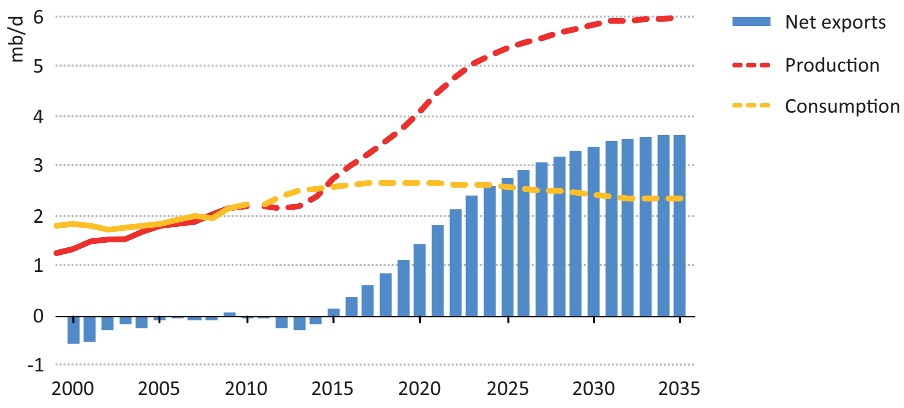



* Deepwater is defined as water with a depth in excess of 400 metres.

In the New Policies Scenario, Brazil becomes a net exporter of oil after 2015, becoming the first country since Canada, in the early 1980s, to go from being an importer to a major exporter of oil (Figure 12.7). The availability of crude oil for export is helped by Brazil's production of biofuels, which substitute for a part of the country's oil consumption. If all of the domestic demand met by biofuels in our projections were instead met by oil products, Brazil's emergence as a net exporter would be postponed and its level of exports in 2035 would be reduced by one-third.

In our projections, the surplus is available as crude oil, since we do not assume any refinery capacity being built beyond that necessary to meet Brazil's domestic demand for products. A few years ago, the natural export market for Brazilian crude might have been North America, but this perspective is narrowing in our projections, as North America's requirement for imported crude shrinks substantially. Instead, we anticipate that a part of Brazil's crude exports go to Europe, but an increasingly large share of the total follows the global shift in demand and is drawn towards Asian markets.[6] Brazil's position is buoyed by its status as a supplier of medium-grade crudes, whose availability is squeezed by rising output of heavier crude and of NGLs (see Chapter 16).

**Figure 12.7 ▷ Brazil oil balance in the New Policies Scenario**




### *Natural gas*

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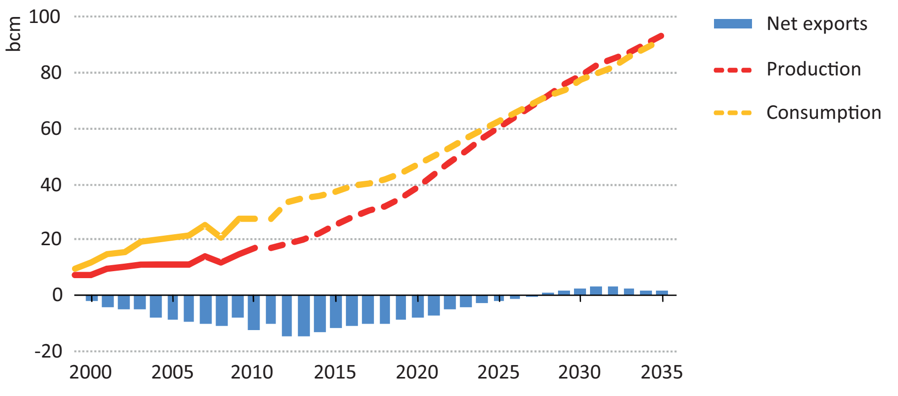
In the New Policies Scenario, the projected gradual increase in natural gas production brings Brazilian supply and demand into balance by the late 2020s, with a small net surplus of gas projected by the early 2030s (Figure 12.8). We assume in our projections that gas imports from Bolivia gradually tail off but, were they to continue at around 10 billion cubic metres (bcm) per year (as per the current contract), then Brazil could become a larger exporter earlier in the projection period. This would not affect Brazil's net gas position, but would provide an indirect route to international markets for landlocked Bolivian output.

At present, Brazil has two LNG import facilities, one in Pecem, a few miles north of Fortaleza in the northeast and one in Rio de Janeiro in the south, which is currently being expanded. A third is being built at Todos os Santos Bay in Bahia state, which would bring overall LNG import capacity to 15 bcm per year. These terminals provide Petrobras with

6. Sailing times from Brazil to Europe (Rotterdam) are around 22 days, ten days less than to Mumbai, although Asian premiums for crude oil are likely going to be high enough to cover the cost differential.

the necessary degree of flexibility to cope with fluctuations in gas demand from the power sector. Our projection that Brazilian supply catches up with demand could be understood to make these import terminals redundant, but this depends in practice on the extent to which other elements of flexibility are put in place, either on the supply side, such as storage or a substantial increase in non-associated gas production, or on the demand side, such as the development of market mechanisms that can absorb the fluctuation of power sector demand. Without these additional elements of flexibility, LNG import capacity would remain a useful insurance policy against swings in the supply-demand balance or temporarily adverse hydrological conditions.

**Figure 12.8 ▷ Brazil gas balance in the New Policies Scenario**




Gas export possibilities and prospects for Brazil are even more uncertain, arising on a sustained basis only towards the end of our projection period. Relatively small fluctuations in either supply or demand could have a large impact on the trade balance. Among the domestic circumstances that could precipitate pressure for export would be if gas discoveries exceed expectations, or, as discussed in Chapter 11, if gas injection proves to be less widespread or less successful than currently envisaged.[7] The construction of LNG export capacity could also be seen as a way to manage the possibility of temporary surfeits of gas, if these cannot be absorbed on the domestic market (although facilities for liquefaction are considerably more expensive to construct than those for regasification).

## *Brazil and international biofuels trade*

Brazil is set to play the central role in the international biofuels market. It is one of the few countries that have both the resources and the intention to develop production capacity to meet the needs of international markets. In the New Policies Scenario, Brazil emerges as the largest net exporter of biofuels in the world early in the *Outlook* period, as its main

7. Floating LNG facilities, essentially a purpose-built barge that can liquefy gas produced from offshore fields, could also be an option for Brazil, providing a possible monetisation option for isolated new gas discoveries, for example in the Brazilian equatorial margin off the north coast of Brazil.

competitor, the United States, becomes a net importer. Brazil's net exports of biofuels (almost all consisting of ethanol) increase to around 0.2 mboe/d in 2035 and equate to about 40% of world biofuels trade at that time. At current prices, this level of exports would generate revenues well in excess of $10 billion per year.

The outlook for biofuels exports will be contingent on a range of factors, notably the level of investment in new capacity, the extent and impact of possible industry consolidation, inter-product price competition (both prevailing international sugar prices and domestic gasoline prices) and the success of individual harvests. International demand for biofuels will continue to be influenced heavily by government policies and regulations in specific markets. In the New Policies Scenario, the European Union and the United States are key export markets for Brazilian biofuels and have the capacity to alter the outlook significantly. The European Union has set ambitious goals for biofuels under its Renewable Energy Directive and these will be difficult to meet with domestic supply alone. The low-emissions credentials of Brazilian biofuels currently play in its favour. However, recent actions, namely the imposition of anti-dumping tariffs on biofuels from Argentina, Malaysia and the United States, suggest that unfettered future access to European markets is far from certain. Brazilian biofuels also seem well-placed to help meet the US Renewable Fuel Standard requirement to significantly increase consumption of "advanced biofuels" through to 2022. However, the US authorities are permitted to reduce this mandate if domestic production capacity falls short of the level required to meet the target and they have done so in the past. Such action could limit or close the opportunity for Brazil to sell into the US market.

## Energy and the environment

The expansion of hydropower and of bioenergy use in Brazil have raised questions as well as plaudits on environmental issues, but they have been pivotal in enabling Brazil to achieve significant socio-economic development while keeping its energy-sector $CO_2$ emissions at relatively low levels. For many countries around the world, a key policy challenge is to decarbonise their energy sector. For Brazil, the task is different: to maintain its low-carbon profile and retain its strong environmental credentials, even as domestic energy demand grows rapidly.

Environmental considerations continue to appear on both sides of the debate over the future of Brazilian hydropower and biofuels. Concerns about large-scale inundation for hydro reservoirs are already a major consideration in Brazilian decision-making on new hydropower developments, tipping the balance in power sector planning towards run-of-river projects. New models for hydropower delivery and enhanced efforts to engage local communities can lessen the impact of construction and operation of projects in environmentally sensitive regions, such as the Amazon. But the balance of the argument could also be swayed if the result of constraints on hydropower is to increase the volumes of fossil-fuel generation and related $CO_2$ emissions. The projected growth in biofuels production raises concerns about changes in land use, although the government has already acted to identify appropriate lands for sugarcane farming and processing (in effect, signalling to the industry that more than 90% of the country's territory should be considered unsuitable in the context of its expansion plans) as a means of avoiding an expansion of biofuels production taking place directly or indirectly at the expense of Brazil's forests.

There are other environmental hazards to be addressed across the Brazilian energy mix, as well as new risks that could emerge with a changing climate (Spotlight). Brazil is among the most bio-diverse countries in the world and its internationally recognised efforts to conserve this heritage have implications for any form of energy and infrastructure development, particularly in the Amazon region. The concentration of oil and gas production in the deepwater requires constant vigilance and the highest standards to avoid the risk of accidents and spills. The prospective expansion of the onshore production of unconventional gas requires a dedicated effort to ensure, similarly, that high standards are observed so as to avoid social and environmental damage.

S P O T L I G H T

### How might climate change affect Brazil's energy sector?

Brazil has vast experience in managing an energy system that is influenced by seasonal and climatic variations, but the high share of renewables in the energy sector (combined with the country's already varied climate) mean that it may be particularly affected by climate change. The nature and scale of this challenge, though, is subject to a broad range of uncertainty. Existing climate models sometimes suggest negative effects on the energy sector and sometimes positive, complicating the task of policymakers and the energy sector in planning actions to mitigate or adapt.

The operation of Brazil's power sector is already affected by periodic droughts. For the future, global warming of about 2 °C by 2050 (compared with pre-industrial levels) would mean that more northern parts of Brazil, where much of the potential hydropower capacity is to be found, could see hydropower output decrease (IPCC, 2012), while the south of Brazil, where the majority of the existing capacity is located, could see an increase in output (Hamadudu and Killingtveit, 2012). These findings are broadly consistent with those of an earlier IPCC report (2011) that, examining the median results of twelve climate model projections, found a large-scale reduction in annual water run-off in the north but increases in the south by the end of this century. Large hydro reservoirs can help compensate for some additional seasonal variations in water inflow, and provide flexibility in freshwater supply for other purposes, while run-of-river projects become more vulnerable to variations in rainfall patterns.

Analysis of the effect of climate change on wind power also draws mixed conclusions: some find that wind resources in Brazil decline (Pryor and Barthelmie, 2010), while others suggest a substantial increase, particularly in coastal areas and the north/northeast regions (Lucena, *et al.,* 2010). As for thermal power plants, rising air and water temperatures would affect their efficiency, either decreasing electricity output or increasing fuel consumption, though the overall effect on Brazil's thermal power output has been estimated at less than 2% (Lucena, Schaeffer and Szklo, 2010). As ambient temperatures increase, a warming climate could be expected to boost demand for cooling (see Chapter 10). Taking into account the combined effects on generation and peak electricity demand, higher temperatures are expected to result in a need for additional peak generation and transmission capacity or greater demand-side response at peak times.

Production of bioenergy (including biofuels) would likewise be affected: higher $CO_2$ levels and a limited temperature increase can extend the growing season, although more frequent extreme weather events or changes in precipitation patterns may reduce these positive impacts. Studies examining the impact of climate change on sugarcane production in Brazil suggest either little overall impact or a positive impact (Pinto and Assad, 2008). As well, any frequency in the incidence of tropical or sub-tropical cyclones (very rare at present in the South Atlantic) would have disruptive consequences for offshore oil and gas operations. Given the expected increase in the number of FPSOs and other offshore facilities over the coming decades, there is a risk that a rise in extreme weather events could become a new risk element for the offshore industry in Brazil.

## *Energy-related emissions*

As the source of more than two-thirds of global greenhouse-gas emissions (IEA, 2013), the energy sector is crucial to tackling climate change, but the energy sector in Brazil has, in the past, played a relatively small role in national greenhouse-gas emissions by international standards, behind emissions from land-use change and the agriculture sector. This is changing fast though, and the energy sector is becoming a more important source of emissions growth and, therefore, a more important target for future policy action (see Chapter 9, Figure 9.11).

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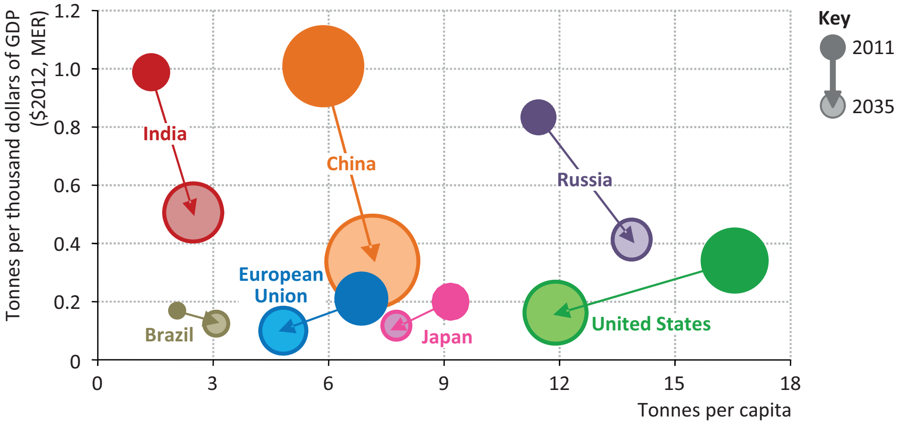
Brazil has set a goal of reducing its greenhouse-gas emissions by at least 36% (compared with a business-as-usual baseline) by 2020 and has captured this commitment in domestic law. This implies, according to EPE, that emissions from the energy sector should remain below 680 million tonnes (Mt) by the end of the decade. This is achieved with room to spare in the New Policies Scenario; indeed, energy-related $CO_2$ emissions in our projections are only slightly above 700 Mt even in 2035. On one hand, this is a tribute to the way that the expansion of renewable sources of energy keeps emissions in check. On the other hand, it suggests that the baseline calculation, as currently formulated, makes generous allowance for emissions growth. Complementary actions to curb energy sector emissions are being taken at state level. For example, the São Paulo State Energy Plan aims to increase significantly the share of renewables in the state energy matrix, and Rio de Janeiro is seeking to introduce an emissions trading scheme.

In our projections, Brazilian energy-related $CO_2$ emissions increase by more than two-thirds by 2035. Oil accounts for nearly half of the growth (mainly in transport), gas for around 40% (mainly in industry and power) and coal the remainder. But the carbon intensity of Brazil's economy (measured as tonnes of $CO_2$ per $1 000 of GDP) remains one of the lowest in the world in 2035, slightly above the level of the European Union, three-quarters the level of the United States and less than half the level of China (Figure 12.9).[8] By 2035, Brazil accounts for nearly 4% of global GDP, but less than 2% of energy-related $CO_2$ emissions. Per-capita $CO_2$ emissions increase by 50% to reach 3 tonnes of $CO_2$, but this is still only 70% of the world average in 2035.

**Figure 12.9 ▷ $CO_2$ per capita and $CO_2$ intensity of GDP in selected regions in the New Policies Scenario**




Notes: Bubble area indicates total annual energy-related $CO_2$ emissions in that region. MER = market exchange rate.

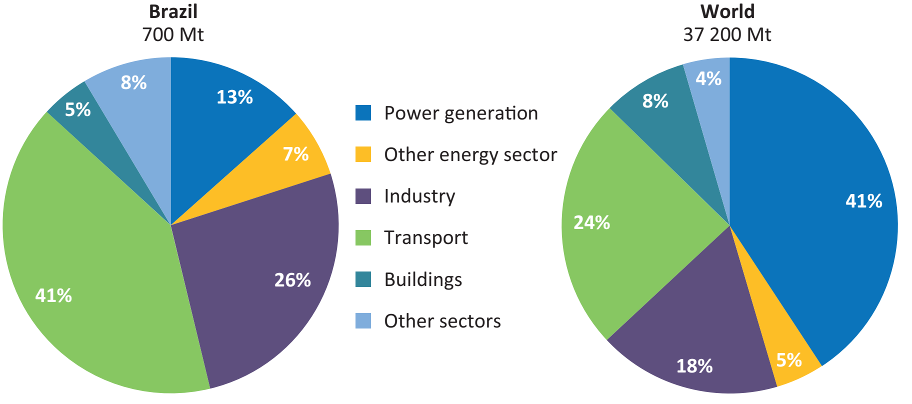
The share of renewable energy sources in Brazil's energy mix remains stable over the *Outlook* period at 43% (or 45% for low or zero-carbon energy, including the contribution of nuclear). This compares very favourably with a global average of 18% for renewables in 2035 (or 24% with nuclear). The power sector, which accounted for less than 10% of Brazil's energy-related $CO_2$ emissions in 2011, increases its share to 13% in 2035, still well below the global average (Figure 12.10). Even though the carbon intensity of the power sector increases, reaching 87 grammes of $CO_2$ per kilowatt-hour (g $CO_2$/kWh) in 2035, it remains a fraction of the OECD average of 265 g $CO_2$/kWh and the non-OECD average of 435 g $CO_2$/kWh.[9] The transport sector is already the largest source of energy-related $CO_2$ emissions in Brazil and its emissions increase by more than 55%, to reach 285 Mt in 2035, making it the sector responsible for the largest share of $CO_2$ emissions in Brazil. Road transport is the main contributor to this growth, which would be still higher if it were

8. GDP is measured at market exchange rate in year-2012 dollars.

9. This indicator does rise above 100 g $CO_2$ per kWh in our Low-Hydro Case (see Chapter 10, Box 10.2), as the gap left by hydropower is filled, in part, by the increased use of fossil fuels.

not for the projected increase in biofuels consumption. Biofuels meet around 45% of the increase in road transport energy demand and the level of $CO_2$ emissions per kilometre declines significantly over the projection period. If conditions are less conducive to biofuels development than we project, then substitution towards biofuels will be weaker, pushing transport sector emissions higher.

**Figure 12.10 ▷ Energy-related $CO_2$ emissions by sector, 2035**




### *Energy efficiency*

In the New Policies Scenario, Brazil is assumed to make continued efforts to capture the available gains from energy efficiency policies, but primary energy demand in this scenario does not move significantly away from the level projected in the Current Policies Scenario, only around 5%, or 20 million tonnes of oil equivalent (Mtoe), lower by 2035. This suggests room for further concerted action to realise Brazil's economically viable energy efficiency potential. Government policies play a critical role in achieving efficiency gains as they can help lower market barriers and minimise transaction costs, unlocking the necessary investment.

To highlight the remaining potential for efficient energy use, not captured in the New Policies Scenario, we have conducted analysis of energy use in key end-use sectors – industry, transport and buildings – to assess the remaining potential for energy savings, and the policies that could unlock this potential.[10] No major technological breakthroughs are assumed, only use of the energy efficiency measures and technologies that exist today and are economically viable (assuming reasonable payback periods).[11] The payback periods are, in some cases, longer than those often required by lending institutions, households or firms, but they are always considerably shorter than the technical lifetime of the assets.

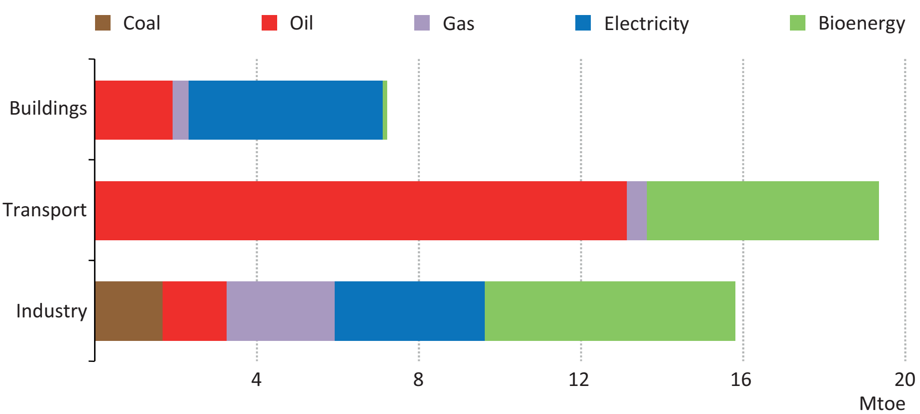
10. The analysis does not cover the potential for energy efficiency savings in energy supply, including power generation and transmission.

11. The methodology and assumptions used are the same as for the Efficient World Scenario in *WEO-2012*.

The policy measures in this Efficient Brazil Case go beyond the measures included in Brazil's National Energy Efficiency Plan, both in terms of their ambition and the assumed level of implementation. In the buildings sector, they include appropriate building codes for new buildings and minimum energy performance standards, enhanced over time, for all major appliances and equipment. In industry, we assume that all new equipment uses the best available technology and efficiency improvements are realised through better energy management and optimised operations. In the transport sector, the main change arises from deployment of the most efficient vehicles, pushed by policies such as mandatory fuel-economy standards and labelling.

The result of this analysis is that final consumption in 2035 is some 42 Mtoe (or 11%) lower than in the New Policies Scenario. The largest savings in absolute and in percentage terms are in the transport sector, mainly due to improvements in fuel economy (Figure 12.11). This analysis validates the importance of the efforts, now started in Brazil with the Inovar-Auto programme, to raise the efficiency performance of cars produced in Brazil. It does not, however, capture all of Brazil's potential in the transport sector, as there is still huge scope remaining in the New Policies Scenario to move freight transport off the roads and onto rail or waterways. The infrastructure projects launched with this aim are some of the most important energy efficiency projects in Brazil (even if they are not always seen in these terms).

**Figure 12.11 ▷ Brazil potential for energy efficiency savings by end-use sector relative to the New Policies Scenario, 2035**




In the industry sector, there are savings available among the large energy-intensive sectors, such as the iron and steel sector and chemicals production, but by and large these industries are typically already attentive to energy-saving opportunities, as energy makes up a large share of their production costs. It is rather in the less energy-intensive sectors that significant savings can be made, as existing opportunities can be overlooked because of a lack of awareness and know-how, or because financing for efficiency improvements is not available. In Brazil, savings of this sort could be made in areas like food processing, through improvements to steam systems and electric motors.

Overall, for the industry sector, we estimate that the additional investment required to realise the savings in the Efficient Brazil Case amounts to more than $15 billion over the course of the projection period. However, this produces much larger savings in terms of reduced spending on energy inputs: cumulative (undiscounted) savings on energy bills are more than $140 billion over the period to 2035. In terms of financing, the support available through the BNDES, such as PROESCO (which gives support specifically to energy efficiency projects) or the Climate Fund Programme, is an important instrument to support industrial energy efficiency. In the residential sector, energy use is already relatively low by international comparison (largely because of low heating requirements in Brazil), so the impact of new measures is relatively small, compared with the other sectors; the largest impact comes from the stringent application of standards for a range of energy-using equipment.

These gains in end-use efficiency are beneficial to Brazil in many ways. Electricity demand is reduced by some 100 TWh in 2035 (roughly equivalent of 2012 production from the massive Itaipu hydropower plant), reducing the need for new capacity and easing the task of addressing demand peaks. Brazil also frees up some 340 thousand barrels per day of oil, saving on refinery investments and increasing potential revenue from export by around $15 billion in 2035. The reduction in the use of fossil fuels means that emissions are further reduced by about 90 Mt, to a level 13% lower than in the New Policies Scenario. As they have in the past, robust and targeted energy policies can continue to shape Brazil's energy outlook for the better.

PART C

# OUTLOOK FOR OIL MARKETS

## PREFACE

Part C of this *WEO* (Chapters 13-16) focuses on the fuel that still meets the largest share of global energy needs: oil. From oil resources to the evolving needs and choices of consumers, the analysis covers the entire oil supply chain, including, for the first time in such detail in the *WEO*, an outlook for the refining sector.

Chapter 13 examines the extent of the world's remaining oil resources, both conventional and unconventional, and the technologies and costs involved in first turning these resources into proven reserves, and then in producing them. It includes a special focus on the prospects for enhanced oil recovery.

Chapter 14 provides a detailed assessment of oil production prospects, starting with an updated analysis of the speed at which output from existing fields is expected to decline. It covers the outlook for different types of oil (with a special focus on light tight oil) and for different countries and regions, and the scale of the investment required.

Chapter 15 turns to the consumers of oil, the sectors and countries that are set to see growing demand and, conversely, those where oil use is in decline. It looks in particular at oil use in the Middle East, the alternatives to oil in the transport sector, oil use in petrochemicals, and the outlook for individual oil products.

Chapter 16 concludes the special focus on oil by examining two sectors that make the connection between oil extraction and its final consumers: oil refining and trade. It examines, region by region, the outlook for the world's refiners and the way that refinery investments and changing patterns of supply and demand affect trade flows of crude oil and oil products.

# From oil resources to reserves

## Should we worry about scarcity, or abundance?

### Highlights

- Estimates of ultimately recoverable resources of oil continue to increase as new technologies, such as multi-stage hydraulic fracturing, unlock types of resources, such as light tight oil, that were not considered recoverable only a few years ago. Light tight oil resources worldwide are still relatively poorly known but, on current estimates, represent some 6% of total remaining recoverable resources.

- Our latest estimates for remaining recoverable resources show 2 670 billion barrels of conventional oil (including NGLs), 345 billion of light tight oil, 1 880 billion of extra-heavy oil and bitumen, and 1 070 billion of kerogen oil. Cumulatively, 790 billion barrels of oil need to be produced in total to meet projected demand in the New Policies Scenario.

- High oil prices in recent years have resulted in an increase in total proven oil reserves, which stand at around 1 700 billion barrels, as the industry has been proving up more reserves than it has produced. Discovery rates of conventional oil and the average size of discovered fields have stabilised, at about 14 billion barrels per year and 50 million barrels respectively, after the drop observed in the second-half of the last century. However, future discoveries are expected to be smaller, contributing to higher per barrel costs for exploration and production.

- Nearly 80% of the world's proven-plus-probable reserves of conventional and unconventional oil are controlled by national oil companies (NOCs) or their host governments. The rest is controlled by privately-owned companies: 7% by the seven major international oil companies and 13% by independents. Almost all of the reserves held by NOCs (outside Venezuela) consist of conventional oil.

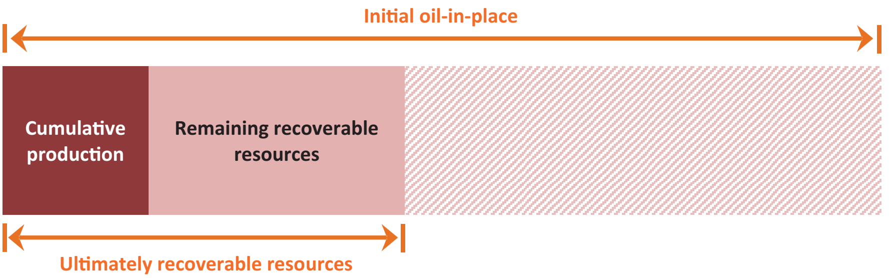
- By increasing recovery rates in conventional reservoirs, enhanced oil recovery (EOR) technologies are currently estimated to have the potential to unlock another 300 billion barrels on top of the current resources estimates, an amount comparable to the resource additions from light tight oil. Injection of $CO_2$ into reservoirs is a proven EOR technique and, if the incentives are right, could also develop as a way to store $CO_2$. Realising the full potential of EOR technologies is hampered in practice by the complexity of projects and the shortage of the necessary skills in the industry.

- Detailed oil supply cost curves for 2013 and 2035 suggest that the marginal cost of producing a barrel in the New Policies Scenario is significantly below the oil price in this scenario. Risks affecting investment in oil supply and difficulties faced by the industry to develop new resources at a sufficiently high pace push oil prices above the marginal cost of production.

## Classifying oil

Understanding oil resources is essential to any analysis of the future prospects of the oil sector. These resources are large, but they are finite and unevenly distributed around the world. Even in a country with a significant endowment of oil, production will usually start decreasing as the depletion of its resources becomes significant. Though there is no hard-and-fast rule, production often starts decreasing when recoverable resources are more than 50% depleted (an empirical observation, highlighted by many analysts and often presented as an argument supporting the peak oil theory).[1] The main reason for the decrease is that, in a given area, oil from the easiest, lower cost, larger reservoirs is usually produced first, followed later by oil from the smaller, more difficult and more costly accumulations. This means that, as depletion increases in a basin, the cost of new developments also goes up; if oil prices do not rise correspondingly (which can happen if other countries or regions still have low-cost oil), production will decrease as the depleted country is out-competed by other players. Alongside understanding the limits imposed by demand for oil and government policies, understanding resource depletion in each country or region is a big part of projecting how much various countries will be able to produce in the future.

**Figure 13.1 ▷ Classification of oil resources**




Notes: Remaining recoverable resources are comprised of proven reserves, reserves growth (the projected increase in reserves in known fields) and as yet undiscovered resources that are judged likely to be ultimately producible using current technology. There are different classification systems for oil reserves and resources, as discussed in this chapter. Ultimately recoverable resources (and therefore remaining recoverable resources) can be defined either as technically recoverable, *i.e.* producible with current technology, or as technically and economically recoverable, meaning that they are exploitable at current oil prices. The resource numbers are for technically, but not necessarily economically, recoverable resources.

To determine depletion, one needs to know how much oil has already been produced and also have an estimate of how much can ultimately be produced (Figure 13.1). The latter figure, for ultimately recoverable resources (URR), is a critical variable for the modelling and analysis, much more so than the (often more widely-discussed) number for oil reserves. URR gives an indication of the size of the total resource base that is recoverable with

1. The interplay between depletion, prices and demand, and the impact of unconventional resources on the peak oil debate is discussed in the Spotlight in this chapter.

today's technologies, both the part that is known (either because it has been produced already or because it has been "proven", *i.e.* its existence established with a high degree of probability) and the part that remains to be found in existing and in undiscovered fields. Reserves are a sub-set of URR and, while important in some cases as an indication of what companies have decided to line up for development, do not provide a complete picture either of the resource base or of long-term production potential.

Our estimate of global, ultimately recoverable resources of conventional crude oil stands at some 3 300 billion barrels. Of this, 1 136 billion barrels, or 34%, have already been produced, leaving a remaining recoverable resource base of 2 200 billion barrels (Table 13.1). Adding natural gas liquids (NGLs)[2] and unconventional oil more than doubles the size of the recoverable resource. However, resource estimates are inevitably subject to a considerable degree of uncertainty; this is particularly true for unconventional resources that are very large, but still relatively poorly known, both in terms of the extent of the resource in place and judgements about how much might be technically recoverable. These uncertainties, as well as the techniques and costs associated with developing oil resources, are the focus of this chapter.

**Table 13.1 ▷ Remaining recoverable oil resources and proven reserves, end-2012** (billion barrels)

| | Conventional resources | | Unconventional resources | | | Totals | |
|---|---|---|---|---|---|---|---|
| | Crude oil | NGLs | EHOB | Kerogen oil | Light tight oil | Resources | Proven reserves |
| **OECD** | **315** | **102** | **811** | **1 016** | **115** | **2 359** | **240** |
| Americas | 250 | 59 | 808 | 1 000 | 81 | 2 197 | 221 |
| Europe | 59 | 33 | 3 | 4 | 17 | 116 | 14 |
| Asia Oceania | 6 | 11 | 0 | 12 | 18 | 47 | 4 |
| **Non-OECD** | **1 888** | **363** | **1 069** | **57** | **230** | **3 606** | **1 462** |
| E.Europe/Eurasia | 347 | 82 | 552 | 20 | 78 | 1 078 | 150 |
| Asia | 96 | 27 | 3 | 4 | 56 | 187 | 46 |
| Middle East | 971 | 168 | 14 | 30 | 0 | 1 184 | 813 |
| Africa | 254 | 54 | 2 | 0 | 38 | 348 | 130 |
| Latin America | 219 | 32 | 498 | 3 | 57 | 809 | 323 |
| **World** | **2 203** | **465** | **1 879** | **1 073** | **345** | **5 965** | **1 702** |

Notes: Proven reserves (which are typically not broken down by conventional/unconventional) are usually defined as discovered volumes having a 90% probability that they can be extracted profitably. EHOB is extra-heavy oil and bitumen. The IEA databases do not include NGLs from unconventional reservoirs (*i.e.* associated with shale gas) outside the United States, because of the lack of comprehensive assessment: unconventional NGLs resources in the United States are included in conventional NGLs for simplicity. Sources: IEA databases; OGJ (2012); BP (2013); BGR (2012); US EIA (2013a).

2. NGLs are liquids produced within a natural gas stream; they are separated from the gas flow either at the well site (field condensate) or at gas processing plants. Field condensate is reported as part of crude oil in some countries (OECD in particular) and part of NGLs in others (OPEC in particular).

## Box 13.1 ▷ Light tight oil, conventional or unconventional?

We use the term light tight oil (LTO) to designate oil produced from shales or other very low permeability formations, using multi-stage hydraulic fracturing in horizontal wells, as pioneered in the United States over the last few years. The interchangeable term "shale oil" is often used as well, by analogy with shale gas; but the term LTO reduces the risk of confusion with oil produced from "oil shales", that is, shales containing kerogen that needs to be heated up, or retorted, to be transformed into oil (which the *World Energy Outlook* designates as kerogen oil).

Just as shale gas is actually quite ordinary natural gas, indistinguishable from conventional gas, so LTO is a normal type of crude oil, though often a light crude.[3] So far, it has been distinguished by the specific production technology involved. However this technology is now more and more applied as well in some low permeability conventional oil reservoirs. And conversely, some LTO (or shale gas, for that matter) can be produced without using horizontal wells, as is the case, for example, in some tests in Argentina and Russia.

The remaining differentiating feature of LTO (and shale gas) is the geological setting: the oil or gas is trapped in "continuous" reservoirs, rock formations spreading over large geographical areas, in which the hydrocarbons are trapped by the nature of the rock itself rather than by the geometrical arrangement of the rock layers (as in conventional structural or stratigraphic traps). In that sense, these continuous plays can be called "unconventional", irrespective of the evolution of the technologies used.[4]

Although we distinguish between conventional and unconventional resources throughout this analysis, the division between the two, in practice, is an inexact and artificial one. There is no unique definition that allows us to differentiate between them; and, as is often said, what is unconventional today may be considered conventional tomorrow. In this *Outlook*, the breakdown shown in Figure 13.2 is used. Our classification of conventional oil includes crude oil and NGLs. The main components of unconventional supply are extra-heavy oil and bitumen (EHOB), which includes oil sands in our definition, and light tight oil (LTO) (Box 13.1). The extracted amounts of conventional and unconventional oil together make up "oil production". The term "oil supply" refers to production plus the volumetric processing gains that accrue during refining, as crude is turned into oil products, which are, on average, less dense (see Chapters 15 and 16). The term "liquids supply" refers to the sum of oil supply and biofuels.

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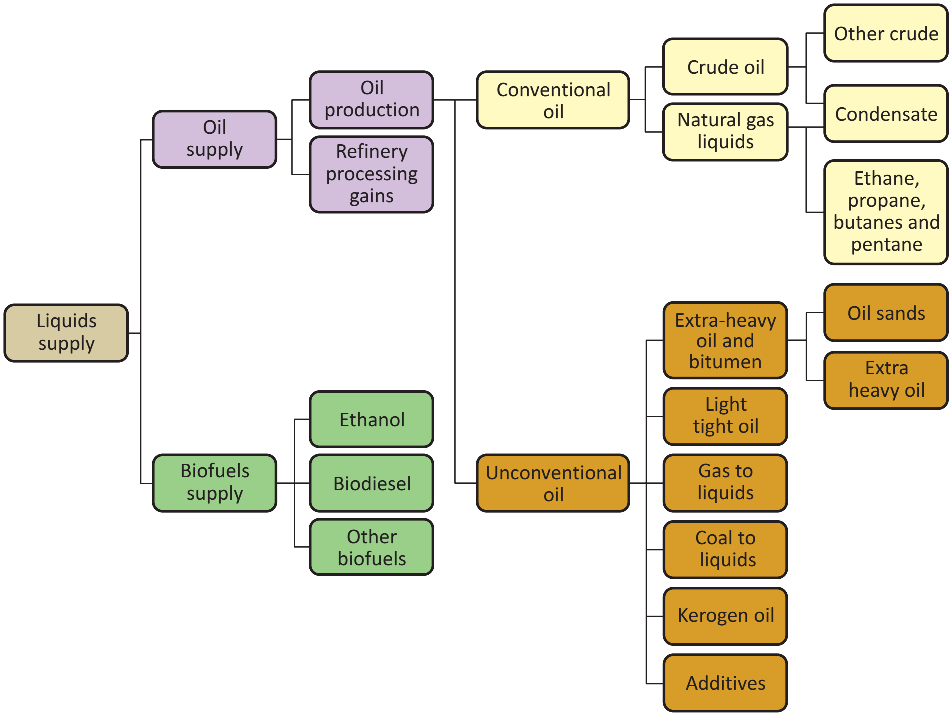
3. Wherever possible, we consider as LTO only oil produced from plays where liquids represent more than 50% of the energy content, reserving the term unconventional wet gas for those with more gas; however there is clearly a continuum between the two and the data are not always publicly available to differentiate between them (and in fact, the notional boundary can also vary with time, as production proceeds).

4. Some reservoirs, sometimes called "hybrid", do not fall neatly into this categorisation. This is the case, for example, of the Bakken play, where one of the producing horizons is a low permeability carbonate, sandwiched between shale layers; so although it is an extended "continuous" play, it can also be said to have a conventional cap rock.

**Figure 13.2 ▷ Classification of liquid fuels**




# Conventional oil

## *Resources*

The *World Energy Outlook* (*WEO*) resources database and the projections for conventional oil (and gas) rely extensively on the work of the United States Geological Survey (USGS), in particular its World Petroleum Assessment, published in 2000, and subsequent updates.[5] The USGS assessment divides the resource base into three parts (Figure 13.3):

- Known oil, including both cumulative production and reserves in known reservoirs.
- Reserves growth, an estimate of how much oil may be produced from known reservoirs on top of the "known oil". As the name indicates, this is based on the observation that estimates of reserves (plus cumulative production) in known reservoirs tend to grow with time as knowledge of the reservoir and technology improves.[6]

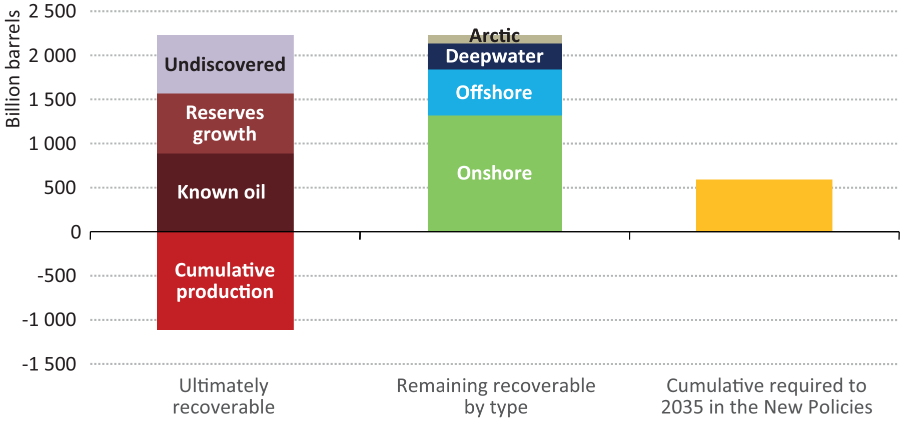
5. More information on the way that we incorporate USGS information into the IEA resources database is available in a methodological supplement at *www.worldenergyoutlook.org*.

6. For the 2000 assessment, reserves growth as a function of time after discovery was calibrated from observation in US fields, and this calibration then applied to the known worldwide reserves to obtain an estimate of worldwide reserves growth potential. The recent USGS (2012a) update uses a field-by-field assessment for the largest fields in the world. USGS geologists have repeatedly been able to demonstrate that their estimates of reserves growth are borne out by actual data (Klett and Schmoker, 2003).

- Undiscovered oil, a basin-by-basin estimate of how much more oil may be found, based on knowledge of petroleum geology.

The estimates of reserves growth, and particularly of undiscovered oil, are uncertain and therefore come with a probability distribution: they have a mean value and also values with a 5% probability and 95% probability (known as P05 and P95). Thus, USGS gives a range for total resources, which is useful for sensitivity studies; for example, the 2010 *Outlook* examined the impact of resources at the lower end of the range (IEA, 2010). In general, (and for all results shown in this *Outlook*) mean values are used for modelling purposes. Based on this approach, as of end-2012, we estimate that remaining recoverable resources of conventional crude oil stand at 2 200 billion barrels (Table 13.1). Of this sum, around 40% consists of known oil (excluding cumulative production),[7] a further 30% of reserves growth and 30% is as-yet undiscovered oil.

**Figure 13.3 ▷ Ultimately recoverable conventional crude oil resources and cumulative production required in the New Policies Scenario**




Notes: The ultimately recoverable conventional crude oil resources are as of January 2012, so the cumulative production required for the New Policies Scenario (for conventional crude only) covers the period 2012-2035. Known oil (in the USGS use of the term) includes also cumulative production.

Resources on this scale are more than sufficient to meet the projected demand for conventional crude oil to 2035, even given the uncertainties over the size of reserves growth and undiscovered oil. Cumulative production of conventional crude over the period 2013-2035 in the New Policies Scenario is 560 billion barrels, a figure that rises to 580 billion barrels in the Current Policies Scenario. If the P95 numbers for reserves growth and undiscovered oil are taken, *i.e.* the volumes at the lowest end of the range provided by USGS (associated with the greatest probability) and added to the figure for remaining known oil, then the remaining recoverable resource base is already 1 460 billion barrels.

7. Note that "known oil" in the USGS sense is actually smaller than reported proven reserves; some of this difference appears in "reserve growth"; see the section on Reserves, following, for further discussion.

Looking only at as-yet undiscovered oil, the projections to 2035 call for 170 billion barrels of cumulative new discoveries between now and 2035, comfortably below the 250 billion barrels that are the sum of USGS P95 estimates.[8]

A similar approach, based primarily on the same USGS publications, feeds into the *WEO* resources database of NGLs, allowing us to look at the total conventional resources shown in the first two columns of Table 13.1. However, the projections of future NGLs production are driven by gas production (see Chapter 3) rather than by NGLs resources.

### *Technically versus economically recoverable resources*

The USGS is careful to say that their estimates are for technically recoverable resources, not necessarily resources that are economically recoverable. For example, the offshore Arctic contains a significant amount of undiscovered oil; but even if some offshore Arctic resource developments appear to be viable at current oil prices (as exemplified by the exploration carried out by Exxon/Rosneft in the Kara Sea), in all likelihood, exploitation of most of the rest will depend on gradual infrastructure development and technological progress before it becomes economically possible at current oil prices.

On the other hand, the methodology used by USGS, which is largely based on drawing analogies with already producing reservoirs, implies that a large fraction of the volumes categorised as undiscovered oil and reserves growth may be recoverable without significant changes in price and technology. In any case, if oil prices rise with time, it is not because there is a shortage of lower cost oil, but rather because the industry's capacity to increase oil production at the same pace as demand growth is limited (by national policies, in some countries, and by shortage of skilled people overall). High prices are therefore required to moderate the growth in demand and bring it into equilibrium with the rate of increase of supply.

One could also argue that the amount of technically, but not economically, recoverable oil in the earth's crust is much larger than estimated by USGS.[9] Indeed, if the cost of doing so were not prohibitive, one could in principle recover close to 100% of the oil-in-place using deep mining technologies, instead of wells (the deepest exploited gold mine in the world reaches a depth of 4 000 metres, comparable to most oil reservoirs). As discussed in the section on enhanced oil recovery, there is scope for ultimately recoverable resources to exceed the USGS numbers.



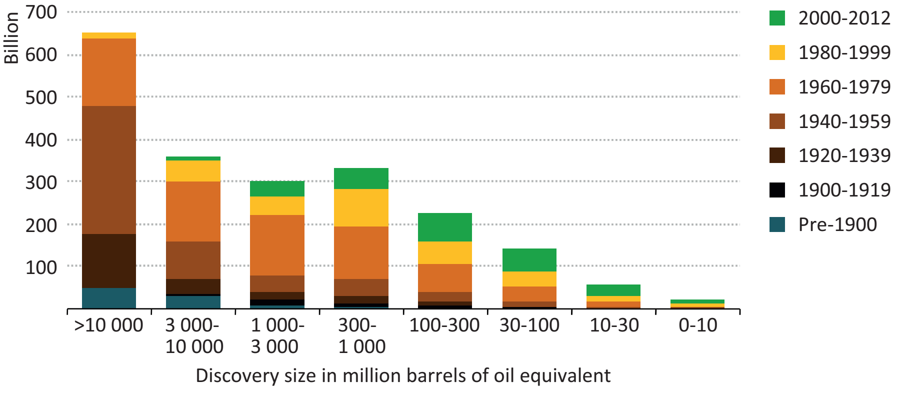
### *Undiscovered field size distributions*

A factor that pushes costs up is the expected distribution of undiscovered field sizes. A review of the discovery dates and size of fields making up today's conventional crude reserves reveals that most of the world's large fields were discovered some time ago. Discoveries over the last ten to twenty years have typically been fields in the 30 million to 3 000 million barrels range (Figure 13.4).

8. Adding together different regional P95 estimates produces a sum with a probability considerably greater than 95%.

9. We focus here on recovery factors; another reason is that the USGS studies do not yet cover all potential oil and gas provinces.

**Figure 13.4 ▷ Conventional crude oil resources by field size and year of discovery**

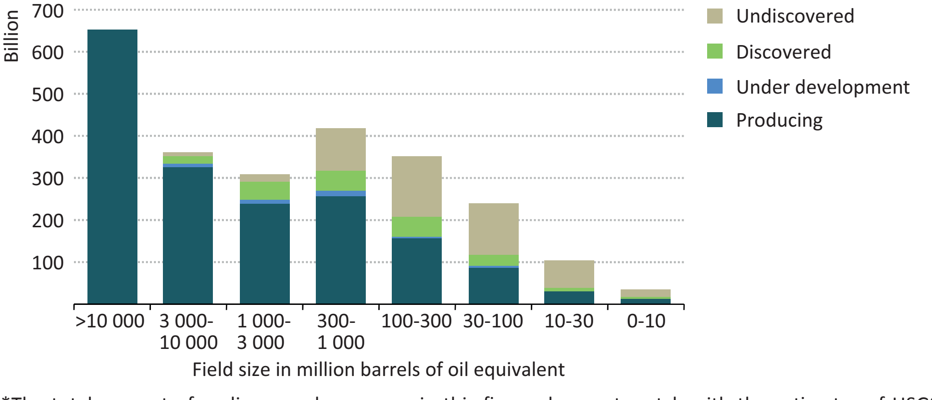



Notes: Includes cumulative production to date. Use of a different database and methodology makes the total not directly comparable with other resource numbers given in this chapter.

Sources: IEA analysis; Rystad Energy AS.

If the picture is extended to include the estimated size distribution of undiscovered fields, the trend towards smaller discoveries is likely to continue: the size distribution of undiscovered fields is concentrated around fields holding between 10 million and 1 000 million barrels (Figure 13.5).

**Figure 13.5 ▷ Estimated conventional crude oil resources by field size***

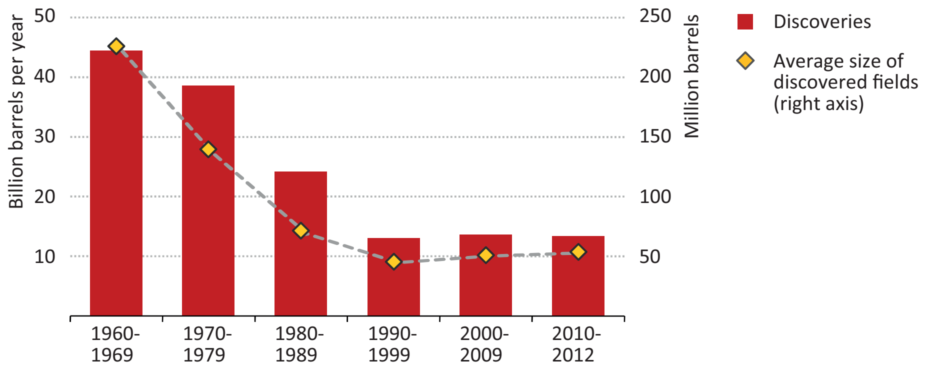



*The total amount of undiscovered resources in this figure does not match with the estimates of USGS, due to different methodologies. USGS has not published a comprehensive set of recent updates to its undiscovered field sizes distribution, but the one contained in the 2000 assessment shows somewhat larger sizes than the field database used here. Notes: It is often argued in the literature that the distribution of field size in the earth should be log normal. The distribution shown in the figure is not (a log-normal distribution cannot have the trough seen in the first three bars). However, there is no theoretical argument for a log-normal distribution: it is more an approximate empirical observation. The actual distribution can deviate from log-normal, due to the effect of a small number of very large fields (and data gaps may also skew the distribution).

Sources: IEA analysis; Rystad Energy AS.

A closer look at trends in discovery rates and discovered field size over the last fifty years shows that the rapid decline observed since the 1960s has been arrested (Figure 13.6). Both volumes discovered per year and the average field size of discoveries has stabilised in the last ten years, a development that is in large part attributable to higher oil prices and improvements in technology that opened-up deepwater and pre-salt provinces.

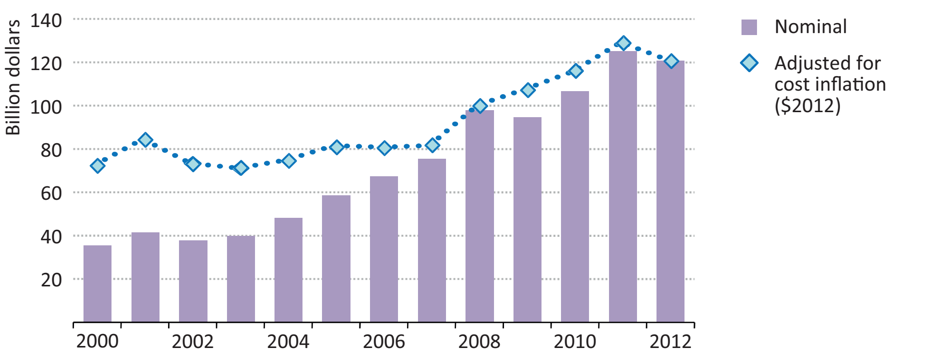
**Figure 13.6 ▷ Observed discovery rates and average discovery size**




Sources: IEA analysis; Rystad Energy AS.

Indeed, discovery rates depend not just on geology but also on exploration spending, which has picked up significantly over the last five years in response to increasing oil prices, after remaining fairly flat in the early part of the 2000's (Figure 13.7). Adjusted for cost inflation in the industry (assuming exploration costs followed the trend given by the IEA Upstream Cost Index, which reflects costs in the entire upstream sector), the pick-up in activity became significant only after 2007. Up to then, tight service industry capacity, after a decade of relatively low exploration levels, resulted in increases in the costs of services and materials, offsetting the growth in spending (increased exploration in higher cost areas, such as deepwater, also contributed).

**Figure 13.7 ▷ Global exploration spending, 2000-2012**




Notes: The graph shows total capital expenditure on exploration, including conventional and unconventional oil and gas; one cannot meaningfully separate exploration spend by categories.

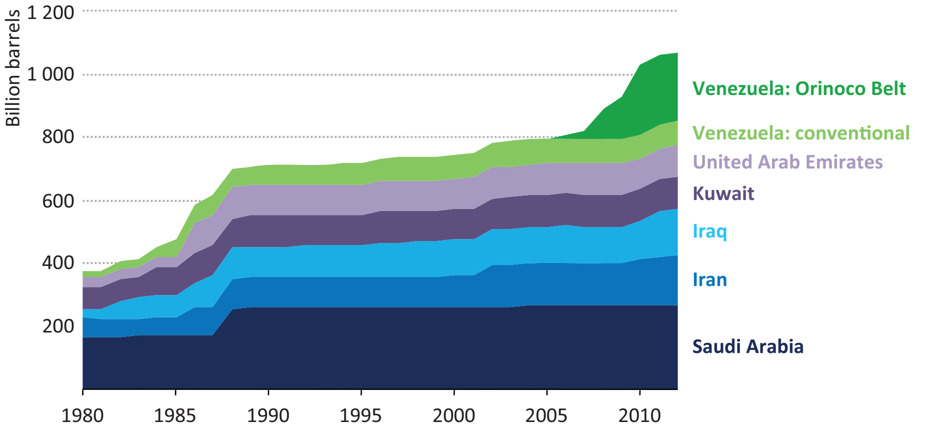
Sources: IEA analysis; Rystad Energy AS.

13

### *Reserves*

Once resources have been discovered and positively appraised, they become reserves. Depending on the degree of certainty of their value and the confidence in their development, reserves are further classified as Proven (1P), Probable (2P) or Possible (3P) (Box 13.2). One often sees the statement that proven reserves have increased substantially over the last twenty years, indicating that the industry is proving up reserves faster than it is producing. However a more detailed look at the evolution of reserves (as published by BP [2013] or the *Oil & Gas Journal* [2012]) reveals that a large part of the increases observed is linked either to revisions in OPEC countries or to the incorporation of unconventional reserves that were previously not included (Figure 13.8).

**Figure 13.8 ▷ Evolution of published proven reserves for selected OPEC countries**




Source: BP (2013).

In relation to some of the revisions by OPEC countries, the published "proven" reserves numbers include values that may not really be proven in the strict sense of the Petroleum Resources Management System (PRMS) (Box 13.2). Several countries have reported large increases in proven reserves that do not seem to be based on field activities that would produce changes in the probability of future production from these fields, beyond new geological assessments (this was in part due to OPEC quotas having been linked to reserves for a number of years). The issue is not that the oil may not be actually there; it is more that the degree of maturity of the corresponding projects is probably more representative of 2P reserves than of 1P.[10]

10. Indeed our special study of Iraq in *WEO-2012* confirmed that, at least for Iraq, the reported reserves correspond to oil that is clearly there, as demonstrated by the plateau production commitments taken by large international companies with access to the detailed geological information about the fields. Given what is known about the regional geology, the reserves reported by Iran, Saudi Arabia, Kuwait and the United Arab Emirates are reasonable, in a 2P sense, compared to those of Iraq.

### Box 13.2 ▷ Oil resources and reserves under different classification systems

The USGS categorisation of resources is less widely known than the designations used under the Petroleum Resources Management System (PRMS) (PRMS, 2007), which is also encapsulated in the United Nations framework classification that covers all energy and mineral types (UNECE, 2009). In the PRMS classification, reserves come in three categories, with decreasing probability of being produced:

- Proven reserves (or 1P), the amount of oil that has a more than 90% probability of being produced. This implies not only near certainty of the geological presence of the oil and of the ability to produce it at current oil prices, but also a high probability of implementation of an actual production project. For listed companies, this is usually taken to mean that the project has been "sanctioned", *i.e.* a final investment decision has been taken.
- Probable reserves (or 2P), the amount of oil that has a more than 50% probability of being produced as part of projects that have a high probability of being implemented. The uncertainty can be in the geology, the possible production rates or the economics of producing that part of the resources. 2P reserves are usually quoted as including 1P reserves (and can also be referred to as "proven + probable").
- Possible reserves (or 3P), the amount of oil that has a more than 10% probability of being produced. The uncertainty usually reflects the availability of only limited information on the geology and the ability to produce.

The PRMS classification also includes a category of Contingent Resources, those resources that are estimated to be technically, but not yet economically, recoverable or for which there is no likely project yet. It can be the case that the production project is down the priority list of the company with the production rights, even though the economics are sound: any oil producer will maintain a portfolio of potential projects beyond those that their capital budget allows them to pursue. Such cases should properly be counted as contingent resources, although in practice they are often included in reserves. There are also prospective resources, which have yet to be discovered.

There is no exact fit between the definitions used by USGS and the PRMS classifications, but USGS "known oil" could be understood to correspond broadly to the figure for proven reserves (1P) plus already produced; the USGS "mean value" for reserves growth to the difference between proven reserves (1P) and probable reserves (2P)[11]; and USGS "undiscovered oil" being equivalent to prospective resources.

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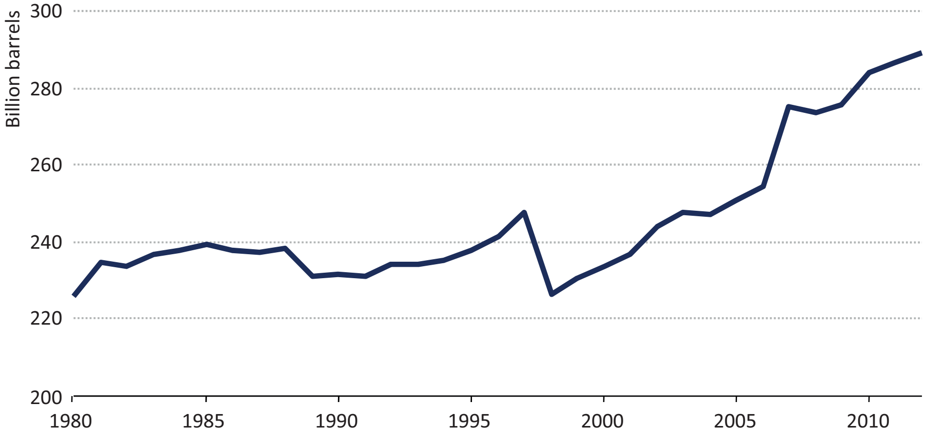
When testing the notion that the industry is proving up reserves faster than it is producing, it is worth looking specifically at non-OPEC conventional reserves, rather than the global totals (Figure 13.9). After a long period of stagnation and a drop in 1998, due to the very

11. With the addition of some probable contingent resources (2C) as well to reflect the fact that the USGS figure is for technically, but not necessarily economically, recoverable oil.

low oil price that year, there has been a clear ramp-up in proven reserves since 2002, as higher oil prices moved reserves from a non-commercial to a commercial category and stimulated an increase in appraisal activities.

**Figure 13.9 ▷ Non-OPEC conventional crude oil proven reserves, 1980-2012**




Source: BP (2013).

Overall, nearly 80% of the world's proven-plus-probable reserves, including both conventional and unconventional oil, are controlled by national oil companies (NOCs) (Box 13.3) or their host governments (Figure 13.10). NOCs control not only by far the largest portion of reserves, but also those with the lowest average development and production costs (although NOC assets are not exclusively low-cost, as shown, for example, by Petrobras' deepwater reserves, discussed in Chapter 11). Remaining reserves are shared between the Majors (7%) and Independents (13%). The share of the Independents is boosted by major Russian non-state reserve-holders (such as Lukoil and SurgutNefteGaz) and by companies that have stakes in the Canadian oil sands. It also includes their equity ownership in upstream projects where the other companies may hold the operatorship: for this reason, the operating share of the Majors is larger than their share of the ownership of reserves. While almost all of the reserves held by NOCs consist of conventional oil (except for PDVSA, the Venezuelan national oil company), unconventional oil reserves play a larger role for the privately-owned companies. Around 40% of the reserves held by Independents consist of unconventional oil. The Majors have a diversified reserve base, with their share of conventional oil being below 80%, extra-heavy oil and oil sands covering 15% and other unconventional oil making up the rest, mainly tight oil and liquids from shale gas production.

The predominance of NOCs in resource ownership does not have uniform implications for markets or investment. NOCs focusing primarily on their national markets tend to have a strong hold on national resource development. While some are operating abroad or increasingly looking to do so, they tend to remain close to their host governments and are subject to political supervision as well as being driven by commercial motivation. Some of the governments in question have a policy of deliberately slowing the rate of depletion of their resources, in the interests both of short-term price management and conservation of resources for future generations. At the other end of the spectrum, there are NOCs that actively seek overseas assets, development opportunities and access to technology/knowledge transfer, which are subject to much the same competitive constraints and pressures as private international companies. Particularly in cases where their capital has been opened up to private investors (with the state retaining a majority), these companies tend to behave more like privately-owned companies in their asset management and development strategies.

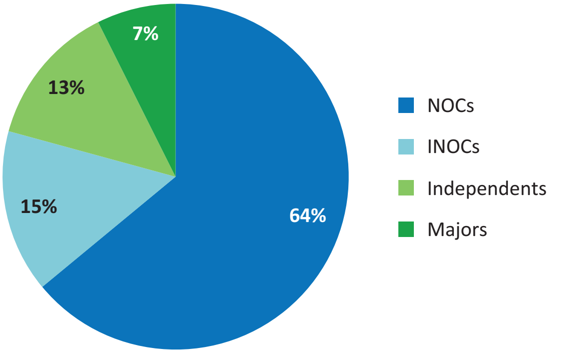
### Box 13.3 ▻ Grouping oil and gas companies in the *WEO-2013* analysis

To analyse by company type the distribution of oil and gas resources and production and investment trends, upstream oil and gas companies are considered in four categories: two of these categories cover companies that are fully or majority-owned by national governments and the other two relate to privately-owned companies. Among the former, we distinguish between national oil companies (NOCs) that concentrate on domestic production and a second group of international national oil companies (INOCs) that have both domestic and significant international operations. Among the privately-owned companies, we distinguish seven large international oil companies (referred to as the “Majors”) from the rest (referred to as “Independents”).

These categories include:

- NOCs include more than 100 companies that are majority- or fully-owned by their national governments and concentrate their operations on domestic territory. The largest of these are in the Middle East (notably Saudi Aramco, National Iranian Oil Company, Qatar Petroleum), but there are also companies in this category in Russia and the Caspian (Rosneft, Uzbekneftegaz) and Latin America (PDVSA).
- INOCs are likewise majority- or fully-owned by their national governments, but have significant international operations alongside their domestic holdings. Around 25 companies are included in this category, such as Statoil, PetroChina, Sinopec, CNOOC, Petrobras, Petronas, ONGC (India) or PTTEP (Thailand).
- Among the privately-owned companies, the “Majors” are BP, Chevron, ExxonMobil, Shell, Total, ConocoPhillips and Eni.
- “Independents” covers all majority privately-owned companies, except the Majors. This category encompasses a wide range of companies active in conventional and unconventional oil and gas, from Russian companies, like Lukoil, to a large number of North American players, like Devon, Apache and Hess, to diversified companies with upstream activities, such as Mitsubishi Corp. and GDF Suez.

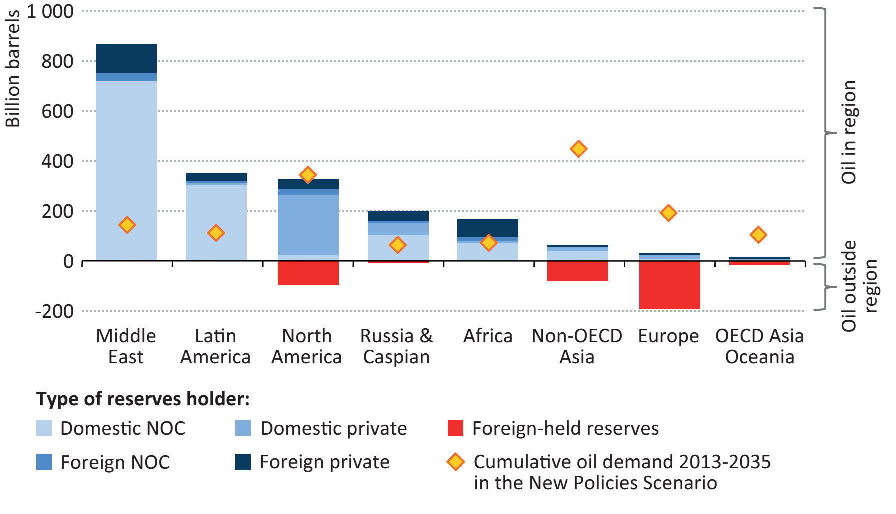
**Figure 13.10** ▷ **Ownership of 2P ("proven-plus-probable") oil reserves by type of company, 2012**




Sources: IEA analysis; Rystad Energy AS.

The activities of the main privately-owned international oil companies and other large private integrated companies are more geared towards shareholders' interests and market signals. They have a broad portfolio of projects, which gives them scope to optimise their operations according to investment conditions. Smaller independent companies are concentrated in North America; their business model does not always comprise the full life-cycle but rather has them specialise on a specific asset type or geographical location.

**Figure 13.11** ▷ **Distribution of proven-plus-probable reserves by region and type of company, 2012**




Note: The sum of foreign reserves held (in red) is equal in aggregate to the amount of assets held in home regions by "foreign private" companies and "foreign NOCs" (two darker shades of blue).

Source: IEA analysis based on AS Rystad Energy.

Considering the location of the assets held by NOCs and privately-owned companies, respectively, the majority of reserves in the Middle East and Latin America are held by the domestic NOCs, whereas in North America (with the exception of Mexico) this role is taken on by private companies (Figure 13.11). In Russia, there are still some strong domestic, privately-owned companies, but the trend over the last few years has been towards consolidation under NOCs: Rosneft's acquisition of TNK-BP in 2012 means that the enlarged company accounts for 4.1 million barrels per day (mb/d) of Russian oil and condensate production (as of the first half of 2013).[12] Together with Gazprom, Gazpromneft and other smaller players, the share of majority state-owned companies in Russian output has risen to more than half. Companies with their headquarters in the Atlantic basin, in Europe and North America, are the largest reserve-holders outside their home regions, having a legacy of foreign assets. Although Asian companies are currently among the most acquisitive internationally, their overseas holdings remain relatively small, in particular by comparison with the extent of their anticipated oil demand.

### *Development of oil reserves by scenario*

A key question for reserve-holders is the expected future trajectory of oil demand and the way that prices and policy interventions by governments may affect this trajectory. As examined in Chapter 15, related uncertainties are diverse. High oil prices create incentives to substitute other fuels for oil, where possible. There is huge latent demand for mobility in many emerging economies, yet this is also accompanied, in many cases in the projections, by a large rise in dependence on oil imports, especially in many parts of Asia: this is likely to generate a policy response favouring alternatives to oil. There is also increasing public pressure in many countries for actions to reduce traffic congestion and local pollution. Climate policy comes into the picture too: as described in Chapter 2, in the New Policies Scenario the world misses, by some distance, the agreed target to limit the long-term increase in average global temperatures to 2 °C. It is therefore reasonable for companies to expect action by policymakers to address these issues through additional measures to increase fuel efficiency, reduce emissions targets from passenger vehicles and support alternative fuels.

Our 450 Scenario gives insights into the implications for oil of a concerted policy push in these areas, making allowance for technological advances in the transportation sector. Compared with the New Policies Scenario, where oil demand rises (albeit at a slowing pace) to more than 101 mb/d by 2035, the 450 Scenario sees oil demand peaking in 2020 at around 91 mb/d, before a gradual decline to 78 mb/d in 2035 leaves oil demand in 2035 some 23 mb/d lower than in the New Policies Scenario. This oil demand trajectory would have wide-ranging implications for the oil sector, but the difference in terms of the volume of oil resources that need to be developed over the period to 2035 is perhaps less striking. *WEO-2012* calculated that, if the world is to reach the 2 °C target, no more than one-third

12. Combined Rosneft - TNK-BP plus its equity share of Slavneft production.

of proven fossil fuel reserves can be consumed prior to 2050, unless carbon capture and storage technology is widely deployed. This finding, which was developed in the *WEO 2013 Special Report Redrawing the Energy-Climate Map*, is applicable to all fossil fuels, including coal – which is the hardest hit by more stringent climate policy. Looking solely at oil, an amount equivalent to around 45% of current proven reserves would be developed in the 450 Scenario, only some seven percentage points less than the equivalent share of oil reserves developed in the Current Policies Scenario. This suggests that the likelihood of leaving upstream assets "stranded" because of policy uncertainty is limited (Box 13.4). The scope for stranded assets in the refinery and distribution sectors is, though, much greater.[13]

### Box 13.4 ▷ The risk of "stranded assets" in the upstream oil sector

Stranded assets, in the context of this discussion, are those investments which are made but which, at some time prior to the end of their economic life (as assumed at the investment decision point), are no longer able to earn an economic return, as a result of changes in the market and regulatory environment. The implications for upstream resource-holders can best be understood by looking at three different categories of oil resources. The first is reserves that are currently being produced, representing investments that have already been made. A second category is resources that are proven but not-yet-developed; in this case, part of the investment (the exploration costs) has already been incurred, but the development costs, typically 85% of total capital investment, are yet to come. The third category is reserves growth and resources that are yet-to-be-found; no investment has been made in this category.

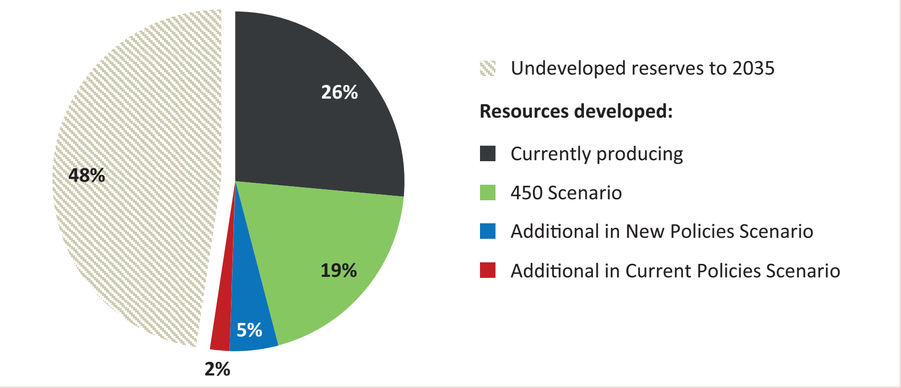
The first category will produce without additional investment and, because the rate of natural decline exceeds any conceivable rate of demand drop due to climate policies, this category is unlikely to be stranded (although the return on investment may drop, due to changes in the oil price). For the other categories, major capital spending lies in the future and can be aligned with changing perceptions of demand. Only the exploration costs of the proven but not-yet-developed reserves (the second category) risk being stranded.

Reserves that are not yet developed nonetheless contribute to the valuation of publicly-listed companies and it has been argued that they may be over-valued in the event of major changes in government energy policies. This view risks overstating the differences for oil and gas reserve-holders between the three scenarios as well as the extent to which today's company valuations reflect an expectation of a return on new investment in exploitation of reserves that may, in certain circumstances, not be

13. The higher risks in the downstream are linked to the fact that refinery investments are large, capital-intensive and long-term and need high utilisation rates to make an economic return. As examined in Chapter 16, there is already a risk in the New Policies Scenario that refinery capacity additions run ahead of the projected demand for refined products. If there were to be an overall decline in oil demand (as in the 450 Scenario) rather than just a fall in OECD countries (as in the New Policies Scenario), then the likelihood of assets being stranded would grow considerably.

developed before 2035 (Figure 13.12). In addition, most of these undeveloped reserves are either unlicensed or are held by national oil companies that are not publicly listed).[14]

**Figure 13.12 ▷ Oil resources that are developed by scenario as a percentage of proven reserves**




Notes: In practice, the oil produced in each scenario comes not only from proven reserves, but also from reserves growth (increases in reserves in known fields) and from as-yet-undiscovered resources. The figures for proven reserves exclude NGLs.

### *Enabling technologies: focus on enhanced oil recovery*

Technological progress has always played a key role in the upstream oil and gas industry. It rarely takes the form of sudden breakthroughs (even the shale gas and light tight oil revolutions are built on the gradual evolution of technologies that had been used for many years), but rather on constant, gradual, progress that always pushes the boundaries determining which resources can be produced and at what prices. Periods of high prices encourage the industry to push the envelope on the most technically ambitious projects in new frontiers, while periods of low prices push innovations on technologies or processes that help contain costs. For conventional oil, two sets of technologies are having and will continue to have a significant impact on available resources: deepwater and enhanced oil recovery (EOR). Deepwater developments are covered in detail in Chapter 11 as part of the special focus on Brazil; here the focus is on the prospects for EOR.

EOR can be defined as the set of technologies that permits production of a greater share of the oil that remains after primary and secondary recovery (Box 13.5). The main classes of EOR technologies are:

- The use of steam to heat the oil. This is usually used for heavy oil reservoirs. Heat reduces the viscosity of the oil, making it easier to move.

14. Under the PRMS system of classification (Box 13.2) oil cannot be classified as reserves unless it is licensed for production, but some of the reported reserves, for example for Canadian oil sands, do not follow PRMS.

- Miscible gas injection, either with hydrocarbon gas or carbon-dioxide ($CO_2$). Miscible means that the gas mixes with or dissolves into the oil, reducing its viscosity and increasing its susceptibility to being pushed by water. Immiscible gas injection (with nitrogen, $CO_2$ or hydrocarbon gas that does not dissolve in the oil) is sometimes also considered as an EOR technique, though it is more a form of secondary recovery. Water-alternating-gas (WAG) injection, in which a water injection cycle is followed by a gas-injection cycle, can also be considered either a secondary or an EOR technique. It is practiced in Norway (and planned for the Santos basin in Brazil, see Chapter 11). WAG and immiscible gas injection have not been included in the EOR numbers.
- Chemical flooding, in which water soluble polymers and/or surfactants are added to the injected water. Polymer flood has long been used in China and to a lesser extent in Russia, Canada and the United States. The higher viscosity of polymer-loaded water allows it to push more oil out of the pores (and also means fewer oil zones are being by-passed). More recently a combination of polymers and surfactants (which reduce the interfacial tension with water) has gained in popularity in the Alkaline Surfactant Polymer (ASP) technique.
- Microbial EOR, in which micro-organisms are injected in the reservoir. They can be used to break-down heavy oil into lighter components that flow more easily, or to produce in-situ some biopolymers or bio-surfactants that help mobilise more oil. There have been numerous pilot trials of microbial EOR over the last 30 years but, so far, no large-scale application.
- Combustion flooding. This involves in-situ burning of some of the oil to generate both heat and gases that help the rest of the oil to flow. Although used commercially for a long time in some reservoirs, it is difficult to control efficiently.
- The use of vibrations (either from the surface, or downhole, using a variety of "shakers" or sound sources). This is a controversial technique, as its mechanisms are poorly understood, but positive effects have been reported in some pilot tests.

Another approach is the use of tailored water in injection schemes. As first shown in the late 1990s in the Ekofisk reservoir in the Norwegian sector of the North Sea, the amount and type of salts contained in the injection water can affect the microscopic recovery rate significantly, because salts can interact with the reservoir minerals, helping to "un-stick" oil from the surrounding rock (Austad, 2013). Tuning these salts to the reservoir properties has recently gained popularity, particularly under the name "low salinity water injection", and replacing by fresh water the sea-water which has traditionally been used has given positive results in a number of regions. In a sense, this is an EOR technique, as it affects recovery at the pore level, but as the technology is not really different from normal water injection, changing only the source of water supply, it is generally not classified as EOR.

### Box 13.5 ▷ Recovery rates and the case for EOR

After primary recovery (where oil is produced due to the natural pressure in the reservoir) and secondary recovery (where pressure is provided by injecting water or, in some cases, gas), around two-thirds of the oil originally in place in a conventional oil reservoir is typically left unproduced. For this reason, there has long been a strong interest in techniques for producing a greater share of the oil, *i.e.* increasing recovery rates. These recovery rates vary greatly from one reservoir to the next; one-third represents a rough global average. Uncertainty about the extent of recovery is inevitable, given that the amount of oil initially in place is not known exactly, and the operator does not know how much oil will be produced from a reservoir until the reservoir is abandoned. Even for individual fields, recovery rates are only estimates, based on oil companies' (usually proprietary) models of their reservoirs and future output. As such, it is not easy to track whether the industry is making progress in increasing recovery rates. The clearest data comes from the Norway Petroleum Directorate (NPD), which shows that in 1995, the expected average recovery for Norwegian fields, after planned shutdown, was 40%. By 2012, it had risen to 46% and NPD is planning to increase it to 50% in the future (NPD, 2013).

There are two mechanisms that contribute to low recovery rates. The first can be called "by-passed oil": this is oil in parts of the reservoir which has not been moved towards the wells. This can occur because that part of the reservoir is fully or partially unconnected to the rest, because of faults or other geological features: in these cases, the reservoir is said to be compartmentalised. Another possibility is that water may have moved towards the well, by-passing some of the oil, which was thus never "pushed" by the water. Trying to produce such by-passed oil calls on technologies often called "improved oil recovery" (IOR), which involve identification of the zones where oil is left (for example with 4D seismic, using time-lapse seismic surveys that allow fluid movements in the reservoir to be tracked) and targeting them with new wells (in-fill drilling) or laterals drilled from existing boreholes. Another approach involves changing the water (or gas) injection patterns to re-route water towards the by-passed parts of the reservoir. As shown particularly in the Norwegian continental shelf, systematic application of such optimised reservoir management technologies can boost average recovery rates close to 50%.

The second reason for incomplete recovery involves the physics of flow in rocks at the microscopic (or pore) level. The oil is contained in small pores in the rock of a size typically in the tens to hundreds of microns. Some of the pores may be connected to others only by very tiny pore-throats, through which oil does not flow well, if at all. Some of the oil may stick to the rock minerals on the walls of the pores. Even on the small scale of pores, water can by-pass small oil globules, flowing around them. As a result of these various mechanisms, not all of the oil contained in the pores is produced: there is an amount of oil (called the "irreducible oil saturation") that always remains. Further reducing the amount of oil left in the pores calls for EOR technologies.

### *Potential of EOR*

Most of the information available about the potential of EOR relates to the United States. A study by INTEK for the US Energy Information Administration (EIA) (Mohan, *et al.*, 2011) gives estimates of more than 50 billion barrels recoverable in the United States from the various known EOR technologies, based on field-by-field studies; about half that amount is thought to be economical at oil prices of $80/barrel. $CO_2$ injection alone is thought to be able to bring 40 billion barrels of additional recovery, chemical EOR around 15 billion barrels, and steam techniques close to 10 billion barrels (some fields are suitable for more than one technology, so the sum of these numbers is more than the total estimated potential). $CO_2$ injection has attracted attention because of its potential to contribute to underground storage of carbon. Various studies give different estimates, for example, the United States National Energy Technology Laboratory has estimated that 137 billion barrels could be recoverable from $CO_2$ EOR in the United States (Kuuskraa, van Leeuwen and Wallace, 2011), of which 67 billion barrels could be recovered economically at oil prices of $85/barrel.

The USGS has looked at a few large fields in the Permian Basin and in California, as part of their assessment of potential reserves growth (USGS, 2012b, 2012c and 2012d) and estimates that, for the 37 fields assessed that contain 38 billion barrels of known oil, an additional 12 billion barrels could be technically recovered (the assessment is not limited to EOR technologies, but in these very mature fields, most of the additional recovery would come from EOR). Scaled-up to the more than 200 billion barrels of known oil in the United States, this could yield 65 billion barrels.

A more top-down approach starts from the estimated conventional crude oil-in-place in the United States, on the order of 1 000 billion barrels. With an average recovery factor, without EOR, of 35%, this gives recoverable resources of 350 billion barrels, of which almost 200 billion have already been produced and 18 billion are proven reserves (the rest being reserves growth and undiscovered). Using a conservative estimate of 10% for the additional average recovery possible by systematic application of EOR technologies gives 100 billion barrels of potential additional oil. This is broadly in line with the field-by-field, bottom-up, estimates.

Worldwide, the information about potential for EOR is more limited. A study of 54 basins for their potential for $CO_2$ EOR gave an estimate of 470 billion barrels (Godec, 2011). A study for the IEA comes up with a similar number (430 billion barrels), provided one assumes the use of technologies that maximise $CO_2$ storage, which are cost-effective only in the presence of a carbon price (IEA, forthcoming). Using a top-down approach, if a 10% improvement in recovery rate is applied to the estimated global amount of oil-in-place of 10 000 billion barrels, this yields an EOR potential of some 1 000 billion barrels, four times the reserves of Saudi Arabia. Not all of this EOR potential is additional to our other estimates of ultimately recoverable resources of conventional oil. Indeed the USGS reserves growth numbers do include the application of EOR technologies to large fields in the world. We estimate, however, that systematic application of available EOR technologies throughout the world, including $CO_2$ EOR+ (Box 13.6), would unlock at least 300 billion barrels on top of the URR values.

### Box 13.6 ▷ $CO_2$ enhanced oil recovery for carbon capture and storage

$CO_2$ enhanced oil recovery ($CO_2$ EOR) has long been practised because $CO_2$ has appropriate properties for enhancing oil recovery: under the right conditions of temperature and pressure, it dissolves in crude oil, increasing the mobility of the oil. Historically, most projects used naturally occurring $CO_2$ found in geological reservoirs similar to those of natural gas (the two are often found together, with $CO_2$ concentrations running from a fraction of 1% up to nearly 100%).

During a $CO_2$ EOR operation, $CO_2$ is injected into the reservoir, mobilises the oil, and is back-produced, together with the produced oil. At the surface, it is separated from the oil and re-injected. However a fraction of the $CO_2$ remains in the reservoir, typically about 0.3 tonnes per barrel of oil produced, and this needs to be compensated for by fresh $CO_2$ supply. Because $CO_2$ is a cost to the operator of the field, the company will try to optimise the process so that the amount of $CO_2$ remaining in the reservoir is as small as possible.

As this $CO_2$ remaining in the reservoir is effectively locked there for a very long time (the oil reservoir is normally capped by a very impermeable layer that has prevented the oil from moving upwards for millions of years, so if the well is properly sealed, $CO_2$ should also be trapped in the reservoir), there is great interest in disposing of $CO_2$ produced by human activities by linking carbon capture and storage (CCS) with EOR.

If, because of incentives to capture carbon to slow down climate change, $CO_2$ is free to the operator or even available at negative cost, there would then be an incentive to leave as much $CO_2$ as possible in the reservoir; a $CO_2$ EOR process optimised in this way has been called "EOR+". Various studies have shown that as much as 0.6 to 0.9 tonnes of $CO_2$ could be stored per barrel of oil produced, while also increasing the amount of oil recovered. A study for the IEA (2014) shows that, while conventional $CO_2$ EOR has the potential to recover about 190 billion barrels worldwide (storing 60 gigatonnes [Gt] of $CO_2$), EOR+ could enable the recovery of 430 billion barrels, while storing up to 390 Gt of $CO_2$ (more than the emissions projected from the power sector between 2013 and 2035). This is one reason why the estimate for "additional EOR" potential resources goes beyond that included in the USGS estimates.

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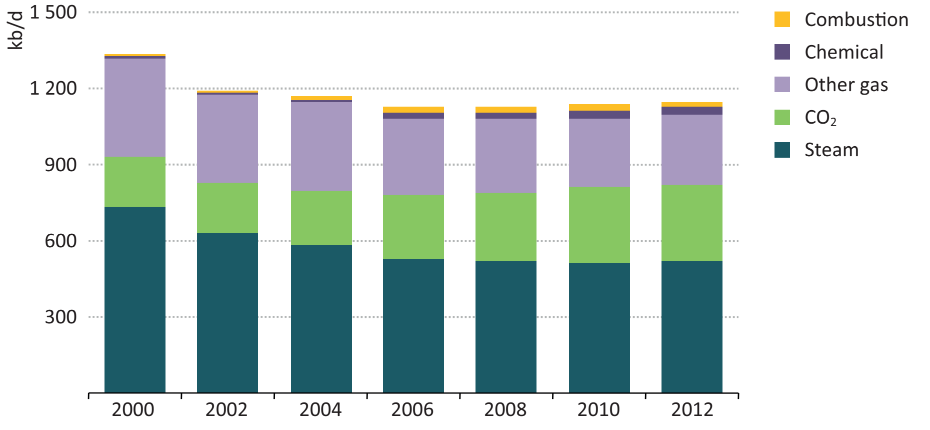
#### *Current status of EOR*

Most of the technologies classified as EOR have a long pedigree, having developed in the early 1980s, and a proven record of improving recovery rates. It therefore remains something of a puzzle that these techniques have not yet made a more substantial contribution to oil production.[15] Our estimate is that there are currently about 280 EOR

15. An initial challenge when analysing EOR around the world is the relative paucity of data. Outside the United States and Canada (the *Oil and Gas Journal* publishes every two years a list of active EOR projects and the corresponding production rates, with good coverage of activities in North America), EOR technologies are widely understood to be deployed in China, Russia and the Caspian region, among others, but the extent of their use is uncertain.

projects around the world, of which 75% are in North America, 10% in China and 15% in the rest of the world. Together, they produce some 1.3 mb/d of oil. The number of projects, the type of projects and the amount of oil produced by EOR has been relatively steady over the past ten years (Figure 13.13).

**Figure 13.13 ▷ Estimated global EOR production by technology**




Notes: The estimate excludes fields that we classify as unconventional, *e.g.* Canadian oil sands and Venezuelan Orinoco belt extra-heavy oil (steam-based technologies are extensively used for such unconventional reservoirs as the main recovery technique, as traditional primary and secondary recovery techniques are generally ineffective). The figure excludes China, because the data series for China are incomplete; China is estimated to produce about 170 kb/d: 150 kb/d from steam technologies and 20 kb/d with polymer injection.

Sources: *Oil & Gas Journal*; IEA databases and analysis.

Among the various EOR technologies, steam-assisted production has in the past given rise to the largest share of output, but this share is on the decrease, largely because the two large sets of steam projects that have dominated production for many years, in the San Joaquin Valley in California and Duri in Indonesia, are getting close to the end of their lives. One can expect the very large Wafra steam project being planned in the neutral zone between Kuwait and Saudi Arabia to offset this decline over time. Chemical EOR remains very small (outside China), but there are signs of growing interest. Shell, for example, is planning ASP pilot projects in Russia (at the Salym field, a joint-venture between Shell and GazpromNeft), in Oman with PDO, and in Malaysia with Petronas (at the Baram Delta and North Sabah fields – these would be the first offshore EOR projects in the world).

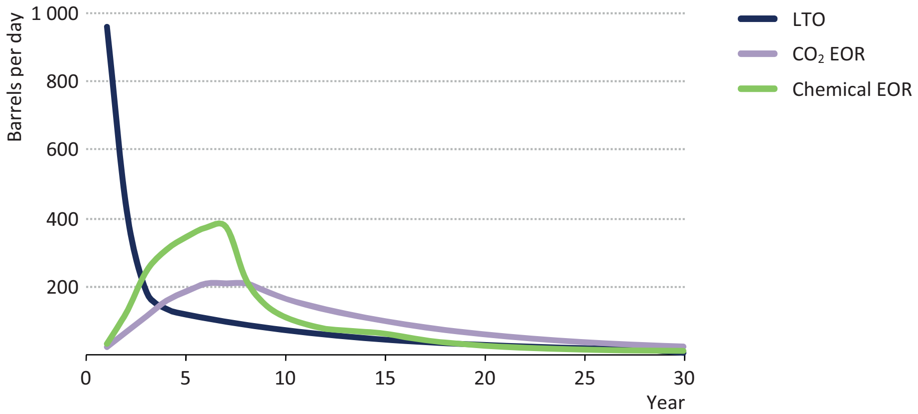
Oil production by $CO_2$ injection has seen a steady growth, gaining popularity, particularly, in West Texas and the Rocky Mountain states in the United States. Fed by $CO_2$ from natural reservoirs in the Rocky Mountains, the gas is piped over several hundred kilometres to the oil reservoirs. $CO_2$ injection technology is by now well established and has proven very effective, with recovery increased by as much as fifteen percentage points (*e.g.* from 35% to 50%). Further growth is limited at the moment by availability of $CO_2$, an ironic state of affairs, given the interest in coupling $CO_2$ EOR with $CO_2$ capture and storage (Box 13.6).

Interest in $CO_2$ EOR is growing around the world, though no full-scale project has materialised yet outside North America. Of particular significance is the interest in using such technology shown by Saudi Arabia and the United Arab Emirates as a 10% increase in recovery rate in fields in these two countries would represent a large amount of oil.

### *EOR economics, enablers and projections*

The potential for oil production through EOR is large and the available information on costs – most of which relates to the United States – suggests that deploying various EOR technologies is profitable at current oil prices. Yet worldwide the level of EOR production remains relatively modest, contributing only 1.5% of total oil production, and it has already been overtaken by LTO production from the United States alone (despite the fact that the estimates for EOR potential in the United States are larger than the estimates for LTO resources). So why is the industry preferring to invest in LTO rather than EOR? The answer lies in a more detailed look at the risks, returns and staffing intensity.

**Figure 13.14 ▷ Typical production profiles for LTO and EOR projects**




Notes: This analysis compares "typical" production profiles for LTO, chemical EOR (ASP) and $CO_2$ EOR projects of similar total production. For EOR, the line represents additional production on top of the (generally declining) secondary recovery production level.

LTO costs are primarily the capital costs of drilling the wells (relatively high, due to the use of horizontal wells and multi-stage hydraulic fracturing) and securing the lease; operating costs are low. Production peaks in the first year and then declines rapidly, so the payback time is short, minimising long-term risks (Figure 13.14). On the contrary, an EOR project (*i.e.* the additional production that results from an investment in EOR techniques) tends to have moderate capital expenditure, but much higher operating costs, because of the costs of the chemicals (or gas in the case of gas injection) and of injection itself.[16] Even

16. Existing wells can sometimes be used for EOR projects. When new wells are needed they are usually low cost simple vertical wells. An exception is steam projects, where the upfront costs of the steam plant can be large, and expensive casing and pipes may be required to withstand the heat.

more importantly, the increase in oil production often takes months, if not years, to materialise, as the injected fluids need to flow the distance between the injecting well and the producing well before providing a significant production increase.

Our review of the economics of generic LTO and EOR projects in Table 13.2 suggests that all three types of projects are highly profitable. The LTO project has the shortest payback period and the highest internal rate of return. The chemical EOR project does well on a calculation of net present value (NPV), return-on-investment and on the lowest breakeven oil price. The $CO_2$ EOR project is the least attractive of the three, but still quite profitable; introducing a premium on $CO_2$ storage would bring its profitability to levels similar to the others. From this we can conclude that the LTO project is the preferred choice for an operator looking for quick returns on borrowed capital, while EOR is more for long-term investors looking for longer-term returns, such as NOCs. $CO_2$ EOR, with its longer project lifetime and possible value for $CO_2$ storage, could be particularly attractive.

**Table 13.2 ▷ Comparative economics of LTO and EOR hypothetical projects**

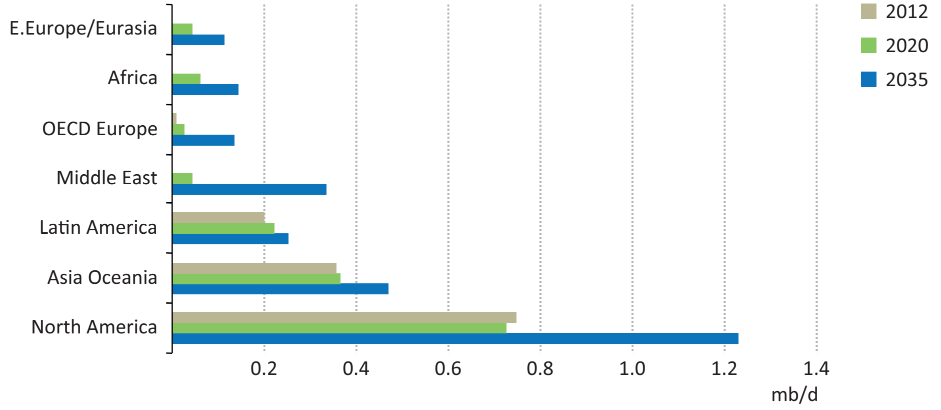
| Input parameters | Unit | LTO | $CO_2$ EOR | Chemical EOR (ASP) |
|---|---|---|---|---|
| Capital expenditure | $/barrel | 17 | 10 | 9 |
| Operating costs | $/barrel | 8 | 10 | 11 |
| $CO_2$ / chemical costs | $/barrel | n.a. | 10 | 10 |
| Royalties and production taxes | $/barrel | 22 | 22 | 22 |
| **Results pre-profit tax (at 15-year point)** | **Unit** | **LTO** | **$CO_2$ EOR** | **Chemical EOR (ASP)** |
| NPV at 10% discount rate | $/barrel | 17 | 10 | 18 |
| Payback time | Years | 2 | 7 | 4 |
| Internal rate of return | % | 53% | 22% | 35% |
| Breakeven oil price (NPV=0 at 15 years) | $/barrel | 64 | 63 | 56 |
| Return on investment | % | 100% | 99% | 197% |

Notes: Costs, royalties and taxes (and therefore economics) can vary greatly, depending on the actual project. Here it is assumed that the same royalties and taxes (taken from a typical LTO project) apply for all three. Slightly lower well-head oil prices for LTO are assumed, to reflect the fact that the liquid production often includes a significant share of NGLs, sold at a discount to West Texas Intermediate (WTI) oil. For this example, WTI prices are assumed to be $90/barrel at the start, gradually rising to $120/barrel over the 30-year lifetime of the project. Including allowance for risks, for example of lower future oil prices (typically reflected in an increased discount rate), would have little effect on the LTO project, but would reduce the attractiveness of the EOR projects.

But economics are not the only consideration and there is a range of other factors that limit the current and future use of EOR technologies. A key constraint is the availability of skilled staff; the various EOR technologies each require specialised knowledge that is often not widely available. The length of projects is another consideration: an EOR project generally starts with laboratory studies on cores to select the best technology, followed by one or several field pilots to apply the method to a small part of the field or a limited set of wells. The results of the pilot can take several years to be confirmed, delaying the moment at which the project is extended to an entire field (a process that may require construction of significant infrastructure to provide the chemicals, steam or $CO_2$). Even then, the results may also take a few years to materialise and could reveal unexpected problems, such as field heterogeneity, or reactions between injected fluids and minerals present in the rock. If the project is considered late in the life of the field, after years of standard secondary recovery, the remaining field life may not be sufficient to justify the project (EOR increases production over secondary recovery but, where production is declining rapidly, total production with EOR can still quickly decline to the point where oil production does not pay for operational expenses). For this reason, successful EOR projects need to be considered early in the life of a field, providing for maximum recovery from the start of the field development planning.

As part of this analysis, EOR has been treated as a distinct category of oil resources in the oil supply model – allowing projections for EOR to be tracked separately.[17] Although there are reasons to argue that EOR should gain in popularity at current and projected oil prices, in the projections we take account of the relatively limited EOR activity seen so far and remain conservative. In the projections, the volume of production attributable to EOR projects rises from 1.3 mb/d in 2012 to 2.7 mb/d in 2035 (Figure 13.15). Nonetheless, there remains significant upside potential for EOR production (not least for $CO_2$ EOR) – another reason to believe that a shortage of oil is not in sight. One of the determining factors will be developments in OPEC Middle East countries, where interest in maximising recovery is growing; a pilot project for steam-based EOR, using solar energy to generate the steam, has been built in Oman and similar projects are planned in the United Arab Emirates.

**Figure 13.15 ▷ EOR production by selected regions in the New Policies Scenario**



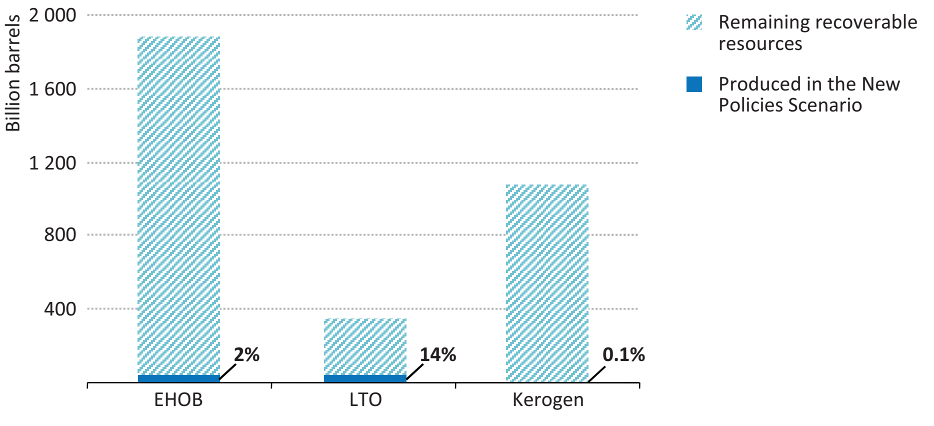

17. *WEO-2008* presented projections for EOR, but the supply module of WEM was revamped in 2010 without retaining separate treatment of EOR. This feature has been re-introduced this year.

## Unconventional oil

### *Resources*

Conventional crude oil has traditionally taken centre stage in any discussion about oil resources, as it has accounted for the lion's share of global production. In 1990, this share was more than 90%; in 2000 it was still 88%. Yet, since the turn of the century, it has declined more quickly; conventional crude oil made up only 80% of total production in 2012, with unconventional output (5.5%) and NGLs (14.5%) contributing the rest. The unconventional resource base, therefore, needs to be understood, even if, with the exception of light tight oil, the resources are so large, compared to the production projected to 2035, that they do not need to be studied in as much detail in the timescale of the *Outlook* (Figure 13.16).

**Figure 13.16 ▷ Cumulative production versus remaining recoverable resources by type of unconventional oil in the New Policies Scenario**




Note: Cumulative production is for the years 2013-2035.

#### *Extra-heavy oil and bitumen*

This category of unconventional oil (in *WEO* definitions) consists primarily of oil sands in Canada and the extra-heavy oil in Venezuela's Orinoco belt. Canadian oil sands oil-in-place has been estimated at 1 845 billion barrels (ERCB, 2013), of which 800 billion barrels might be recoverable (IEA, 2010). The Orinoco belt in Venezuela is estimated to contain about 1 360 billion barrels of oil-in-place (PDVSA, 2013), of which about 500 billion barrels might be recoverable (USGS, 2009). In addition to Canada and Venezuela, significant extra-heavy oil and bitumen resources are thought to exist in Russia and Kazakhstan, and modest amounts in Angola, Azerbaijan, China, Madagascar, the Middle East, the United Kingdom and the United States, for a global total of close to 1 900 billion barrels recoverable. Outside Canada and Venezuela, the projections to 2035 include some production only in Russia (Tatarstan) and China, where projects either already exist or are at an advanced planning stage.

*Light tight oil*

LTO is oil that has been generated from kerogen-rich shales over geological time but has either remained in the shale (instead of having migrated to a conventional reservoir) or has migrated to a nearby low-permeability rock. Because of the low permeability of the shale or host rock, it can generally be produced economically only by using special technologies, such as multi-stage hydraulic fracturing in horizontal wells. It is only in the last few years that commercial exploitation has reached a significant scale, with the rise of production in the Bakken and Eagle Ford plays in the United States.

In the United States, the US EIA estimates LTO resources at about 58 billion barrels, up from 35 billion barrels estimated in 2012 (US EIA, 2013b). This figure may well be revised again as more data become available. The USGS also reports undiscovered light tight oil onshore in the United States, with numbers smaller than the US EIA (13 billion barrels), though the definition of undiscovered is unclear (most LTO plays in the United States are known; the question is how much oil can be produced from them – the methodology used by the USGS is more geared to assessment of undrilled areas, whether discovered or not).

**S P O T L I G H T**

## Has the rise of LTO resolved the debate about peak oil?

It has become fashionable to state that the shale gas and LTO revolutions in the United States have made the peak oil theory obsolete. Our point of view is that the basic arguments have not changed significantly. To understand why, it is useful to revisit the main peak oil argument, which is based on the observation that, for a given basin or country, the amount of oil found and the amount produced tend to follow a rising, peaking and then declining curve over time – known as a "Hubbert" curve. This is either because big fields tend to be found and produced first, followed by smaller fields as the basin matures, or because the cheapest fields are produced first and, as depletion sets in, costs increase (because of smaller, more complex fields) and the basin is outcompeted by other regions. This phenomenon has been observed in many countries (Laherrère, 2003). Where technology opens up a new set of resources that were not previously accessible (as with deepwater or LTO), there can be multiple Hubbert peaks, as each type of resource moves up and then down the curve.

The crux of the peak oil argument has been the assumption that these dynamics, which are well established empirically at the basin or country level, will also take place at the world level (an assumption that has not been vindicated by empirical facts so far). For the purposes of the peak oil argument, the advent of LTO (or other technology breakthroughs) may shift the overall peak in time, but it does not change the conclusion: once the peak is reached, decline inevitably follows rather quickly (and, given the amount of LTO resources compared to the total resources, it could be argued that the peak would be shifted by only a few years in any case).

It is this last assumption – that it is possible to transpose observed country or basin-level dynamics to the world level – that is open to serious doubt. In all the countries that have seen oil production peak, oil demand has continued to increase. This demand has been satisfied, where necessary, by imports from regions that were still pre-peak and therefore lower cost. At the world level, since there is no possibility to import, demand has to be equal to supply. If supply is limited, price will rise, reducing demand (and increasing supply). This price mechanism is expected to lead to a long plateau, or slow decline, rather than the rapid decline observed on a country-by-country basis.

With the acceptance that demand is as important as geology and price in determining worldwide supply, it becomes clear that other factors can play a crucial role. One that has been emphasised in successive *Outlooks* is the role of government policies. Whether driven by the desire to tackle climate change, or simply to encourage efficient uses of resources, government policies have a large effect on future oil demand. This is illustrated by the policy-driven differences between the scenarios; where we see that oil production peaks (as in the 450 Scenario) it is not because oil is becoming more difficult and more expensive to produce, but because demand decreases as a result of policy choices.

Taking into account the large amount of unconventional resources that becomes available as oil prices increase, in addition to the significant remaining conventional resources and the sizable potential for EOR in conventional fields, no peak occurs before the end of the projection period. (In peak oil language, the URR value that enters into the Hubbert equation is large enough to delay the peak until after 2035). This was already the case before LTO. It has not changed much with the arrival of LTO.

In last year's *Outlook*, a value of 240 billion barrels was used for worldwide LTO resources, based on the assumption that the extent and distribution of LTO and shale gas resources in the United States and worldwide would be roughly correlated. More bottom-up estimates have since been made, primarily by private consultancies, which range from 100 billion barrels to 600 billion barrels. In June 2013, the US EIA released the first publicly available study of a large number of basins in the world, with an estimate of the global technically recoverable LTO resource of close to 350 billion barrels and country estimates for the major resource-holders (Table 13.3) (US EIA, 2013a).[18] These US EIA numbers have been used as the basis of the projections this year.[19] In the United States, the current estimate of

18. The estimates leave out the unknown but potentially large resources in the Middle East, on the grounds that these are unlikely to be produced, given the large remaining amount of cheaper conventional oil.

19. Prior to the release of the 2013 US EIA study, information on LTO resources outside North America was very sparse, with only some basins in Argentina having been studied enough to provide solid estimates (at least 7 billion barrels, with significant upside). The Russian government agency, Rosnedra, has estimated recoverable tight oil resources in the Bazhenov shale in Western Siberia at more than 25 billion tonnes (180 billion barrels). ERCB estimates Alberta's light tight oil in-place at 424 billion barrels, of which 1-5% may be recoverable.

resources starts to constrain production levels before the end of the projection period (see Chapter 14). In the rest of the world, technical, economic and environmental constraints allow only much slower development, so that resources are not a limitation in the timeframe of this *Outlook*.

**Table 13.3 ▷ Major LTO resource-holders** (billion barrels)

| Country | Areas assessed | Technical recoverable LTO resources |
|---|---|---|
| **Russia** | Bazhenov shale | 76 |
| **United States** | Bakken, Bone Springs, Eagle Ford, Granite Wash, Niobrara, Spraberry, Wolfcamp, Monterey and Woodford shales | 58 |
| **China** | Sichuan, Yangtze, Jianghan, Greater Subei, Tarim, Junggar and Songlia basins | 32 |
| **Argentina** | Neuquen, San Jorge, Magallanes and Parana basins | 27 |
| **Libya** | Ghadames, Sirte, and Murzuq basins | 26 |
| **Australia** | Cooper, Maryborough, Perth, Canning, Georgina, and Beetaloo basins | 18 |
| **Venezuela** | Maracaibo basin | 13 |
| **Mexico** | Burgos, Sabinas, Tampico, Tuxpan and Veracruz basins | 13 |
| **Pakistan** | lower Indus basin | 9 |
| **Canada** | Horn River, Cordova, Liard, Deep, Alberta, Windsor basins, Duvernay, Bakken, Utica shales | 9 |

Source: US EIA (2013a).

### *Kerogen oil*

Kerogen is the solid organic matter contained in shales that is the source of oil and gas. When heated under the right conditions, over geological time, kerogen is transformed into liquid or gaseous hydrocarbons. Shales containing kerogen are ubiquitous around the world. Some outcropping kerogen-rich shales have been exploited for centuries and burned for heat or power. If kerogen-containing shale is retorted (*i.e*. heated at a controlled rate), the kerogen can be transformed into liquid hydrocarbons. Kerogen oil is produced today in this way in small quantities in Estonia, China and Brazil.

The easiest kerogen shales to exploit are those near the surface, accessible with mining techniques. In principle, one can also exploit deeper deposits through in-situ heating, but the near-surface resources are already enormous. The largest known such kerogen shales are in the Utah/Colorado/Wyoming area of the United States. These have been studied in detail by the USGS and are thought to contain kerogen resources equivalent to 4 285 billion barrels of oil, of which more than 1 000 billion barrels is contained in the richest deposits that are more likely to be economically developed (USGS, 2012e). Several pilot projects have been demonstrating the technical feasibility of exploiting these deposits over the last 30 years, though there are significant environmental concerns related to water and land use.

Worldwide, the resources contained in near-surface kerogen shales are thought to be at least 1 100 billion barrels, with Jordan (30 billion barrels), Australia (12 billion), Estonia and China (4 billion each) and Israel, Morocco and Brazil (all around 3 billion) known to have large resources. Australia had planned a large-scale project in the Stuart shale in the 1990s but it was abandoned, in large part due to environmental concerns. Jordan, Israel and Morocco have a number of project proposals under study. Australia has recently approved a new pilot project, initially targeting 40 barrels per day.

### *Coal-to-liquids*

The applicable resources for coal-to-liquids (liquid hydrocarbons produced from coal) are so vast that it is enough to focus solely on the proven reserves. If only 10% of global coal reserves were turned into liquid hydrocarbons, using known coal-to-liquids (CTL) technologies, this would produce 275 billion barrels of oil. With only 5.3 billion barrels of CTL projected to be produced in the New Policies Scenario to 2035 (6.0 billion barrels in the Current Policies Scenario), resources are clearly not a limitation. Economics and environmental acceptability are the constraints on CTL development. Countries with large, low cost coal resources and significant oil import needs, such as China or India, will lead the investments in this technology. Although not strictly speaking CTL, rapid development of coal-to-chemicals is taking place in China, displacing demand for oil as feedstock. (See Chapter 15 for a discussion of the petrochemicals sector.)

### *Gas-to-liquids*

The resources available to transform natural gas to liquid hydrocarbons (GTL) are linked to the remaining recoverable resources of natural gas, estimated to be 810 trillion cubic metres (see Chapter 3). If 10% of this amount were transformed into liquid hydrocarbons with current GTL technologies, this would produce 280 billion barrels of liquids. This is more than ample to cover the most optimistic projections of use of GTL: in the New Policies Scenario, the cumulative production of GTL to 2035 is 4.1 billion barrels (4.6 billion barrels in the Current Policies Scenario).

More than 20% of gas resources are currently considered to be “stranded”, meaning that they need construction of significant new transport infrastructure before they can be brought to market. For most of these stranded resources, pipeline construction is not an economic option, as the size of the field does not warrant the investment. Although today both liquefied natural gas (LNG) and GTL make sense only for large enough reservoirs, technical developments in floating LNG (which enables the LNG plant to be used on several fields over its lifetime), in small-scale LNG and in small-scale GTL are likely to open the development of such stranded resources. In this context, GTL will be competing with LNG; if the market were to be split 50/50 between the two technologies, this would correspond to 11% of gas resources being available for GTL.

### *Reserves*

The standard PRMS definition of proven reserves, although it can be applied to unconventional resources such as oil sands or LTO, does not give a good feel for the amount of those resources that are likely to be developed. Indeed, because those resources tend to be large and spread over large geographical areas, they are developed piece-by-piece over many years. So in addition to the proven reserves amount, which corresponds to the part of the play for which there is a specific approved development project, it is useful to look at the total amount of recoverable resources that is known to exist and is thought to be currently economically and technically recoverable with reasonable certainty.

For oil sands, this is what the Canadian federal and provincial governments describe as "established" reserves. Canada's National Energy Board and Alberta's Energy Resources Conservation Board currently consider 168 billion barrels in this category, *i.e.* currently technically and economically recoverable in areas of planned developments (as not all these reserves correspond to sanctioned projects, this is a looser concept than strict PRMS 1P reserves).[20] Cumulative production from oil sands to 2035 in the New Policies Scenario is 27.2 billion barrels (28.4 billion barrels in the Current Policies Scenario). In addition to established reserves, Canada uses the concept of "ultimate potential" which is similar, but with lower probability of being geologically present and technically and economically recoverable under current conditions, somewhat along the lines of PRMS 2P reserves. The estimate for this category is 315 billion barrels (ERCB, 2013).

A similar question of definition arises for LTO. For example, in the Bakken play of North Dakota, it is expected that it will take 40 000 wells, drilled over twenty years, to develop the resources (NDDMR, 2012). Clearly the presence and economic and technical recoverability of the oil is very likely, but one cannot today assign a 90% or more probability to the drilling of 2 000 wells in 2030. So companies involved in LTO (or shale gas, for which a similar situation arises) tend to report both a PRMS proven amount and a resources amount that gives an indication of the amount they might be able to develop over the years. The company EOG Resources, for example, reports 552 million barrels of oil equivalent (boe) of proven reserves in the Eagle Ford play and 2 200 million boe of resources. World proven reserves of LTO (essentially all of it in the United States and Canada) are estimated at 5 billion barrels at the end of 2012.



For the Venezuela Orinoco belt, PDVSA has been regularly reporting updates to reserves as part of the progress with its Magna Reserva assessment project. The latest reported number stands at 220 billion barrels. The details have not been publicly documented, so it is unclear whether this is a proven reserves number (which seems unlikely, in view of the announced projects) or a 2P or 3P number, or rather whether it is an "established reserves"

20. ERCB, the Alberta Energy Resources Conservation Board has now been integrated in a new regulatory agency under the name Alberta Energy Regulator (AER).

number or an "ultimate potential" number.[21] Projected cumulative production to 2035 in the New Policies Scenario amounts to 11.8 billion barrels (12.7 billion barrels in the Current Policies Scenario).

## *Enabling technologies*

### *How technology and learning-by-doing have unlocked LTO*

One of the most important technological developments of the last decade has been the advent of multi-stage hydraulic fracturing in horizontal wells, unlocking vast new resources in low permeability, "tight" rocks. As a result of this "shale revolution", worldwide ultimately recoverable resources of oil have increased by as much as 350 billion barrels, and those of gas by 1 300 billion barrels of oil equivalent.

Horizontal wells have been routinely drilled since the 1980s. In the early 2000s, many new oil field developments outside the United States used horizontal wells; somewhat ironically, the lower 48 states in the United States was one of the few places still dominated by vertical wells. But this has changed dramatically over the last few years and, by early 2013, more than 60% of drilling rigs in the United States were drilling horizontal wells.

Hydraulic fracturing also has a long history, starting in the 1950s. By the early 2000s, it was routinely practiced in vertical wells around the world, and occasionally (as far back as the 1990s in the North Sea) in horizontal wells as well. Prior to its impact on the shale revolution, hydraulic fracturing had already been in large part responsible for the renaissance of Russian oil production in the mid-2000s. Since it increases productivity, hydraulic fracturing can be practised in most wells provided the value of the production increase exceeds the cost of the operation.[22]

The essence of the shale revolution has been process optimisation. A significant part of the cost of a hydraulic fracturing operation resides in the equipment used (trucks, pumps, mixing tanks, etc.). Performing multiple fracturing operations in the same horizontal well and drilling many wells in the same area maximise equipment utilisation, increasing the range of reservoir characteristics for which the operation is cost effective. In the early days of shale gas development in the Barnett shale, this alone was not sufficient and simplification of the fracturing fluid (*i.e*. the advent of the "slick-water" fracturing fluids) was required to achieve enough cost reduction to make the operation worthwhile. As the shale revolution took off, a series of further means of optimising the process were identified and others are under evaluation:

- More modular and mobile drilling rigs that can move to nearby locations easily without having to be fully dismantled.

21. The target plateau production of all proposed projects amounts to about 1 billion barrels per year production (IEA, 2010). Even if maintained for 30 years, such projects would amount to only a small part of the Magna Reserva reserves number.

22. Exceptions are thin oil zones near oil-water contacts, where hydraulic fracturing might increase water production rather than oil (or gas) production, and reservoirs where the stress profile prevents the formation of hydraulic fractures.

- Pad drilling, *i.e*. drilling of multiple wells from a single drilling location, reducing site preparation costs.
- More rapid succession of the stages of multi-stage fracturing, thanks to ball-activated (or pressure- or tubing-activated) sleeves, or smart-fluids, allowing pumping at all the stages without pulling the equipment out of the wellbore.
- New approaches to water management, with piping and recycling at the field level, reducing supply costs.
- A number of companies are experimenting with gas-powered trucks and pumps to reduce fuel costs and reduce gas flaring in locations with no outlet to a gas market.

Most of these approaches contributed to the increased efficiency achieved over the last two years in some of the main shale plays in the United States. For example, in North Dakota (where most of the Bakken light tight oil play is found), 2 086 wells were spudded in 2012, (*i.e*. drilling started), using 200 drilling rigs, *i.e*. an average of ten wells per rig over the course of the year. This represents a significant improvement on the 2011 average of 8 wells per rig (1 528 wells with 182 rigs) (NDDMR, 2013).[23]

For all this progress, drilling for shale gas or light tight oil remains largely a trial-and-error operation. When moving into a new area, an operator will experiment with different lateral well lengths, different number of fracturing stages, different types of fracturing fluids and different perforation strategies until a combination that provides good economic returns is found. Finding the "sweet-spots", the parts of the reservoir that give good production, is also often hit-and-miss. In shale plays in the United States, currently about only one-third of the wells are economic and the good wells have to cover the costs of the less productive ones. If further process optimisation alone will probably give only slow additional cost gains, there is a large potential of further gains if new technological breakthroughs can improve this success rate.

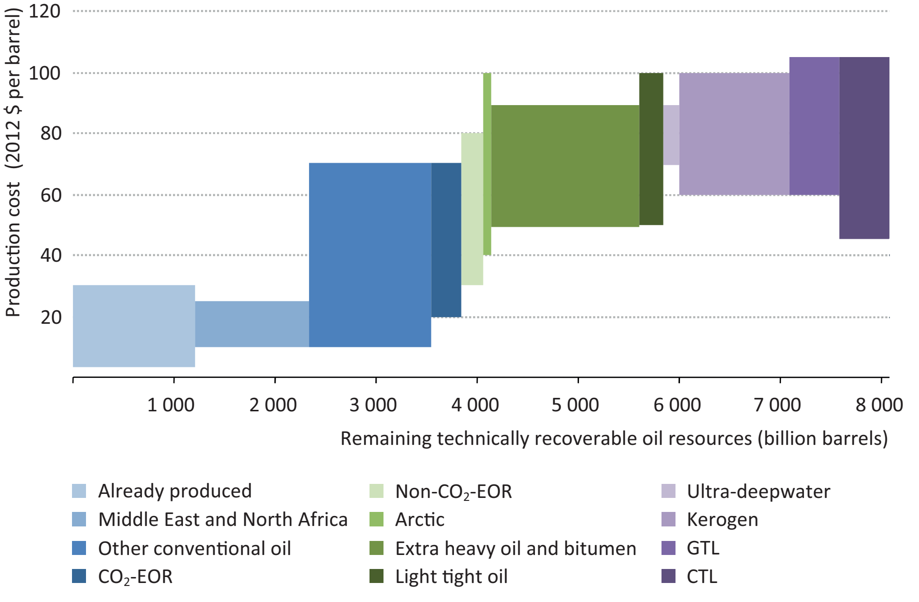
## Supply costs

Since 2005, the IEA has regularly published diagrams giving estimates of the oil price at which various amounts of resources can reasonably be expected to be produced (IEA, 2005). The most recent update is illustrated in Figure 13.17 (IEA, 2013). Such diagrams have been widely reproduced and are often used to argue that there is plenty of relatively "cheap" oil available. However, such figures can easily be over-interpreted and it is important to remember their limitations. The illustration shows the extent of various types of resources, as well as the range of oil prices that make production from these resources currently possible on a commercial basis in various parts of the world. But, clearly, not all the resources will, in practice, be produced under current conditions; with costs varying over time, today's economic prices may not represent the required prices at the time in the future when the resources will be produced.



23. Changes in average target depths have also contributed, as well as a reduction in weather-related downtime.

**Figure 13.17 ▷ Supply costs of liquid fuels**




Source: *Resources to Reserves* (IEA, 2013).

A more dynamic picture of the evolution of costs is captured in the World Energy Model (WEM) by three factors (not all of which push in the same direction):

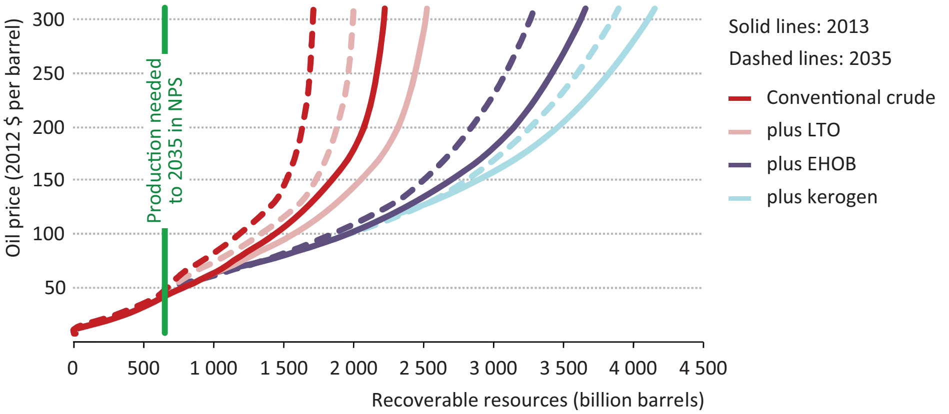
- Depletion of the resources in each country (and type of resources): as a larger fraction of the resources is produced, capital and operating costs increase.
- Technology learning: the evolution of existing technologies and the introduction of new ones tend to reduce the capital and operating costs with time.
- Industry-specific inflation: the period 2000-2008 clearly showed that, as an increasing oil price pushes up industry activity levels, so increasing supply and service costs also drive up capital and operating costs. The correlation between oil prices and industry costs observed during that time period is encapsulated in the WEM, so that higher oil prices lead to higher costs.[24]

The inputs to the WEM are not supply cost curves, but estimates of current costs by country and by type of oil (capital and operating costs, plus government take) which then evolve with time, subject to the three factors listed above (government take – as a percentage of net income -- and discount rates are normally kept constant throughout the projection

24. Some may argue that the 2000-2008 period was atypical, as the supply industry had to build-up very quickly after a decade of relatively low activity, leading to price tensions. However it is reasonable to expect that all industry participants (producers, supply and services companies, and governments awarding the licenses and imposing various production taxes) will always try to capture their share of higher oil prices, *de facto* pushing costs up proportionally.

period). So one can use the WEM to derive the implied supply cost curves at various times for different regions or different oil types (Figure 13.18).[25]

**Figure 13.18 ▷ World supply cost curves for 2013 and 2035 in the New Policies Scenario**




Notes: The supply curves are cumulative, *i.e*. the "plus LTO" line includes conventional crude and LTO; the "plus EHOB" includes conventional crude, LTO and EHOB, and so on. The vertical green line indicates the amount of production required between 2013 and 2035 in the New Policies Scenario (NPS).

For a given year (*e.g*. 2012), remaining recoverable oil is assumed to be produced with the technology learning factor of that year and the industry-specific inflation factor of that year, but the depletion factor increases as one moves up the curve. For each level of resources, a "breakeven oil price" can be calculated, being the oil price that gives a NPV of zero, with a discount rate of 10%. As expected, there is a large amount of conventional oil that can be produced at relatively low cost and, when oil prices increase, more unconventional resources are gradually opened up.

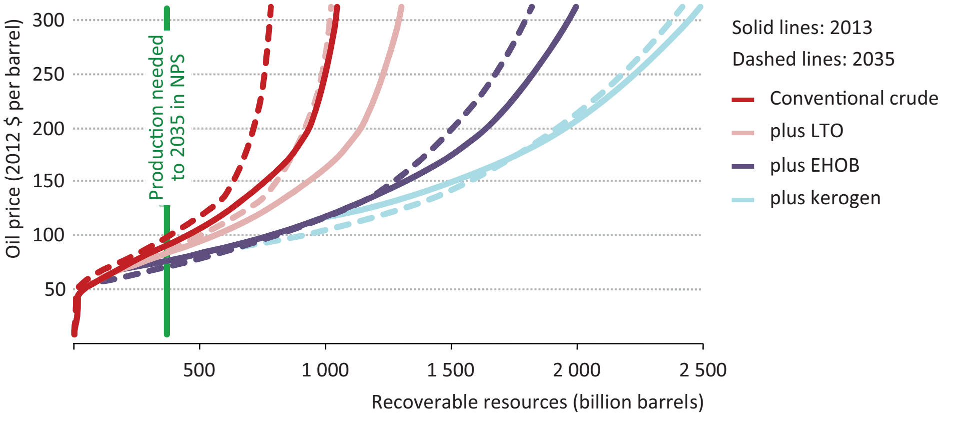
Since the cumulative production required in the New Policies Scenario between 2013 and 2035 is about 640 billion barrels (crude+LTO+EHOB+kerogen oil, *i.e*. excluding NGLs, GTL, CTL and additives), one might conclude from the figure above that the marginal barrel to meet this demand (the highest cost barrel produced to meet such a demand) costs only $50. However, the view at world level can be misleading as most of the low cost oil is located in OPEC countries, where production is limited as a matter of policy. It is therefore more meaningful to look at the same curves for non-OPEC countries (Figure 13.19, noting the change in scale on the horizontal axis).

The expected cumulative demand for oil from the non-OPEC countries in the New Policies Scenario is 380 billion barrels. On this basis, one still observes that the marginal barrel to meet the expected demand costs no more than $80-90/barrel, below the average IEA

25. CTL and GTL are not included as depletion does not affect their costs: feedstocks represent only a small fraction of their costs, which are dominated by investment and operating costs of the plant.

import price of \$128/barrel in 2035. This is due to the fact that looking at resources is not enough: one must also look at production rates. The ability of the industry to develop new resources quickly is limited (in large part by the availability of skilled personnel, as well as the long timescales of new large projects). So there are constraints on supply keeping pace with demand, even though production projects may be highly profitable. The oil price trajectory, at a level above the marginal cost per barrel, serves the purpose of limiting demand to a level that can reasonably be expected to be supplied, given expected limitations in both OPEC and non-OPEC countries (see Box 1.3 for a discussion of how the oil prices used in this *Outlook* are determined).

**Figure 13.19 ▷ Non-OPEC supply cost curves for 2013 and 2035 in the New Policies Scenario**




Note: The vertical green line indicates the amount of production required between 2013 and 2035 in the New Policies Scenario (NPS).

In economic terms, this is a dynamic situation: the long-term equilibrium, in which price is equal to marginal production cost, is never reached (even if demand was constant, one would not necessarily reach equilibrium, because production from existing fields always declines and the industry has to invest constantly in new developments in order to meet demand). In principle, classical economic theory would imply that the industry would increase its intake and training of skilled personnel until this no longer represented a limitation, but empirical evidence suggests the oil industry is very risk averse in its recruiting policies, leading to long lasting imbalances. Another factor contributing to the difference between the marginal cost of supply and the projected price is that the latter is computed with a risk-free discount rate; provision for risks requires higher prices, as the market factors in risks, such as geo-political risks. The role of OPEC and the fiscal needs of some of the OPEC countries (see Chapter 14) can also contribute to maintaining elevated oil prices.

# Prospects for oil supply

## Decline does not always lead to a fall

### Highlights

- Oil supply is projected to reach 101 mb/d in 2035 in the New Policies Scenario, a rise of 12 mb/d from 2012. Key components of the increase are unconventional oil (up by 10 mb/d) and natural gas liquids (NGLs) accompanying the increase in global gas output (up by 5 mb/d). They fill the gap between increasing global demand and conventional crude oil production; the latter's share in total oil production falls, from 80% in 2012 to two-thirds in 2035, despite rising offshore deepwater output.

- Analysis of more than 1 600 fields confirms that the observed decline rate for conventional fields that have passed their peak – averaged across all fields and weighted by their cumulative production – is around 6% per year. Decline rates vary substantially by field size, with the largest fields having the lowest rates of decline and onshore fields depleting more slowly than offshore. Conventional crude output from existing fields is set to fall by around 40 mb/d by 2035.

- Unconventional plays, such as light tight oil or oil sands, are heavily dependent on continuous investment and drilling to prevent the large initial decline rates for individual wells translating into rapid field-level declines. In our projections, production of LTO does not take off at scale outside North America before 2035, but still reaches 5.9 mb/d by the mid-2020s.

- The role of OPEC in quenching the world's thirst for oil is temporarily reduced over the next ten years, due to rapid growth of supply from LTO in the United States, from oil sands in Canada, from deepwater production in Brazil and from NGLs from all over the world, but the share of OPEC countries in global output rises again in the 2020s, as they remain the only large source of relatively low cost oil. Iraq is the single largest contributor to global production growth.

- Supply developments exceed expectations in a Low Oil-Price Case, easing market balances and bringing the oil price down to $80/barrel for the duration of the *Outlook* period. The result is an increase in oil demand, which reaches almost 108 mb/d in 2035 (6.5 mb/d higher than in the New Policies Scenario). OPEC countries provide the bulk of the increase in demand in 2035, but their revenues fall.

- Declining output from existing fields is a major driver of upstream investment. Total upstream spending in the oil and gas sectors is expected to rise to more than $700 billion in 2013, a new high, and the projections call for spending to remain around these levels for the next decade, before the annual average dips slightly, as non-OPEC supply starts to tail off and lower cost OPEC Middle East countries (through their national oil companies) provide most of the increase in supply.

## Global oil supply trends

Global oil supply differs strikingly across the three main scenarios analysed in this *Outlook*, in line with the wide variations in demand.[1] From a starting point of 89 million barrels per day (mb/d) in 2012, there is a 33 mb/d difference by 2035 in projected oil supply between the Current Policies Scenario, where it reaches 111 mb/d and the 450 Scenario, where oil demand – and therefore supply – starts to drop in the mid-2020s, declining to 78 mb/d in 2035. The focus in this chapter is the central, New Policies Scenario, which falls in between these two, with supply raising to 101 mb/d in 2035 (Table 14.1).

**Table 14.1 ▷ Oil production and supply by source and scenario** (mb/d)

| | | | New Policies | | Current Policies | | 450 Scenario | |
|---|---|---|---|---|---|---|---|---|
| | 1990 | 2012 | 2020 | 2035 | 2020 | 2035 | 2020 | 2035 |
| **OPEC** | **23.9** | **37.6** | **37.8** | **45.2** | **38.3** | **49.3** | **36.1** | **34.4** |
| Crude oil | 21.9 | 30.9 | 29.4 | 33.0 | 29.7 | 36.2 | 28.4 | 25.4 |
| Natural gas liquids | 2.0 | 6.1 | 6.8 | 9.3 | 7.0 | 9.9 | 6.2 | 6.9 |
| Unconventional | 0.0 | 0.6 | 1.6 | 2.8 | 1.6 | 3.2 | 1.5 | 2.1 |
| **Non-OPEC** | **41.7** | **49.4** | **55.0** | **52.9** | **56.1** | **58.1** | **52.5** | **41.3** |
| Crude oil | 37.6 | 38.4 | 38.3 | 32.3 | 38.9 | 35.2 | 36.7 | 25.4 |
| Natural gas liquids | 3.6 | 6.6 | 8.0 | 8.3 | 8.2 | 9.0 | 7.5 | 6.6 |
| Unconventional | 0.4 | 4.4 | 8.8 | 12.3 | 9.0 | 13.9 | 8.4 | 9.2 |
| **World oil production** | **65.6** | **87.1** | **92.8** | **98.1** | **94.4** | **107.4** | **88.6** | **75.7** |
| Crude oil | 59.6 | 69.4 | 67.7 | 65.4 | 68.6 | 71.4 | 65.1 | 50.8 |
| Natural gas liquids | 5.6 | 12.7 | 14.8 | 17.7 | 15.2 | 18.9 | 13.7 | 13.6 |
| Unconventional | 0.4 | 5.0 | 10.4 | 15.0 | 10.6 | 17.1 | 9.8 | 11.3 |
| *Processing gains* | *1.3* | *2.1* | *2.6* | *3.3* | *2.6* | *3.6* | *2.5* | *2.5* |
| **World oil supply*** | **66.9** | **89.2** | **95.4** | **101.4** | **97.1** | **111.0** | **91.1** | **78.2** |
| World biofuels supply** | 0.1 | 1.3 | 2.1 | 4.1 | 1.9 | 3.3 | 2.6 | 7.7 |
| **World total liquids supply** | **67.0** | **90.5** | **97.6** | **105.5** | **98.9** | **114.3** | **93.8** | **85.9** |

* Differences between historical supply and demand volumes given in Chapter 15 are due to changes in stocks. ** Expressed in energy-equivalent volumes of gasoline and diesel. The average energy to volume conversion factor is close to 7.8 barrels per tonne of oil equivalent throughout the projection period in the New Policies Scenario, reflecting the projected share of biodiesel versus ethanol.

The three main components of oil production – crude oil, natural gas liquids (NGLs) and unconventional oil – adjust to the different scenarios in their own ways. Production of conventional crude oil sees relatively little of the upside in the scenarios in which demand increases, as there are limits imposed by investments and by policy on how quickly production can grow, and crude oil production takes a disproportionate share of the downside in the 450 Scenario. Output of NGLs proceeds according to a separate logic, in

1. As described in Chapter 13, oil supply denotes production of conventional and unconventional oil and NGLs plus processing gains, the latter being the volume increase in supply that occurs during crude oil refining.

that their availability is driven by the dynamics of the gas market rather than that of oil: in line with the trajectories for gas demand (see Chapter 3), production of NGLs increases in all the cases examined, albeit less strongly in the 450 Scenario.

Production of unconventional oil also rises in all scenarios, proving robust even in the conditions of the 450 Scenario, where overall oil consumption is declining. This is because many unconventional projects – for example in oil sands or extra-heavy oil – depend on large upfront capital investment and then produce at steady rates for a long time, so projects started before demand flattens out will continue to produce.[2] One other component of supply that rises in all scenarios is "processing gains", which refer to the volumetric increase in production as it passes through the refining sector.

## Decline rate analysis

### *The importance of decline*

The rate at which the output of currently producing oil fields declines is a major factor determining the pattern of future supply. This decline has to be compensated for by developing new reserves in known fields, by discovering and developing new fields or by developing unconventional resources, such as oil sands, which may come at higher economic and sometimes environmental costs. All of these processes require large, continuous commitments of capital from the oil industry in exploration and production. This explains a leitmotif of the *World Energy Outlook* (*WEO*) year after year: the main threat to future oil supply security is insufficient investment.

A small difference in the decline rate makes a large difference to the investment requirement and can, therefore, have a large influence on future market conditions. In the projections, the compound annual decline rate of currently producing conventional fields is around 4%. If this decline rate were to be one percentage point higher, at 5%, the additional amount of "new" oil needed over the projection period would be 6 mb/d, close to the difference between the New Policies Scenario and the Current Policies Scenario. This implies that oil prices would have to be about $15 per barrel (12%) higher. Conversely, a smaller rate of decline would lead to a much more comfortable oil market balance.

For these reasons, understanding decline rates in currently producing oil fields is a cornerstone of the assessment of the outlook for oil markets. The IEA published an analysis of decline rates in the *WEO-2008*, and we revisit the issue in this *Outlook* to see how the picture might have changed. Technology may be evolving so as to reduce decline rates, or ever-increasing depletion could, on the contrary, be increasing them. New and growing types of supply such as light tight oil or extra-heavy oil may also be altering the global picture.

2. Even coal-to-liquids output expands in the 450 Scenario, where low coal demand and coal prices provide a strong incentive to turn coal into more valuable hydrocarbon liquids; since carbon capture and storage technology is widely deployed in this scenario, it can be used at relatively small additional cost per barrel to limit CTL $CO_2$ emissions.

**Box 14.1 ▷ Why does production decline?**

A conventional oil field usually starts producing under "primary recovery": the pressure of the fluids (oil, gas and water) contained in the reservoir drives the oil towards the wells. Once in a well, the oil can flow naturally to the surface, pushed by this reservoir pressure, or can be lifted by pumps or other artificial lift techniques. As oil is produced, reservoir pressure drops as the remaining fluids fill the gap left by the produced oil, and therefore the driving force decreases, leading to decreasing output, *i.e.* decline. At a certain point in the pressure drop (sometimes almost from the beginning of production), the operator will start a pressure maintenance programme by injecting water in the reservoir through different "injector" wells.[3] This is secondary recovery, or water flood.

If the volumes injected match the volumes of oil produced, pressure will be maintained and decline arrested. However, more subtle decline mechanisms soon come into play. As more water is injected, water becomes more mobile than oil and more and more water eventually reaches the production wells. Pressure maintenance can keep the total flow rate constant, but more water inflow means that less oil is produced: decline has set in again. Over time, the wells produce smaller and smaller amounts of oil, until the value of the oil becomes insufficient to pay for the costs of injection, lifting (if needed) and oil/water separation and the wells will be shut-in. In some cases, the operator may embark on tertiary recovery, using the enhanced oil recovery (EOR) techniques described in Chapter 13.

A starting point for the analysis is to review why output from oil fields declines. At the level of an individual well, this is linked to the basic mechanisms of recovery (Box 14.1). At the level of a conventional oil field, the dynamics are slightly different. A field is divided into sections that are tapped by different wells (either because the different sections [reservoir compartments] are not hydraulically well-connected or because the field is large and it would take too long to drain it with a single well). So the actual field-level decline depends in large part on the schedule for drilling wells. Typically, an operator will drill a number of wells, one after another, during the early part of the life of the field, leading to a gradual increase in production as more wells come on-stream, called the ramp-up phase. The operator then produces with a fixed number of wells for a while, leading to a plateau phase and a gradual decline as each well declines; then starts drilling new wells, a process called in-fill drilling, as part of an "improved oil recovery" programme based on an assessment of where there is oil remaining and how best to target it. The operator may also resort to enhanced oil recovery (EOR) techniques to extract a further proportion of the oil (see focus on EOR in Chapter 13).

In fields where drilling is expensive, such as offshore deepwater fields, these processes may occur in rapid succession as the operator tries to accelerate production as much as possible,

3. For simplicity we describe only water injection; similar mechanisms, leading to similar results, also result from pressure maintenance with gas injection.

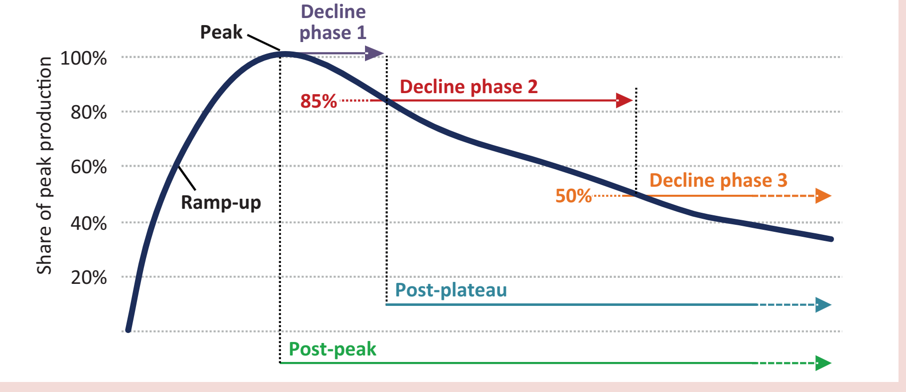
leading to a rapid ramp-up, short peak and rapid decline. In other fields, such as onshore super-giants, the economics allow for a more leisurely development and the production profile may be determined more by national policies on the desirable production and recovery rates. A large onshore field may be developed in successive tranches, thereby maintaining a steady production plateau for a long time. In such a case, decline at the field level becomes observable only towards the end of the productive life of the field.

### Box 14.2 ▷ Concepts used in the decline rate analysis

This analysis is limited to fields that are in decline, *i.e.* fields for which production in a given year has been lower than the highest production level previously reached. We also distinguish between *observed decline rates*, which are derived from the actual production histories of the various fields in our database and which include the effect of continuing investment by operators to mitigate the effects of decline, and *natural decline rates*, which we calculate as the decline rates that would have been seen in the absence of these investments. We calculate decline rates for individual fields as the compound annual decline rate (CADR) since the year in which production peaked. These are then combined into representative decline rates for types of field, for countries, regions or for the world as a whole, by weighting the contribution of each field according to its cumulative production to 2012. This produces a weighted average CADR.

All fields that are in decline are said to be "post-peak". To provide a more detailed analysis, these fields can be further divided into decline phases 1, 2 or 3 (Figure 14.1), as was done in the study published in *WEO-2008*. Decline phase 1 covers the years between peak and the first year when production goes below 85% of peak. Decline phase 2 is between the end of phase 1 and the last year in which production is above 50% of peak production. Decline phase 3 is reached when production is consistently below 50% of peak. Fields in decline phases 2 or 3 are said to be "post-plateau".

**Figure 14.1 ▷ Indicative illustration of decline phases and concepts**



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Decline is therefore field-dependent, both because the reservoir characteristics vary and because development strategies vary. The operator will typically construct a computer model of the field and will be able to predict decline under various assumptions about future investment (*e.g.* drilling more wells, changing injection patterns). These models are normally proprietary and the expectations about future decline are not publicly available (and future investment patterns are, in any case, subject to change). Without access to the reservoir models for the 8 000 or so producing conventional oil fields in the world, an alternative approach is to analyse past production to infer likely future patterns of decline. This is the basis for the findings presented here.

## *Decline rates for conventional oil*

### *Field database*

The basis used here for estimating decline from historical production data is a field-by-field production database. In *WEO-2008*, we used a database of 798 fields, coming from various sources. This year we have used a database of 1 634 currently producing, conventional oil fields, for which the available historical production time series is thought to be reliable (Table 14.2). The period covered by the database is 1950 to 2012 and the fields in the database represent close to two-thirds of global production of conventional crude oil.

**Table 14.2 ▷ Breakdown of the field database by field size (recoverable resources) and geographic location**

| *Million barrels* | **Super-giants** *More than 5 000* | **Giants** *500 to 5 000* | **Large** *100 to 500* | **Small** *Less than 100* | **All sizes** |
|---|---|---|---|---|---|
| Onshore | 38 | 227 | 550 | 352 | 1 167 |
| Offshore | 14 | 79 | 193 | 181 | 467 |
| Depth up to 125 metres | 13 | 55 | 129 | 143 | 340 |
| Depth from 125 to 1 500 metres | 1 | 23 | 62 | 36 | 122 |
| Depth greater than 1 500 metres | 0 | 1 | 2 | 2 | 5 |
| **Total** | **52** | **306** | **743** | **533** | **1 634** |
| OPEC | 36 | 118 | 202 | 112 | 468 |

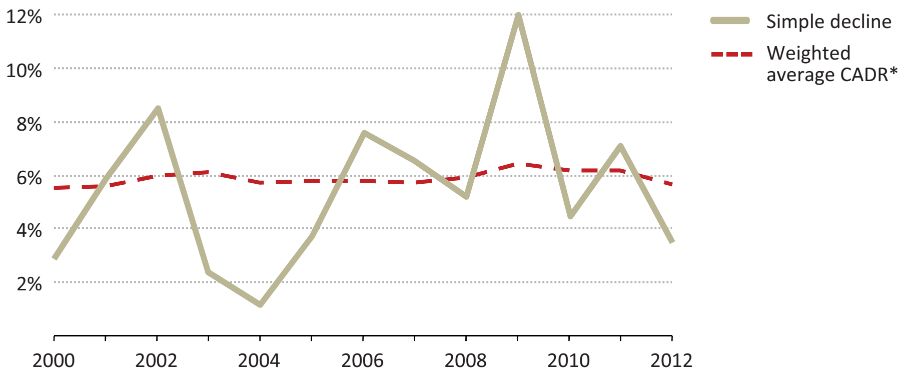
### *World production decline rates*

With a database of fields that includes historical records for production, a first task is to look only at those fields that are in decline. One approach is to sum up the output from all these post-peak fields in a given year and compare this with production from the same set of fields in the previous year, defining an "observed year-on-year decline rate". This decline rate can be calculated for any year and the results for the period 2000-2012 are shown in Figure 14.2 as the "simple decline" line.[4] This approach shows a wide year-on-year variation, because production in any given year is affected by many factors (such as OPEC

4. With the change of year, the set of fields that are in decline that year also changes: the database contains 1 524 fields that were post-peak in 2012, but only 957 that were post-peak in year 2000.

production constraints, maintenance programmes, fluctuating oil demand), which tend to skew the overall result. The high observed decline rate figure for 2009 is a case in point: demand was subdued that year, because of the economic crisis, and clearly production in a number of fields was deliberately reduced because of weak demand.[5]

**Figure 14.2 ▷ Observed year-on-year decline rate and weighted average CADR* for conventional oil fields**




* Compound annual decline rate.

Sources: Rystad Energy AS; IEA analysis and databases.

Because of these large year-to-year fluctuations, we use a different approach for the analysis of decline rates. We select all the fields that are post-peak in a given year. For each of these, we calculate the compound annual decline rate since the year in which production peaked. This approach is much less sensitive to year-to-year variations than the calculation of a one-year decline. But it still leaves the question of how to average those individual field decline rates to obtain a representative world level decline rate. The method used is to calculate a weighted average decline rate, weighing each field by its cumulative production to 2012 (Figure 14.2, red dashed line).

With this methodology, the year-on-year changes are relatively small and the weighted average world decline rate settles at around 6%, a finding consistent with the similar analysis conducted in *WEO-2008*.[6] No significant change in decline rates for conventional oil fields can be seen over the past twelve years.

5. The observed decline rates shown here are slightly lower than those observed through a similar approach in *WEO-2008*. This is linked to a difference in methodology: unlike in 2008, we have included here all post-peak fields, including those whose production was post-peak but nonetheless saw some year-on-year increases. In the first part of the 2000s, for example, many post-peak Russian fields saw increases in production. This situation also arises in some OPEC fields, as their production fluctuates according to OPEC or individual members' production policy. The results of the new methodology are less affected by such fluctuations and therefore more robust.

6. The *WEO-2008* weighted average world decline rate was 5.1%. The database used at the time was smaller than the one used here, with a bias towards larger fields, so the calculation was extrapolated to a figure of 6.7% for all producing fields. The value of 6% seen here falls between the observed and extrapolated values of *WEO-2008*.

### *Decline rates by field type and by decline stage*

Breaking down decline rates by the type of conventional field shows some wide variations (see last column of Table 14.3). Production from larger fields tends to decline more slowly than from smaller fields. Production from offshore fields tends to decline more quickly than onshore fields. Because of these differences, the decline rates calculated for OPEC (where fields tend to be very large and onshore) are significantly lower than those for non-OPEC conventional production.

**Table 14.3 ▷ Weighted average CADR to 2012 by decline phase**[7] (%)

| | Decline Phase 1 | Decline Phase 2 | Decline Phase 3 | Post-plateau | Post-peak |
|---|---|---|---|---|---|
| Onshore | 3.4 | 2.5 | 7.7 | 5.4 | 5.4 |
| Offshore | | | | | |
| Shallow | 5.2 | 1.6 | 12.9 | 8.2 | 7.5 |
| Deepwater (including ultra-deepwater) | 12.3 | 7.9 | 14.1 | 12.9 | 12.7 |
| Super-giant | 4.6 | 1.1 | 7.3 | 4.4 | 4.0 |
| Giant | 5.1 | 4.5 | 10.6 | 7.8 | 8.0 |
| Large | 4.5 | 5.4 | 10.8 | 9.1 | 9.3 |
| Small | 4.0 | 8.1 | 12.6 | 11.4 | 11.9 |
| **All fields** | **4.8** | **2.4** | **9.2** | **6.4** | **6.2** |
| Non-OPEC | 5.2 | 3.6 | 9.4 | 8.1 | 7.8 |
| OPEC | 3.9 | 1.7 | 9.0 | 4.2 | 4.5 |

* Compound average annual decline rate.

Note: For field type size and geographic location refer to Table 14.2.

A single decline rate for world production, even when broken down for different types of fields, is still not a very robust basis for long-term projections of supply. This is because decline rates also vary according to the point reached in its decline by a given field: using the generic decline rates to project future production would be unsatisfactory since, as years pass, the number of fields in the different phases of decline may vary. That is why, in Table 14.3, we further divide the period of post-peak decline into three distinct phases, calculating weighted average decline rates for each phase.[8]

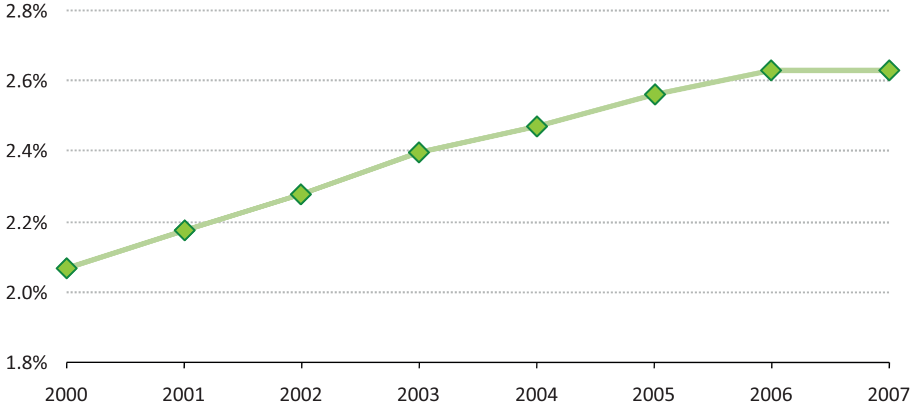
7. These results are consistent with the analysis conducted in *WEO-2008*. The larger decline figures for Phase 1 are not statistically significant. Because of the weighting by cumulative production, super-giant fields tend to dominate the global averages and there are very few (less than half a dozen, depending on the year) super-giants in Phase 1. After a short peak, these fields tend to be maintained at plateau in phase 2 for a very long time, which explains the low decline rates in this phase.

8. For each phase a field decline rate is defined as the compound annual decline rate from the beginning of the phase to either the end of the phase or the last year for which production data is available. These field decline rates are then weighted by the cumulative field production to 2012 to obtain a world average for each phase (fields that stop producing are excluded from the calculation).

## *Natural decline rates*

It is important to distinguish the observed decline rates, discussed thus far, from natural decline rates, which are the rates of decline that would be seen if investment in those fields were stopped. In a currently producing field, the operator will typically invest to try and mitigate decline, taking such actions as drilling more wells in already developed parts of the reservoir (in-fill drilling), installing new water injection capacity, developing new parts of the field or even applying some EOR technologies.[9] Natural decline is a very important parameter in the supply modelling, because it drives the need for future investment in existing fields. We estimate the difference between observed and natural decline rates by using industry databases on the amount of capital investment spent each year in currently producing fields, together with making assumptions about the efficiency of these investments (barrel per day added per unit of investment). In this way, we can estimate what the production from those fields would have been in the absence of the additional expenditure, leaving us with a production-weighted average difference between the natural decline rate and the observed decline rate.

**Figure 14.3 ▷ Estimated difference between natural and observed decline rates in currently producing conventional fields**




Note: The decline rate is estimated using at least five years of natural decline, so here data to 2012 are used.

Sources: Rystad Energy AS; IEA databases and analysis.

We estimate that the global average difference between the observed and natural decline rates is around 2.5 percentage points (Figure 14.3). This implies that the impact of the ongoing investment by operators in currently producing fields is to reduce, by 2.5% on average, the decline rates that would otherwise be seen. There is a small upward trend in this number over time, but this is relatively small and could well reflect

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9. The operator also spends money every year – operating costs – for a number of actions that are not normally considered capital investment, such as cleaning well bores or reservoir zones near wellbores, installing, running or replacing pumps, re-perforating, performing well stimulation treatments, adjusting chokes in injections or production wells, etc. The definition of capital and operational expenses may depend on local accounting rules.

inaccurate estimates of the efficiency of capital investment, rather than a real increase in natural decline rates. The result of this analysis is similar to the estimate made in *WEO-2008* of 2.3%, a good match given that the required parameters can only be estimated approximately. Adding our new estimate to the current observed decline rate of 6% (Figure 14.2) gives an average production-weighted figure for natural decline of close to 9% for the post-peak fields in the database.

### *Decline rates for unconventional oil*

Unconventional sources of oil have different decline patterns from those of conventional oil and understanding these differences is important, given the growing role of unconventional sources in meeting future oil demand. As discussed in Chapter 13, the main resource types are light tight oil (LTO), Canadian oil sands and Venezuelan Orinoco belt extra-heavy oil. We also have projections for production of coal-to-liquids (CTL), gas-to-liquids (GTL), additives[10] and kerogen oil.

LTO and Canadian oil sands have similar decline characteristics. The resources are spread over large geographical areas and each well[11] produces only a small amount over a relatively short time period: it takes many wells to achieve substantial production and continuous drilling to maintain production. As a result, the decline rate at field level is mostly driven by the drilling schedule, *i.e.* the rate of investment. Production ramps-up as the number of wells drilled per year increases, then can reach a long plateau as the drilling rate stabilises and a rapid decline as drilling locations diminish.[12] These features have implications for the discussion of decline rates and future patterns of investment, particularly in relation to LTO (Spotlight).

Among the other types of unconventional oil, Venezuelan extra-heavy oil is produced either by primary recovery with horizontal wells, in which case it follows a pattern similar to conventional oil reservoirs during primary recovery, or by heating the oil with injected steam, in which case it follows a pattern similar to that of Canadian oil sands. CTL, GTL and additives are produced in large industrial plants, requiring very large upfront investments. As a consequence, plants are built only in places where the supply of feedstock is secure for the lifetime of the plant. In addition, because of the large upfront investment, the operator will try to produce at a level as close to maximum capacity as market conditions and maintenance schedules allow. The result is basically no decline during the nominal lifetime of the plant (normally 25 to 30 years), possibly followed by rapid ramp-down as the depreciated plant is superseded by newer plants using new technologies. Given the

10. Compounds such as MTBE, ETBE and methanol that are added to gasoline to adjust its performance, coming at least in part from gas or coal feedstocks.

11. Or pair of wells in the case of Steam-Assisted Gravity Drainage (SAGD) technology in Canadian oil sands, or each shovel for mined oil sands.

12. In-situ oil sands projects in particular will try to maintain a long plateau at the capacity of the steam plants, which represent a significant upfront capital investment. (See *WEO-2010* for a discussion of oil sands technologies [IEA, 2010]).

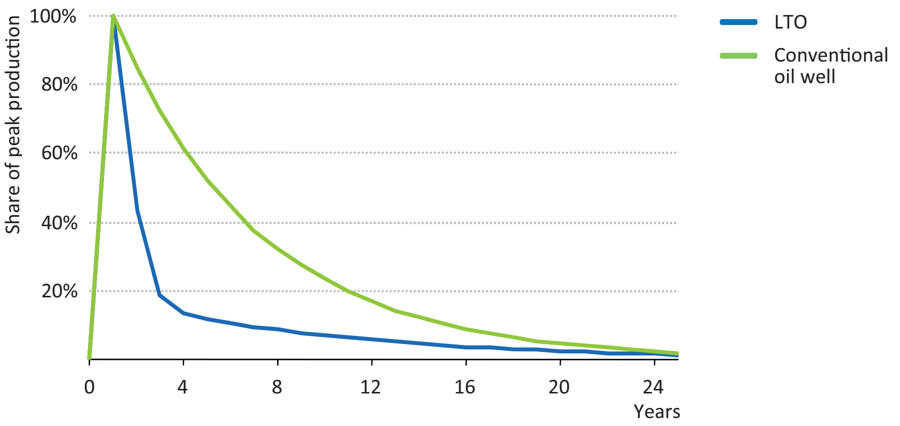
very small number of active CTL and GTL plants in the world, only small pilot plants have been retired so far. Experience with kerogen oil production is very limited but, as it is more akin to a mining process, a long plateau can be expected, followed by abrupt decline once resources are no longer exploited.

SPOTLIGHT

## What does the rise of light tight oil mean for decline rates?

It is sometimes argued that the advent of LTO in the United States means a significant change to the likely evolution of decline rates. This stems from the fact that the decline in production of each well is very rapid compared with production from a typical conventional oil well (Figure 14.4). Because of the very low permeability of the rock, each LTO well – even with hydraulic fracturing – drains only a very small volume of the overall reservoir. Initial production consists largely of the oil contained in fractures or fissures (either pre-existing or generated by hydraulic pressure). These drain rapidly and then there is a long tail of low-level production. If the reservoir pressure is sufficient and the reservoir does not contain water, the low production level can be maintained for a long time, as lifting costs (including gas flaring costs, if required) are low. However, if any pumping is required or water production sets in, the well quickly becomes uneconomic and needs to be shut-in and abandoned.

**Figure 14.4 ▷ Typical production curve for a light tight oil well compared with a conventional oil well**




This characteristic does not necessarily affect the observed decline rates at the field level, which are not significantly different from conventional fields. Each well may decline quickly, but there are many possible drilling locations in the field (as each well drains only a small part of the reservoir). As long as drilling continues, production can be maintained. So the advent of light tight oil does not significantly affect the field-level analysis of observed decline rates presented so far.

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Natural decline rates, however, are strongly affected by this production profile as, by definition, they are the decline rates that would be observed if investment stopped. Natural decline rates in LTO fields would not be quite as steep as the well decline rates, because wells are often drilled and completed as a batch; at any moment in time, an operator will typically have a stock of wells that are ready to be put into production but are not yet connected to the production gathering system. Still, natural decline rates for LTO fields can be expected to be in the order of 30% per year for the first three years in a typical LTO play (meaning that production falls to around one-third of the initial production level after this time), before stabilising at around 5% per year.

These large initial natural decline rates make LTO production potentially much more responsive to fluctuations in oil prices than conventional fields: a decision to stop drilling translates into a rapid fall in output. This creates the possibility that LTO could absorb at least some part of the risk of variable global demand and price volatility. Whether this will happen in practice has yet to be tested. There are limits to the amount of flexibility that might be available: operators may, for example, hedge output at certain price levels, which would limit their incentive to respond to short-term price signals. And, even though a fall in production is easily achieved by stopping drilling activity, ramping-up again can take longer: drilling rigs and hydraulic fracturing fleets need to be brought back on line, which may require both equipment and personnel moves.

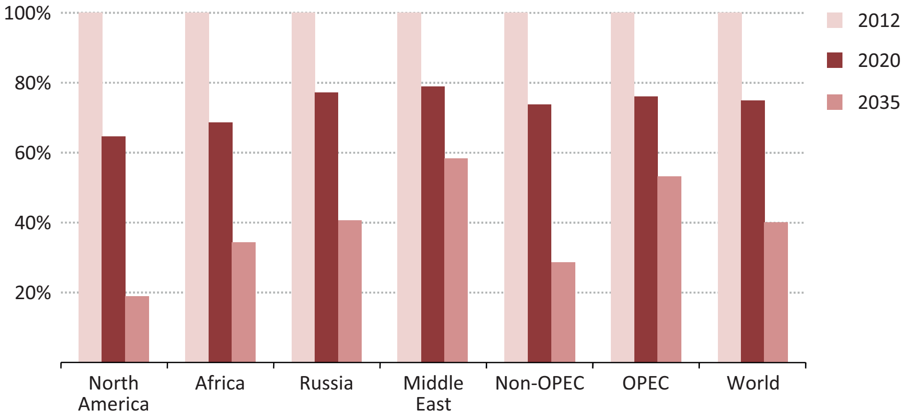
## *Implications for future production*

### *Future production from currently producing conventional fields*

On the basis of our analysis of historical decline rates, we now have the main ingredients required to project production from existing conventional fields.[13] In the New Policies Scenario, the result is that the year-on-year decline in output from all currently producing conventional fields gradually increases, from 2% in the early years of the projection period (as some existing fields are still ramping up) to around 4.7% in the early 2020s, and then stabilises around 4% by the end of the projection period. That this decline rate settles around 4% (rather than at 6%, which is the CADR for all fields) is linked to the fact that, by the 2030s, the remaining production from currently producing fields is concentrated in large onshore fields (mostly in OPEC countries); as shown in Table 14.3, these fields have the lowest decline rates, around 4%.

13. For each field in the database, this would mean assigning a field type and determining the decline phase, then projecting future production for the field as per the corresponding decline rate in Table 14.4, updating decline rates as the field moves into a different phase. The main remaining uncertainty is over fields that are not in the database and over projected output from fields that are currently ramping up (*i.e*. one needs to know their future peak year and peak production). The World Energy Model (WEM) methodology for this calculation, which is verified against a proprietary commercial database that contains a representation of possible future production for all fields in the world, is described in the WEM documentation available at *www.worldenergyoutlook.org*.

**Figure 14.5 ▷ Decline in production of conventional crude from currently producing fields in selected regions in the New Policies Scenario**




The speed at which output from currently producing fields declines over the projection period varies substantially by region (Figure 14.5). This is related to differences in the average size of fields, which is related, in turn, to the extent to which resources are already depleted and to whether the fields are onshore or offshore. The Middle East has the lowest projected decline to 2020 and 2035 (shown as a percentage of 2012 production) because of the preponderance of very large, onshore fields. This has, in turn, a strong influence on the figures for OPEC as a whole.

At the other end of the scale, in North America, fields in production today produce less than one-fifth of today's conventional crude output by 2035. For the world as a whole, conventional crude output from existing fields falls from 69 mb/d today to 28 mb/d by 2035, meaning that about 40 mb/d of capacity (or more than 20 times today's production of LTO) needs to be added over the projection period just to compensate for the effects of decline in conventional fields.

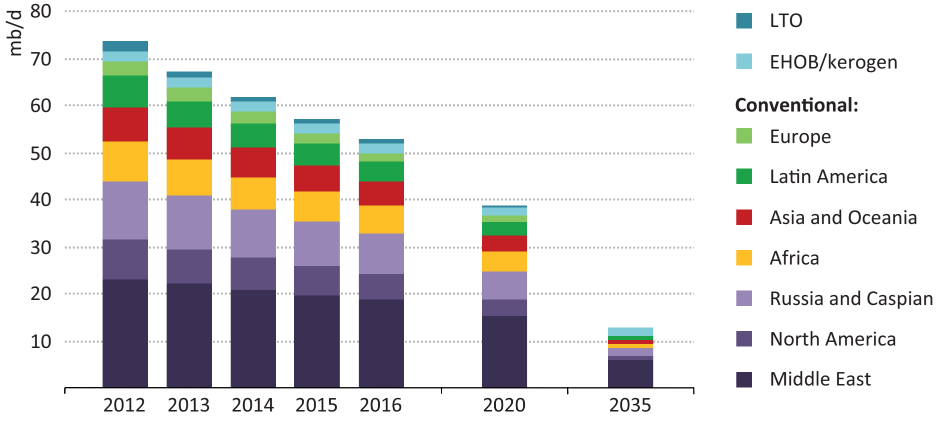
### *Future production from all fields*

As discussed, adding unconventional oil into the equation does not have large implications for global observed decline rates, but it does increase the dependence of overall oil production on continuous investment. This can be seen by examining natural decline rates (Figure 14.6).[14] In this case, the fall in production is even steeper, with oil output (excluding NGLs) dropping from 74 mb/d in 2012 to less than 13 mb/d in 2035, half of which would be from large onshore fields in the Middle East where decline rate are lowest. This puts

14. LTO output falls off rapidly, but the effect on overall natural decline rate is offset by the much slower decline in extra-heavy oil and bitumen. Our modelling of slow natural decline for oil sands and extra-heavy oil is a simplification, as, for example in in-situ production of oil sands, one needs to continue drilling pairs of shallow wells to maintain production, but these investments are very small compared with the initial upfront investment, so a low natural decline is a good approximation.

a new perspective on the challenge facing the upstream oil industry. Raising production (excluding NGLs) from 74 mb/d in 2012 to 80 mb/d in 2035 might appear to be a relatively modest undertaking, involving the addition of 6 mb/d. Once, though, it is understood that the actual requirement is to add close to 67 mb/d to reach the 80 mb/d target, both through net capacity additions and efforts to mitigate decline at existing fields, the scale of the task becomes clearer.

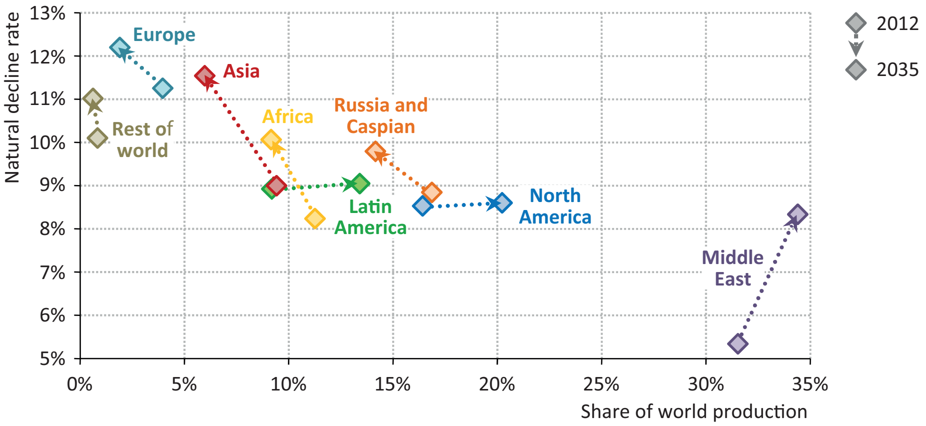
**Figure 14.6 ▷ Production that would be observed from all currently producing fields in the absence of further investment** (excluding NGLs)




Note: EHOB = extra-heavy oil and bitumen.

The question of how natural decline rates will evolve in the future is complex, as the mix of fields constantly evolves. On the one hand, world production becomes more and more dominated by large, ageing fields in OPEC Middle East countries, with relatively lower decline rates. On the other hand, the remaining production in many other parts of the world tends to come from smaller and smaller fields with higher decline rates, though this may be counter-balanced by the fact that a greater proportion of these may be in the early part of their decline (phases 1 and 2), when the decline rates are lower. Over the first half of the projection period, this trend is also affected by the start of production at some giant and super-giant fields in Brazil and Kazakhstan. Finally, the partially offsetting contributions of LTO and EHOB evolve as the mix between the two changes and their overall contribution to total supply grows. Overall, natural decline rates are projected to increase modestly in all regions between 2013 and 2035 (Figure 14.7). This trend could be modified by wider deployment of EOR technologies, although rapid growth is not projected in this area (see focus on EOR in Chapter 13).

**Figure 14.7 ▷ Projected evolution of natural decline rates in key regions in the New Policies Scenario, 2012-2035**




## Oil production by type

Four main sources of oil production that are developed over the projection period can usefully be distinguished. There are conventional fields that are known but not yet developed; new conventional fields that are expected to be discovered and developed during the projection period; growing production from unconventional oil sources; and a rapidly growing amount of NGLs accompanying the worldwide growth in gas production. In the New Policies Scenario, these sources take global oil production from 87 mb/d in 2012 to 98 mb/d in 2035 (Table 14.4).

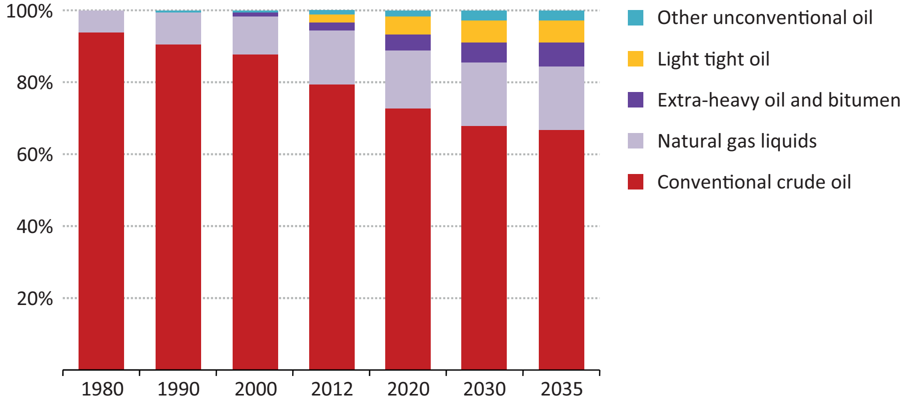
**Table 14.4 ▷ World oil production by type in the New Policies Scenario** (mb/d)

| | 2000 | 2012 | 2020 | 2025 | 2030 | 2035 | 2012-2035 | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | Delta | CAAGR* |
| **Conventional** | **73.8** | **82.1** | **82.5** | **82.5** | **82.3** | **83.1** | **1.0** | **0.1%** |
| Conventional crude oil | 66.0 | 69.4 | 67.7 | 66.6 | 65.5 | 65.4 | -4.0 | -0.3% |
| Existing fields | 64.5 | 68.0 | 50.9 | 40.9 | 32.8 | 27.1 | -41.0 | -3.9% |
| Yet-to-be-developed | n.a. | n.a. | 13.9 | 16.6 | 18.1 | 19.8 | 19.8 | n.a. |
| Yet-to-be-found | n.a. | n.a. | 1.4 | 7.2 | 12.3 | 15.9 | 15.9 | n.a. |
| Enhanced oil recovery | 1.5 | 1.3 | 1.5 | 1.8 | 2.2 | 2.7 | 1.4 | 3.1% |
| Natural gas liquids | 7.8 | 12.7 | 14.8 | 15.9 | 16.8 | 17.7 | 5.0 | 1.4% |
| **Unconventional** | **1.4** | **5.0** | **10.4** | **12.5** | **14.2** | **15.0** | **10.0** | **4.9%** |
| of which light tight oil | 0.0 | 2.0 | 4.7 | 5.7 | 5.9 | 5.6 | 3.6 | 4.7% |
| **Total** | **75.2** | **87.1** | **92.8** | **95.0** | **96.5** | **98.1** | **11.0** | **0.5%** |

* Compound average annual growth rate. Note: The figures for production from existing fields are based on observed decline rates for conventional oil fields, *i.e.* it includes the effect of investment by operators to mitigate the decline in output.

Total production of conventional crude oil is projected to remain within a relatively narrow range over the projection period, falling slightly to 65 mb/d in 2035, compared with 69 mb/d today. This means that the share of crude oil in total oil production falls from 80% today to 67% in 2035 (Figure 14.8). Within this total, the amount coming from offshore fields is relatively constant, but the share of deepwater output rises from 7% in 2012 to 14% in 2035, reaching 9 mb/d in 2035 (see the focus on deepwater in the special section on Brazil, Chapter 11).

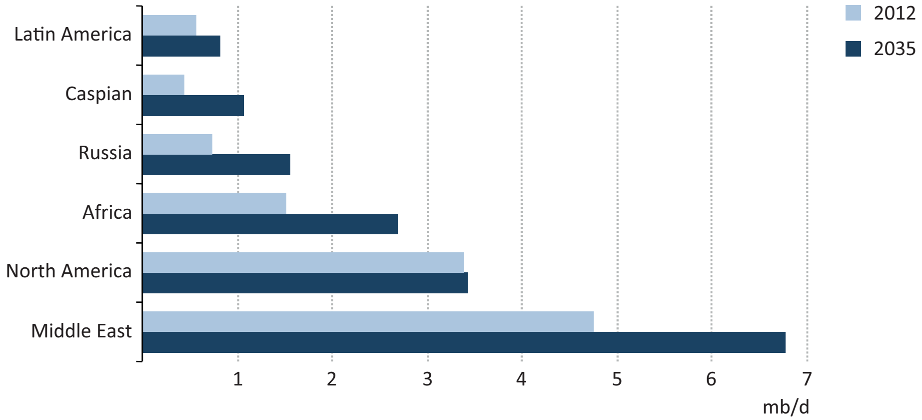
**Figure 14.8 ▷ Shares of world oil production by type in the New Policies Scenario**




The offshore Arctic is another frontier area with potentially large conventional oil resources (134 billion barrels of crude oil and NGLs [USGS, 2008]). A number of companies are pursuing exploration projects, for example, Shell in the Chukchi and Beaufort Seas; Cairn in offshore Greenland; Rosneft/ExxonMobil in the Kara Sea and Rosneft/ENI in the Russian Barents Sea. However, costs are high and environmental risks substantial. Given that alternative sources are available, less than 200 thousand barrels per day (kb/d) are projected to be produced from the offshore Arctic by 2035. Some developments could go faster, in particular those spearheaded by Russia, in partnership with international companies, in the Kara Sea and the Barents Sea, or by Norway in the Norwegian part of the Barents Sea.

With total crude oil production remaining at approximately today's levels, all of the growth in oil production comes from other sources. Chief among these is NGLs, production of which grows by almost 40%, to reach almost 18 mb/d by 2035 (Figure 14.9). By the end of the projection period, NGLs account for almost 20% of global oil production and become an increasingly influential factor both in gas and oil markets. Although sometimes considered a by-product of gas production, NGLs are often a major factor in upstream gas economics as companies increasingly target liquids-rich gas plays (see Chapter 3). NGLs provide a ready source of light oil products and their ever-growing supply has implications for the refining and petrochemicals sectors (examined in detail in Chapters 15 and 16).

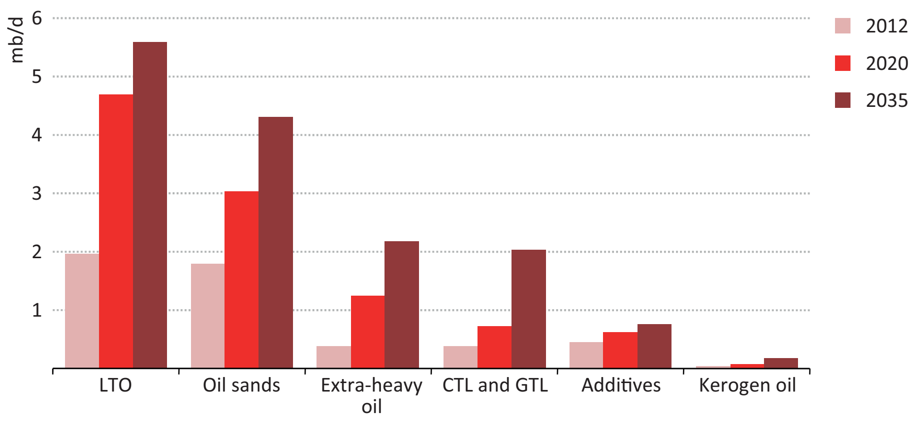
**Figure 14.9 ▷ Production of NGLs in selected regions in the New Policies Scenario**




Notes: NGLs production in North America grows significantly in the first half of the projection period, before falling to a level close to its 2012 value. This is linked to the expectation that the current focus on wet-gas plays will shift back to drier gas production as the gap between oil and gas prices closes to some extent and as depletion of wet-gas plays begins to increase costs.

Another source of production growth is unconventional oil, production of which rises from 5 mb/d in 2012 to 15 mb/d in 2035. These unconventional supplies come primarily from Canadian oil sands, LTO and extra-heavy oil in Venezuela (Figure 14.10). Rapid growth is also envisaged in GTLs output in the latter part of the projection period, with the largest volumes coming from Qatar and North America, and in CTLs production, primarily in China, with South Africa, Australia, Indonesia and the United States also contributing. Despite the size of the resource base, production of kerogen oil remains marginal, because of relatively high costs and environmental concerns.

**Figure 14.10 ▷ Unconventional oil production in the New Policies Scenario**

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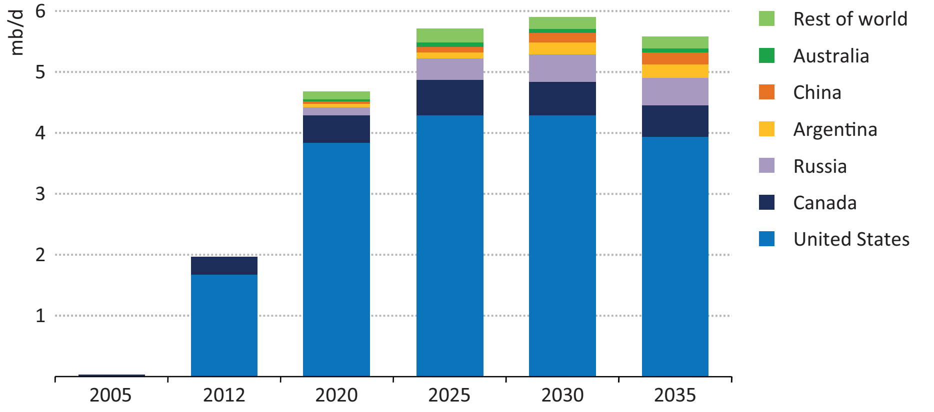
## *Focus on light tight oil*

From close to zero in 2005, production of light tight oil (LTO) in the United States reached 2.3 mb/d by mid-2013, a turnaround that has been dramatic for the North American oil industry and, together with the growth in shale gas, has had profound effects across the international energy arena. In this section, we re-visit the projections for North America in the light of another year's worth of data from the main plays and new estimates of resources. We also look at the potential for LTO production outside the United States, in particular in three countries that have been estimated by the US Energy Information Administration to have the largest resource potential: Russia, China and Argentina (see Chapter 13).

Overall, it is anticipated that North America – the United States with a smaller contribution from Canada – will continue to dominate global LTO output (Figure 14.11). The upward revision in the resource estimate for the United States means that the projections see a higher plateau for LTO production and one that is sustained for longer, compared with *WEO-2012*. Elsewhere, most countries struggle to replicate the North American experience at scale: LTO production in 2035 reaches 450 kb/d in Russia, 220 kb/d in Argentina and 210 kb/d in China, but elsewhere stays in the tens of thousands of barrels per day. Regulatory barriers and the absence in most countries of a strongly competitive and innovative upstream environment tend to keep production costs above the levels at which significant investments are forthcoming (economies of scale are important in achieving competitive production costs). Tight oil production technologies do, though, have a somewhat wider impact than the LTO output numbers alone would suggest: the multi-stage hydraulic fracturing in horizontal wells techniques that have been the key to LTO and shale gas developments are now beginning to be deployed in more conventional fields as well. Their use is set to increase in a way that extends the life and yields of some lower quality conventional plays (Box 14.3).

**Figure 14.11 ▷ LTO production in selected countries in the New Policies Scenario**




Sources: IEA databases and analysis; Rystad Energy AS.

**Box 14.3 ▷ Will LTO techniques improve recovery at conventional reservoirs?**

Hydraulic fracturing generally increases production rates in all the reservoirs it can be applied to (though, if practised near water or gas zones, this may mean faster breakthrough of water or gas production). The question is whether the improved production rate provides sufficient payback for the cost of the operation. Single hydraulic fracturing stages are fairly commonly applied to conventional wells, to improve the flow where permeability is low. However the type of intensive multi-stage fracturing that is applied to shale reservoirs is expensive and is generally considered economically viable only where there is sufficient scale (and thus high equipment utilisation rates) to bring the costs down.

As such it is reasonable to imagine that in basins such as the Permian in Texas, where activity levels ensure that wells can be treated with multi-stage fracturing relatively inexpensively, the techniques will be applied to conventional plays, as well as to shale plays, increasing the overall economically recoverable resources in some ageing conventional reservoirs. This could potentially unlock more conventional resources globally, in areas where the scale of unconventional developments has reduced the cost of the services. Other possibilities are very large fields with small recovery factors, such as Chicontepec in Mexico or some mature fields in Russia.

### *LTO outlook for North America*

As highlighted in the earlier analysis, a feature of LTO resource development is the rapid decline in oil output at each well, with most of the oil from a single well produced in the first few years. For this reason, increasing production of LTO – or sustaining a significant level of output – requires continuous investment in drilling new wells to compensate for decline at existing ones. What counts is the number of rigs in operation, how quickly these rigs can drill a well and how productive these wells are before decline sets in. In most plays in the United States, these indicators continue to improve year-on-year, with the LTO rig count increasing, and drilling costs and time decreasing.

For the moment, LTO production in the United States is concentrated on tight rock formations in North Dakota (Bakken) and Texas (Eagle Ford and the plays in the Permian basin). The Bakken is the largest continuous oil accumulation that the US Geological Survey (USGS) has ever assessed. When considered together with its neighbouring Three Forks play, it covers an area larger than the size of France. The North Dakota part of the Bakken was producing more than 800 kb/d as of July 2013 and had not yet reached its plateau production level, which is anticipated to be in excess of 1 mb/d. The rate of month-on-month growth in output is slowing: as production increases, it takes more and more wells to offset the decline in already drilled wells. Indeed, the ratio of incremental production to the number of new wells drilled has been falling in the first half of 2013. We estimate that maintaining Bakken production at 1 mb/d (after it reaches that level) will require drilling around 2 500 new wells per year (for comparison, maintaining output of 1 mb/d at a large conventional field in, for example, southern Iraq, would require only around 60 wells per year). With 6 000 currently producing wells in the Bakken (at mid-2013) and an estimate of around 40 000 further possible well locations, a plateau lasting a dozen years is possible.

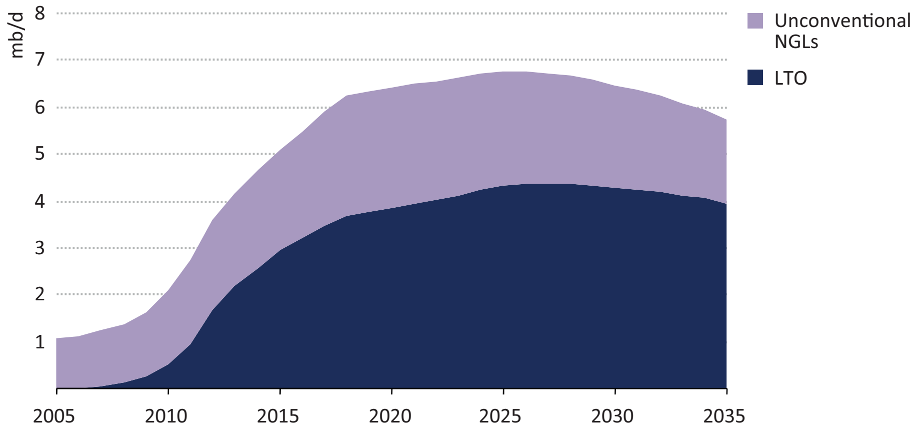
There is for the moment no sign that output at the main LTO plays in Texas has reached the point at which it would start to flatten out. Even though activity levels at the Eagle Ford play have been flat over the last year (in terms of the number of wells drilled and the number of hydraulic fracturing stages completed), there has still been consistent growth in production levels, which were above 600 kb/d at mid-2013. Efficiency gains have meant that each rig in the Western Gulf basin, where the Eagle Ford play is located, is now drilling an average of one well per month, a 30% improvement over the average for 2012. Production in the Eagle Ford exceeds that in the Bakken by 2015. Elsewhere in Texas, LTO output from the Permian basin (a well-established conventional oil and gas province) has risen sharply, to reach 500 kb/d by mid-2013.

Beyond these three large-scale areas, another half-dozen tight oil plays are currently being investigated in various parts of the United States. In aggregate, these and the other plays already discussed are set to maintain LTO output at the projected plateau level of around 4.3 mb/d between 2025 and 2030, with a slight drop by 2035 (Figure 14.12). It is, though, still too early to speak with confidence about the trajectory for LTO production in the United States: performance has consistently overshot most projections to date and it is possible that more resources will be found and developed to sustain production at a higher level and for longer than we project, especially if oil prices hold up, technology advances continue and environmental concerns are allayed.

There are also downside risks. Resources in some of the new plays could be more difficult to access or expensive to produce and there is certainly no guarantee that each of the plays will be as prolific as the Bakken or Eagle Ford. The Utica shale in Ohio, for example, initially seen as promising, turned out to produce mostly gas, rather than oil (possibly because the oil it contains is not mobile); it produced only 700 000 barrels of oil in total in 2012, less than one day's production from the Bakken. Production could also be constrained by limitations in the supply chain or in downstream infrastructure, although in most cases these would result in delays, rather than resources being left in the ground. There are also social and environmental concerns, very similar to those for shale gas development. These need to be properly addressed if curbs on upstream activity are to be avoided. Finally, there is the possibility that oil prices will fall to a level at which production is no longer economic. Most estimates put the breakeven price of tight oil production in the United States at between $60-80/barrel, so it would take only a relatively modest fall in the price to affect production prospects at the higher end of this range. In any event, United States light tight oil production starts to decline in the last five years of the projection period, as drilling locations for the "sweet spots" in the key shale plays run out and activity moves to less productive zones, which struggle to compete in terms of cost, with other sources of oil from other countries.

North American LTO production is bolstered in the projections by output from Canada, which rises from low levels today to reach 600 kb/d by 2027, before declining slightly to 500 kb/d in 2035, following a trend similar to that of the United States. Compared with its southern neighbour, Canada is in the early stages of developing its tight oil resources, with a focus on the northern part of the Bakken play (which extends across the border) and on parts of British Columbia (the Montney play, which also extends into Alberta), the Duvernay and Cardium formations in Alberta and the Viking play in Alberta and Saskatchewan. The latter four are predominantly liquid-rich gas plays, but they also contain some oil.

**Figure 14.12 ▷ Projected LTO and NGLs production from unconventional plays in the United States in the New Policies Scenario**




In addition to LTO, there is also rapidly growing production of NGLs from shale gas plays in the United States (Figure 14.12). In fact, the boundary between LTO and liquid-rich shale gas is more and more blurred. LTO plays often produce large amounts of associated gas (up to one-third of which, in the case of the Bakken play, is currently flared because of a lack of means to bring it to market) and, conversely, in liquid-rich shale gas plays, the liquids often completely drive the economics. A complex interplay between geology and economics can determine which is targeted. For example in the Eagle Ford, the oil zone tends to be shallower and well costs are lower than in the wet-gas zone, but lower pressure leads to smaller liquid production rates (as production is driven by the natural pressure in the reservoir). Towards the end of the projection period, production of NGLs in the United States flattens and begins to decrease, as activity gradually shifts back to drier gas plays, driven by the improved gas-to-oil price ratio and increasing depletion of the wet-gas plays.



### *LTO outside North America*

As with shale gas, the experience in the United States has alerted other potential LTO resource-holders worldwide. Companies and governments are looking for similar geological conditions, where an abundant source rock is both rich in hydrocarbons and brittle, lending itself to fracturing techniques to extract the oil. However, only very preliminary estimates of potential resources are available and there is essentially no experience of production nor basis for economic appraisal. As a result, the projections remain modest, though production could grow much faster. Among the most promising areas geologically are the Neuquen basin in Argentina, the Bazhenov shale in Russia and parts of China and the Middle East, although the abundance of easily accessible conventional resources in the Middle East makes it less likely that the unconventional oil will be developed.

Good geology alone is not sufficient to replicate the US experience – it will also take a regulatory environment and an oilfield service capacity able to match the scale of operations, bring operational efficiencies and make the developments economic. Outside North America, these factors are by and large not yet in place. Governments are still studying suitable regulatory and fiscal regimes. For the moment, the scale of activity is insufficient even to enable the trial-and-error learning that is necessary to determine the right well-completion design for each play, let alone to achieve the economies of scale that are needed to make production profitable. Over 6 000 wells were drilled for tight oil in the United States and Canada in 2012, and only 100 outside North America.

Not surprisingly, we are seeing the first wave of non-US LTO activity in countries with a history of oil and gas production, existing infrastructure and well-developed supply chains. Of the countries that are looking at light tight oil potential, most also have shale gas potential. Only Argentina and Russia have indicated that their prime focus is oil, whereas in the others, such as Australia, Algeria or China, the indications are that unconventional gas will take priority.

In Argentina, activity is focusing on the Vaca Muerta shale in the Neuquén basin, one of the most significant LTO plays so far identified outside the United States. YPF announced potential resources of 7 billion barrels in February 2012 (YPF, 2012). Initial wells have given flow rates that indicate that the play could be produced economically (albeit at higher costs than US plays).[15] Argentina has a clear imperative to develop tight oil: the country used to be an exporter but is now an importer of oil. The Neuquén basin is an established oil and gas province with a long history of production meaning that relevant expertise and some infrastructure are available. The key uncertainty lies in the regulatory framework and the need for security for the large investments required (worries exacerbated by expropriation of Repsol's assets in 2012, though the recent agreement between YPF and Chevron for joint exploitation in the Vaca Muerta indicates that some international investors may not be deterred).

LTO is an increasingly important subject of discussion also in Russia. The Bazhenov shale, the main source rock for the western Siberian conventional oil reservoirs, has high potential and, although other geographical areas and geological layers could be rich in LTO, the Bazhenov is likely to be the main focus. It is rich in organic content and there are indications that it is also suitably brittle. Resource estimates vary widely, in part because the extent of the deposit is so large that it is unlikely ever to be fully

15. At mid-2013, YPF was producing about 10 kb/d for LTO in Vaca Muerta; the wells tested at average initial rates of between 200 b/d and 560 b/d.

developed. Activity is likely to concentrate close to currently exploited conventional reservoirs, where infrastructure and industry capabilities are in place. Extending the life of the western Siberian oil towns is an objective for both the government and the industry, as the conventional reservoirs in the region are ageing rapidly. GazpromNeft has reported promising well-test results in the Bazhenov, both from its own wells and in wells operated by the joint venture with Shell, Salym Petroleum Development. Several of the major Russian oil companies are actively investigating the potential of the Bazhenov in their respective license areas.

In addition to the scale of the potential developments, taxation levels will be a key determinant of the level of future Russian LTO production: the normal mineral extraction tax (MET) and export tax basically require full-cycle production costs to be below $25/barrel, an unlikely level for most LTO resources. At the end of July 2013, the MET was suppressed for selected LTO formations for the first fifteen years of production (and partial MET exemptions given to some other "hard-to-produce" resources). The Russian Ministry of Energy has estimated potential output from the Bazhenov under this new tax regime at between 800 kb/d and 2 mb/d by 2020. The projections are much more conservative at only 450 kb/d in 2035, pending evidence from production tests and economic appraisal.

There are many reasons to be optimistic about LTO production in China in the long term. Strong market demand is likely to drive the country to find a way to exploit its resources. And China, perhaps more than any other country outside the United States, has the potential to bring costs down by maximising the use of locally built equipment and through economies of scale: with about 1 200 active units, its fleet of drilling rigs is second only to that of the United States. Although China has not specifically assessed nor targeted its shale LTO resources (with less than 20 wells drilled so far), it has experience in producing from low-permeability reservoirs: about one-quarter of Chinese oil production is reported to come from low-permeability fields, requiring traditional hydraulic fracturing or horizontal wells. Some wells are reported to have used a limited number of hydraulic fracturing stages in horizontal wells. But China also faces many obstacles: high population density in some areas, water scarcity in others, lack of competition (as the three state-owned oil companies automatically have exclusive rights to oil resources and are currently focused entirely on conventional resources) and a relatively high cost structure in most parts of the country, even for conventional developments. This is why current projections remain conservative.

## Oil production by region



### *Non-OPEC*

In the New Policies Scenario, non-OPEC production maintains the upward trajectory of recent years through to around 2020, but then levels off and begins to tail away from the late-2020s. By 2035, output is still around 3.5 mb/d higher than in 2012. In the early part of the projection period, output of both conventional and unconventional oil expands, but the former peaks already before 2020 and, within a few years, its decline outpaces the growth in unconventional oil, which slows. Total oil production falls between 2012 and

2035 in the majority of non-OPEC countries, the principal exceptions being Brazil, Canada, Kazakhstan and the United States (though US production is in decline before the end of the projection period).

As described, oil output in the *United States* is undergoing a renaissance, thanks mainly to spectacular growth in LTO, and this is expected to continue. On the assumption that Saudi Arabia reins back production levels in its capacity as the swing producer within OPEC, this means that the United States becomes the largest oil producer in the world (including crude, NGLs and unconventional oil) by 2015 and retains this status until the beginning of the 2030s. Growing output of LTO, NGLs and gas- and coal-to-liquids is sufficient to more than offset dwindling output of US conventional crude oil until late in the projection period.

Across the border in *Canada*, oil production grows steadily through the projection period, with rising output from oil sands and light tight oil more than making up for a slow decline in conventional crude oil. In total, output rises by 62%, from 3.8 mb/d in 2012 to 6.1 mb/d in 2035. Oil sands produce 4.3 mb/d in 2035, up from 1.8 mb/d in 2012, with their share of overall oil production rising from just under half to 70%. While the resources are unquestionably large enough to support such an expansion, achieving it is contingent on the construction of major new pipelines to enable the crude to be exported to Asia and the United States. Two pipelines from the oil sands in Alberta to the Pacific Coast have been proposed – the 530-kb/d Northern Gateway line to Kitimat and the expansion, from 300 kb/d to 890 kb/d, of the Trans Mountain line to Vancouver – as well as the Keystone XL line to the United States. The first two projects require provincial and federal approval (the environmental review process for the Northern Gateway is expected to be complete at the end of 2014), while the Keystone XL line is awaiting approval from the US government. The US administration indicated in June 2013 that the project would be approved only if it does not "significantly increase" greenhouse-gas emissions. In the meantime, transport of Canadian oil by rail has increased dramatically, though the major rail accident that occurred in July 2013 in Quebec might slow it down. Export routes from the east coast of Canada are also being explored.

*Mexico* has recently managed to halt the sharp plunge in oil production that started in the mid-2000s. Output from new fields, notably Ku/Maloob/Zaap, was able to offset the drop in supply from mature fields, including the super-giant Cantarell field, which has seen its production drop from a peak of over 2.1 mb/d in 2003-2004 to barely 400 kb/d today. Production is projected to stabilise at around current levels over the *Outlook* period, though much will depend on progress in pushing through the much-needed reforms in the oil sector promised by the new president. The monopoly of the national oil company, Pemex, over all hydrocarbon resources in Mexico has stifled investment and innovation. The constitutional reform proposed in August 2013, if adopted, could facilitate private investment and unleash significant production growth (see later Low Oil-Price Case section).

**Table 14.5 ▷ Non-OPEC oil production in the New Policies Scenario** (mb/d)

| | 1990 | 2012 | 2020 | 2025 | 2030 | 2035 | 2012-2035 | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | Delta | CAAGR* |
| **OECD** | **19.0** | **19.9** | **23.2** | **23.1** | **22.8** | **22.4** | **2.5** | **0.5%** |
| Americas | 13.9 | 15.9 | 19.3 | 19.8 | 19.9 | 19.6 | 3.8 | 0.9% |
| Canada | 2.0 | 3.8 | 5.0 | 5.3 | 5.7 | 6.1 | 2.3 | 2.1% |
| Mexico | 3.0 | 2.9 | 2.7 | 2.6 | 2.6 | 2.6 | -0.3 | -0.4% |
| United States | 8.9 | 9.2 | 11.6 | 11.8 | 11.5 | 10.9 | 1.7 | 0.7% |
| Europe | 4.3 | 3.5 | 3.1 | 2.6 | 2.2 | 2.0 | -1.5 | -2.3% |
| Asia Oceania | 0.7 | 0.6 | 0.7 | 0.7 | 0.7 | 0.7 | 0.2 | 1.1% |
| **Non-OECD** | **22.7** | **29.5** | **31.9** | **32.0** | **31.4** | **30.6** | **1.0** | **0.2%** |
| E. Europe/Eurasia | 11.7 | 13.8 | 13.7 | 13.7 | 13.9 | 14.2 | 0.4 | 0.1% |
| Kazakhstan | 0.5 | 1.6 | 1.9 | 2.5 | 3.2 | 3.7 | 2.1 | 3.6% |
| Russia | 10.4 | 10.7 | 10.4 | 9.9 | 9.6 | 9.4 | -1.3 | -0.6% |
| Asia | 6.0 | 7.8 | 7.7 | 7.4 | 6.8 | 6.0 | -1.8 | -1.1% |
| China | 2.8 | 4.2 | 4.4 | 4.3 | 4.1 | 3.4 | -0.8 | -0.9% |
| India | 0.7 | 0.9 | 0.8 | 0.7 | 0.7 | 0.6 | -0.3 | -1.7% |
| Middle East | 1.3 | 1.5 | 1.3 | 1.1 | 1.0 | 0.9 | -0.6 | -2.2% |
| Africa | 1.7 | 2.3 | 2.9 | 2.6 | 2.3 | 2.1 | -0.2 | -0.4% |
| Latin America | 2.0 | 4.2 | 6.2 | 7.2 | 7.4 | 7.4 | 3.2 | 2.5% |
| Brazil | 0.7 | 2.2 | 4.1 | 5.4 | 5.8 | 6.0 | 3.8 | 4.5% |
| **Total non-OPEC** | **41.7** | **49.4** | **55.0** | **55.1** | **54.2** | **52.9** | **3.5** | **0.3%** |
| *Non-OPEC market share* | *64%* | *57%* | *59%* | *58%* | *56%* | *54%* | *n.a.* | *n.a.* |
| **Conventional** | **41.3** | **45.0** | **46.2** | **44.6** | **42.6** | **40.7** | **-4.3** | **-0.4%** |
| Crude oil | 37.6 | 38.4 | 38.3 | 36.4 | 34.3 | 32.3 | -6.1 | -0.7% |
| Natural gas liquids | 3.6 | 6.6 | 8.0 | 8.1 | 8.3 | 8.3 | 1.7 | 1.0% |
| **Unconventional** | **0.4** | **4.4** | **8.8** | **10.5** | **11.7** | **12.3** | **7.9** | **4.6%** |
| *of which:* | | | | | | | | |
| Canada oil sands | 0.2 | 1.8 | 3.0 | 3.3 | 3.8 | 4.3 | 2.5 | 3.9% |
| Light tight oil | 0.0 | 2.0 | 4.7 | 5.7 | 5.8 | 5.5 | 3.6 | 4.6% |
| Coal-to-liquids | 0.1 | 0.2 | 0.4 | 0.7 | 0.9 | 1.2 | 1.0 | 8.3% |
| Gas-to-liquids | 0.0 | 0.1 | 0.1 | 0.2 | 0.3 | 0.4 | 0.4 | 9.9% |

* Compound average annual growth rate.

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The long-term decline in oil output in Europe continues apace, with overall production in OECD countries dropping by 300 kb/d in 2012, to under 3.5 mb/d, down 3.3 mb/d on the peak in 2000. Production is set to slide further through the projection period, in spite of slightly rosier medium-term prospects in the *United Kingdom*, following recent investment-friendly tax measures, and developments in *Norway*, where exploration successes have raised hopes of stemming the projected decline in output.

Oil production in *Russia* is approaching the record levels of the Soviet era, but maintaining this trend will be difficult, given the need to combat declines at the giant western Siberian fields that currently produce the bulk of the country's oil. Output climbed 130 kb/d in 2012 to a post-Soviet high of 10.7 mb/d and is projected to stay close to this level until the end of the decade. Thereafter, Russia's success in combating a declining trend in crude output will depend on four factors: success in raising recovery rates at existing conventional fields; the related issue of developing Russia's unconventional oil (these first two challenges are often grouped together in Russian debates and in fiscal policy as "hard-to-recover" oil); the continued expansion into new onshore production areas, for example in eastern Siberia; and, for the longer term, the prospect of output from the Arctic offshore. Success in each of these areas depends on supportive fiscal conditions and, in the case of the Arctic at least, successful partnerships with international companies. In the projections, efforts in these areas are not sufficient to keep oil output above the 10 mb/d level beyond 2025 and Russian oil production slips to around 9.5 mb/d by 2035.

In *Kazakhstan*, the main sources of production growth over the projection period are the Kashagan, Tengiz and Karachaganak fields. After years of delay, Kashagan – the largest conventional field discovered worldwide in the last 30 years – is finally set to begin producing significant volumes in 2014, as production from the first phase of the project ramps up. The timing and size of the second phase of development, which is planned to raise production towards 1 mb/d, remains highly uncertain. It is assumed that this starts, at the earliest, in the mid-2020s. Further increases in condensate production from Karachaganak and crude output from Tengiz are planned, but they require expanded transport capacity in order to ship the liquids to export markets. Total Kazakh oil production is projected to climb from 1.6 mb/d in 2012 to 1.9 mb/d in 2020 and 3.7 mb/d in 2035.

The majority of the projected increase in oil production in Latin America comes from *Brazil*, driven in large part by the development of the country's massive offshore pre-salt deposits that have been found in recent years (see Chapter 11 for a detailed discussion of Brazilian oil prospects). Among the other non-OPEC countries, prospects for production in *Colombia* have brightened alongside improvements in the security situation and regulatory framework. Output from the established Rubiales heavy oil field continues to grow, having reached more than 250 kb/d in early 2013. Yet the country's production, which should hit 1 mb/d in 2013, is still expected to peak within the current decade at close to 1.2 mb/d and then to fall over the longer term to around 0.5 mb/d in 2035, as mature fields decline. No major field has been found in recent years, despite increased exploration activity. There is potential for light tight oil developments, but these are early days and the economics have yet to be established. Elsewhere in the region, production peaks and then drops in *Peru* and *Bolivia*, despite efforts to attract more investment, as well as in *Argentina*. In Argentina, NGLs associated with shale gas and light tight oil rise, but production is not sufficient to offset the decline in conventional crude oil production from mature fields in the Neuquén region. Overall production drops from 675 kb/d in 2012 to 550 kb/d in 2035.

Production among the non-OPEC African countries diverges, with mature producers, such as Egypt, Chad and Gabon, seeing declines over the projection period, while output takes off in some countries of East Africa and West Africa. East Africa has become a hotspot of exploration and development activity, with the discovery of major new deposits in recent years in offshore Tanzania, Uganda and – most recently –onshore Kenya; but how much and how soon these fields will start producing remains very uncertain. While most of the existing producers in West Africa have met with limited success in finding more conventional oil, exploration into deepwater pre-salt formations – geologically similar to those to the west offshore Brazil – is underway all along the West African coast and could bring new discoveries. Morocco could also see production rise over the *Outlook* period as a result of increasing exploration activity. In aggregate, non-OPEC African output is projected to rise modestly over the next decade, before falling back to just below current levels by 2035. Among the other main non-OPEC Middle East producers, Oman and Yemen are both expected to see production declines before 2035. Jordan could see moderate growth, if it gets the long-discussed kerogen oil projects under way.

Our revised recoverable resources number for *China* (coming from the USGS updates) is sufficient to enable the country to maintain production above 4 mb/d until at least 2030, before decline at its mature workhorse fields, including the super-giant Daqing field, takes over. This is consistent with the Chinese government target of maintaining production at the current level in the long term. Supplies from new light tight oil deposits and CTL plants are projected to grow (one CTL plant is already operating). In *Australia*, soaring NGLs supplies resulting from the big expansion of gas production and the emergence of an unconventional oil industry (LTO, CTL and/or kerogen oil) compensate for dwindling crude oil production, bringing production to a plateau of around 600-700 kb/d over the *Outlook* period.

### *OPEC*

The projected growth in output by OPEC countries comes mainly from the Middle East, which sees its production rise by about 7 mb/d between 2012 and 2035, compared with less than 1 mb/d in OPEC countries outside this region. Middle East OPEC countries have the biggest conventional resource endowments and generally benefit from the lowest development costs in the world, thanks to favourable geology and access to established infrastructure. They could increase production even more (as projected in the Current Policies Scenario), but short-term market management policies and long-term depletion policies are likely to continue to hold back investment.

The increase in overall OPEC production to 2035 is lower than projected in *WEO-2012*, mainly because of stronger growth in non-OPEC supplies. NGLs are the biggest contributor to OPEC production growth, accounting for more than 3 mb/d of the increase, 50% more than the rise in crude oil output. Venezuelan extra-heavy oil accounts for most of the rest. Large GTL plants in Qatar and Nigeria, as well as small-scale GTL in other countries, make a minor contribution.

**Table 14.6 ▷ OPEC oil production in the New Policies Scenario** (mb/d)

| | 1990 | 2012 | 2020 | 2025 | 2030 | 2035 | 2012-2035 Delta | 2012-2035 CAAGR* |
|---|---|---|---|---|---|---|---|---|
| **Middle East** | **16.4** | **26.7** | **27.3** | **29.2** | **31.1** | **33.6** | **6.9** | **1.0%** |
| Iran | 3.1 | 3.5 | 3.3 | 3.6 | 3.8 | 4.2 | 0.7 | 0.8% |
| Iraq | 2.0 | 3.0 | 5.8 | 6.7 | 7.3 | 7.9 | 4.9 | 4.3% |
| Kuwait | 1.3 | 3.0 | 2.4 | 2.5 | 2.7 | 2.9 | -0.1 | -0.1% |
| Qatar | 0.4 | 2.0 | 2.0 | 2.2 | 2.4 | 2.6 | 0.6 | 1.1% |
| Saudi Arabia | 7.1 | 11.7 | 10.6 | 10.9 | 11.4 | 12.2 | 0.5 | 0.2% |
| United Arab Emirates | 2.4 | 3.5 | 3.3 | 3.3 | 3.5 | 3.7 | 0.3 | 0.3% |
| **Non-Middle East** | **7.5** | **11.0** | **10.5** | **10.7** | **11.2** | **11.6** | **0.6** | **0.2%** |
| Algeria | 1.3 | 1.8 | 1.7 | 1.7 | 1.7 | 1.8 | 0.1 | 0.1% |
| Angola | 0.5 | 1.9 | 1.6 | 1.5 | 1.4 | 1.4 | -0.4 | -1.2% |
| Ecuador | 0.3 | 0.5 | 0.4 | 0.3 | 0.3 | 0.3 | -0.2 | -2.3% |
| Libya | 1.4 | 1.5 | 1.6 | 1.7 | 1.8 | 1.9 | 0.4 | 1.1% |
| Nigeria | 1.8 | 2.6 | 2.4 | 2.5 | 2.6 | 2.8 | 0.2 | 0.3% |
| Venezuela | 2.3 | 2.7 | 2.8 | 3.0 | 3.3 | 3.3 | 0.6 | 0.9% |
| **Total OPEC** | **23.9** | **37.6** | **37.8** | **39.9** | **42.2** | **45.2** | **7.5** | **0.8%** |
| *OPEC market share* | *36%* | *43%* | *41%* | *42%* | *44%* | *46%* | *n.a.* | *n.a.* |
| **Conventional** | **23.9** | **37.0** | **36.2** | **37.9** | **39.7** | **42.4** | **5.3** | **0.6%** |
| Crude oil | 21.9 | 30.9 | 29.4 | 30.1 | 31.2 | 33.0 | 2.1 | 0.3% |
| Natural gas liquids | 2.0 | 6.1 | 6.8 | 7.8 | 8.5 | 9.3 | 3.2 | 1.9% |
| **Unconventional** | **0.0** | **0.6** | **1.6** | **2.0** | **2.5** | **2.8** | **2.2** | **6.9%** |
| *of which:* | | | | | | | | |
| Venezuela extra-heavy | 0.0 | 0.4 | 1.2 | 1.5 | 1.9 | 2.1 | 1.7 | 7.5% |
| Gas-to-liquids | 0.0 | 0.1 | 0.2 | 0.3 | 0.4 | 0.4 | 0.3 | 5.1% |

* Compound average annual growth rate. Notes: Data for Saudi Arabia and Kuwait include 50% each of production from the Neutral Zone.

*Saudi Arabia* is the world's biggest oil producer and holds the largest conventional oil reserves in the world, sufficient to underpin high levels of production for decades to come. Official policy is to maintain crude oil production capacity at 12.5 mb/d – about 500 kb/d above the current level – and to have available spare capacity of at least 1.5-2 mb/d (it averaged 2.2 mb/d in 2012). Several major projects are currently underway to ensure such capacity is sustained: the development of the 900-kb/d offshore Manifa heavy oilfield, which produced first oil in spring 2013 and is due to be completed in 2014; the expansion of the Khurais and Shaybah onshore fields; and the redevelopment of the Zuluf and Berri fields offshore. A decision is due at the end of 2013 on whether to proceed with steam injection to boost heavy oil production at the Wafra field, shared with Kuwait, in the Neutral Zone. The project, led by Chevron, would be the largest of its kind. Meanwhile, the drilling effort needed to sustain output at existing fields, including Ghawar, the world's biggest, is rising as they age. Saudi Aramco has been gradually increasing the number of drilling rigs in the country and this is expected to continue. Ghawar still accounts for more than half of the country's crude oil production. In the projections, Saudi Arabia remains the largest exporter of oil throughout most of the period, though it is tied with Russia between 2015 and 2020, a time when we project that OPEC will limit output in the light of the growing North American LTO production.

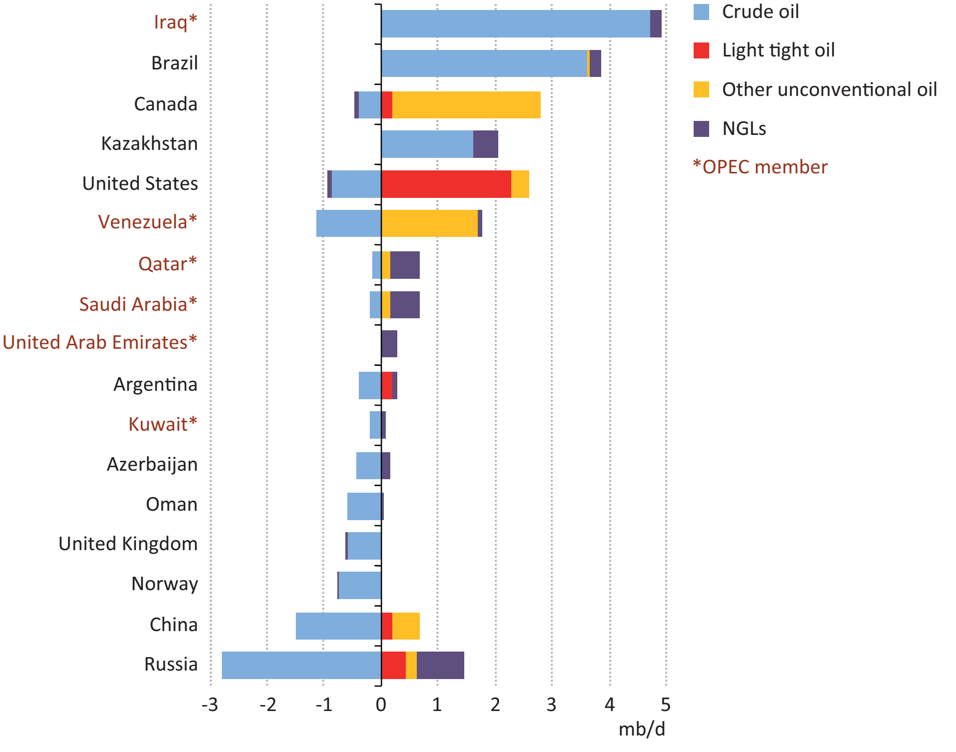
*Iraq* makes the largest contribution to OPEC (and worldwide) supply growth (Figure 14.13), its production rising from 3.0 mb/d in 2012 to 7.9 mb/d in 2035, 0.4 mb/d lower than projected last year, as progress on the ground in the last year has been slower than expected. The plateau production targets for two of the main southern fields have been renegotiated downwards from the initially agreed levels: for the West Qurna field, from 1.8 mb/d to 1.2 mb/d, and for Zubair, from 1.2 mb/d to 850 kb/d. But plateau production is now due to last for longer (and the duration of the technical service contracts has been extended accordingly). Similar discussions with other operators are reportedly underway, in line with the downward revision of Iraq's official production targets. In the *Outlook*, a range of hurdles, including persistent security concerns, infrastructure constraints and logistical difficulties, continues to constrain the rate of growth over the current decade, with production reaching 5.8 mb/d in 2020.

The outlook for production in *Iran* remains highly uncertain in view of the international sanctions imposed on the country in response to its nuclear programme. Production fell to 3.5 mb/d in 2012 and crude production (excluding NGLs) reportedly dropped to just 2.6 mb/d in mid-2013 – the lowest level in more than twenty years – as the country's main customers reined in their purchases because of the sanctions. A lack of access to technical expertise and equipment, and under-investment have, in any case, reduced capacity, while rising domestic gas demand, especially for power generation, is also restricting the availability of gas for reinjection into oilfields to sustain flow rates. The government is reportedly preparing revisions to its unsuccessful buyback contracts and may consider production-sharing contracts; but interest is expected to be weak until political uncertainty recedes. In June 2013, the government announced that it had offered a production-sharing contract to Indian investors to develop a block in the offshore Farzad-B gas field – the first such contract since the 1979 Iranian revolution. Oil production is projected to remain low in the coming years as it will take time to rebuild capacity even if sanctions are loosened or lifted soon. Production recovers slowly after 2020, to 4.2 mb/d in 2035, on the assumption that the current international stand-off is resolved.



In the *United Arab Emirates*, Abu Dhabi – the leading producer – is discussing the conditions of the new concessions that will replace its 75-year concession agreement with the Abu Dhabi Company for Onshore Oil Operations (ADCO, a joint venture with international companies), which is expiring soon (two other, offshore, concessions will expire in 2018 and 2026). The new concessions are likely to involve conditions to bolster investment in output at the country's mature fields, notably Upper Zakum and Bab, and to develop new deposits, including Qusahwira. Abu Dhabi holds the bulk of United Arab Emirates' oil reserves, which rank seventh in the world, but production growth increasingly relies on the deployment of improved oil recovery techniques. The government recently pushed back its target date for crude oil production capacity of 3.5 mb/d from 2017 to 2020, because of delays in some of the upstream projects and in awarding development contracts, including for Upper Zakum. For the United Arab Emirates as a whole, total oil production, including NGLs, is projected to edge higher from 3.5 mb/d in 2012 to 3.7 mb/d in 2035.

**Figure 14.13 ▷ Change in oil production in selected countries in the New Policies Scenario, 2012-2035**




*Kuwait*'s oil production prospects continue to depend on the political acceptability of the participation of international companies, which have the expertise to develop the country's heavy oil deposits in order to offset stagnating output at mature fields. Kuwait is still officially targeting an expansion of overall oil production capacity from 3.2 mb/d today to 4 mb/d by 2020, though delays in signing agreements with foreign companies have made meeting that target unlikely. For example, Shell's project in gas condensate fields in the north of the country was meant to add 350 kb/d of light oil and condensate capacity by 2020, but less than half of that may be available by then. The country's total oil output, including NGLs, remains around current levels throughout most of the projection period (after an initial drop when the call on OPEC is reduced in the coming few years).

In *Qatar*, all of the projected 550-kb/d growth in oil production to 2.6 mb/d between 2012 and 2035 comes from NGLs and GTL, underpinned by a continuing expansion of gas production and LNG exports. A new round of LNG projects is expected to be undertaken in the 2020s, on the assumption that the current moratorium on development of the North Field – the world's largest conventional gas field – is lifted later in the current decade (see Chapter 3). It is also assumed that new GTL projects are sanctioned, boosting nameplate capacity to around 400 kb/d from 174 kb/d at present (34 kb/d at the Oryx plant, commissioned in 2007, and 140 kb/d at Pearl GTL, completed in 2012). These capacity additions are expected to offset a decline in crude oil production. Several production sharing agreements with international companies will expire soon and the new deals are expected to see the national company, Qatar Petroleum, take bigger stakes. Access to international technological expertise will be crucial in arresting sliding production at the country's mature fields, including the offshore Al-Shaheen field, where Maersk has agreed a new plan to raise output, previously targeted at 525 kb/d.

Prospects for oil production in the sub-Saharan OPEC countries in the longer term depend both on the extent of civil unrest and political instability in Nigeria, and on the discovery and development of major new deposits, the best hope for which probably lies in pre-salt formations. In *Nigeria*, theft and attacks on oil facilities continue to disrupt onshore and shallow water production, though output received a boost in 2012, with the start-up of the 160-kb/d deepwater Usan field. Other offshore developments are proceeding slowly, largely as a result of uncertainty over the fiscal and royalty terms under the long-awaited Petroleum Industry Bill, which is still in preparation. We project a slight decline in production through to 2020 and a modest recovery thereafter to about 2.8 mb/d in 2035, assuming the requisite investment materialises, most of which will need to come from abroad. *Angola*'s deepwater production is set to rise in the near term, with the completion of BP's Saturno development, as well as satellite projects at the Clochas and Mavacola fields, which should offset small declines at the mature Girassol field – the country's biggest. In the absence of major new discoveries, output is expected to edge lower in the longer term, reaching 1.4 mb/d in 2035. But this bearish outlook could be transformed if ongoing exploration drilling proves up large pre-salt reserves. Non-OPEC Gabon, to the north, has already made commercial discoveries of pre-salt oil.

Both North African OPEC members, Libya and Algeria, will struggle to boost production capacity over the longer term unless they step up exploration. In *Algeria*, output has been on the slide for several years, mainly because of declines at old fields that have been in production for decades, insufficient exploration drilling and dwindling discoveries. The terrorist attack on the In Amenas gas complex in January 2013 has further undermined industry confidence and augurs ill for future investment. The government announced in 2013 that it will reform the 2005 Hydrocarbons Law, to introduce tax incentives for foreign investment, and will raise Sonatrach's capital budget for the next five years to $80 billion. We project production to remain around current levels through to 2035, in part due to offshore and unconventional developments.

In *Libya*, production rebounded in 2012, to around 1.5 mb/d – close to pre-conflict levels – but a return of insecurity and political instability in 2013 is clouding the near-term outlook. Longer-term prospects hinge on developing a larger part of the reported reserves and the new government is planning a licensing round covering new onshore and offshore zones later in 2013, but the terms are not yet known. We project that production will remain around the levels seen in early 2013, prior to the latest unrest, for the rest of this decade, before starting a modest rise through to 2035 on the assumption of increased political stability and increased investment.

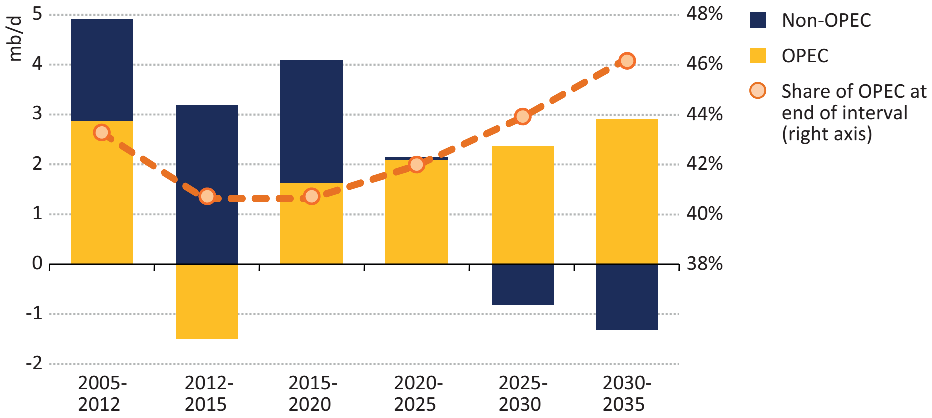
*Venezuela* holds the largest oil reserves in the world, made up primarily of unconventional extra-heavy oil in the Orinoco Belt. Production has slumped in recent years, due to a lack of investment by the national oil company, PDVSA, and policies that have discouraged foreign investment. There are few signs of a change of course under the newly-elected president and, given that PDVSA revenues are a vital source for government expenditure, the squeeze on funds available for investment is likely to continue, making a rapid reversal in declining crude oil and NGLs production unlikely. Over the medium to long term, rising extra-heavy oil output is projected to outweigh weak conventional production thanks to large-scale projects, most of which are undertaken in partnership with international companies. Total output reaches 3.3 mb/d in 2035, up from 2.7 mb/d in 2012. By contrast, production in *Ecuador*, the only other Latin American OPEC member, is projected to fall from about 500 kb/d today to less than 300 kb/d by 2035, as its declining reserves are depleted, though development of the heavy Ishpingo-Tambococha-Tiputini oilfields in the environmentally sensitive Yasuni National Park could arrest or even reverse this decline if it were to proceed (as suggested by statements made by Ecuador's President in August 2013).

## Supply trends and potential implications for prices

Our projections in the New Policies Scenario highlight how the anticipated growth in reliance on oil production in the Middle East has been postponed, as a result of steady upstream technological innovation that is bringing new resources elsewhere into the realm of commercial viability. The growth in LTO and the expansion of deepwater production are examples of this trend and these two phenomena play a large role in determining the dynamics of oil supply in the early part of the projection period, during which non-OPEC supply is sufficient to meet the lion's share of the growth in demand. This implies that OPEC producers will need to limit their output in order to balance the market (allowing, also, for a continued increase in production in Iraq).

Over the longer term, however, the situation is reversed as non-OPEC production first stabilises and then begins to decline in the latter part of the 2020s. Increases in demand are then met by growth in OPEC production (Figure 14.14). Over the whole period to 2035, OPEC countries provide over two-thirds of the overall increase in supply, OPEC increasing its share of global production from 43% to 46%. This share is considerably less than OPEC's share of the world's remaining recoverable resources of oil. It is also lower than that projected in recent *WEO*s, when it has been closer to 50% by 2035.

**Figure 14.14** ▷ **Oil production changes by OPEC/non-OPEC grouping in the New Policies Scenario**




Note: Share of OPEC is for the end of the interval shown, *i.e.* for 2012 in the first column, for 2015 in the second, and so on.

These longer-term market dynamics are accompanied by some shorter-term signals that might be understood to indicate a more comfortable supply-demand balance ahead. Global demand growth has slowed, compared with the years between 2000 and 2008, in large part as a result of the protracted economic crisis in Europe, efficiency gains in the United States and some signs of a slowing rate of growth in the Chinese economy. Alongside uncertainties over the future pace of economic growth and of oil demand, there is also an expectation in some quarters that supply prospects are sufficiently bright to outpace demand growth in the years ahead. Focusing on the rapid growth of light tight oil production in the United States, this view posits the start of a new era of ample supply, raising the possibility that the market could in practice be brought into equilibrium with a lower oil price than the one we project in the New Policies Scenario (where the price rises slowly to reach $128/barrel [in year-2012 dollars] in 2035[16]). The Brent and WTI futures curves indeed point to an easing in the oil price over the next few years (although history shows that futures prices are not reliable predictors of future prices).

We examine the possibility of a sustained period of lower prices below. But there are also reasons to support a more cautious assessment of the supply outlook. Although the resource base is more than sufficient to justify an optimistic outlook for oil production, low-risk and low-cost opportunities for investment are limited and it remains a huge



16. The trajectory in the New Policies Scenario tends to be relatively flat over the first half of the projection period and increases at a slightly faster pace after 2020, reflecting the overall dynamics of markets. However, our price paths follow smooth trends as we do not attempt to anticipate the timing or extent of fluctuations in the oil price over the projection period (while recognising that, in reality, the oil price may from time to time deviate substantially from the assumed path in response to economic, energy market or geopolitical perturbations). We examine in this section a Low Oil-Price Case: some commentators also argue that we may be heading for a substantially higher price than in the New Policies Scenario (IMF, 2012).

undertaking to mobilise new investment at the pace required to keep up with the impact of declining output from existing fields. On LTO, we are not as bullish as some about the North American prospects: after rapid increases over the next five years, we project a period of slower growth, eventually leading to a plateau in the latter part of the 2020s and a slow decline thereafter, due to depletion of currently estimated recoverable resources. Moreover, LTO growth outside North America is projected to be too slow for LTO to take over as the engine of production growth in the latter part of the projection period.

We also see downside risks in a number of other key producing countries. The political and logistical challenges to growth of output in Iraq remain formidable; in fact, the projections for Iraq are revised downwards compared with last year, as a result of slow progress on the ground. The technological and investment challenges in the Brazil pre-salt fields are also formidable; even at the levels of our more conservative view on production prospects, compared with those held by Petrobras and the Brazilian government, there remains the possibility of slippage in project implementation (see Chapter 11). Similarly, the recent track record in moving projects forward in Kazakhstan invites a prudent view of the speed of new developments there. Iraq, Brazil and Kazakhstan together account for more than 10 mb/d of the production growth anticipated in the New Policies Scenario to 2035 (total projected growth in oil production is 11 mb/d).

The prospects in some other OPEC countries, besides Iraq, also raise questions. Libyan production has again plummeted amid labour disputes, civil unrest and political discord. Nigeria is struggling to resolve its internal conflicts and production is decreasing. Though there are hopeful signs, a quick resolution of the tensions between Iran and the international community still seems some way off. Venezuela is going through a political transition that has so far failed to provide certainty for future upstream investment. Kuwait is no further along than it was ten years ago in the political process required to put its ambitious capacity increase targets on track. Even in Saudi Arabia, United Arab Emirates and Qatar, there are some hints that the US shale revolution could induce a slowdown in investment. Our estimate of global spare capacity rises from 5 mb/d currently to more than 7 mb/d after 2015, but this would already start diminishing again by 2018.[17] As emphasised in successive *Outlooks*, shortage of investment remains a significant threat to future supply and this consideration informs the judgments underlying the New Policies Scenario.

## *A Low Oil-Price Case*

A Low Oil-Price Case is based on the premise that supply developments in a number of countries turn out more positively than we project in the New Policies Scenario.[18] There are a number of countries that could deliver production above expectations. In the United States, the astounding vitality of the industry could deliver LTO output of up to 6 mb/d

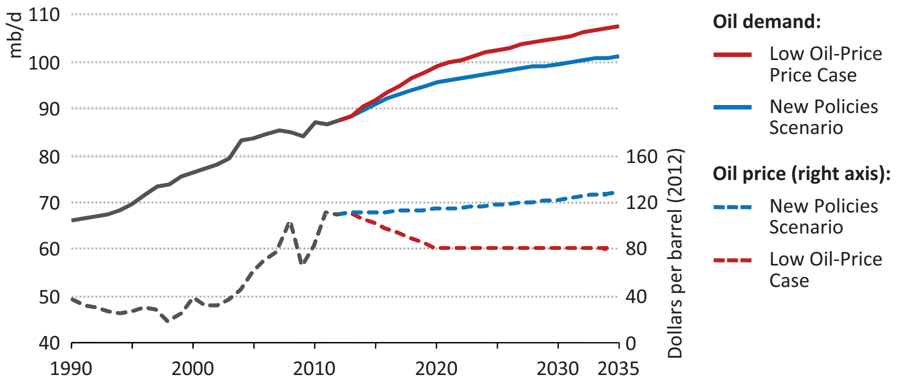
17. This is based on the production capacity projections from the *Medium-Term Oil Market Report 2013* (IEA, 2013) versus the oil demand projections of the New Policies Scenario.

18. An alternative low oil-price case could emerge in the event of persistent weakness in the global economy, bringing down the anticipated growth in oil consumption: see Chapter 1, Box 1.2.

(as some industry sources predict), about 2 mb/d above the projections. In Canada, if the controversies over the Keystone XL pipeline and the pipelines from Alberta to the British Columbia coast were to be resolved quickly, oil sands production could easily grow 1 mb/d higher than we project.[19] Also in North America, Mexico's reform of the laws limiting the participation of foreign companies in the hydrocarbon sector is high on the agenda of the new administration and such reforms have the potential to generate much more rapid development of its large resources.

Moving outside North America, successful implementation of Petrobras' plans in Brazil could provide another 1 mb/d or more in output on top of our projections in 2020 (as in the High Brazil Case that we examine in Chapter 11). Venezuela is suffering from a severe lack of capital and technical expertise to develop its massive hydrocarbon resources: re-opening the country's oil sector could easily deliver an additional 2 mb/d by 2035. Iraq's stated ambition to reach 9 mb/d of output by 2020 is about 1 mb/d above the 2035 projections. If Iran were to resolve its conflict with the international community and embark on an ambitious programme of attracting upstream investment, its resources, which are similar in extent to those of Iraq, would support production at a level some 4 mb/d higher than the projections. Nigeria, Syria, Libya, North and South Sudan, and, even, Russia (if it makes progress on the evolution of its hydrocarbon tax system) all have potential for higher output. Taking all these possibilities together, there is potential for a level of production capacity close to 13 mb/d higher than the production level projected in the New Policies Scenario. Of course, not everything can be expected to go well in all of these countries: but, even an extra 5-6 mb/d of capacity would have a marked impact on the oil market.

**Figure 14.15 ▷ Oil price and oil demand trajectories in the Low Oil-Price Case compared with the New Policies Scenario**



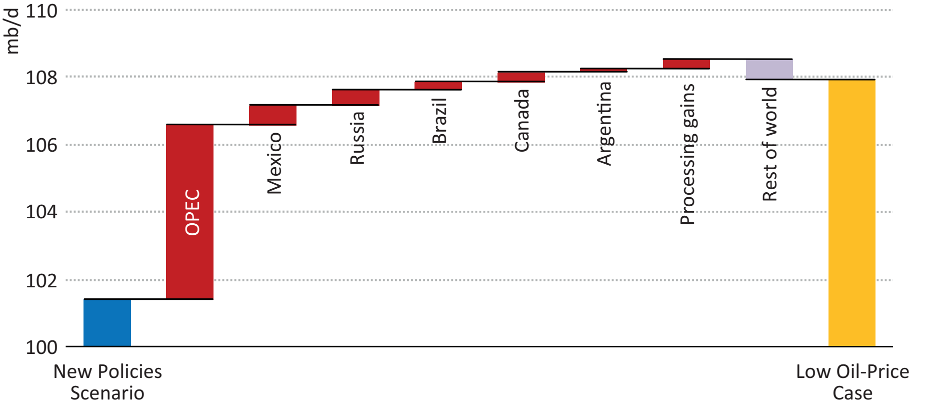

We model this possibility as a Low Oil-Price Case, in which supply growth is sufficiently rapid to ease the market balance, bringing on and supplying additional consumption

19. This would track more closely the projections of the Canadian Association of Petroleum Producers and of ERCB, the regulator in Alberta.

of oil.[20] As suggested by the supply cost curves discussed in Chapter 13, prices could reasonably be expected to stabilise in this case at around $80/barrel, around the level of the cost of the marginal barrel required to meet the additional demand, which reaches 107.9 mb/d in 2035 in this case (Figure 14.15). Note that the assumptions on policies (on efficiency, biofuels, etc.) remain those of the New Policies Scenario, which explains why demand is still lower than in the Current Policies Scenario.

To examine the consequences of such a Low Oil-Price Case, one needs to specify which countries are actually able to produce more. The United States, Canada, Brazil and Russia, even if one takes a more optimistic view of their supply potential, would be penalised by lower oil prices (as the costs of incremental production are relatively high), so their output remains at levels similar to those in the New Policies Scenario. In the projections, it is rather Mexico, Venezuela, Iran and, to a lesser extent, Nigeria, Libya and Kuwait that provide the bulk of the required increase in production. Indeed Figure 14.16 shows that the bulk of the increased demand is met by OPEC countries, with Mexico the leading contributor among non-OPEC countries, followed by Russia, and smaller contributions coming from Brazil, Canada and Argentina. Other countries see a decrease in production, due to lower prices.[21]

**Figure 14.16 ▷ Contributions to meeting the additional demand in the Low Oil-Price Case relative to the New Policies Scenario, 2035**




Such a scenario would be a mixed blessing for OPEC countries – a finding that calls into question its likelihood in practice. Despite higher production, lower prices mean that OPEC total revenues in 2035 decline from $1.6 trillion in the New Policies Scenario to $1.1 trillion

20. In Chapter 13, we have argued that production is limited not by price but by the capabilities of the industry to develop resources fast enough. In the context of the Low Oil-Price Case, though this continues to be a limitation, it is partly alleviated by easier access to lower cost resources, which also are less dependent on skilled personnel.

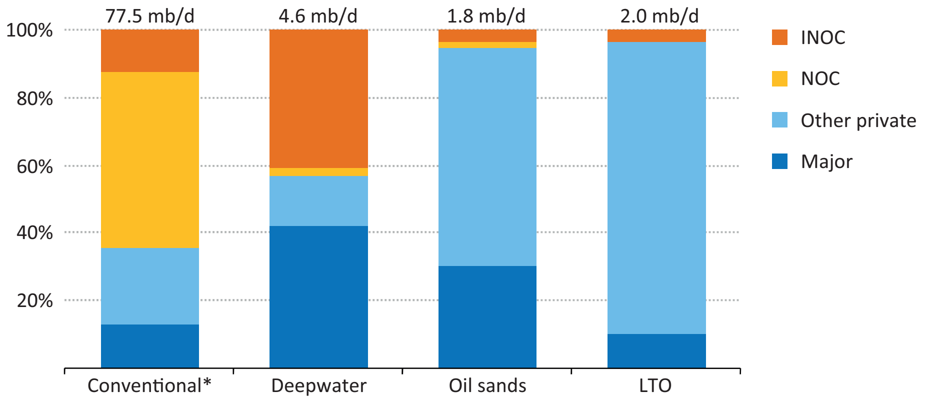
21. Because the Low Oil-Price Case is not a fully-fledged scenario, *i.e.* it only changes parameters for the oil sector rather than for all fuels, it uses the same gas and coal prices as the New Policies Scenario. This results, in particular, in a large drop in coal-to-liquids and gas-to-liquids production, as the ratio of oil to coal and gas prices is less favourable than in the New Policies Scenario.

in the Low Oil-Price Case. The Low Oil-Price Case would also bring international prices below the estimated fiscal breakeven prices in many large resource-owning countries, *i.e.* the price needed to generate sufficient revenue to balance government budgets (based on current spending commitments). Estimates for these fiscal breakeven prices vary, but one recent study put the OPEC output-weighted average in 2013 at $105/barrel, an increase of $6/barrel since 2012 (APICORP, 2013). These breakeven price estimates for 2013 vary by country from $58/barrel in Qatar to (an exceptionally high) $144/barrel in Iran, meaning that the fiscal risks associated with a fall in price would not be evenly distributed. Nonetheless, for many significant producers, this could be an important source of resistance to the production levels and price trajectory outlined in the Low Oil-Price Case.

## Upstream industry structure

In Chapter 13, we presented the estimate that national oil companies (NOCs) or their host governments control almost 80% of the world's proven-plus-probable reserves, compared with around 20% for privately-owned companies.[22] There are also differences in the types of resources in which NOCs (whether nationally focused or internationally-oriented) are involved in developing. NOCs and international NOCs (INOCs) tend to dominate conventional oil production, accounting for two-thirds of total output in 2012 (excluding deepwater production). Private companies are pushed towards a stronger presence among resources that are more technically challenging to exploit (but more accessible), such as deepwater projects (57% of production in 2012), oil sands (95%) and the rapidly expanding area of LTO (96%) (Figure 14.17). Growth in LTO output is strongly associated with the ability of smaller entrepreneurial companies to react quickly, deploy technical innovations and control costs.

**Figure 14.17 ▷ Oil production by selected resource and company type, 2012**




* Excluding oil produced in deepwater.

Source: IEA analysis based on AS Rystad Energy.

22. See Chapter 13, Box 13.3 for an explanation of the company categories used in this analysis

**Box 14.4 ▷ The rising overseas presence of Asian national oil companies**

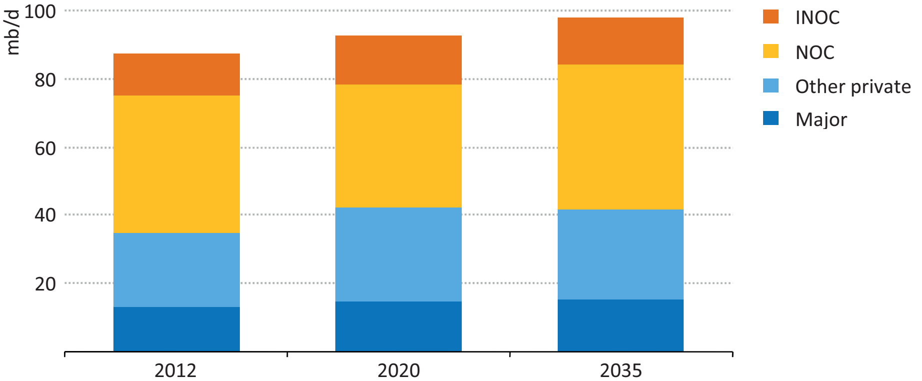
As the centre of gravity of global oil demand (and imports) shifts ever more towards the Asia-Pacific region, so Asian NOCs have become increasingly prominent buyers of upstream assets outside their home markets. In 2012, for the first time, national oil companies took the largest share of global spending on mergers and acquisitions. Chinese and Southeast Asian companies, notably CNPC, CNOOC and Sinopec from China, Malaysia's Petronas, Indonesia's Pertamina and Thailand's PTT, took the lead. Their acquisitions (including both oil and gas) accounted for over one-fifth of the world total. This increase in overseas holdings is motivated by various factors: the desire to hold more diversified portfolios of assets, to access new resources and to develop integrated supply chains (the latter in particular for natural gas) or, simply, to gain technical know-how and expertise (for example, for deepwater or unconventional resources). As a result, Asian NOCs are becoming increasingly important producers outside their borders. In the case of China, we estimate that, as of mid-2013, the overseas oil production entitlement of China's companies has grown to around 2 mb/d. There is scope for this figure to increase further and we expect that it will rise to between 3-3.5 mb/d by 2015, based on production growth from existing assets as well as new acquisitions.

It is sometimes assumed that this overseas production is earmarked directly for the domestic Chinese market, but there is no evidence that this is the case. Even if it were, the volumes of China's overseas oil, while impressive, would fall far short of the projected requirement for oil imports, which reaches 6.7 mb/d by 2015 and continues to rise strongly to 12.2 mb/d by 2035. The gap between overseas production and the import requirement is even likely to widen in the longer term, as the accumulation of overseas assets runs up against limits in the opportunities for productive international investment (due, in large part, to the grip of other NOCs over their domestic resources).

Over the projection period, we anticipate a gradual move towards a more interconnected upstream landscape. Markets in North America are increasingly a focus for international mergers and acquisitions; of the total spending on upstream acquisitions in 2012, more than half was in the United States and Canada, although Africa has also seen a rise in activity. The acquisition interest in North America has been driven in large part by unconventional oil and gas. NOCs are increasingly involved in North America, seeking a foothold in an important market as well as access to technology and expertise. Asian NOCs have been particularly active, with Canada alone seeing two major deals go through in 2012: CNOOC's $15 billion acquisition of Nexen and Petronas' $5 billion purchase of Progress (Box 14.4).

Despite the rise in NOC holdings outside their home markets, in the medium term, at least until the mid-2020s, international majors and other private companies do have opportunities to increase their share of global production. As long as the oil price remains relatively high, these companies can develop resources at the higher end of the international cost curve, which play to their strengths and technical expertise. Resources in this category are more generally accessible. International majors and other private companies are also able to apply knowledge gained from North America in other countries that have unconventional resource potential. The estimates for oil production by company type suggest that majors and other private companies are set to increase their share of global production from 40% today to 45% in 2020 (Figure 14.18). Over this period, which broadly coincides with the anticipated rise and plateau of non-OPEC production, they would account for all of the anticipated growth in global production.

**Figure 14.18 ▷ Oil production by company type in the New Policies Scenario**




Note: The projections assume no change in the ownership of reserves.

Source: IEA analysis based on Rystad Energy SA.

In the longer term, as growth in output from unconventional oil slows and production from private companies' conventional assets declines, the trends are reversed. NOC access to the world's largest, lowest-cost conventional oil resources underpins an expansion in their share of global production, from 39% to 43% (excluding INOCs) between 2020 and 2035 in the New Policies Scenario. This process would be accompanied in some countries by opportunities for new partnerships between NOCs and international companies, to marry the resources of the former with the expertise and investment capital of the latter.

## Investment

We estimate that the total investment required in upstream oil activities for the period from 2013 to 2035 is around \$9.4 trillion (in year-2012 dollars) in the New Policies Scenario (Table 14.7). If upstream investment in natural gas is included, the cumulative total rises to more than \$15 trillion. This means an annual average upstream spend, for oil and gas, of \$660 billion per year, to provide the capacity needed to meet growing demand and to offset decline at existing fields, allowing for the higher capital cost of exploiting more technically-challenging sources of supply, such as deepwater and unconventional projects in non-OPEC countries. The overall total allows, also, for increased unit upstream costs for exploration and development, partly offset by technology learning.

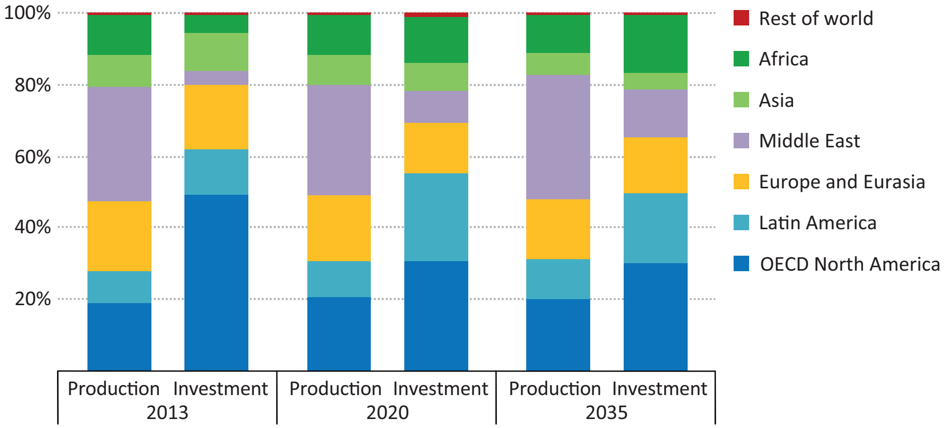
**Table 14.7 ▷ Cumulative investment in upstream oil and gas supply by region in the New Policies Scenario, 2013-2035** ($2012 billion)

| | Cumulative total | | Annual average |
|---|---|---|---|
| | Oil | Gas | |
| **OECD** | **3 354** | **2 383** | **249** |
| Americas | 2 826 | 1 645 | 194 |
| United States | 2 060 | 1276 | 145 |
| Europe | 450 | 562 | 44 |
| Asia Oceania | 77 | 176 | 11 |
| **Non-OECD** | **6 041** | **3 331** | **407** |
| E. Europe/Eurasia | 1 180 | 937 | 92 |
| Russia | 739 | 610 | 59 |
| Asia | 664 | 972 | 71 |
| China | 422 | 347 | 33 |
| India | 59 | 117 | 8 |
| Middle East | 872 | 245 | 49 |
| Africa | 1 507 | 711 | 96 |
| Latin America | 1 818 | 466 | 99 |
| Brazil | 1 270 | 118 | 60 |
| **World** | **9 394** | **5 714** | **657** |

Looking at the upstream investment requirement on a regional basis, the amounts required are not at all proportional to the volumes of oil that the respective regions are anticipated to produce (Figure 14.19), because of large regional differences in unit development costs and decline rates. In the Middle East, the capital intensity of production and the decline rates for production at existing fields are the lowest in the world; as a result, the share of this region in global upstream investment is considerably lower than its share in production. The Middle East's share in total production rises by three percentage points to 2035 (reflecting the increasing reliance on large Middle East resource-holders in meeting global demand in the latter part of the projection period), but it is noteworthy that their share in total investment grows by ten percentage points. This reflects a gradual rise in the region's unit production costs, as the easiest resources are depleted and operators move on to tackle more difficult and expansive accumulations.

North America, by contrast, the current location for half of the world's upstream investment in oil, is responsible for only one-fifth of output, reflecting the fact that the resources being developed in this region, notably the Canadian oil sands and LTO in the United States, are relatively expensive to produce. The share of investment in North America stabilises at around 30% of the global total in the projections, but remains high relative to the region's level of production. South America's global share of capital expenditures rises sharply in the period to 2020, as production in Brazil ramps up.

**Figure 14.19 ▷ Global share of oil production and investment by region in the New Policies Scenario**




The required level of investment is within the capacity of the industry to deliver. Based on analysis of the spending plans of seventy leading upstream companies, we estimate that total upstream oil and gas spending in 2013 will be around $710 billion, a year-on-year increase of 6% and a record high for a fourth consecutive year (Table 14.8).[23] This is above the average level required between 2013 and 2035 in the New Policies Scenario. In the projections, the required level of annual upstream spending is close to $700 billion in the first part of the projection period, but dips slightly in the latter part, when lower cost OPEC Middle East countries start to deliver most of the production increases.

Annual global upstream oil and gas investment increased in real terms almost three times between 2000 and 2013 (Figure 14.20). The trend of rising spending has been supported by the high oil prices which have prevailed since 2008, which increase the potential return on investment, and the rising cost of projects, of which a growing share has been unconventional. Part of the increase also reflects higher unit costs for exploration and development, taking into account the 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.

As outlined in the analysis of supply cost in Chapter 13, the World Energy Model anticipates a further evolution in costs over the projection period. On the one hand, there are new and improved technologies that tend to reduce capital and operating costs over time. On the other, there are increases associated with the need to develop more difficult and expensive (and generally smaller) reservoirs, as oil resources in various countries and regions are depleted. There are also cost pressures that are related to the oil price, following the logic that high prices tend to push up supply and service costs, as companies in that sector try to capture a larger share of the rent. The net result in the New Policies Scenario is an increase

23. These investment trends are based on the announced plans of 70 oil and gas companies. Total upstream investment is calculated by adjusting upwards their spending according to their share of world oil and gas production for each year.

**Table 14.8 ▷ Oil and gas industry investment by company** (nominal dollars)

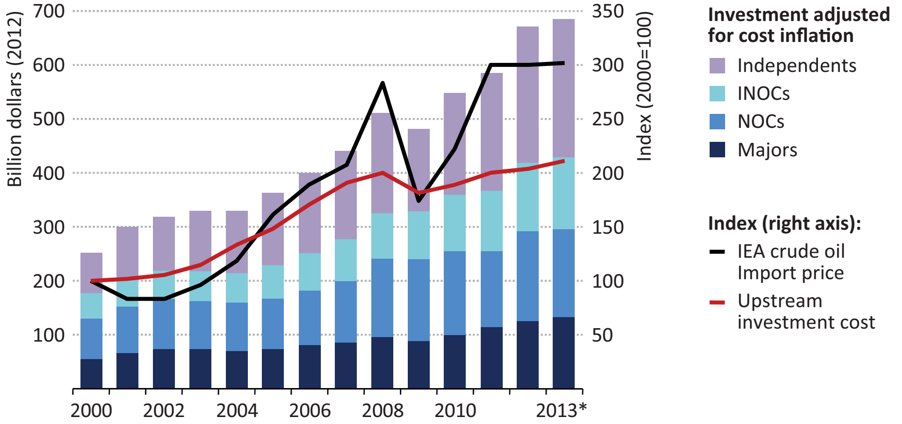
| | Upstream | | | Total | | |
|---|---|---|---|---|---|---|
| | 2012 ($ billion) | 2013 ($ billion) | Change 2012/2013 | 2012 ($ billion) | 2013 ($ billion) | Change 2012/2013 |
| Petrochina | 36.2 | 38.5 | 6% | 56.6 | 57.0 | 1% |
| Petrobras | 24.5 | 30.5 | 24% | 42.9 | 47.3 | 10% |
| ExxonMobil | 36.1 | 37.2 | 3% | 39.8 | 41.0 | 3% |
| Gazprom | 38.5 | 35.6 | -7% | 43.2 | 40.0 | -7% |
| Chevron | 27.5 | 33.0 | 20% | 30.9 | 36.7 | 19% |
| Royal Dutch Shell | 25.3 | 28.0 | 11% | 29.8 | 33.0 | 11% |
| Sinopec | 12.7 | 13.7 | 8% | 27.1 | 29.2 | 8% |
| Total | 19.0 | 22.4 | 18% | 23.8 | 28.0 | 18% |
| Pemex | 19.7 | 20.0 | 1% | 23.6 | 25.3 | 7% |
| BP | 18.3 | 19.5 | 7% | 23.1 | 25.0 | 8% |
| Rosneft | 8.6 | 11.5 | 34% | 14.9 | 20.0 | 34% |
| Statoil | 16.4 | 17.3 | 6% | 18.0 | 19.0 | 6% |
| Eni | 13.5 | 13.3 | -1% | 17.7 | 17.5 | -1% |
| ConocoPhillips | 14.2 | 14.3 | 1% | 15.7 | 15.8 | 1% |
| Lukoil | 8.9 | 12.0 | 35% | 11.6 | 15.7 | 35% |
| CNOOC | 8.5 | 12.9 | 51% | 8.6 | 13.0 | 51% |
| BG Group | 11.0 | 11.7 | 6% | 11.3 | 12.0 | 6% |
| Apache | 9.0 | 9.9 | 10% | 9.5 | 10.5 | 10% |
| Occidental | 8.2 | 7.7 | -6% | 10.2 | 9.6 | -6% |
| Chesapeake | 12.2 | 6.4 | -48% | 14.6 | 7.6 | -48% |
| Anadarko | 5.8 | 6.7 | 14% | 7.3 | 7.4 | 1% |
| Suncor Energy Inc. | 5.6 | 5.9 | 6% | 6.3 | 7.2 | 13% |
| Devon Energy Corp | 7.3 | 5.5 | -24% | 8.2 | 6.7 | -19% |
| Repsol YPF | 3.3 | 3.4 | 5% | 4.3 | 4.5 | 5% |
| EnCana | 3.3 | 3.0 | -9% | 3.5 | 3.1 | -11% |
| Sub-total 25 | 393.8 | 420.0 | 7% | 502.7 | 532.0 | 6% |
| Total 70 companies | 541.3 | 572.8 | 6% | n.a | n.a. | n.a. |
| **World** | **669.6** | **708.6** | **6%** | **n.a.** | **n.a.** | **n.a.** |

Notes: Only publicly available data have been included (IEA databases include both public and non-public estimates for all major oil and gas producing companies). The world total for upstream investment is derived by prorating upwards the spending of the 70 leading companies, according to their estimated share of oil and gas production in each year. Pipeline investment by Gazprom is classified as upstream, as it is required for the viability of projects. The "Total" column includes both upstream and downstream, as well as other investments (such as petrochemicals, power generation and distribution) for a few companies for which a breakdown is not publicly available. The 2013 figures are based on mid-year budgeted spending plans. The figure for Rosneft includes TNK-BP's 2013 spending plan; the one for CNOOC excludes Nexen's proposed spending.

Sources: Company reports and announcements; IEA analysis.

in real costs over the projection period. This tendency towards increased costs might be expected to lead to a rising figure for annual investment over the projection period. In practice, though, it is more than counter-balanced over the projection period as a whole by the growing share of production anticipated to come from the Middle East, where both direct costs and the cost of capital – either NOC cash flow or government funds – are the lowest. This explains why the projected annual investment requirement (which averages $660 billion) shows a slight decline in the latter part of the projection period.

**Figure 14.20 ▹ Worldwide 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.

Sources: IEA databases and analysis based on industry sources.

Although industry has already demonstrated the ability to invest at the required level, its capacity to do so over a period of decades is subject to a number of potential barriers. As described earlier, there is something of a two-paced approach to investment over the coming decades. In the initial period, which lasts until the early 2020s, the incremental barrel brought to market tends to come from investments made by private companies – broadly in line with the gradual expansion of non-OPEC supply. This puts the accent over this period on ensuring appropriate conditions and incentives that allow this investment to take place in a timely way, whether related to fiscal terms, licensing arrangements or other regulatory arrangements, such as local content requirements.

These elements continue to be important in the longer term but, as reliance for satisfying the additional barrel of demand switches over in the 2020s more towards national oil companies, notably those of OPEC countries, some additional considerations come more firmly into play. These include the depletion policies of major resource-owning countries, rising government call on oil revenue in some major producing countries and the related possibility that oil revenues could be so apportioned as to leave the upstream short of capital for investment. Among the other factors that could affect investment flows, political instability and other political considerations provide an unpredictable, but ever-present, backdrop to the decisions to be made about commitments of upstream capital. The conflict in Syria and the economic sanctions imposed by the United States and the European Union on Iran provide two current examples. More broadly, though, an increasingly potent constraint faced by the industry as a whole (and which remains, at least partly, within its power to address) is the availability of sufficient skilled employees (Box 14.5). The looming shortage of key personnel stems from a downturn in the hiring cycle from the 1980s until the mid-1990s – a consequence, in part, of low oil prices over this period – that essentially skipped a generation of employees. Had those human resources joined and remained in the industry, they would now have the experience needed to replace an older generation approaching retirement. The industry has to confront and manage this gap in available expertise if it is to keep operating at the demanding pace indicated here.

### Box 14.5 ▷ Staffing the oil and gas business

Sufficient availability of skilled personnel – geologists, geophysicists, reservoir engineers, drilling and completion engineers, and production engineers, among others – is a vital condition that has to be met for the projections in the *Outlook* to be realised. This cannot be taken for granted. The oil and gas industry currently has a high level of vacancies in key disciplines and is confronted with an expertise gap, resulting from uneven past hiring cycles and a high rate of attrition among its oldest and most experienced employees (SBC, 2012).

According to a recent survey of companies operating in the North Sea, over 70% reported difficulties in recruiting qualified candidates (OGP, 2013). On a regional basis, the largest deficits in skilled personnel are in North America, Africa and the Middle East, with the situation perhaps most pressing in sub-Saharan Africa, where around three-quarters of the targets for recruitment from universities in the region are presently unmet. In the United States, the pool of talent from universities is sufficiently deep, but over 60% of post-bachelor graduates are non-US citizens and often leave the country after graduation (SBC, 2012). While companies have stepped up their recruiting efforts in the last few years, it takes time (ten to fifteen years on average) for new recruits to gain sufficient experience to take on leadership positions. Concerns over climate change and environmental issues exacerbate the recruitment challenges faced by the industry in some countries, emphasising the self-interested need for oil companies to demonstrate clearly their social and environmental credentials.

The result of staffing difficulties can be felt in higher costs or in project delays – or, potentially, in the quality of project implementation. All of these could have an impact on our projections and the latter could have potentially very serious consequences for an industry under increasingly strict scrutiny for its environmental performance. Against this background - and until the new recruits come through into more senior positions –companies have to be imaginative: they can outsource, seek to standardise projects in a way that reduces learning times, or invest in new technologies that relieve pressure on existing personnel.

Chapter 15

# Prospects for oil demand

## Growth in a narrowing set of markets

### Highlights

- Demand for oil grows from 87.4 mb/d in 2012 to 101.4 mb/d in 2035 in the New Policies Scenario, but the pace of growth slows steadily, from an average increase of 1 mb/d per year in the period to 2020 to an average of only 400 kb/d in the subsequent years to 2035. This is mainly due to new efficiency policies and fuel switching in OECD countries, where the decline in oil demand accelerates. In 2035, the OECD share of global oil demand falls to one-third, from just under half today.

- Oil use in China increases the most in volume terms, rising by around 6 mb/d to reach almost 16 mb/d, with China overtaking the United States as the largest oil consumer by around 2030. But expanding demand for mobility and for freight transport sees India emerge as a key centre of oil consumption, especially in the period after 2020, when it becomes the largest single source of oil demand growth.

- The Middle East becomes the third-largest centre of oil demand, at 10 mb/d in 2035. The rise in consumption is underpinned by a fast-growing population and subsidies to oil consumption, which were equivalent to $520/person in 2012. Demand growth comes from transport (2.2 mb/d) and the petrochemicals sector (1.1 mb/d). Oil use for electricity generation eventually tails off, as the almost $200/MWh cost of oil-for-power (at international oil prices) is high enough to make all other technologies competitive.

- At global level, oil consumption is increasingly concentrated in just two sectors: transport – where oil use grows by 12 mb/d to close to 60 mb/d in 2035 – and petrochemicals (most of which is feedstock), which sees an increase of more than 3 mb/d. Energy efficiency improvements contribute significantly to curbing oil demand growth and alternatives to oil are also gaining ground, in particular in road transport and shipping: the share of natural gas in transport energy use reaches 5.6% by 2035, up from 3.8% today.

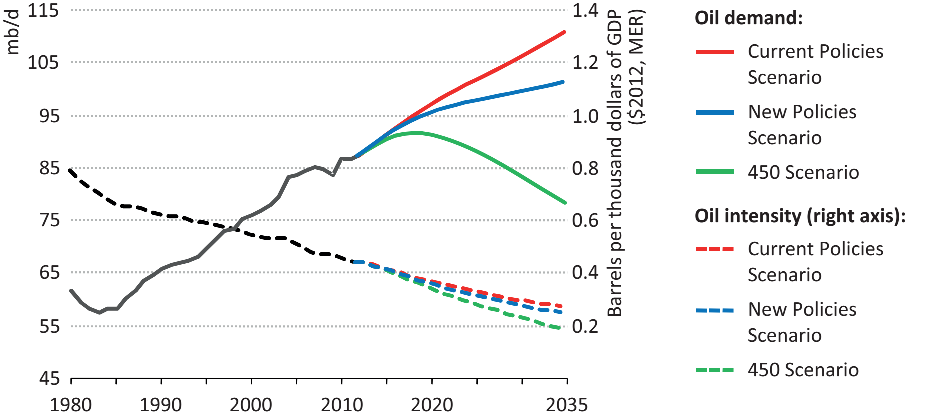
- Oil use as a feedstock for petrochemicals rises to 14 mb/d by 2035. Petrochemicals output in the Middle East and in North America expands, helped by local availability of ethane, resulting from the large rise in production of natural gas liquids. China also sees a large rise in petrochemicals output, using both oil and coal as feedstock.

- Among oil products, demand growth is concentrated in the middle distillates. Across all sectors, diesel sees by far the largest increase in volume terms, rising by more than 5 mb/d to 31 mb/d between 2012 and 2035, compared with a rise in gasoline consumption of 2 mb/d. All of the net increase in diesel demand comes from the road-transport sector in non-OECD countries.

## Global oil demand trends

The relationship between growth in economic activity and in oil demand continues to weaken over the coming decades, as oil use becomes more efficient and substitutes for oil start to eat into its position in the global energy market. The share of oil in the energy mix falls in all three scenarios examined in this *Outlook* over the period to 2035. But the speed at which this change takes effect remains contingent on the policies adopted by governments around the world. For this reason, the actual trajectory for oil demand differs substantially between the three scenarios (Figure 15.1). Additional actions to curb demand are strongest in the 450 Scenario, with the result that global consumption starts to decline by around 2020. Measures adopted in the New Policies Scenario have a less dramatic impact, but still put a measurable brake on consumption growth, compared with the Current Policies Scenario. Demand in the New Policies Scenario reaches 101.4 million barrels per day (mb/d) in 2035 – 14 mb/d higher than in 2012.[1]

**Figure 15.1 ▷ World oil demand and oil intensity by scenario**




Note: MER = market exchange rate.

The average IEA crude import price – used in our analysis as a proxy for the international oil price – was $109 in 2012, just shy of the annual average record price seen in 2011. Even though underlying economic and demographic factors tend to push global oil consumption higher, prices at these levels create incentives for consumers to moderate their demand for oil or to switch away from it entirely, if they can – at least in those countries where consumers are not shielded by subsidies that keep prices artificially low (see focus on the Middle East). High prices can also stimulate governments to implement policies promoting more efficient oil use and to reduce subsidies, where these are in place. In

1. The preliminary data so far available for 2012 relate only to total oil demand. The sectoral breakdown of demand is available up to and including 2011. All sectoral oil demand data presented for 2012 are therefore estimated. Oil demand projections in the World Energy Model at sectoral and product demand level are done using energy units (million tonnes of oil equivalent). They are then converted into volumetric units, using product specific conversion factors, which we have reviewed and revised as part of our more detailed work in *WEO-2013* on oil product demand.

the Current Policies Scenario, reactions by governments are weak or absent (in line with the overall assumptions for this scenario, see Chapter 1), meaning that a higher price is required to keep supply and demand in long-term balance – $145/barrel (in year-2012 dollars). In the New Policies Scenario, there is a stronger response, resulting in a different market equilibrium and an oil price of $128/barrel in 2035. In the 450 Scenario, strong policy intervention to curb demand results in a decline in the international oil price to $100/barrel in 2035; governments are assumed to act in this scenario to keep oil products prices to final consumers at higher levels through higher taxes and subsidy removal.

**Table 15.1 ▷ Oil and total liquids demand by scenario** (mb/d)

| | | | New Policies | | Current Policies | | 450 Scenario | |
|---|---|---|---|---|---|---|---|---|
| | 2000 | 2012 | 2020 | 2035 | 2020 | 2035 | 2020 | 2035 |
| OECD | 44.6 | 40.8 | 39.4 | 32.8 | 40.1 | 37.1 | 38.0 | 24.9 |
| Non-OECD | 26.5 | 39.6 | 48.3 | 59.2 | 49.2 | 64.2 | 45.6 | 45.6 |
| Bunkers* | 5.2 | 7.0 | 7.8 | 9.3 | 7.8 | 9.7 | 7.5 | 7.7 |
| **World oil** | **76.3** | **87.4** | **95.4** | **101.4** | **97.1** | **111.0** | **91.1** | **78.2** |
| World biofuels** | 0.2 | 1.3 | 2.1 | 4.1 | 1.9 | 3.3 | 2.6 | 7.7 |
| **World total liquids** | **76.5** | **88.7** | **97.6** | **105.5** | **98.9** | **114.3** | **93.8** | **85.9** |

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

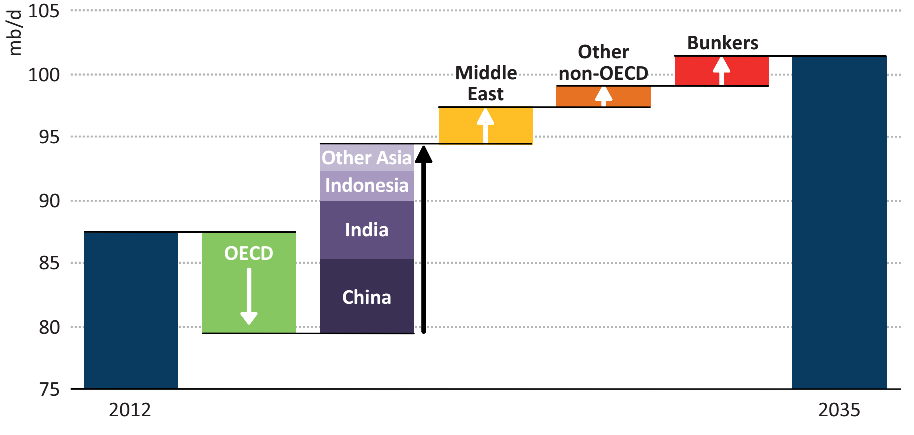
## *Oil demand by region*

In the New Policies Scenario, the annual increase in demand averages around 1 mb/d per year until 2020, but this growth slows significantly thereafter, to an average of some 400 thousand barrels per day (kb/d) per year in the period to 2035, as policies affecting oil consumption (such as new fuel-efficiency standards in OECD) start to have widespread impacts and demand growth starts to level off in major non-OECD consuming countries, notably in China (Table 15.2). The countervailing pressures on oil consumption balance out differently inside and outside the OECD. In the OECD, demand for oil declines as efficiency gains and fuel switching outweigh the impact of economic and population growth. Outside the OECD, the situation is reversed, with increases in demand for personal mobility and freight outpacing projected efficiency gains.

OECD oil demand trends are broadly similar to those of the *World Energy Outlook 2012* (*WEO-2012*), although some revisions have been made on a regional and country level. US oil demand was revised upward due to higher growth expectations in industrial activity especially in the medium term and a slightly more cautious outlook for biofuels following the downward revisions by the US Environmental Protection Agency to short-term biofuels quotas under the Renewable Fuel Standard. For Europe, a lower short-term outlook feeds through into lower long-term demand growth.

In line with the trends seen in previous *Outlooks*, the centre of gravity of oil demand growth continues to move towards developing Asia, which accounts for almost two-thirds of the gross increase in demand over the projection period (Figure 15.2). China's oil demand grows most in absolute terms, by 6 mb/d to almost 16 mb/d over 2012-2035, but the pace of China's oil demand growth lessens significantly over time, going from 3.7% per year on average over the period to 2020 to an average of 1.3% per year thereafter. This is related in part to a slowing pace of economic and population growth, but the dynamics of the Chinese transport sector – the main oil-consuming sector – also play a role. Although passenger light-duty vehicle (PLDV) ownership in China in 2035, at a little over 300 vehicles per 1 000 inhabitants, is still far lower than the OECD average of around 540, saturation effects are likely to begin to appear in some regions, mostly in the richer provinces in the coastal areas, while expansion of private vehicle use in other regions is likely to become more and more constrained by the pace at which road infrastructure can develop. Nonetheless China becomes the largest oil market by around 2030, overtaking a US market where consumption peaks at 17.7 mb/d before 2020 and where efficiency policies in road transport and diversification away from oil across all sectors subsequently bring demand down 20% below this level by 2035.

**Figure 15.2 ▹ Growth in world oil demand by region in the New Policies Scenario, 2012-2035**




For the projection period as a whole, demand in India grows at the fastest average rate (at 3.6% per year), representing the largest absolute increase after China. The size of the oil market in India is expected to overtake that of Japan before 2020. Between 2020 and 2035, the volumetric growth in Indian demand is larger than that of China. The volumetric growth in demand in India and Southeast Asian countries combined over this period is almost 75% larger than the expected growth in China, as their economies grow faster and rising incomes per capita spur vehicle ownership (which grows from a lower base than in China). The Middle East, the subject for more detailed analysis in the next section, is also expected to see very significant growth in demand: its domestic oil consumption reaches the level of the European Union before 2030, despite having a population only half the size and an economy only one-fifth of the size of the European Union by that time.

**Table 15.2 ▷ Oil demand by region in the New Policies Scenario** (mb/d)

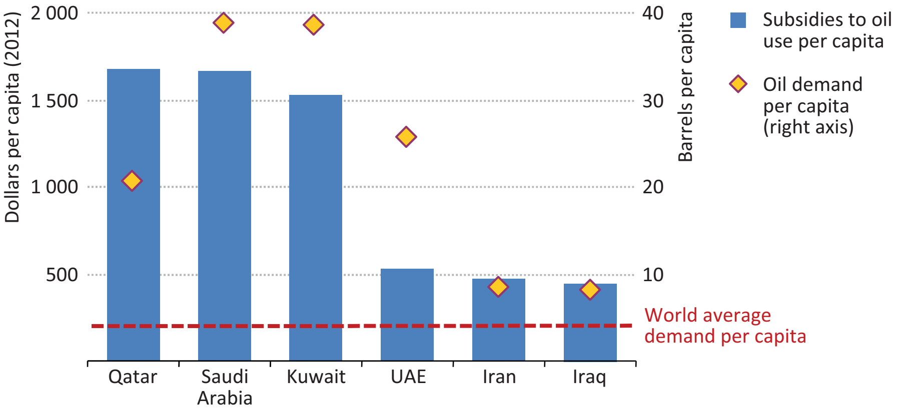
| | 2000 | 2012 | 2020 | 2025 | 2030 | 2035 | 2012-2035 | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | Delta | CAAGR* |
| **OECD** | **44.6** | **40.8** | **39.4** | **37.3** | **34.9** | **32.8** | **-8.0** | **-0.9%** |
| Americas | 22.7 | 21.3 | 21.9 | 20.8 | 19.6 | 18.4 | -2.9 | -0.6% |
| United States | 18.7 | 17.1 | 17.5 | 16.4 | 15.1 | 14.0 | -3.1 | -0.9% |
| Europe | 13.7 | 11.7 | 10.9 | 10.2 | 9.4 | 8.9 | -2.9 | -1.2% |
| Asia Oceania | 8.2 | 7.8 | 6.7 | 6.3 | 5.9 | 5.5 | -2.2 | -1.5% |
| Japan | 5.3 | 4.7 | 3.6 | 3.3 | 3.0 | 2.8 | -1.8 | -2.2% |
| **Non-OECD** | **26.5** | **39.6** | **48.3** | **52.3** | **55.8** | **59.2** | **19.6** | **1.8%** |
| E. Europe/Eurasia | 4.2 | 4.7 | 5.1 | 5.2 | 5.3 | 5.4 | 0.7 | 0.6% |
| Russia | 2.6 | 2.9 | 3.1 | 3.1 | 3.2 | 3.2 | 0.3 | 0.4% |
| Asia | 11.5 | 19.3 | 24.8 | 27.6 | 30.1 | 32.5 | 13.2 | 2.3% |
| China | 4.7 | 9.6 | 12.9 | 14.1 | 15.0 | 15.6 | 6.0 | 2.1% |
| India | 2.3 | 3.6 | 4.7 | 5.7 | 6.9 | 8.1 | 4.5 | 3.6% |
| Middle East | 4.3 | 6.9 | 8.2 | 8.7 | 9.3 | 9.9 | 2.9 | 1.6% |
| Africa | 2.2 | 3.4 | 4.0 | 4.2 | 4.4 | 4.6 | 1.2 | 1.3% |
| Latin America | 4.2 | 5.3 | 6.2 | 6.5 | 6.7 | 6.9 | 1.5 | 1.1% |
| Brazil | 1.8 | 2.4 | 2.9 | 3.1 | 3.3 | 3.4 | 1.0 | 1.6% |
| Bunkers** | 5.2 | 7.0 | 7.8 | 8.3 | 8.8 | 9.3 | 2.4 | 1.3% |
| **World oil** | **76.3** | **87.4** | **95.4** | **97.8** | **99.5** | **101.4** | **14.0** | **0.6%** |
| European Union | n.a. | 10.9 | 9.9 | 9.1 | 8.3 | 7.7 | -3.2 | -1.5% |
| World biofuels*** | 0.2 | 1.3 | 2.1 | 2.7 | 3.4 | 4.1 | 2.8 | 5.0% |
| **World total liquids** | **76.5** | **88.7** | **97.6** | **100.5** | **102.9** | **105.5** | **16.8** | **0.8%** |

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

## *Focus on the Middle East*

Alongside its long-standing role as the fulcrum of global oil production, the Middle East is rapidly becoming one of the main centres of oil demand. Since 2000, oil consumption in the region has risen by 2.6 mb/d, reaching 6.9 mb/d in 2012, accounting for almost one-quarter of the net increase in global demand. At 4%, the average annual growth in oil consumption over this period was not far behind that of China (6.2%), although the starting point for oil demand per capita in the Middle East, at nearly 10 barrels per year in 2000, was already more than double the global average. Today's oil consumption per capita in the Middle East as a whole is 50% higher than in the European Union and on a converging path with the United States, despite the fact that average incomes are much lower. The average figure for the Middle East conceals some wide variations within the region: per-capita oil consumption in Saudi Arabia, for example, is around 39 barrels/person/year (or some 17 litres/person/day), followed by the United Arab Emirates at 26 barrels/person/year, while the figure for Iraq and Iran is around 8 barrels and that for Yemen just above 2 (Figure 15.3).

**Figure 15.3 ▷ Oil consumption subsidies and oil demand per capita by selected countries in the Middle East, 2012**



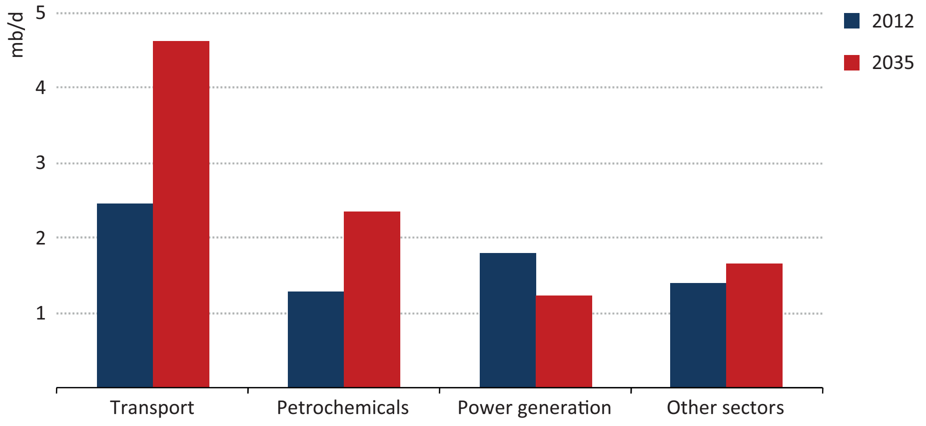

The rapid increase in oil demand in the Middle East has been underpinned by subsidised oil product prices. Gasoline and diesel prices across the region are among the lowest in the world and other oil products are also sold at prices well below their international market value, the benchmark for our calculation of subsidy values. We estimate that the cost of the subsidies provided in the Middle East for oil products in 2012 was $112 billion (or 13% of oil-export revenues), with the largest share in Saudi Arabia, Iran and Iraq. Expressed on a per-capita basis, oil consumption subsidies were equivalent to about $500/person in Iraq, Iran and the United Arab Emirates (UAE), and over $1 500/person in Kuwait, Saudi Arabia and Qatar. Adding in the subsidies provided to natural gas and electricity (most of which is generated by fossil fuels), the total for the region rises to $203 billion, representing almost 40% of global fossil-fuel consumption subsidies in 2012 (see Chapter 2).

Governments in the Middle East are becoming increasingly aware of the implications of fossil-fuel consumption subsidies, but removing these subsidies is a politically delicate matter. Iran announced a subsidy reform plan in 2010, designed gradually to replace subsidised prices by targeted assistance (both to households and to industry); but implementation has been patchy. The reform has been criticised for contributing to inflation and is complicated by the absence of good data on incomes, meaning that it has proved difficult to target assistance effectively; under the initial reform plan, over 90% of the population indicated their eligibility for aid. In Saudi Arabia, policy has been focused more on efforts to improve efficiency and to diversify away from oil than on reducing energy subsidies, but senior officials went on record in 2013 to express their concern about the implications for the national budget and the distortions that subsidies introduce into the national economy. Failure to reform the existing system has a high economic price.

Over the *Outlook* period, oil demand in the Middle East increases by 2.9 mb/d to reach almost 10 mb/d in 2035, fuelling a rapidly growing economy and responding to a 40% increase in population (Figure 15.4). Transport demand grows by over 2 mb/d, as the PLDV fleet expands by close to 2 million vehicles per year, at a rate similar to economic growth.

The fuel economy of the vehicle fleet improves at a slower rate than in other parts of the world, as subsidies continue to limit the incentive for consumers to switch to more efficient vehicles. At the extremely low gasoline prices prevailing in Saudi Arabia today, an investment in a more efficient car (consuming half the gasoline per 100 kilometres (km) of the average car on Saudi Arabia's roads today) would pay back only after almost twenty years. Preference for gasoline-fuelled cars over diesel persists over the *Outlook* period, and passenger transport grows faster than freight. As a result, road gasoline demand increases by 1.2 mb/d, 30% more than road diesel.

**Figure 15.4 ▷ Oil demand by sector in the Middle East**




Note: Other sectors include energy transformation, buildings, agriculture and non-energy use other than petrochemical feedstocks. Power generation includes oil use for new combined water desalination and power plants.

In an effort to diversify the reliance of their economies on fuel production, countries in the Middle East have started investing heavily in the petrochemicals sector (and in export refineries). Petrochemicals capacity in the region has doubled over the past five years and implementation of plans to continue this expansion will result in a doubling of oil use as feedstock and fuel over the *Outlook* period. By 2035, the use of oil in petrochemicals production is second only to its consumption in the transport sector and the share of those two areas in oil use jumps from just over half today to 70% in 2035.

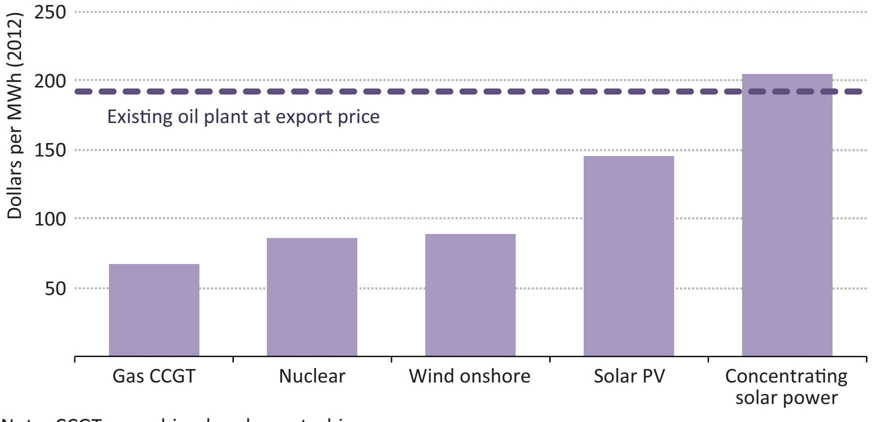
Efforts to diversify the Middle East power generation mix have not kept pace with soaring demand, meaning that large volumes of oil continue to be used for electricity generation – particularly during the summer months, when seasonal demand for air conditioning is at its highest. Outside the Middle East, the share of oil-fired plants in total power generation has become marginal, at 4% in 2012. But in the Middle East, these plants account for more than one-third of total power generation and absorb almost 2 mb/d of oil. With international oil prices above $100 per barrel, this is a very costly way of generating electricity: cheaper options are available, such as natural gas or some low- or zero-carbon technologies. At today's international prices, the cost of oil as a fuel to produce one megawatt-hour (MWh) of electricity is just below $200. This is not the cost paid by oil-

15

fired power plants in the Middle East, as the price they pay is heavily subsidised. But it is a cost that is borne by the economy at large. With an eye on the international market value that is forgone, authorities are seeking ways to switch away from oil in power generation whenever possible. When the benchmark is set by short-run marginal costs for oil-fired power around $200 per MWh, almost every alternative technology for power generation looks attractive (Figure 15.5).

Since 2000, oil use in the power sector has grown less than electricity demand, and the amount of new installed natural gas capacity has been four times larger than that of oil. Natural gas is an obvious choice for the Middle East, given the large size of the gas resource base (although its development is hindered by a relatively under-developed transmission and distribution network in many countries). With large volumes of associated gas anticipated from its huge southern oil fields, the Iraqi government plans a major shift over the coming decades away from oil-firing to more efficient gas-fired generation. The Government of Saudi Arabia is pursuing a broad range of diversification options in the power sector, encompassing not only natural gas but also renewables-based projects. The stated ambition is to generate between 150-190 terawatt-hours (TWh) of electricity from renewables by the early 2030s, with the largest contribution coming from concentrating solar power, followed by solar photovoltaics (PV), wind energy, waste-to-energy and some geothermal. Nuclear power is also being considered in the region: since 2012, the United Arab Emirates have started the construction of two out of the four reactors planned at the Barakah nuclear power plant.

**Figure 15.5 ▷ Electricity generating costs by technologies in the Middle East, 2015**



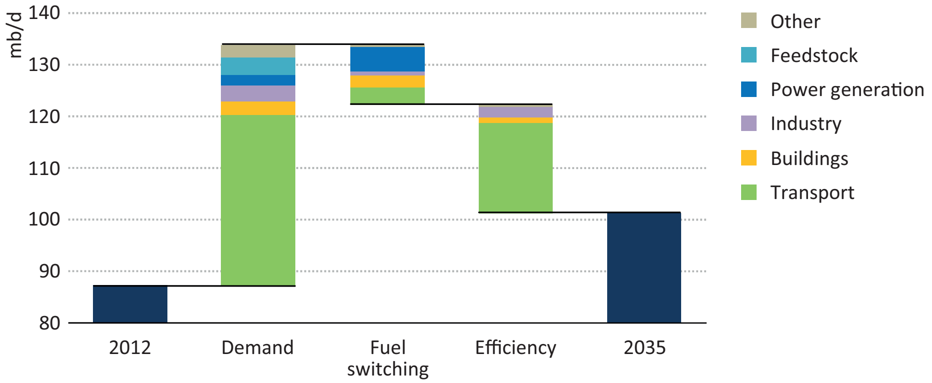

Note: CCGT = combined-cycle gas turbine.

In our projections, the Middle East makes progress with the diversification of its power mix. After continuing to rise during the current decade, output from oil-fired plants peaks before 2020 and is well below current levels by 2035. With oil use declining, natural gas accounts for the largest share of the growth in regional power generation, an increase of more than 700 TWh over the period to 2035, followed by renewable technologies (whose contribution grows by more than 200 TWh) and nuclear (a rise of 60 TWh). The costs of failure to substitute for oil in the power sector would be high, both for the region and for the world. Maintaining today's fuel mix would mean an extra 2 mb/d of oil being used in the Middle East's power sector by 2035, representing both a financial drain on the region's fiscal balances (although partly alleviated if oil prices increased correspondingly) and a diminution of its oil exports.

## Oil demand by sector

Oil demand responds in large part to three variables: the level of economic activity in each sector; the efficiency levels of the end-use transformation process; and the economical and commercial availability of alternatives to oil. Government levers act primarily on the latter two and they have increasingly been used to contain rapidly rising import expenditures, to diminish the environmental impact of oil use or, in some instances, to expand the country's ability to export oil. The measures introduced by governments range from efficiency standards to fuel pricing policy, from modal shifts in transport to encouraging fuel switching (Table 15.3). All these measures play a role in our oil demand projections, with improvement in efficiency being the most important in the New Policies Scenario (Figure 15.6). The increase in vehicle ownership, industrial activity and number of dwellings would imply, other things being equal, a growth in oil demand over the level in 2012 of 46 mb/d. But anticipated efficiency improvements, resulting from both policy interventions and technological improvements, curb 45% of this consumption growth while delivering the same level of service. Fuel switching also plays an important role, displacing almost 12 mb/d of oil consumption.

**Figure 15.6 ▷ Impact of fuel switching and efficiency on global oil demand in the New Policies Scenario**




The degree to which oil can be substituted varies according to the service demanded and sector concerned. Over the last few decades, oil has lost market share to other fuels in providing heating services in buildings and for power generation, for reasons of both cost and – except where replaced by coal – environmental impact. Today, oil meets only a small share of total energy use in these sectors and its share is expected to decline even further in the future.

**Table 15.3 ▷ New policies in 2012/2013 with a potential impact on oil demand**

| | Sector | New policy measures |
|---|---|---|
| **United States** | Transport efficiency | Intention announced to increase fuel-economy standards for heavy-duty vehicles beyond 2018. |
| | Industry | The Boiler MACT (Maximum Achievable Control Technology) Rule is an emissions standard that requires industrial, commercial and institutional boilers, and process heaters located at major sources to meet specific emissions limits for hazardous air pollutants. |
| **Canada** | Transport efficiency | Proposed extension of emissions standard for passenger and commercial light-duty vehicles beyond 2016, requiring an annual reduction in greenhouse-gas emissions of 3.5-5% to 2025. |
| **European Union** | Transport efficiency | Agreement on emissions standards for new cars of 95g $CO_2$/km by 2020. |
| | Transport fuel switch | Proposed Clean Fuel Strategy, with provision for certain levels of infrastructure for clean fuels. |
| **China** | Subsidies reform | Energy price reform, including more frequent adjustments in oil product prices and an increase in the price of natural gas by 15% for non-residential consumers. |
| | Industry | New large industrial facilities must satisfy energy efficiency assessments as well as environmental assessments. |
| **Brazil** | Transport efficiency | Inovar-Auto programme approved that requires car manufacturers to produce more efficient vehicles in order to qualify for a tax discount. |
| **India** | Subsidies reform | In January 2013, state fuel retailers were allowed to start increasing the price of diesel on a monthly basis until it reaches market levels and the price cap on liquefied petroleum gas cylinders was raised. Plans were adopted to nearly double natural gas prices from April 2014, and to revise them quarterly until 2017. |
| | Transport fuel switch | National Mission for Electric Mobility adopted, targeting 6-7 million vehicles on the road by 2020. |
| **Indonesia** | Subsidies reform | Increased price of gasoline by 44% and diesel by 22% in June 2013. Promotion of natural gas use in transport to reduce oil subsidies. Continuing successful kerosene-to-LPG conversion programme, which started in 2007. |
| **Iran** | Subsidies reform | In January 2013, subsidised gasoline for cars with engines of 1 800 cubic centimetres and above was discontinued, and sales of subsidised gasoline restricted near border areas. |

Nonetheless, today oil remains the dominant fuel in providing mobility, in particular in road transport, aviation and navigation. In the case of road transport, oil-based fuels still account for around 95% of total energy use – a share that is barely lower than in 1971 – due to practical and economic barriers to the deployment of alternative fuels. The industry sector also remains a substantial consumer of oil – one-fifth of global oil consumption – both as an energy source and for non-energy uses (mainly as a feedstock for production of petrochemicals).[2] In this section, we review the scope for substitution of oil in the different sectors and examine in more detail the prospects for oil use in transport and in petrochemicals.

**Table 15.4 ▷ Oil demand by sector in the New Policies Scenario** (mb/d)

| | 2000 | 2012 | 2020 | 2025 | 2030 | 2035 | 2012-2035 | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | Delta | CAAGR* |
| **Total primary oil demand** | **76.3** | **87.4** | **95.4** | **97.8** | **99.5** | **101.4** | **14.0** | **0.6%** |
| Power generation | 5.7 | 5.5 | 4.1 | 3.4 | 2.9 | 2.7 | -2.7 | -3.0% |
| Transport | 38.4 | 46.7 | 52.7 | 54.9 | 56.9 | 58.8 | 12.1 | 1.0% |
| Petrochemicals | 9.7 | 11.9 | 13.7 | 14.5 | 15.0 | 15.5 | 3.6 | 1.2% |
| of which feedstock | 8.2 | 10.6 | 12.4 | 13.1 | 13.6 | 14.1 | 3.5 | 1.2% |
| Other industry | 5.1 | 5.1 | 5.5 | 5.5 | 5.4 | 5.3 | 0.2 | 0.1% |
| Buildings | 7.9 | 7.6 | 7.5 | 7.2 | 6.9 | 6.6 | -1.0 | -0.6% |
| Other** | 9.5 | 10.6 | 12.0 | 12.2 | 12.4 | 12.4 | 1.8 | 0.7% |

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

Two sectors – transport and petrochemicals – drive growth in oil consumption out to 2035 (Table 15.4). Transport oil demand grows by 12 mb/d and consumption in the petrochemicals sector (most of it for feedstock purposes) rises by 3.6 mb/d. All other sectors (except non-energy use) are stable or in decline. All of the net increase in transport demand occurs in non-OECD countries; oil use for transport falls in all three OECD regions, thanks to efficiency gains and, to a lesser extent, switching to other fuels. By 2035, oil use in transport and in petrochemicals accounts for three-quarters of global consumption, six percentage points higher than their share today. Although transport accounts for the largest share (58%) in 2035, petrochemicals use (more than 15 mb/d in 2035) is larger than today's oil demand for all purposes in China, India and Indonesia combined.

## *Transport*

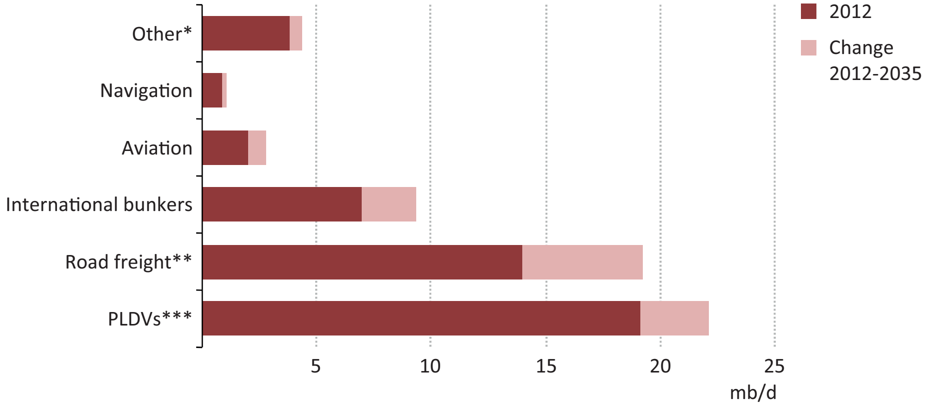
### *Modal trends*

PLDVs are the leading component of transport oil demand and this is projected to remain the case in 2035 in the New Policies Scenario, even though road freight and aviation grow at faster rates (Figure 15.7). Of the total increase in transport oil demand, PLDVs account for around one-quarter, as oil use by PLDVs rises from 19 mb/d in 2012 to 22 mb/d in 2035. Road freight accounts for nearly 45% of transport oil demand growth. Developing

2. In the remainder of the chapter, if not explicitly mentioned otherwise, oil use in the industry sector is understood to include the use of oil as a petrochemical feedstock.

Asia contributes around two-thirds of this growth. In energy tems one-third of global net oil demand growth arises from the use of oil in road freight trucks and light-commercial vehicles in developing Asia alone. Demand for international marine and aviation bunkers, predominantly heavy fuel oil and jet kerosene, grows at a rate of 1.3% per year, from 7 mb/d in 2012 to 9.3 mb/d in 2035 and accounts for about 20% of transport oil demand growth. Aviation accounts for another 7% of transport oil demand growth, its growth rate averaging 1.5% per year between 2012 and 2035, faster than that of any other mode of transport. [3]

**Figure 15.7 ▷ World oil demand for transport by sub-sector in the New Policies Scenario**



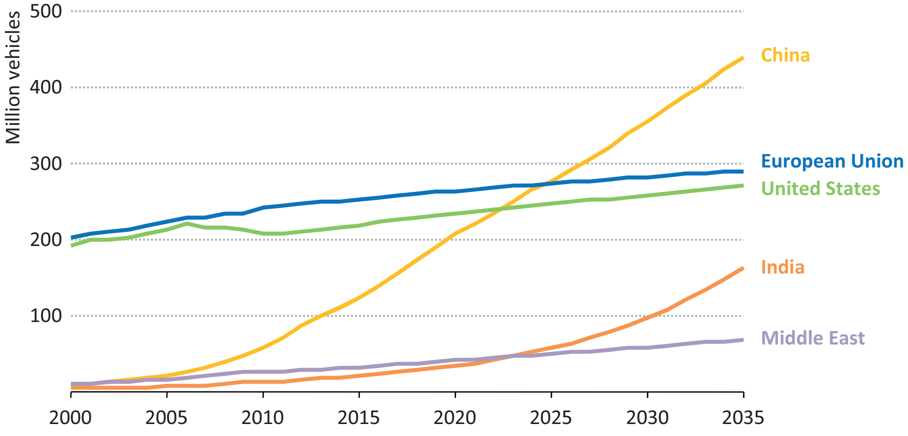

* Includes other road, rail, pipeline and non-specified transport. ** Includes light-commercial vehicles and freight trucks. *** Passenger light-duty vehicles.

Demand for oil to run PLDVs is determined not just by the underlying demand for personal mobility (which reveals itself in the number of vehicles in circulation and the average distance driven), but also by the choice of fuel or vehicle technology and the fuel efficiency of the vehicle. The PLDV fleet worldwide is projected to expand from around 900 million in 2012 to over 1.7 billion in 2035. Most of this growth comes from non-OECD countries (Figure 15.8), a trend which is also reflected in the figures for PLDV oil use across regions. These fall in all parts of the OECD, reflecting saturation of the car market, tightening fuel-economy standards and increasing fuel substitution; but they rise rapidly in many other parts of the world, alongside rising levels of car ownership. Most of these new cars are oil-powered (gasoline, diesel and liquefied petroleum gas [LPG]), but biofuels, natural gas and electricity claim a growing share of the PLDV stock over the projection period. Our projections incorporate major improvements in the fuel efficiency of PLDVs (including wider use of hybrid vehicles), stimulated by a combination of high international oil prices and

3. Aviation here refers to domestic aviation, *i.e.* it excludes international aviation. International aviation is referred to as international aviation bunkers in IEA statistics.

government initiatives (including the removal of subsidies, the imposition of fuel-economy standards and efficiency labelling, financial incentives, and research and development), which greatly reduce the overall increase in oil demand for road transport. The average PLDV on the road in 2035 in the New Policies Scenario consumes around 30% less fuel than today.

**Figure 15.8 ▷ PLDV vehicle fleet growth by region in the New Policies Scenario**




Oil consumption by road freight vehicles worldwide is boosted by rising economic activity and the more limited scope for switching away from oil-based fuels in heavy-duty vehicle (HDV) engines. Freight tonne-kilometres (freight-mass times the distance over which it is transported by road) is expected to remain correlated with economic growth. This link gradually weakens in some advanced OECD countries, but there are relatively few opportunities (via rail or inland waterways) to move freight off the road. Road freight demand for oil jumps from 14 mb/d in 2012 to more than 19 mb/d in 2035 in the New Policies Scenario. While improved fuel economy of HDVs means that fuel demand grows less rapidly than freight activity, the lack of targeted and well-designed efficiency policies to reduce fuel consumption in many countries is still a major barrier to a more widespread dampening of demand growth in this sector (IEA, 2012).

Oil use in road transport will continue to be dominated by gasoline and diesel. In the New Policies Scenario, the share of gasoline (used to a large extent in PLDVs) falls from 57% in 2012 to 50% in 2035 – while the share of diesel rises from 41% in 2012 to 47% in 2035 mainly because of the rapid rise in diesel use for HDVs. Autogas – LPG used as an automotive fuel – currently accounts for the remaining 1.6% of road-transport oil use, a share that is expected to increase only modestly over the *Outlook* period (see section on demand by product).

#### Box 15.1 ▷ Could the world ever fall out of love with the automobile?

In our projections, vehicle use (*i.e.* the kilometres driven per car) grows broadly in line with increasing income, moderated by price effects – the historical pattern. There is another school of thought, however, known as "peak car", which implies that car use will eventually peak – or has already peaked in some advanced economies. While the idea of peak car is not new, it has gained increasing attention in recent years, as statistical data in some countries (and especially in cities) indeed shows, at least, a reduction in the growth of car use (Goodwin, 2012).

Despite a great interest in this phenomenon, the forces at work are less well understood. While the changes observed in recent years may well be explained by the economic recession and increasing fuel prices, the reasons could be somewhat more structural and be explained by cultural, social and policy considerations. These include, but are not confined to: improved availability and comfort of public transport; greater reliance on social media; reactions to congestion; difficulties related to parking; and insurance and fuel costs. In some OECD countries, there may be a more general perceived decline in the attractiveness of suburban lifestyles and a desire to shift back into more concentrated urban living. Recent work on the demographics of licensed US drivers shows that the share of young people holding driving licenses is considerably lower than 30 years ago (Schoettle and Sivak, 2013) and that young people in the United States increasingly use alternative means of transportation, in part as a matter of preference (Davis and Dutzik, 2012).

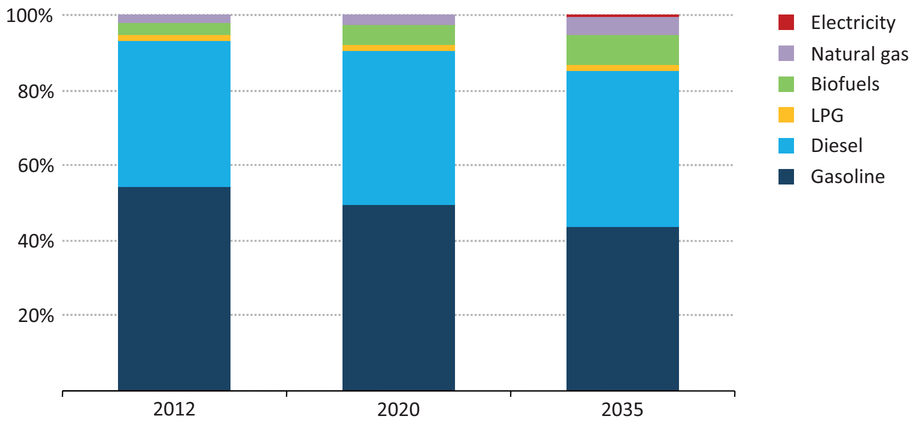
The question whether this phenomenon of peak car exists cannot easily be answered, and there is almost certainly not one single reason for the observed changes in car use patterns. But this topic deserves attention, particularly in advanced economies, as it could have an impact on projected levels of oil demand. In developing countries the projected pace of growth of the vehicle stock is probably of greater uncertainty to future oil demand than the extent of changes to the average level of car use: in the event that PLDV motorisation in non-OECD countries were to grow 1% faster per year than the projected level of 4.3%, then this would add 3.4 mb/d to the global oil consumption in 2035 (assuming all else equal). But the downside also holds true: if growth were 1% slower per year than projected, global oil demand in 2035 would be 2.7 mb/d lower.

### *The impact of alternative fuels on transport oil demand*

The rate of penetration of alternative fuels and technologies is a key factor affecting oil use in all modes of transport. While oil has been largely replaced in stationary uses of energy, it remains king in transport – partly because alternative fuels, for the most part, have so far proved unappealing to end-users. The leading alternative to petroleum fuels today is biofuels, their use being led by the United States and Brazil. In most cases they are blended into conventional gasoline or diesel, requiring no change to the vehicle if mixtures are kept within certain limits (see Chapter 6 and the special focus on Brazil, Chapters 9-12).

In the New Policies Scenario, we project biofuels use in road transport to expand from 1.3 million barrels of oil equivalent per day (mboe/d) in 2012 to 4.1 mboe/d in 2035. Their share of total road-transport energy use increases from 3% to 8% over the same period (Figure 15.9). The projections for biofuels in the New Policies Scenario are contingent on continued government support, largely through blending mandates and subsidies. But the use of biofuels has come under critical scrutiny in recent years in many countries, owing to the direct and indirect impacts on other agricultural uses for the land, uncertainty about the actual greenhouse-gas savings that biofuels offer, doubts about the feasibility of reaching supply targets in view of blending restrictions (*e.g.* the "blend wall" debate in the United States), the acceptability of biofuels to consumers, delays in achieving commercial feasibility of advanced biofuels and the costs associated with various forms of biofuels support. This has led us to revise our biofuels projections downward, compared with *WEO-2012*, although we have assumed that government support remains widespread.

**Figure 15.9 ▷ Fuel mix in road-transport energy demand in the New Policies Scenario**




Note: Shares for oil products are calculated on a volumetric basis; the contributions of other fuels are shown as equivalent volumes of the oil product that they displace.

Beyond biofuels, the main alternatives to oil as a transport fuel in the medium- to long-term are natural gas (in compressed or liquefied form) and electricity (in plug-in hybrids and battery-electric vehicles). Both options require a fundamental change in vehicle technology or refuelling infrastructure, or both. Another possibility is hydrogen used in fuel cells installed in the vehicle, but they do not play a significant role in meeting transport energy needs worldwide in the New Policies Scenario within the timeframe of our projections, given the technical and economic barriers.

Natural gas is currently seen as the most promising alternative, given the abundance of its availability, often at low prices. Moves are underway to use gas in various transport sectors. Liquefied natural gas (LNG) can be used as a locomotive fuel for trains: in North America, the General Electric and Caterpillar companies are developing a LNG-powered engine, and

BNSF – the largest rail company in the United States – is testing the technology. But, even if the results are positive, large-scale deployment will take time and volumes will be small, due to the small size of the rail market (global oil demand from rail was 0.6 mb/d in 2012). The use of LNG in rail is not expected to make a significant dent in oil demand over the projection period.

LNG can also be used as a fuel for maritime navigation. Stricter emissions regulations, as proposed by the International Maritime Organization (IMO), could stimulate a switch away from heavy fuel to alternatives, among which LNG is likely to be prominent. A new supply infrastructure would be required in the world's major ports, so, for the moment, we have adopted a cautious view about the extent of LNG use in the maritime sector. This reaches just over 5 billion cubic metres (bcm) in 2035, displacing 90 kb/d of oil.

In terms of volumes, road transport is the most attractive sector for the use of natural gas. Today, natural gas accounts for just 2% of total energy use in road transport, and this use is highly concentrated in just a few countries: Iran, Pakistan, Argentina, Brazil and India account for 68% of the global natural gas vehicle (NGV) fleet.[4] In most other countries, natural gas for transport use is minimal, but moves are afoot to expand its use, particularly in North America, where a large price differential with liquid fuels has emerged. Historical evidence from countries where NGVs successfully entered the market (such as Pakistan, Iran or India) or failed to do so (like New Zealand) suggest that, besides the availability of natural gas resources and/or an extensive network of gas pipelines, long-lasting and targeted policy support is essential in order to overcome initial hurdles to investment – including insufficient refuelling infrastructure and higher investment costs per vehicle. Our projections in the New Policies Scenario assume a generally supportive policy environment for NGVs, although this varies by country and region. Global sales of NGVs increase four-fold over the period to 2035 and the share of natural gas in the road-transport market reaches 2.8% in 2020 and 4.8% in 2035.

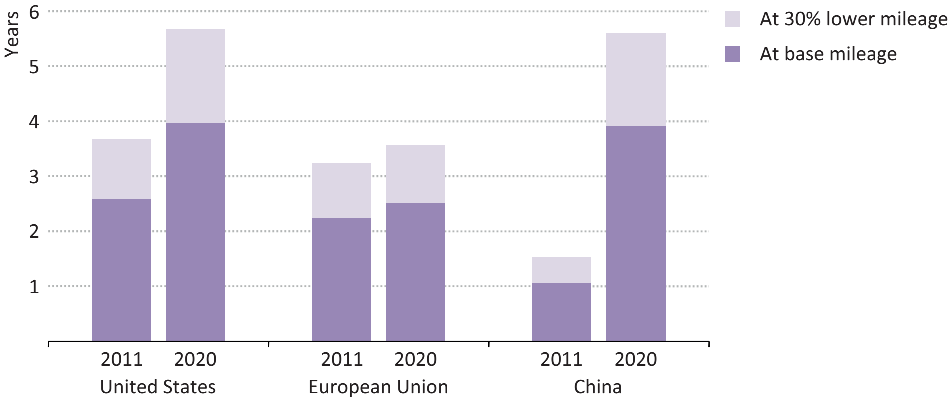
Natural gas can be used in liquefied form or as compressed natural gas (CNG) in road vehicles. Depending on the application, it would replace diesel (if used *e.g.* in trucks) or gasoline (if used in PLDVs). CNG has a lower energy density than LNG, making it a less attractive substitute for diesel in long-haul trucks, as the fuel tank occupies too much space and adds too much weight. LNG is therefore considered a more viable option than CNG for long-distance trucks, despite the higher upfront cost of building LNG refuelling infrastructure and the vehicle itself. CNG is often considered more attractive for PLDVs or local-service fleet applications, such as buses and refuse trucks (that can benefit from centralised refuelling), although the development of a refuelling network for PLDVs in densely populated regions, such as Europe, could, in theory, also facilitate an uptake of CNG for long-distance trucks.

In North America, growth in natural gas use for road transport is expected to come primarily, at least in an initial phase, from HDVs. Around half of all sales of new waste collection trucks and a large proportion of new buses in the United States today are CNG-fuelled, a share

4. Detailed statistics on NGV fleets can be found at *www.iangv.org/current-ngv-stats/*.

that is likely to climb further in the coming years. In addition, a number of North American road-haulage companies are considering switching to LNG as an alternative to diesel for long-haul trucking. In North America, LNG may be a financially attractive option, as the higher initial cost of an LNG truck, compared to a conventional vehicle (of up to $75 000), and the additional safety precautions and training required in using LNG can be recouped over time by the fuel-cost savings: the payback period is currently estimated at around two to four years for long-haul trucks, though it is sensitive to the number of miles travelled, the price differential between diesel and LNG, the incremental cost of the vehicle and its residual value (Figure 15.10). Such payback periods are attractive for large fleet operators with adequate financial means for the required upfront investment and who can justify investment in a centralised refuelling network. But, for many companies, shorter payback periods will probably be necessary to entice them to make the switch. In the United States, most trucking companies are very small, with limited financial resources and borrowing power, and so may be reluctant or simply unable to adopt what is still a relatively unproven technology.[5] Where trucks are often operated on average only six to eight years, payback periods must be low to justify the investment.

**Figure 15.10 ▷ Estimated payback periods of LNG-powered long-haul trucks in selected markets, 2011 and 2020**




Notes: Assumes annual base mileage of 200 000 km (United States), 130 000 km (European Union) and 160 000 km (China). Gas prices for the European Union and United States 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 an additional liquefaction cost of $3/MBtu for the United States. For China, LNG prices are assumed to be 60% of gasoline end-user prices for 2011, and 75% for 2020. The cost premium for LNG trucks is assumed to be $75 000 (United States), $55 000 (European Union) and $20 000 (China) in 2011. For China, it is assumed that this cost increment rises to EU levels in 2020 due to a transition from gasoline-type engines to diesel-type engines for LNG trucks. Generally, regional cost differences reflect different typical truck types and sizes; no subsidies are assumed.

The establishment of a viable LNG market in North America is hampered by a dilemma over investment (Box 15.2): who invests first, those building the infrastructure or those buying

5. According to the American Trucking Association, 97% of the more than 620 000 registered companies operate fewer than 20 trucks.

the vehicles? The business model being envisaged to solve this problem involves retailers building refuelling stations along corridors of major truck use, to limit initial infrastructure construction costs, and to target a small number of high-volume fuel users, such as large, long-distance fleet operators. Several partnerships between HDV fleet operators, including some leading courier companies and LNG retailers, have been announced recently and a number of refuelling points have already been built along some routes. Initial investment requirements for LNG refuelling stations can be significantly higher than those for diesel stations and, as the range of single-tank LNG trucks is, typically, only half of that of diesel trucks, the refuelling infrastructure density has to be higher than for conventional vehicles to accommodate large LNG truck fleets (TIAX, 2012).[6] Initial volumes are therefore set to be small, and regionally concentrated, but, if pilot programmes are successful, the market could grow rapidly in the coming years. We project LNG and CNG use in road transport to grow quickly in the United States, but it still accounts for just 0.7% of total fuel use in road transport in 2020, displacing around 70 kb/d of oil use, and 5% in 2035 (450 kb/d). Additional policy support for the deployment of NGVs, wider price differentials than we assume and/or lower NGV construction costs could lead to a much bigger shift to gas.

### Box 15.2 ▻ Of chickens, eggs, trucks and cars

A major barrier to the creation of a market for natural gas as a fuel for road vehicles is the classic chicken-and-egg dilemma: vehicle owners are discouraged from buying an NGV until refuelling stations are available, while potential fuel retailers are reluctant to invest in new gas fuel pumps until demand for the fuel is high enough to yield an acceptable return on investment. Other than through government intervention, overcoming this dilemma requires a gamble by either the retailers or consumers on the demand or supply materialising, or active collaboration between the retailers and large potential consumers to guarantee a market. This is easier in the case of HDVs, where large road-haulage companies can get together to agree with bulk fuel retailers on infrastructure investments. In the LDV market, there are more players on both the retail and vehicle sides, making co-ordination much harder, though large LDV fleet operators with high mileage and established routes may be able to negotiate a deal with one or more large retailers. Gas use in transport in new markets, such as the United States, is likely to be driven primarily by long-distance HDVs, which means that gas will probably be sold largely as LNG rather than CNG.

Natural gas has the potential to make significant inroads into oil use for road transport in China, too. The number of NGVs in China has increased sharply over the last few years, reaching around 2 million at the end of 2012, most of which were CNG light-duty vehicles (LDVs) – many of them taxis, which drive around 300 kilometres a day on average. But the use of LNG is also increasing: at end-2012, there were an estimated 71 000 LNG vehicles on the road in China and over 800 LNG refuelling stations. LNG trucks constitute about 60%

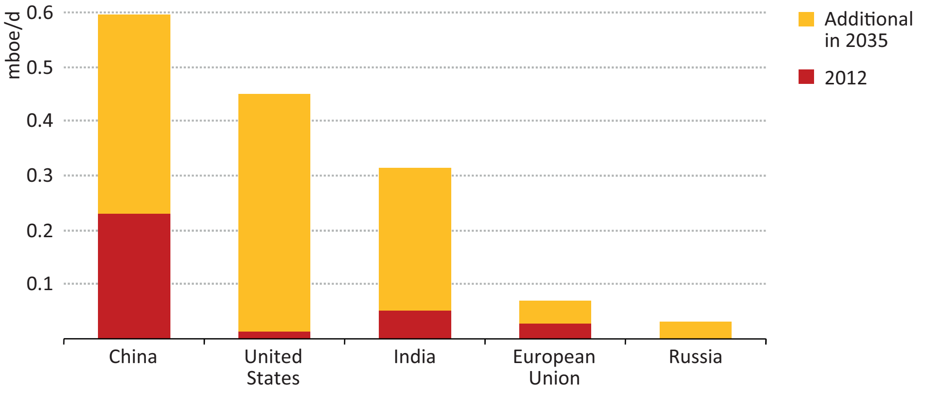
6. A possible solution is dual-tank trucks, but they carry significantly higher upfront investment costs.

of this stock, with much of the remainder being inter-city buses. The sales of LNG HDVs in China increased by 60% in 2012.

The purchase of an LNG long-haul truck in China breaks even after only about one to two years at current prices and average mileage, despite prevalent use of gasoline-type engines in China's LNG trucks today (which entails a very high fuel consumption penalty). For taxis, breakeven has been reported to be of the order of a few months only. However, payback periods are set to rise sharply with the current roll-out of gas-pricing reforms, which are expected to lead to a significant increase in natural gas prices in most regions. On an energy-equivalent basis, the cost of gas at present is around 60% of 90-RON gasoline, but the central government plans to raise this to around 75%. Nonetheless, the central government remains committed to the use of LNG in HDVs in order to curb the growth in oil demand and imports, for energy security reasons and, more urgently, to reduce tailpipe emissions of soot and other pollutants in response to worsening urban pollution. In addition, a growing number of provincial and city governments are providing financial support for LNG refuelling infrastructure and vehicle manufacturing.

In the New Policies Scenario, we project a continuing increase in China's use of natural gas for road transport through to 2020, driven mostly by CNG use in taxis and urban buses, but also by LNG use in HDVs. Demand grows more slowly thereafter, as we do not yet expect significant growth in CNG use in the passenger vehicle segment, which is the major segment of the growth in road-transport energy demand in the latter half of the projection period. By 2035, natural gas demand in China's road transport sector reaches almost 0.6 mboe/d, around three times higher than today's levels (Figure 15.11).

**Figure 15.11 ▷ Natural gas demand for road transport by selected regions in the New Policies Scenario**

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In Europe, gas use in transport is projected to grow more slowly than in the United States or China, despite policy moves to promote a range of alternative fuels and the fact that taxes on diesel and gasoline are high, implying a relatively low payback period on purchases of natural gas-fuelled vehicles. An estimated 14% of the 100 000 refuse trucks and urban buses in Europe already run on CNG and further penetration of this sector by gas is likely.

But the use of CNG in PLDVs at a larger scale is so far confined to a few countries like Italy or Sweden, as the lack of a widespread availability of refuelling stations reduces the attractiveness of CNG vehicle for many consumers.

There is significant potential for LNG in the European long-haul HDV fleet, which is still largely fuelled by diesel. But for LNG use to take off, the first requirement is a refuelling network along the main highways. At present, there are only 38 LNG refuelling stations in Europe, and creating such a network would require active government support, in the absence of industrial initiatives. In recognition of this, the European Commission proposed in January 2013 an ambitious package of measures to encourage the development of alternative fuel stations across Europe, including LNG refuelling stations. It is now preparing a directive, but, as this is still a policy area under development, we take a cautious view of the prospects. In our projections, European Union gas use in road transport in the New Policies Scenario climbs from 1.4 bcm in 2011 to around 3.8 bcm in 2035, its share of total road-fuel energy demand rising from 0.4% to 1.3%. Gas displaces around 70 kb/d of oil by 2035, compared with just 26 kb/d in 2012.

Other countries are also looking at the potential for using natural gas as a road fuel. Russia's Gazprom has been a long-standing promoter of gas use in transport and is investing in Russian refuelling infrastructure, as well as teaming up with other companies to develop and test CNG vehicles. In India, the NGV fleet – made up largely of CNG-powered buses, taxis and motorcycles – has grown rapidly in recent years, largely thanks to public mandates to switch to the fuel in New Delhi and several other large cities, in response to worsening air pollution. Air quality benefits are the primary justification for policy support for natural gas in transport in many countries (though modern diesel particulate filters reduce the air quality advantage of LNG *vis-à-vis* diesel), and reduced imports of oil can bring energy security and economic benefits too.

We remain cautious about the medium-term prospects for the uptake of electric vehicles (EVs) – plug-in hybrids and battery-electric vehicles – in view of the continuing difficulties in bringing to market commercially attractive models. Sales are rising, but still represent only a small fraction of total vehicle sales (and it will be a major struggle to attain the levels of deployment for 2020 required in the 450 Scenario). A mere 100 000 EVs were sold worldwide in 2012, mostly in the United States and Japan, despite additional measures in many countries to encourage sales. But subsidies and other incentives are so far not big enough to make the price of EVs attractive to most private motorists, and the ambitious targets of several countries are accordingly under critical scrutiny.

At around 100 000 EVs and plug-in hybrids on the road in the United States, the US administration's target, announced in 2011, of putting 1 million EVs and plug-in hybrids on the road by 2015 is distant. In Europe, the European Commission is set to propose measures to promote EVs under its new clean fuel strategy, including mandating a minimum number of recharging points and adopting a standard plug across member states. Among EU member countries, Germany has re-stated its goal of 1 million EVs on the road by 2020, but with just 72 000 sold up to end-2012, it is far from reaching this target. In China, the government is targeting 500 000 EVs on the road by 2015 and 5 million by 2020, but sales amounted to less than 13 000 in 2012, far below the government expectations. In India, a new "National Mission for Electric Mobility" was launched in January 2013, with a target of putting 6-7 million EVs on the road by 2020, of which 4-5 million are expected to be two-wheelers (a proven technology that is already in widespread use in China). A note of caution in relation to EV projections arises from the failure of the world's first large-scale public battery-swap and EV-charging network, developed by Better Place in Israel, which filed for bankruptcy and was subsequently sold, having failed to achieve targeted levels of use.

As with any emerging technology, projecting the expansion of the EV market is extremely difficult. Present sales are low, but several major car manufacturers and premium brands are launching EV models. A large improvement in the performance of batteries and a big fall in their cost could lead to rapid take-off in demand; but without these advances, EVs are likely to remain a niche market. In the New Policies Scenario, global EV sales reach only about 500 000 vehicles in 2020 – far below the aggregate of targets of 7 million around the world – and less than 4 million in 2035. The projected oil savings from EVs globally total around 35 kb/d in 2020 and about 235 kb/d in 2035 – far smaller than those from biofuels or natural gas. In the 450 Scenario, in which the deployment of EVs expands much more rapidly, savings reach 73 kb/d and 1.5 mb/d respectively.

### *Industry*

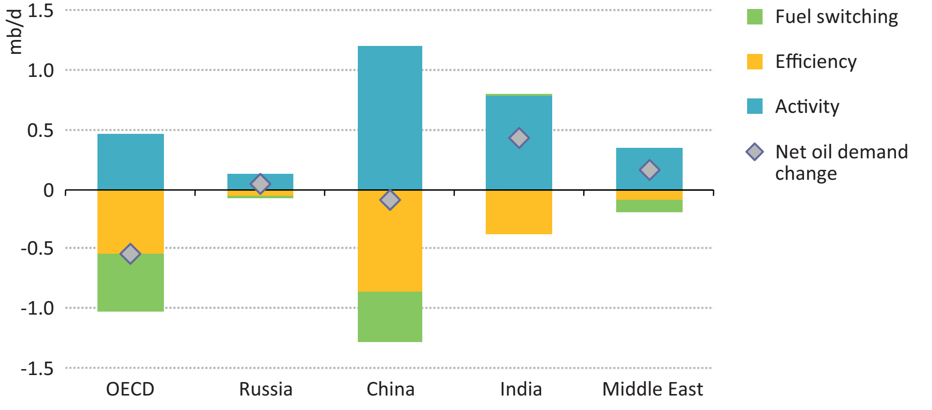
Every day the global industry sector consumes 17 million barrels of oil products, 19% of total demand. Industry is the second most important oil consumer after transport. The largest share of this oil, 11 mb/d, is used for non-energy purposes, mainly as feedstocks in the petrochemical industry, while the rest is used for steam production, process heat and off-road vehicles. The outlook for the two categories differs in the New Policies Scenario: oil use for petrochemical feedstock use increases by 1.2% per year up to 2035, but oil for heating, steam production and off-road vehicles barely grows at 0.2% per year.

As a source of fuel for the industry sector, oil has to compete against a full range of alternative energy sources and, as oil prices have risen, oil has lost competitiveness in most regions. Natural gas, which has become more widely available, is often preferred to oil for steam production and direct heat, as it is more efficient and cheaper. It is also a cleaner fuel, emitting fewer noxious pollutants and a lower level of carbon dioxide. Where environmental regulations permit, coal has also been substituted for oil, on grounds of cost. For these reasons, global final oil consumption in industry peaked in the late 1970s (before the second oil price shock in 1979) and has since declined substantially. Oil's share of total industrial final consumption of energy has halved since 1980, reaching 13% in 2012. A modest absolute increase in industrial oil use in non-OECD countries over this period was more than outweighed by a sharp fall in the OECD.



We do not expect significant changes in these trends over the projection period. In the New Policies Scenario, industrial oil consumption as a fuel rises slowly in absolute terms over the coming decade, levelling off in the 2020s, but its share of industrial fuel use continues to decline. All of the increase comes from non-OECD countries, with OECD consumption continuing to tail off and, by 2035, oil meets only 10% of industry's energy needs (excluding feedstocks). Efficiency improvements in steam systems and process heat contribute to this slower growth in oil demand (Figure 15.12). A significant portion of industrial oil consumption for non-feedstock purposes is consumed to provide steam, and we project that energy savings of 10-15% are achieved in steam systems over the *Outlook* period, through waste heat recovery, better maintenance and process control. In China, since oil is the most expensive option to provide steam and there still exists large potential for higher energy efficiency, fuel switching (to natural gas) and efficiency gains offset increasing demand for oil. In steam cracking, the core process of the petrochemical industry, large differences in the improvement potential exist between regions, with crackers in the United States using about 30% more energy than those in Japan and Korea (UNIDO, 2010).

**Figure 15.12 ▷ Change of industrial oil demand (excluding feedstocks) by driver in the New Policies Scenario, 2012-2035**




## *Petrochemicals*

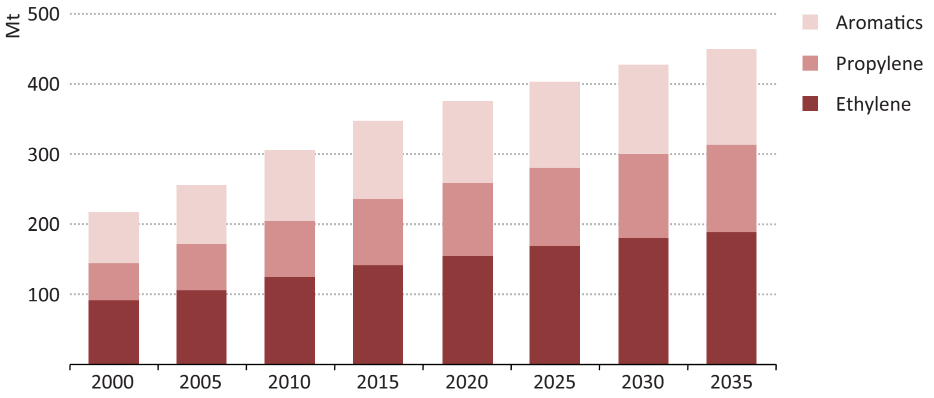
Among energy-intensive industries, petrochemicals are – along with paper – expected to see the fastest growth in output over the projection period, entailing high demand for oil as feedstock. Products in high demand include plastics, fibre and rubber. In the past, plastic products have replaced traditional materials, such as wood, glass or ceramic, for purposes as diverse as packaging, toys, furniture and piping. Given future population and economic growth, together with the relatively low cost of plastics, their versatility and resistance to water, demand for plastic products is expected to be robust (Box 15.3).

In the New Policies Scenario, output of high-value chemicals (HVO)[7] expands by 1.6% per year on average between 2012 and 2035, with ethylene output rising by 1.7% per year. Growth in propylene demand is expected to outpace that of ethylene, with an annual growth rate of 1.9%, primarily due to strong demand for polypropylene, the second most important polymer (Figure 15.13). Demand for ethylene and other petrochemicals had outpaced gross domestic product (GDP) growth until the start of the present century,

7. High-value chemicals include ethylene, propylene and aromatics (benzene, toluene and xylenes).

but has since matched GDP growth more closely. In the New Policies Scenario, this trend continues, with growth in petrochemical demand close to the trajectory of global GDP in the earlier part of the projection period, but then falling lower in the later years. One contributing factor is a rise in the recycling of plastics. This is costly today, compared with disposal in landfills, and policy support is limited, so that global recycling rates are far lower than for other products, such as paper; but positive exceptions exist, such as in Japan. In the latter part of the *Outlook* period, we see recycling playing a more important role on a global scale, supported by technology improvement and stronger policy intervention.

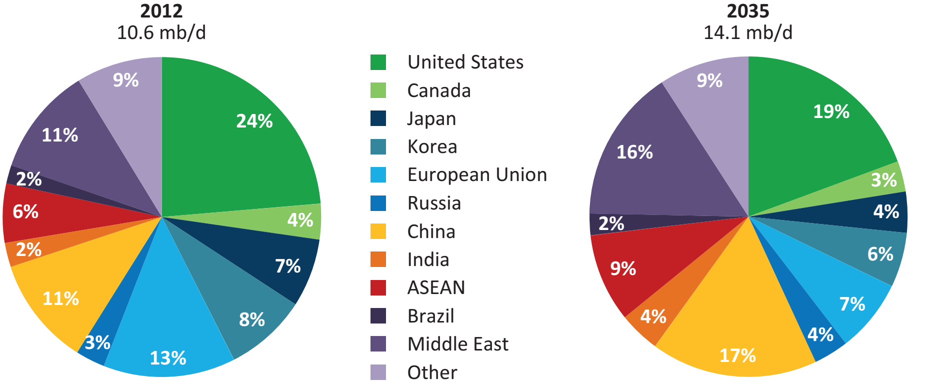
**Figure 15.13 ▷ Production of high-value chemicals in the New Policies Scenario**




The laws of chemistry dictate the feedstock requirements that are needed to support these production increases. On the supply side, the growth in production of natural gas liquids (NGLs) brings with it greater availability of LPG and ethane, both inputs for the petrochemical industry. The expansion of refinery capacity also increases the supply of naphtha as a petrochemical feedstock. These trends result in oil consumption for feedstock purposes increasing from today's 10.6 mb/d to some 14.1 mb/d in 2035.

While the overall outlook is for steady growth in the use of oil-based petrochemical feedstock, there are marked differences across regions (Figure 15.14). Demand is projected to grow rapidly in the Middle East, where the relevant industrial capacity has doubled over the last five years and where we assume that it will double again to 2035. Currently, Saudi Arabia is the dominant petrochemical producer in the region, accounting for roughly 60% of ethylene production, with Iran, Qatar, the United Arab Emirates and Kuwait accounting for most of the remainder. These countries are expected to be the main sources of output growth, with the United Arab Emirates and Qatar seeing the fastest relative increases in production. The expansion of the petrochemicals sector in the Middle East is based on the availability of cheap feedstock: natural gas supply grows by almost 60%, with a corresponding increase in the volume of NGLs, providing a ready source of ethane that makes the region the cheapest global producer of ethylene. However, as petrochemical production increases faster than ethane supply, a gradual shift towards heavier feedstock is projected in the long term.

**Figure 15.14 ▷ Demand for oil as petrochemical feedstock by region in the New Policies Scenario**



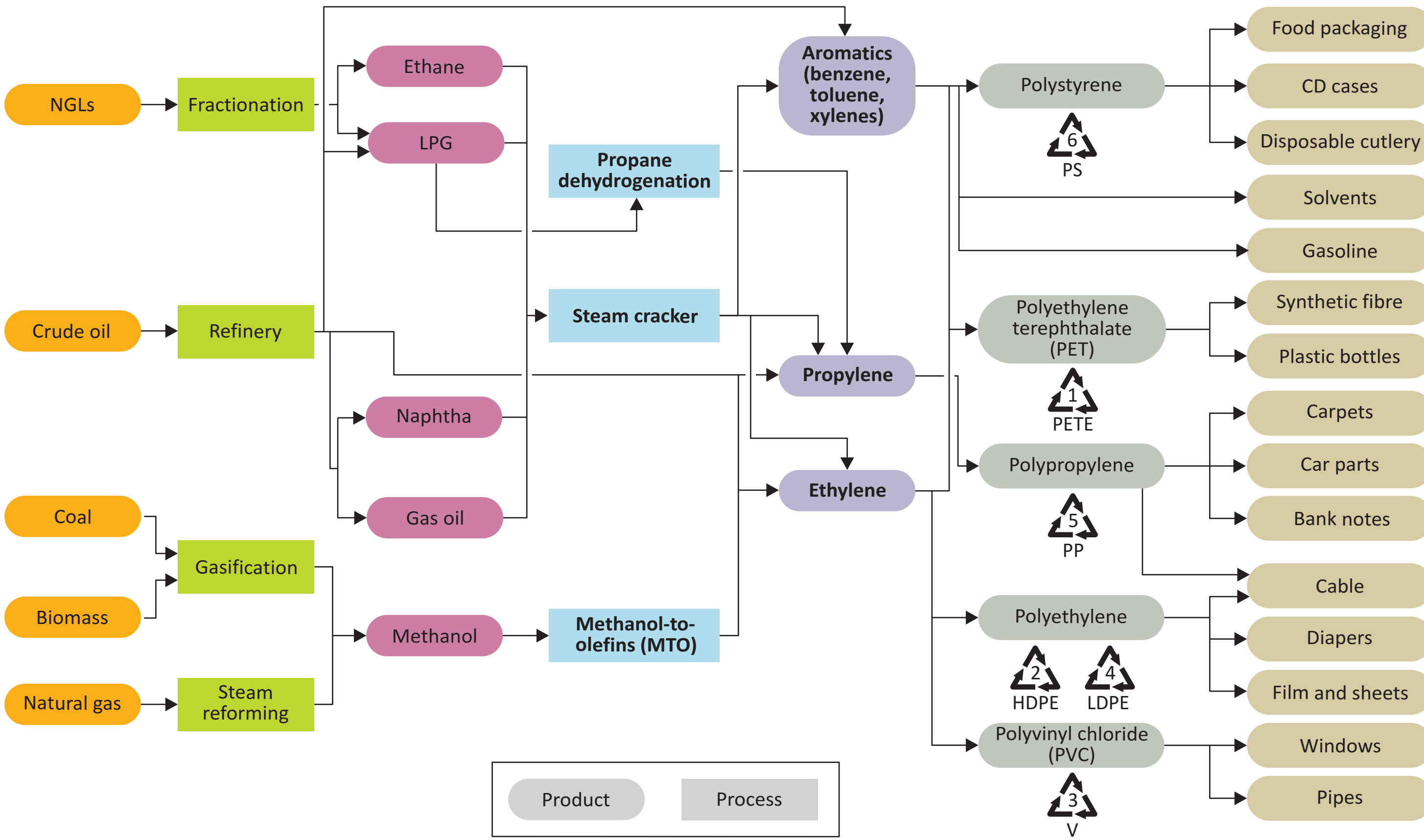

**Box 15.3 ▷ A guide to petrochemicals**

Petrochemicals are chemical products traditionally derived from crude oil, though some chemical compounds are nowadays also obtained from coal and biomass. The main feedstocks are naphtha, LPG (propane and butane), ethane and diesel (gasoil). In our modelling, we track production of the major, high-value petrochemical building blocks, divided into two broad categories: olefins, including ethylene and propylene; and aromatics, including benzene, toluene and xylenes. These petrochemical products come mainly from steam cracking and oil refining and are further processed, sometimes in combination to produce a range of plastics, synthetic rubbers, resins, fibres and solvents, which are used in a variety of household and industrial applications, such as plastic bottles, clothing, paints and automobile parts (Figure 15.15).

The petrochemical industry is highly energy-intensive, requiring a large amount of energy both in the production process for heat and as feedstock. Steam cracking – the key petrochemical process – and other conversion processes are carried out in large plants in order to profit from economies of scale. The choice of feedstock is determined by availability and price, as well as the desired range of products: yields vary according to the mix of feedstock. For example, one tonne of ethane yields 0.80 tonnes of ethylene, while the yield of ethylene from naphtha is 0.32 tonnes and from propane 0.47 tonnes. Propane and naphtha also produce propylene and other chemicals as by-products, but ethane produces almost no by-products.

Recently, alternative process routes have gained in importance. These include methanol-to-olefins (MTO), a process that yields ethylene and propylene, via a catalytic process, from methanol. The methanol can be produced from a variety of feedstocks, including natural gas, oil, biomass and, particularly in China, from coal (coal-to-olefins). Another alternative is bio-based olefin production; Braskem started the first polyethylene plant based on renewable feedstock in Brazil in 2010 and several bio-plastic plants, for example to produce polylactic acid, are in operation that produce polyesters directly from maize or other biomass types, instead of producing olefins first.

**Figure 15.15 ▷ Simplified principal petrochemical product chains**



Emerging petrochemical producers in Asia, particularly China, the ASEAN countries and India also see substantially higher oil feedstock consumption, driven by a rapidly increasing demand for plastics. Currently the region as a whole is a net importer of petrochemical intermediate products, but the anticipated increase in domestic production capacity reduces this dependence on imports over the coming decades. Under the 12th Five-Year Plan, China is targeting an increase in ethylene production capacity of 27 million tonnes (Mt) by 2015, an addition of 11 Mt compared with 2011, equivalent to the entire capacity of Germany and the Netherlands combined. Driven by close proximity to the big Chinese market and the ASEAN-China free-trade agreement, oil demand for petrochemical feedstocks almost doubles in ASEAN countries. Growth is anticipated to be held back somewhat in India (despite increasing demand for plastics) by slow licensing procedures for new capacity and tariff barriers for imported equipment.

Among the OECD markets, the United States is the only one that is able to increase petrochemical production. As in the Middle East, this is based on the availability of ethane from increasing production of NGLs, the prospect of cheap feedstock having spurred a wave of interest in new ethylene and derivate processing plants (Box 15.4). Up to 11 Mt of new ethylene capacity is planned, but we anticipate that, due to limited ethane supply, only around half the amount results in additional production through to 2020. This, nonetheless, represents a 20% increase over current production. Most of the output from the new US petrochemical plants, as well as the surplus propane and butane from NGLs, will be exported. Ethane could also be exported to Europe or Asia, but there are several obstacles to overcome: the ethane would have to be liquefied, with costs similar to those of LNG liquefaction (moreover, most of the steam crackers in Europe run on naphtha and very few on ethane). It is far more economical to transport plastics.

The shift from heavier feedstocks, such as naphtha, towards ethane has put other petrochemical streams, including propylene and aromatics, at a disadvantage. This has resulted in lower propylene production from steam crackers in the United States (by some 2 Mt per year, a fall of around 25%), leading to higher and more volatile propylene prices and encouraging investment in on-purpose production of propylene, based on LPG. Over the longer term, post-2020, growth in petrochemical production in the United States is expected to level off and then fall, as a consequence of increasing feedstock prices and a tighter ethane balance.

In contrast to the outlook for the United States, Europe sees a 25% drop in demand for oil-based feedstock in our projections and Japan a fall by 20%, driven by weak domestic demand and relatively high feedstock prices. Production in Europe and Japan is mainly based on expensive naphtha from refineries, which makes these regions the highest cost producers in the world. Refinery runs in these regions are expected to decline, reducing the availability of naphtha, entailing the closure of several steam crackers. The petrochemical industry in the far east and Europe is suffering from a significant disadvantage in terms of feedstock costs and can limit the negative effects only by further increasing efficiency, considering refinery integration and moving to higher value products (see Chapter 8).

South American petrochemical production, dominated by Brazil, sees a production increase though the region remains a minor producer. A substantial portion of the increase in petrochemical capacity is projected to be built after 2020 when Brazilian oil and gas production is expected to increase. Brazil is a pioneer in the commercial production of ethylene and plastics from biomass, with a first plant built in 2010 and a second expected to come onstream in 2015. Production costs are still high, compared with conventional technologies, which accounts for its limited growth in our projections.

### Box 15.4 ▷ Is cheap coal the Chinese answer to cheap gas in the United States?

The United States has enjoyed an impressive surge in natural gas production from unconventional sources over the past five years, making it the world's leading gas producer (see Chapter 3). As a consequence of rising NGLs production, ethane output surged to around 1 mb/d and its price dropped to below $5 per million British thermal units (MBtu) at the start of 2013, from as high as $20/MBtu in 2008. With feedstock costs accounting for roughly 75% of total petrochemical production costs, the availability of ethane at these prices has made the United States the world's second lowest-cost producer of ethylene, after the Middle East. The improved outlook for such an important industrial sector has prompted many governments around the world to examine whether and how they might replicate, at least in part, the experience of the United States.

In our projections, unconventional gas does not play a major role in the Chinese energy balance until well into the 2020s. But China has another feedstock that is both cheap and readily available: coal. Given oil prices in the range of $120 to $130/barrel in the longer term, and domestic coal prices in China of less than $100/tonne in the New Policies Scenario, coal-to-olefins (CTO) plants have a distinct cost advantage in China compared to oil-based petrochemicals. This represents a potential source of industrial advantage that China is expected increasingly to develop, as well as a way to slow the rise in oil imports.

China already has large coal-to-methanol facilities and the expansion of CTO plants is well underway: the first propylene plant to use coal opened in 2010 and three CTO plants have been added since, resulting in total capacity for olefins production of 2 Mt per year. Another 2 Mt of olefin capacity is under construction and we see 10 Mt coming online within the next five years, by then accounting for more than one-fifth of China's total ethylene production and curbing the increase in oil demand by about 300 kb/d. Unlike ethane-based production in the United States, coal-based production can be adjusted to yield the required ethylene-to-propylene ratio. There are limits, however, to the scope for expansion: after 2020, difficulties over access to water and concerns about the environmental impact of such projects – they are both water and carbon-intensive – are likely to constrain further investment.

### *Other sectors*

#### *Power generation*

Oil has been largely displaced by other fossil fuels, nuclear power and/or renewables in the power generation sector in most countries. Where it is used, it often serves to provide back-up power in the event of a shortfall in capacity or to meet peak load. Globally, the use of oil to generate electricity in steam and gas turbines dropped by one-fifth between 1990 and 2012, to just 5.5 mb/d, and it is projected to fall by half to 2.7 mb/d by 2035 in the New Policies Scenario. Diesel is expected to account for a growing share of the oil that is still used for power generation, as old baseload steam-boiler plants that burn heavy fuel oil are retired over the projection period. As noted previously, a few countries do burn significant volumes of oil in power stations at present, notably Saudi Arabia, where shortages of gas have forced power generators to turn to burning heavy fuel oil or crude oil directly. Other oil-producing countries, mainly in the Middle East, at present burn significant volumes of oil for power, often in stations with very low thermal efficiency, because it is heavily subsidised. In 2035, just under half of projected oil-fired production is in the Middle East.

#### *Buildings*

Energy is used in residential, commercial and public buildings in a variety of ways, including for space and water heating, air conditioning, lighting, electrical appliances and equipment. Oil products are used almost exclusively for heating and cooking, for which alternatives are often available – notably natural gas and electricity. In most instances, piped natural gas is preferred to oil in areas served by a distribution network, for reasons of convenience and cost. For this reason, the share of oil in energy use in the buildings sector worldwide has been falling steadily since the 1970s, it was 15% in 1990 and just 11% in 2012. In the New Policies Scenario, the share falls further to 7% in 2035, with consumption in absolute terms falling slowly through the projection period. This entire decline is in OECD countries; consumption continues to rise marginally in non-OECD countries, due mainly to growing demand for LPG in the residential sector, especially in rural and peri-urban areas that cannot be served economically by natural gas networks.

## Oil demand by product

The different trends in energy and oil demand across transformation and final end-use sectors naturally determine the outlook for the different types of oil products that make up overall oil supply. For this year's *Outlook*, we have expanded our modelling to include eight product groups: ethane, LPG, naphtha, gasoline, kerosene, diesel (gasoil), fuel oil and other products.[8] The current split of oil demand by product (and main sectors of use) shows how diesel is the leading product by volume and the most versatile, being used in all the main sectors. It is followed by gasoline, which is used almost exclusively as a road-transport fuel (Table 15.5). Together, these two fuels currently make up almost 54% of total oil product consumption.

8. These include refinery gases, asphalt, wax, solvents, petroleum coke, etc.

**Table 15.5 ▷ Main sources and uses of oil products, 2012**

| Product | Main sources | Main sectors | World demand | |
|---|---|---|---|---|
| | | | mb/d | % of total |
| Ethane | NGL fractionation | Petrochemical feedstock | 2.4 | 2.8 |
| LPG | NGL fractionation, condensate splitters, petroleum refineries | Petrochemical feedstock, buildings, road transport | 7.6 | 8.7 |
| Naphtha | Condensate splitters, Petroleum refineries | Petrochemical feedstock, gasoline blending | 5.7 | 6.5 |
| Gasoline | Petroleum refineries | Road transport | 20.8 | 23.8 |
| Kerosene | Petroleum refineries | Aviation fuel, buildings | 6.3 | 7.3 |
| Diesel | Petroleum refineries | Road transport, bunkers, buildings, industry, power generation | 26.0 | 29.7 |
| Fuel oil | Petroleum refineries | Bunkers, industry, power generation | 8.3 | 9.5 |
| Other products | Petroleum refineries | Non-energy use, refinery own use, power generation | 10.2 | 11.7 |
| **Total** | | | **87.4** | **100.0** |

Notes: Diesel excludes biodiesel (made from biomass feedstocks), but includes coal- and gas-to-liquids (CTL and GTL) diesel. Gasoline excludes ethanol, but includes additives and CTL/GTL gasoline.

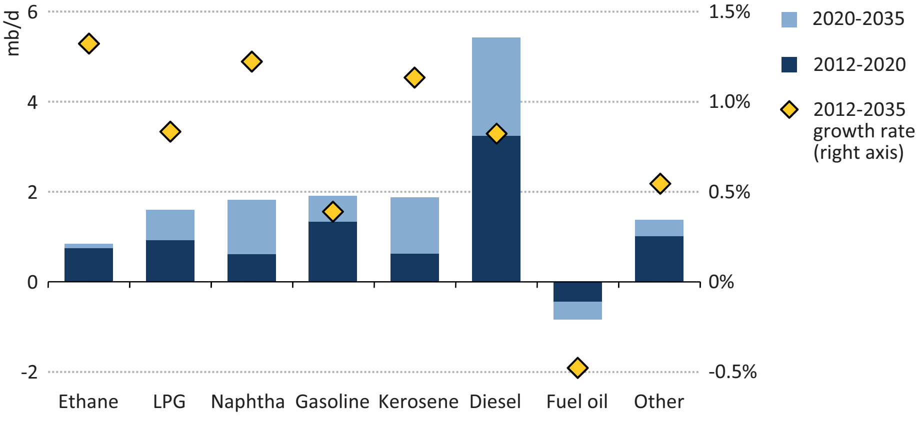
**Table 15.6 ▷ World primary oil demand by product in the New Policies Scenario** (mb/d)

| | 2000 | 2012 | 2020 | 2035 | 2012-2035 | |
|---|---|---|---|---|---|---|
| | | | | | Delta | CAAGR* |
| Ethane | 1.7 | 2.4 | 3.2 | 3.3 | 0.9 | 1.3% |
| LPG | 5.9 | 7.6 | 8.6 | 9.2 | 1.6 | 0.8% |
| Naphtha | 4.3 | 5.7 | 6.3 | 7.5 | 1.8 | 1.2% |
| Gasoline | 18.7 | 20.8 | 22.1 | 22.7 | 1.9 | 0.4% |
| Kerosene | 6.5 | 6.3 | 7.0 | 8.2 | 1.9 | 1.1% |
| Diesel/gasoil | 20.2 | 26.0 | 29.2 | 31.4 | 5.4 | 0.8% |
| Heavy fuel oil | 8.7 | 8.3 | 7.8 | 7.4 | -0.9 | -0.5% |
| Other products | 10.2 | 10.2 | 11.3 | 11.6 | 1.4 | 0.5% |
| **Total** | **76.3** | **87.4** | **95.4** | **101.4** | **14.0** | **0.6%** |

* Compound average annual growth rate. Notes: Naphtha includes only petrochemical feedstock use. Naphtha used as a gasoline blending component is included in gasoline.

In the New Policies Scenario, demand growth is concentrated in the middle distillates: diesel sees by far the largest increase in volume terms, rising 5.4 mb/d to more than 31 mb/d between 2012 and 2035 (Table 15.6 and Figure 15.16). Some of the lighter products also see substantial demand growth, notably ethane for use as a petrochemical feedstock. Heavy fuel oil is the only product for which demand falls over the projection period. Refiners have some flexibility in the short term to adjust the mix of product output to meet seasonal or other fluctuations in demand, but, as discussed in Chapter 16, longer-term shifts require investment in secondary processing facilities. Levels of consumption can be determined by availability (notably for ethane and LPG), with the price adjusting to ensure that demand comes into balance with supply.

**Figure 15.16 ▷ Change in demand for oil by product in the New Policies Scenario, 2012-2035**



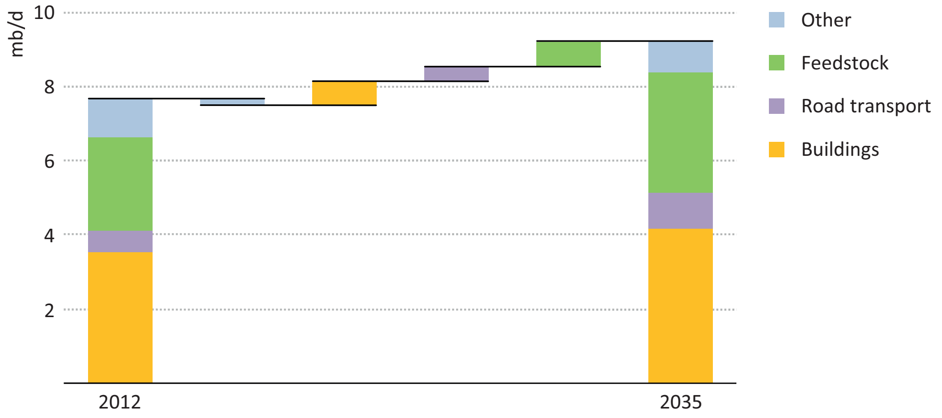

### *Ethane*

Worldwide, ethane is the second most important feedstock in steam crackers, after naphtha. Both types of feedstock can be substituted by diesel, LPG and methane (natural gas), but with a different yield of intermediate petrochemical products. The Middle East and the United States together account for almost three-quarters of world ethane use today. Of the projected 860 kb/d, or 35%, increase in ethane consumption between 2012 and 2035, 60% occurs in the Middle East and 12% in the United States, with ethane supplies in both regions boosted by rising natural gas production. Most of the increase occurs during the period 2012-2020, when a number of new crackers – many of them already under construction – are expected to come online.

### *LPG*

LPG is a mixture of hydrocarbons, mainly propane and butane that changes from a gaseous to liquid state when compressed at moderate pressure or chilled. It is a highly versatile fuel, used to provide a range of energy services in several different sectors. Some 40% of current consumption is for cooking and heating in the residential sector, while one-third is used as a petrochemical feedstock. Most of the remainder is used, in almost equal measure, in industry and as an alternative road-transport fuel. In the New Policies Scenario, the use of LPG grows in all the main sectors where it is currently used (Figure 15.17). The biggest increase is projected to come from the petrochemicals sector, which adds some 800 kb/d to 2035, on the back of strong underlying demand for the derivative products and an assumption that LPG will be competitively priced in the main producing regions that are geared up to using this type of feedstock, notably the Middle East and the United States.

**Figure 15.17 ▷ LPG demand in the New Policies Scenario**




All of the growth in LPG use in the buildings sector arises in the developing world, where rising incomes and population boost demand for clean cooking fuels (see Modern Energy for All in Chapter 2). LPG is particularly well-suited to domestic cooking and heating uses, because of its clean-burning attributes and practical advantages over both solid fuels and kerosene – the other main type of cooking fuel in developing countries. Increased use of LPG for cooking and heating in Africa, India and other developing regions more than offsets the projected decline in such uses in North America and Europe.

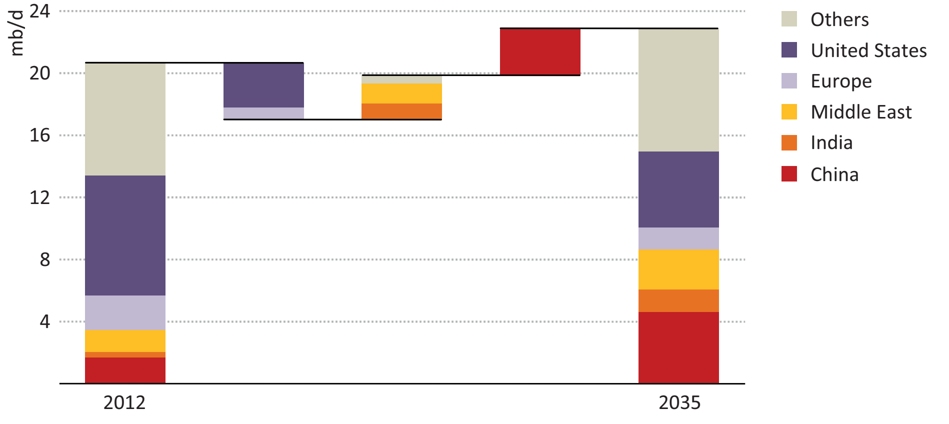
### *Naphtha*

Demand for the use of naphtha as a petrochemical feedstock is projected to climb from 5.5 mb/d in 2012 to more than 7 mb/d by 2035, driven by strong growth in China and, to a lesser extent, in ASEAN countries and the Middle East. By contrast, naphtha consumption declines in Europe, where petrochemical producers struggle to compete with lower cost producers in the United States and the Middle East, which rely mainly on cheaper ethane.

### *Gasoline*

The outlook for gasoline demand differs markedly across regions. The overall prospect is that strong demand in China and other emerging economies will compensate for weak demand in the OECD. In the New Policies Scenario, global demand rises slowly, from 20.8 mb/d in 2012 to 22.7 mb/d in 2035. Gasoline continues to be used almost exclusively for road transport, mainly in passenger and commercial LDVs. It remains the leading fuel for PLDVs in all regions outside Europe (where diesel use remains about even with gasoline) and Brazil (where biofuels continue to gain market share). Overall, diesel use for road transport (including freight) approaches that of gasoline by 2035. But these trends mask some very big differences between countries and regions. Gasoline consumption declines substantially in North America, Europe and OECD Asia Oceania, mainly as a result of major improvements in fuel economy and increased use of biofuels (largely blended into gasoline). In these countries, already high levels of vehicle ownership limit the scope for an expansion of the PLDV fleet to compensate for efficiency gains. By contrast, demand continues to soar in China and other emerging economies. Gasoline use in China alone jumps by almost 3 mb/d between 2012 and 2035 – almost equivalent to the projected fall in US gasoline use – with a projected five-fold increase in the PLDV fleet.

**Figure 15.18 ▷ Gasoline demand by region in the New Policies Scenario**



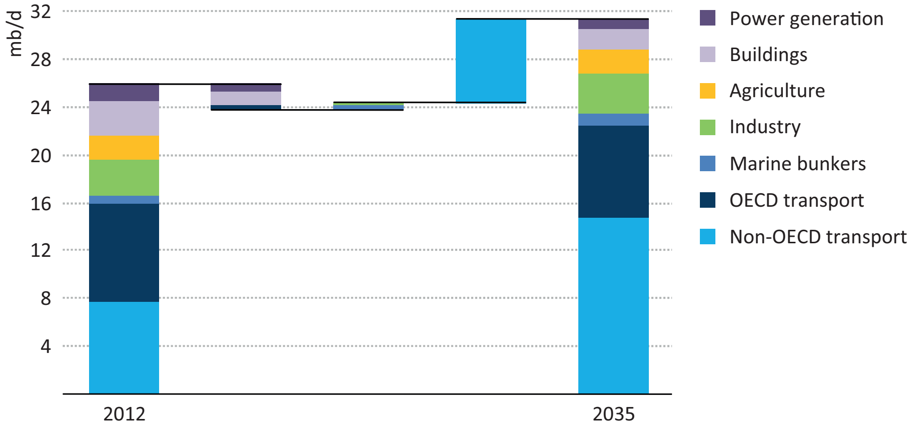

### *Kerosene*

Kerosene is used both as jet fuel in aviation and as a household cooking and heating fuel, mainly in developing countries. The prospects for kerosene use in these two segments are very different. Continuing strong growth in demand for domestic and international air travel is projected to more than compensate for improvements in the efficiency of jet engines, pushing demand for aviation kerosene up by around 45% between 2012 and 2035. Domestic aviation demand grows most in the United States, China, Brazil and Russia, while international aviation bunkers see most growth in hubs in ASEAN countries and the Middle East. Biofuels are the only viable substitute for jet kerosene, but they remain too costly in the *Outlook* to make major inroads into aviation fuel demand before 2035. By contrast, kerosene use in buildings decreases by almost 40% over the projection period. In OECD countries, households switch to natural gas and electricity for heating, while in Africa and south Asia, many households switch to less polluting and safer fuels for cooking, largely offsetting the effect of increased demand for fuels as incomes and populations rise.

### *Diesel*

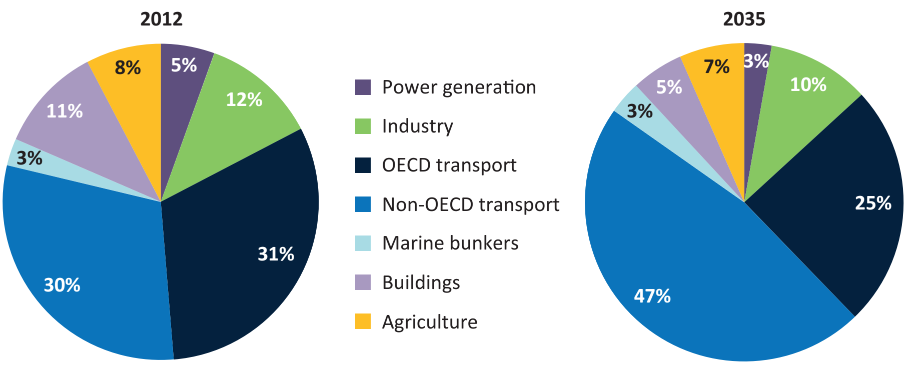
The confluence of technological and economic trends points to diesel consolidating its position as the leading oil product, while being used increasingly as a transport fuel. In the New Policies Scenario, diesel consumption increases from 26 mb/d in 2012 to more than 31 mb/d in 2035, its share of total primary oil demand edging up to 31%. All of the net increase in demand comes from the road-transport sector in non-OECD countries. Demand in most of the other sectors and in transport in the OECD falls – substantially in the case of buildings, where diesel in the form of light heating oil is replaced largely by natural gas and electricity (Figure 15.19). Non-OECD transport demand for diesel almost doubles from 7.8 mb/d to 14.7 mb/d between 2012 and 2035.

**Figure 15.19 ▻ Diesel demand by sector in the New Policies Scenario**




We project only a minor increase in the use of diesel in marine bunkers, despite the proposed initiative by the International Maritime Organisation to introduce lower sulphur limits on bunker emissions on the high seas, which could be expected to increase diesel use, at the expense of heavy fuel oil (bunker C). The increase in diesel demand required to replace bunker C fuel entirely would be around 3.5 mb/d by 2020, an amount that, in the *Outlook*, would be beyond the capacity of the world's refining system to deliver given that demand for diesel is, in any event, rising faster than that of any other product. To provide additional volumes for a switch to marine distillates, the premium for diesel over heavy fuel oil would need to rise to such an extent that other solutions to the lower sulphur limits would become financially viable, including sulphur scrubbers on board ships or the use of LNG as bunker fuel.

**Figure 15.20 ▻ World diesel demand by sector in the New Policies Scenario**

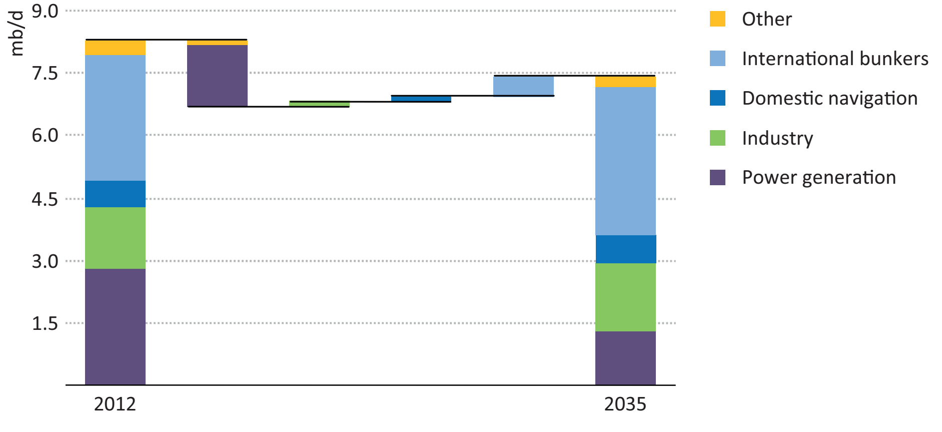


Overall, the New Policies Scenario sees a significant increase in the share of the transport sector (road and inland waterways navigation) in diesel demand, from 64% in 2012 to 75% in 2035. This is driven by increased consumption in non-OECD countries, where the transport sector alone accounts for half of world diesel consumption by 2035. Outside the non-OECD transport sector, diesel demand declines, but because of overall decline in consumption rather than because of switching to other oil products.

### *Heavy fuel oil*

Global demand for heavy fuel oil is expected to be replaced by other fuels in most end-use sectors, continuing its long-term decline. In the New Policies Scenario, demand drops by 10% between 2012 and 2035 to 7.4 mb/d (Figure 15.21). Switching to natural gas, nuclear power and renewables brings demand down in the power sector, while switching to gas and electricity is the main reason for falling demand in industry. Marine bunkers and domestic navigation are the only sectors where heavy fuel oil use increases – from a combined 3.6 mb/d to 4.2 mb/d. Most large ships use heavy fuel oil in diesel engines and this is not expected to change significantly over the projection period, although the use of LNG is starting to make inroads, driven by economics and stricter environmental regulations. Overall bunker fuel demand is driven by a continued expansion of international maritime shipping of manufactured goods, mainly from Asia, and of bulk commodities (including energy), though the rate of growth is expected to slow markedly, compared with that of the past two decades. The increased volume of shipping more than offsets further improvements in the efficiency of ship engines, since most of the potential for saving energy from large ships has already been exploited.

**Figure 15.21 ▷ Heavy fuel oil demand by sector in the New Policies Scenario**



# Implications for oil refining and trade

## The great migration

### Highlights

- The global refining sector is set for turbulent times over the coming decades as the industry is re-shaped by declining oil demand in OECD markets alongside rapid growth in demand in non-OECD Asia and the Middle East. Anticipated refinery additions are concentrated in China, India and the Middle East, corresponding in part to the traditional model of refining close to the point of consumption, but also reflecting the ambition of crude exporters in the Middle East to expand into products trade and petrochemicals.

- Strains on the refining system are amplified by the changing composition of feedstocks. A growing share of oil supply bypasses the refining system altogether, including most natural gas liquids as well as oil products produced directly from gas or coal. As a result, global demand for refined products grows only by 10 mb/d over the period to 2035, less than the growth in overall liquids demand of 16.8 mb/d (including biofuels) and less than anticipated net refinery capacity additions of 13 mb/d.

- Refining over-capacity means increased competition for available crude as well as for product export markets. The consequences in terms of lower utilisation rates and potential rationalisation of capacity are mostly borne by the refining sectors in OECD regions, where oil demand is falling. Europe's vulnerability is increased by declining local crude production, product demand that is heavily skewed towards diesel and disappearing export markets for gasoline.

- The outlook for the United States is helped by the increasing availability of local crude, although infrastructure constraints and continuing, if diminishing, import reliance means that not all refineries are in a position to benefit. The net North American requirement for imported crude all but disappears by 2035, and the region becomes a large exporter of products.

- Asia becomes the unrivalled centre of the global oil trade as the region draws in a rising share of the available crude not only from the Middle East (where total crude exports start to fall short of the Asian import requirement), but also from Russia, Africa, Latin America and Canada. Even with the large additions to refining capacity, both India and China are net importers of oil products in 2035.

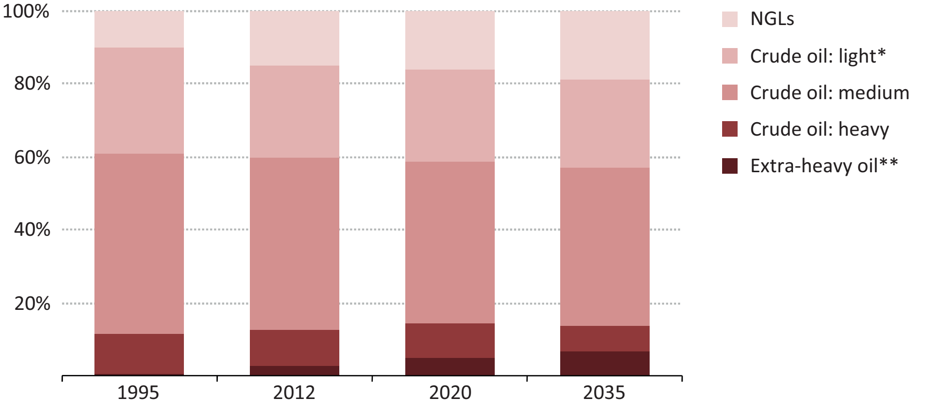
- Refinery capacity additions in the Middle East contribute to a decline in the region's crude and condensate exports over the period to 2020 and a rise in exports of products. However, by 2035, most of this new refining capacity serves to cater to increasing product demand from within the region.

## Making the connection between oil demand and supply

Between the extraction of oil and the delivery of oil products to final consumers are two large and complex industrial and commercial operations: oil refining and trade. Refiners, traders and shipping companies provide the ultimate link between oil demand and reliable supply, determining the fate of each barrel of oil produced and its destination. By virtue of this position in the oil value chain, these industries must frequently adjust to changes in the composition or location of oil supply and demand, always seeking to find the most advantageous ways to transform the various oil input streams into the right combination of products for the market.

The global refining sector is now undergoing a period of major adjustment. One of the main issues confronting refiners worldwide is the changing composition of feedstocks (Figure 16.1). Before the shale gas and light tight oil revolutions in the United States, world crude supply was generally getting heavier and higher in sulphur, with a higher yield of residual fractions. Refiners were preparing for a heavier crude slate by constructing cracking and coking units to break down long carbon chains of heavy residues into the ranges of lighter, more desirable products. However, with the start of large-scale production of light tight oil (LTO) and increasing output of natural gas liquids (NGLs), the world crude slate has bifurcated. The heavy side of the barrel is still getting heavier, as output of Canadian and Venezuelan extra-heavy oil and bitumen increases, requiring more severe cracking processes with high yields of petroleum coke and sulphur. But the share of lighter crudes in global output is also getting bigger, with the contribution of LTO and the condensate portion of NGLs.

**Figure 16.1** ▷ **World oil production by quality in the New Policies Scenario**




* Includes light tight oil. ** Includes Canadian oil sands.

A related challenge for refiners is the increasing share of products that find a way to market without passing through the refining sector at all. These include a proportion of fractionated NGLs (ethane, liquefied petroleum gas [LPG] and natural gasoline), products from coal-to-liquids (CTL) and gas-to-liquids (GTL) technologies, and biofuels. If we subtract all of these elements from total liquids demand, we find that total demand for refined products in 2012 amounted to 79 million barrels per day (mb/d), considerably less than total demand for liquids that was nearly 89 mb/d (Table 16.1). Moreover, while total liquids demand increases by some 17 mb/d over the period to 2035 in the New Policies Scenario, nearly half of this is met by the non-refinery components of total supply, so the increase in demand for refined products in the New Policies Scenario is a more modest 10 mb/d.

**Table 16.1 ▷ Global total demand for liquids, products and crude throughput in the New Policies Scenario** (mb/d)

| | 2012 | 2020 | 2035 |
|---|---|---|---|
| **Total liquids demand** | **88.7** | **97.6** | **105.5** |
| of which biofuels | 1.3 | 2.1 | 4.1 |
| Total oil demand | 87.4 | 95.4 | 101.4 |
| of which CTL/GTL and additives | 0.9 | 1.4 | 3.0 |
| Total oil product demand | 86.5 | 94.0 | 98.4 |
| of which fractionation products (from NGLs) | 7.7 | 9.2 | 9.7 |
| **Refinery products demand** | **78.9** | **84.9** | **88.7** |

## Products bypassing the refining sector

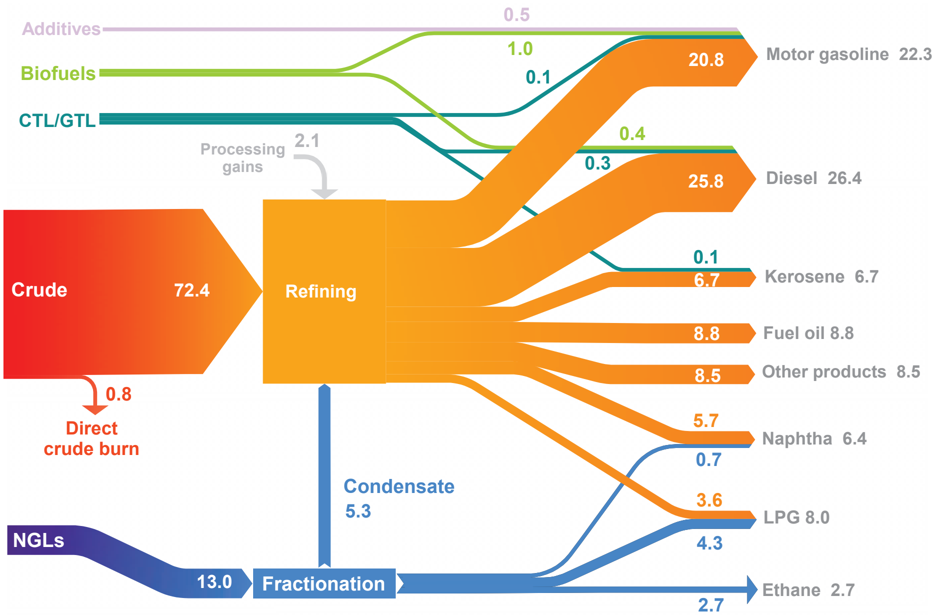
For as long as oil supply remained dominated by conventional crude oil, so the refining sector retained a firm grip on oil product supply. For conventional crude, refining remains a necessary and sole link with oil demand (with the exception of some crude oil burned directly for power generation, mostly in the Middle East). But, as seen in Figure 16.2 and in Chapter 14, the composition of oil supply is changing. CTL/GTL technologies generate transport fuels directly from natural gas or coal (in regions where the two feedstocks are especially cheap), producing various combinations of diesel, kerosene and gasoline, depending on local demand or export priorities. Broadening the horizon to total liquids supply, the biofuels industry also produces bioethanol and biodiesel for transport use, which are blended into gasoline or diesel at various rates in refineries or storage facilities, or, less frequently, sold as pure ethanol or biodiesel.

### *Natural gas liquids*

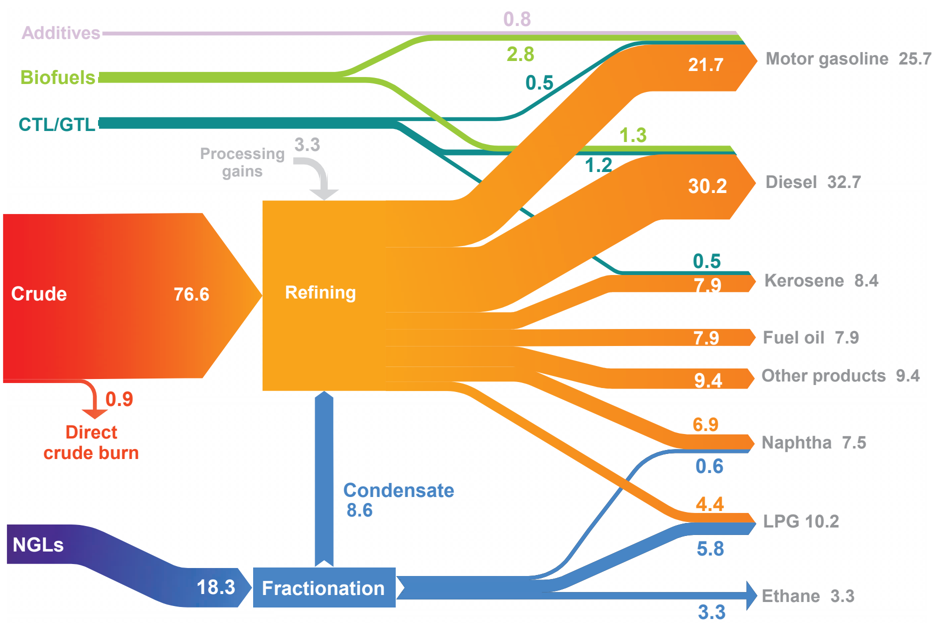
NGLs are an increasingly important part of global oil production. Their output rises by 5 mb/d to about 18 mb/d in 2035, 45% of the overall growth in output. NGLs congregate at the light end of the oil spectrum and do not yield as high a proportion of transport fuels as more conventional crude oils. Nonetheless, some of the heavier NGLs (the condensate portion) do work their way into the regular refining system and into transport fuel; in our projections, the petrochemicals industry absorbs a large share of the lighter ends.

**Figure 16.2 ▷ World liquids supply in the New Policies Scenario, 2012 and 2035** (mb/d)

(a) 2012



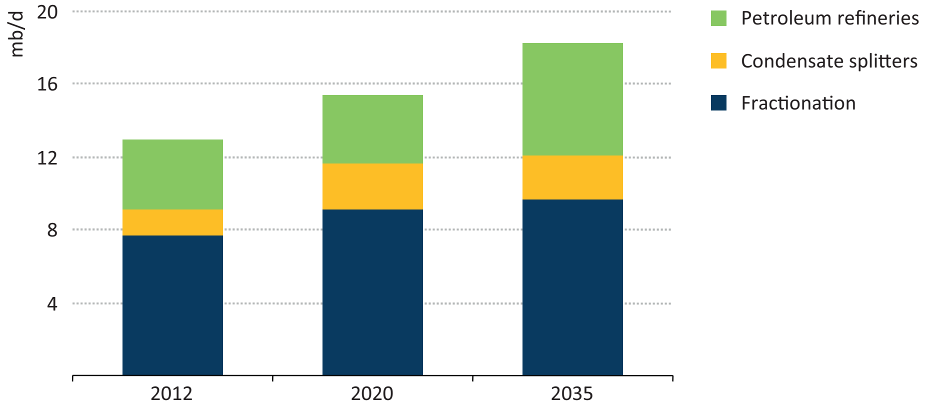

(b) 2035




Notes: Volumes of crude oil and NGLs here do not correspond to the values in Chapter 14, Table 14.1, as some US ultra-light crude is treated as condensate for the purposes of refining analysis. Rounding may lead to minor differences between totals and the sum of their individual components.

The definition and composition of NGLs differs by region. In the United States, for example, condensate is reported as part of the crude stream, so the remaining NGLs are lighter, with a greater share of ethane and LPG, the lightest components. In other regions, such as the Middle East, the Caspian and West Africa (which provide a significant share of NGLs output growth in the latter part of the projection period), there tends to be a higher proportion of heavier, refinable liquids, like condensate, included in the definition of NGLs. All of these NGLs are fractionated (*i.e.* separated out) from the natural gas stream. For around 60% of NGLs, mostly ethane, LPG and natural gasoline (a type of light naphtha), this is where the process ends.[1] The remainder is heavier condensate that is sent either to condensate splitters or to petroleum refineries.[2]

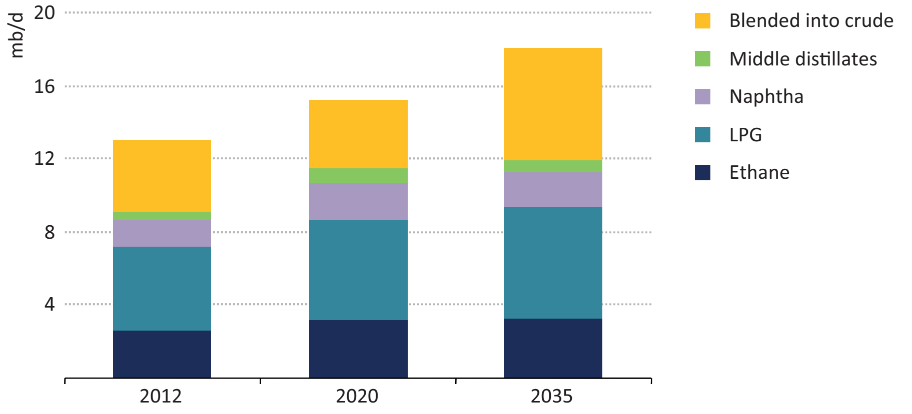
**Figure 16.3 ▷ Routes to market for NGLs by process in the New Policies Scenario**




In petroleum refineries condensate is mostly blended with crude oil, and it is not possible to derive product yields specifically for the condensate part of the refinery intake. The rest of NGL volumes can be split into products that are the output of condensate splitters and earlier fractionation: middle distillates, naphtha, LPG and ethane (Figure 16.4). All of the ethane and naphtha, and around half the volumes of LPG, in the projections, go to the petrochemical sector as feedstock.[3]

1. This is the component shown in Table 16.1 under "fractionation products (from NGLs)".
2. This share is included as an input to the refinery model (which incorporates condensate splitters).
3. The use of oil as feedstock would have pleased the Russian chemist Dmitry Mendeleev, the father of the periodic table of chemical elements, who was not happy seeing crude oil from the fledgling oilfields of Baku, then part of the Russian empire, used as a fuel, famously claiming that it is the same as burning money in boilers. His point was that one should use oil to derive versatile chemical compounds that otherwise do not occur in nature.

**Figure 16.4** ▷ **NGLs product yields in the New Policies Scenario**




Note: The share blended into crude corresponds to the amount going to petroleum refineries in Figure 16.3: this is used to produce a standard range of refined products.

## The refining sector

Refining has come a long way from its origins in small, unsophisticated "teapot" facilities, although this form of refining still survives in certain regions. Modern day refining operations are a complex manufacturing process that brings a wide range of products to market, from primary transport fuels to specialised petrochemical feedstocks. In addition to initial distillation of crude oil, refineries contain a variety of secondary processing units that use a range of catalysts and hydrogen to process intermediate feedstocks into finished products.

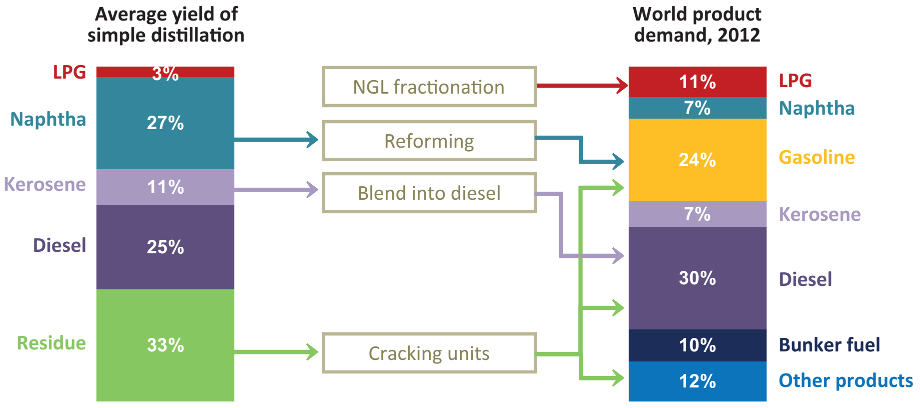
Crude distillation units (CDU), sometimes known as topping units, are the starting point for crude oil refining operations. They essentially boil the crude in order to separate it into different fractions. The lightest fractions, like LPG, come out at the top of the distillation tower, followed by light and heavy naphtha, kerosene, straight-run (or atmospheric) gasoil and, finally, residual oil, that has the highest boiling temperature of above 350 degrees Celsius.

LPG and naphtha (and gasoline by association with the latter) are known as light ends, or light distillates. Light and heavy naphtha undergo hydrotreatment, in which hydrogen is used to remove excess sulphur. After this they can either be sold as they stand for petrochemical use or be sent to reformer or isomerisation units that upgrade naphtha into, respectively, reformate and isomerate, the main components of gasoline.[4]

4. Reformer units boost the octane rating of naphtha by removing excess hydrogen atoms through catalytic processes, thereby producing the hydrogen that is needed for diesel hydrotreatment units. Hydrogen can also be produced by dedicated units using another feedstock – methane (natural gas), but for many refineries naphtha reforming remains the only source of hydrogen production. Thus, since diesel production needs the hydrogen that is the by-product of gasoline output, lower gasoline output may affect the quality of diesel output.

Next is the middle distillates fraction, which includes kerosene and straight-run gasoil. Kerosene can be used either as aviation fuel or as heating/cooking oil. [5] Gasoil is hydro-treated to remove close to 100% of its sulphur when destined for use as road diesel, and slightly less intensively than that for other applications, such as domestic heating oil, off-road use in agriculture and power generation. Marine gasoil is the heaviest type of gasoil and most often represents a blend of middle distillates with residual oil derivatives.

**Figure 16.5 ▷ Outputs from simple distillation versus final product demand**




Residual fuels can be used with little or no further processing to make heavy products such as bunker fuel, lubricants, asphalt or bitumen, or they can be partially converted into lighter products. A refinery's ability to do so depends upon its complexity. In addition to their CDUs, simple refineries might have only reformers and hydrotreaters. Complex refineries will have a range of specialised units to deal with the heavier residues. These include vacuum distillation units (VDU) that distil residual fuel oils into vacuum residue and vacuum gasoil, a feedstock for upgrading units that convert it into various combinations of gasoline, jet fuel and diesel, along with a range of by-products. Catalytic cracking units (mostly fluid catalytic cracking units [FCC]) are geared to producing gasoline; their by-products include gases, petrochemical feedstocks and light cycle oils that can be used in heating oil blending. Hydrocracking units are designed to produce ultra-low-sulphur diesel and kerosene. These units are ideal for maximising a refinery's middle distillates yield, but are generally expensive to build and operate, and require a large hydrogen supply. Another upgrading process, called coking, also produces a solid by-product called petroleum coke.

This traditional measure of a refinery's sophistication, or complexity, may need to be re-thought somewhat in the future as the crude input slate changes. With the growth in supply of lighter crudes and continued strong demand for middle distillates, there may instead be a growing call for processes that can build heavier products out of light



5. In Europe and Russia, kerosene is traditionally blended into the diesel pool to increase the volumes, and also to improve the cold properties of the latter, especially during winter.

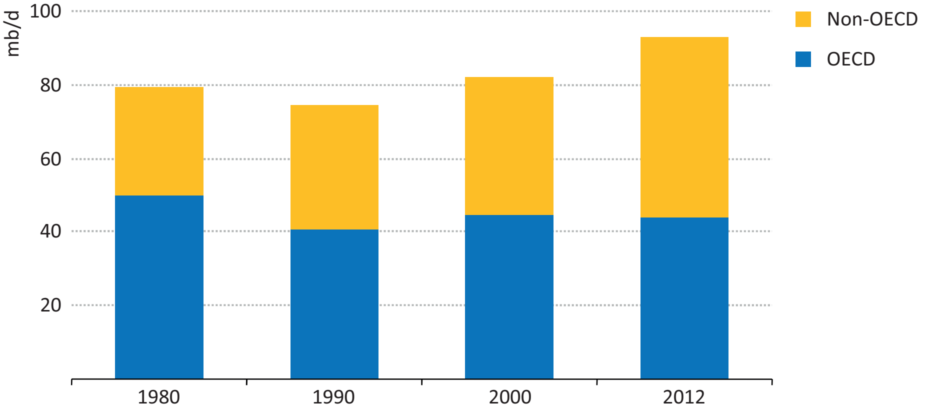
ends. In refining, breaking something down is somewhat simpler than building it up, but there are some promising technologies that can combine molecules of light products, such as LPG and naphtha, with a small number of carbon atoms to obtain heavier, more carbon-intensive products. This can be achieved by a combination of processes, known as dehydrogenation and oligomerisation, which can convert lighter products into middle distillates. The dehydrogenation process was first developed in the petrochemical industry, where it constitutes an important part of operations, and now refiners are also looking at it, in combination with oligomerisation, to enhance middle distillate yields. For the moment, there are no known commercial projects of stand-alone LPG-to-middle distillates conversion plants but, given the projected increase in LPG supply, such facilities may not be far away.[6]

Aside from their capacity to process conventional crude oil, refineries often have facilities to handle condensates. A condensate splitter, like a CDU, separates out LPG, naphtha and kerosene, with heavier condensates yielding some volumes of diesel and even residual oil. The naphtha and middle distillate fractions are reformed and hydrotreated respectively to meet gasoline and diesel specifications.

## *Global refining outlook*

Traditionally, well-to-wheel fuel supply has involved transporting crude oil and refining it close to the point of consumption, as products are transported in smaller vessels, compared with crude oil, and thus incur higher shipping costs. The present distribution of refinery capacity between OECD and non-OECD countries, therefore, broadly matches their respective shares of oil products consumption (Figure 16.6). As of 2012, non-OECD countries account for just under half of global oil use, and just over half of refinery capacity.

**Figure 16.6 ▷ World refining capacity***




* CDU and condensate splitter capacity.

6. The projections foresee stand-alone facilities appearing in North America and Middle East, as well as such processes integrated within refineries to enhance middle distillate yields at the expense of refinery produced LPG and naphtha.

This traditional model remains fundamental to the projections: oil-importing regions maintain or build refinery capacity roughly to match their internal product demand, preferring reliance on imported crude to reliance on imported products. In some cases, investments are made in order to develop (or sustain) oil product exports. The consequences are that, with the shift of the main demand centres towards Asia and the Middle East, refining capacity builds up in these regions, while, in many of the historically dominant refining industries in OECD countries, declining domestic demand and competition in export markets cause shutdowns. However, some major oil-producing countries, building on a trend that is already apparent, become important refining centres, not only to cover growing domestic demand but also to capture the added value from exports of refined products. A related motivation is to expand into the highly specialised petrochemical business that, although not particularly labour-intensive, generates much-needed jobs for fast-growing populations (and provides a degree of diversification for economies that are often very dependent on crude oil exports).

Aside from the changing composition of refining feedstocks, refiners also have to adapt to the shifting patterns of global demand for oil products, described in Chapter 15. By 2035, these result in an increase in the share of middle distillates (diesel plus kerosene) in world consumption from 37% to almost 40%, as well as an increase for light petrochemical feedstocks, such as ethane and LPG (which increase their total share of global demand by 0.8 percentage points). By contrast, the share of other light ends – gasoline and naphtha – declines by 0.5 percentage points. The share of fuel oil falls from 9% to 7% even without a switch away from fuel oil use in bunkers. This means that refiners have to shift the product slate away both from the refinery light ends (naphtha and gasoline) and the heavy ends (fuel oil) towards the middle distillates. This is achieved by deploying additional hydrocrackers and, in places, oligomerisation technologies, with the result that global yields of middle distillates increase from an average of 41.4% in 2012 to 42.9% in 2020 and 44.4% in 2035. Over the same period, gasoline and naphtha yields decline from 33.7% to 32.8% and those of fuel oil fall by two percentage points to 9%. These changes play an important role in dictating the pattern of refinery investment.

Another challenge that refiners face in many parts of the world is the need to meet higher standards of product quality and environmental performance. In OECD and other mature demand markets with stricter regulations, the investments focus on upgrading secondary units and processes for fine-tuning product specifications. In emerging markets, where mandatory product quality specifications are less stringent and product demand is growing, the investments are more balanced between distillation and upgrading units.

The survival of refineries ultimately depends on their profitability, the margin earned depending on crude purchase and transportation costs, the costs incurred during processing and the value of the various products in the market. These can vary from refinery to refinery, but regional indicative margins give a broad idea about the state of the industry in different parts of the world.[7] Refinery margins tend to have both a cyclical and seasonal nature, but they ultimately depend on demand for products from the world economy and demand for crude oil from competing refiners. While such indicators can be used in short-term analysis of the refinery sector as a guide to the overall state of the sector, the focus here is on their long-term drivers that provide the fundamentals for the refinery sector: regional and global oil product demand, the availability of crude oil and projected refining capacity.

### *Capacity*

As of 2012, global refinery capacity stood at 93 mb/d while refinery runs were under 78 mb/d. However, this does not mean that there was 15 mb/d of excess capacity: refineries need operational downtime for repairs and maintenance, usually put at around 5% of capacity. We have a higher downtime assumption, at 14%, to take into account not only scheduled maintenance, but also temporary run-cuts in lower margin environments as well as emergency closures due to natural catastrophes and industrial accidents.[8] By this measure, the "real" excess capacity is far from 15 mb/d, but is still a quite significant 4.8 mb/d, almost equal to India's current refinery capacity.

Despite this existing overhang, there is no shortage of countries planning to add refining capacity. Over 10 mb/d of new refinery projects have been announced by countries around the world, even after excluding some of the more speculative projects. We have made a critical assessment of the announced projects in order to identify those that we consider very likely to go ahead, from which the assumption is derived that 7.4 mb/d in net refining capacity is added over the period to 2020 (after offsetting announced shutdowns over this period). After 2020, a further 5.8 mb/d of refinery capacity is added in selected regions between 2020 and 2035.

In the New Policies Scenario, the projections suggest that, over the period to 2035, some 9.5 mb/d of global capacity is "at risk" of permanent shutdown, up from 4.8 mb/d today (Table 16.2).[9] This capacity is not removed from our calculations (beyond closures that have already been announced) so that, in our model, the refinery sector is balanced instead via lower utilisation rates. But, in practice, the implication of the projections is that at

7. Calculation of indicative margins is currently limited to areas where there is an open spot market to determine product and crude prices and where price assessment agencies publish feedstock and product price sets. These are the North-West Europe (NWE), Mediterranean (MED), Singapore and US Gulf coast, Midcontinent and New York Harbour trading hubs. Estimates of margins for Russian, Middle East, Indian, Chinese or other regional refiners are approximations, often defined as netbacks from international markets.

8. In regions where refineries have historically run between 90-100% of nameplate capacity, we assume zero excess capacity (rather than negative).

9. Our assumption of global capacity additions in the New Policies Scenario is conservative, compared with the volume of announced projects, but it remains sufficient in the aggregate to cater for the higher oil demand and, correspondingly, higher refined product demand of the Current Policies Scenario. In this scenario, required refinery throughputs are significantly higher than in the New Policies Scenario, at 84 mb/d in 2020 and 94 mb/d by 2035, but still 10-12% below the nameplate capacity that accumulates in the New Policies Scenario.

least some of this capacity is likely to face closure before 2035. In our assessment, the largest reductions in refinery runs occur in Europe and North America, both regions with significant projected declines in oil consumption. The decline in refinery runs in Europe is larger, relative to the size of the decline in demand, because many North American refiners benefit from access to lower priced locally produced oil.

**Table 16.2 ▷ World refining capacity and refinery runs in the New Policies Scenario** (mb/d)

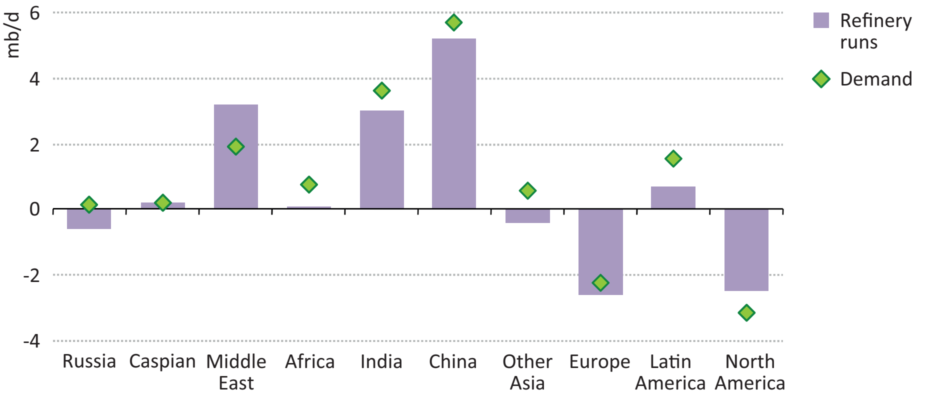
| | 2012 Capacity | Capacity additions to 2035 | Refinery runs | | | Capacity at risk | | |
|---|---|---|---|---|---|---|---|---|
| | | | 2012 | 2020 | 2035 | 2012 | 2020 | 2035 |
| Europe | 17.2 | 0.2 | 13.7 | 12.0 | 11.1 | 1.3 | 3.5 | 4.5 |
| North America | 20.9 | 0.3 | 19.0 | 18.4 | 16.5 | - | - | 2.0 |
| China | 11.7 | 4.7 | 9.1 | 12.2 | 14.4 | 1.0 | 0.6 | - |
| India | 4.4 | 2.6 | 4.0 | 4.9 | 7.0 | - | - | - |
| OECD Asia | 8.1 | -0.7 | 6.7 | 6.3 | 5.7 | 0.3 | 0.1 | 0.9 |
| ASEAN | 4.8 | 0.4 | 4.0 | 4.0 | 4.6 | 0.2 | 0.4 | - |
| Russia | 5.7 | 0.2 | 5.3 | 5.1 | 4.7 | - | 0.1 | 0.5 |
| Middle East | 7.6 | 3.4 | 6.7 | 9.1 | 9.9 | - | - | - |
| Brazil | 2.0 | 1.4 | 2.0 | 2.6 | 3.4 | - | - | - |
| Others | 10.3 | 0.5 | 7.2 | 7.7 | 7.8 | 1.9 | 1.7 | 1.7 |
| **Total** | **92.8** | **13.1** | **77.7** | **82.3** | **85.2** | **4.8** | **6.3** | **9.5** |

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

The need to cut capacity in some regions is accompanied by continued growth in capacity in others, where growth in product demand outstrips refining capacity to a significant extent. Most of the assumed 13.1 mb/d of capacity additions are in China, India and the Middle East. Brazil dominates in the refinery construction in South America (see Chapter 10), while other crude oil exporters in Africa, the Caspian region and Russia add less than 1 mb/d of capacity in total. Despite the large capacity additions in China and India, both of these countries are net importers of petroleum products in 2035, as capacity additions slightly lag the projected growth in demand. New refineries in the Middle East reflect the ambition of key producers in this region to become significant product exporters, although almost 80% of the additional capacity by 2035 serves to cover increased oil consumption within the region.

The implications for refinery runs are not limited entirely to net importing regions with declining demand. There are two considerations driving the projections for refinery runs – the dynamics of regional demand, *i.e.* the domestic market for refined products in each of the regions; and the developments in local crude supply that determine reliance on imported crude for the refining sector. Thus, lower utilisation rates and potential refinery shutdowns also concern some oil-exporting countries, for example Russia, where local oil production declines.

**Figure 16.7 ▷ Changes in refinery runs and changes in demand in the New Policies Scenario, 2012-2035**




## *Refining sector outlook by region*

The countries and regions analysed can usefully be divided into four categories, depending on their current roles in global crude and products trade (Figure 16.8).

I. Net importers both of crude oil and of refined products (Group I): these currently are Europe, China and many other parts of Asia, including ASEAN and Japan. In the case of China and Europe, both are large net importers of crude oil. China, although it has recently become self-sufficient in gasoline and diesel, imports larger volumes of fuel oil, some of which goes into teapot refineries as their main feedstock. Europe still imports more distillates than it exports gasoline.

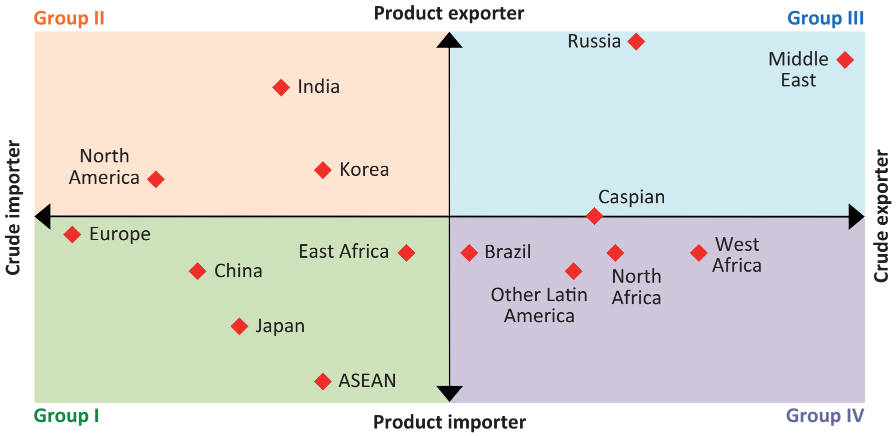
II. Net importers of crude oil that are net exporters of oil products (Group II): these include North America, India and Korea.

III. Net exporters both of crude oil and oil products (Group III): this is where many hydrocarbon resource-holding countries declare that they want to be, although currently only Russia and the Middle East occupy this quadrant. Aside from crude oil, Russia exports mostly diesel and fuel oil. The Middle East as a whole is a net exporter of kerosene and naphtha.

IV. Net exporters of crude oil that are net importers of refined products (Group IV) (all of the other crude exporting regions are in this group): Latin America (including Brazil), the Caspian, North and West Africa, none of which has yet become self-sufficient in oil products.

The regional analysis starts by looking at Europe and North America, historically the largest refining centres in the world, where the fortunes of the refining industry diverge in the projections, even though demand in both of these regions follows the same downward trajectory. Europe remains a net importer of both crude and oil products, while North America makes a major transition over the period to 2035, all but removing its need for net crude imports and becoming a significant net exporter of oil products (in the process getting very close to moving into Group III).

**Figure 16.8 ▷ Selected regions shown by their net trade position in crude oil and oil products, 2012**




Notes: The position of countries on each axis provides an indicative sense of their trading volume relative to the largest importer or exporter. The East African net crude import position is due to inclusion of South Africa. Oil products include both refinery and NGL fractionation products.

This is followed by a review of other net crude importing regions, notably those in Asia, where demand and refinery capacity is on the increase. The most dramatic change here is the loss by India of its position as a net exporter of oil products: it joins the group of net importers of crude and products (Group I). In addition, we examine the outlook for the various regions that are net exporters of crude oil and the way that their crude and product flows evolve. Here, the only significant change is with Brazil obtaining product self-sufficiency and increasing its ranking as a crude oil exporter.

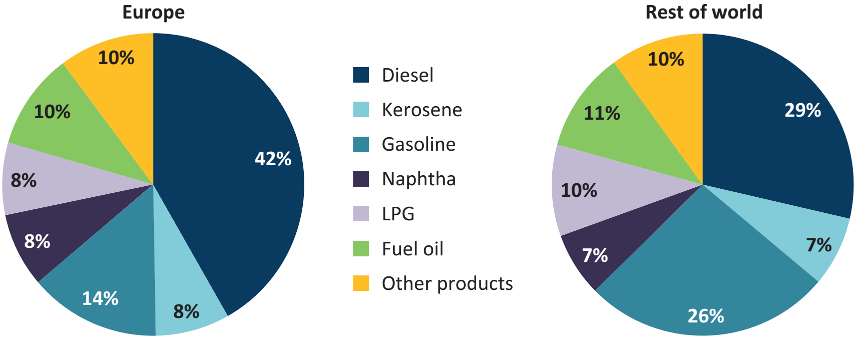
### *Europe*

In the *Outlook*, the European refining sector (encompassing both OECD and non-OECD Europe) continues to face the most acute challenges in the global refining sector. Refinery shutdowns have already become a feature of the European landscape: of the 4 mb/d of refining capacity that has been permanently shut down worldwide over the last five years, half was in Europe.[10] But despite these reductions, European refining capacity is still well above the continent's demand for refined products. This would not in itself be a problem if European refiners had access both to sufficient crude oil and to sufficient product export opportunities. However, Europe is being squeezed on both these counts, and it is anticipated that trends will continue to work against the European refining sector over the coming decades.

10. Table 16.2 shows a 200 thousand barrel per day addition to refining capacity in Europe. This is a refinery project in Turkey, being built by Azerbaijan's state-owned oil company. The refinery is already under construction, and we assume it will be completed.

One reason for Europe's refining woes is a pronounced imbalance in European demand for refined products, with diesel accounting for an unusually high share of consumption (Figure 16.9). Since the end of the 1990s, European gasoline consumption has decreased by about 1.2 mb/d, but diesel demand has increased by a similar amount, turning Europe into the biggest importer of diesel and the largest exporter of gasoline in the world. This situation is largely a result of government policies, notably fuel taxation, which have stimulated diesel consumption over gasoline. In the projections, total European oil product demand declines by 2.4 mb/d by 2035, but middle distillates retain their dominant position in the mix, their share of total product demand growing from 50% to 55%.

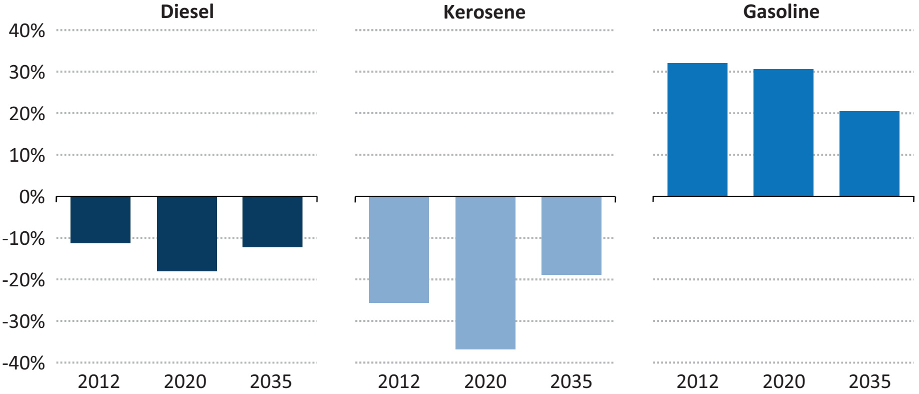
**Figure 16.9 ▷ European product demand split compared with the rest of the world, 2012**




Imbalances in demand for different products can in many instances be managed by the refinery industry through short-term measures such as adjustments to operating unit parameters and choice of catalysts or, in the longer term, by actions such as investment in specialised refining units that can alter the yields of products. However, the scope for this in Europe is limited: having added hydrocrackers and hydrotreaters since the end of the 1990s, European refineries already have one of the highest diesel yields in the world, with an average 40% yield of diesel and only 22.6% of gasoline. The projections include an increase in the total yield of middle distillates from an average of 46.6% in 2012 up to 52.5% in 2035, primarily at the expense of gasoline yields that go down by 7.4 percentage points to a very low 15.1% (a necessary decrease given the anaemic domestic demand and the limited export outlets for European gasoline). This assumes shutdown of refineries that have the lowest middle distillates yield (which often coincides with the highest gasoline yields), and deployment of the most advanced of today's refining technologies, including incorporation of oligomerisation processes within some refineries. However, these are very capital-intensive projects that could prove to be beyond the reach of many of European refiners, especially in the light of the generally unfavourable margin environment since 2009. If there is no shift in refinery yields, and no reversal in policies that favour diesel use over gasoline, then a further 2-3 mb/d of refinery runs in Europe would be at risk.

Even with the move to higher diesel and lower gasoline yields, Europe's dependence on imports of diesel and jet fuel (imports as a share of total demand) grows substantially by 2020, while its surplus of gasoline for export (as a share of refinery gasoline output) recedes only very slightly (Figure 16.10). By 2035, this share of gasoline exports remains relatively high, while dependence on imported diesel is at the same level as in 2012 because European demand for diesel falls.

**Figure 16.10 ▷ European dependence on trade for selected transport fuels in the New Policies Scenario**




Note: Negative numbers show the share of imports in total consumption; positive numbers show the share of exports in refinery output.

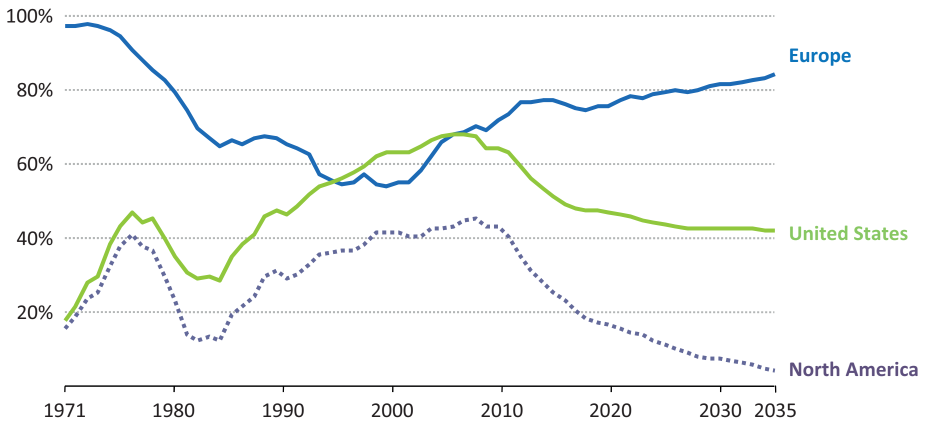
The current lifeline for European refining is the export of excess gasoline to the northeast of the United States and, for lower grades of gasoline and naphtha, to West Africa. These exports have been declining since 2006 and we see export opportunities closing further over the projection period. With declining US gasoline demand and increasing production from US Gulf Coast refineries, it is only a matter of time before the product deficit in northeast North America is covered from domestic refineries. Currently infrastructure bottlenecks and the Jones Act[11] slow this process, but it is assumed that large-scale solutions for supplying the northeast of the United States and Canada from the Gulf Coast will not be long delayed, eventually turning the North American region into a substantial net exporter of gasoline. Gasoline exported from the Gulf Coast refineries is already making its way to West Africa. This may be the final blow for those European refineries whose margins cannot survive without sustained gasoline export outlets.

A second cause of concern for European refining is increasing reliance on imported crude, a dependence that is expected to reach over 80% by the end of the projection period (Figure 16.11). This is significant because it occurs in a broader context of increased

11. The Jones Act restricts cabotage activities, *i.e.* coastal navigation between two US ports, to only vessels built in the United States, owned by US entities and manned by US citizens or permanent residents, thus generally raising its cost relative to international shipping that is not subject to such restrictions.

competition for crude in international markets, in which refining margins may come under pressure from even slight increases in transportation costs. One contributing factor, specific to Europe, is that Russia has been reducing exports of crude oil via the Black Sea and the westward Druzhba export system, routes that bring crude oil to dozens of refineries in the Mediterranean region and Central Europe. These deliveries have halved to only 600 thousand barrels per day (kb/d) since 2007 and increased flows through the new Baltic export system have not fully compensated for this fall. The main reason for this decline, up until now, has been an increase in Russian refinery runs, which have boosted Russian product exports (another blow to European refinery margins). The diversion of Russian crude for eastern export has, thus far, been a minor additional factor, but a new 25-year agreement between Rosneft and China National Petroleum Company (CNPC) to increase supplies of Russian crude to China (through the direct ESPO pipeline link, various rail links and possibly through swaps with Kazakhstan), means that diversion of Russian crude oil is set to become a more important consideration over the coming decades.

**Figure 16.11 ▷ Share of imported crude in North American and European refinery runs**



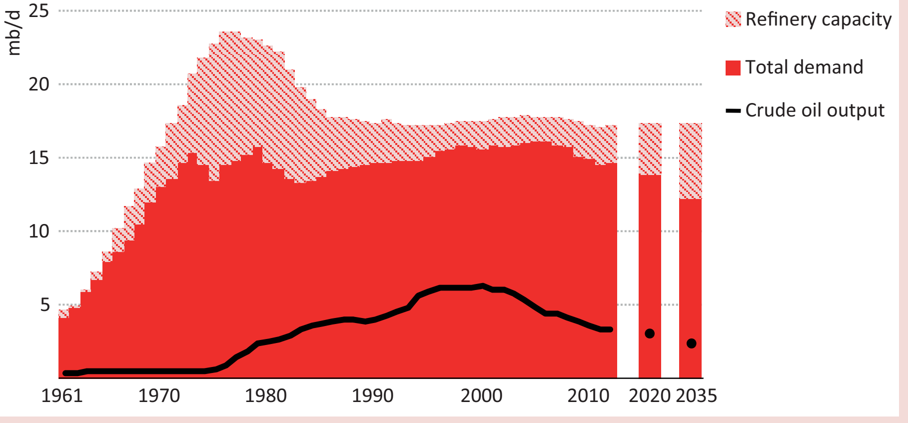

Notes: The graph shows US import reliance as a function of crude oil produced in the United States (excluding NGLs) and US refinery runs. Thanks to Canadian and Mexican exports to the United States, in practice, the reliance of the United States on crude oil imports from other regions is smaller.

By the mid-2020s, it is estimated that the availability of crude oil to Europe from its traditional sources of supply will have declined by 2.1 mb/d, as North Sea oil output and Russian exports decline. The European refining industry has faced difficult times before (Box 16.1), but this combination of declining domestic crude output, more competition from refiners elsewhere for internationally traded crude, loss of gasoline export markets and continued dieselisation at home adds up to a very challenging environment ahead. In the projections, the net result is that European refinery runs by 2035 decline by 2.6 mb/d, more than the 2.4 mb/d reduction in European demand.

### Box 16.1 ▷ Is history repeating itself for European refining?

The current over-hang of capacity in European refining has more than a few echoes of the situation that faced the industry in the 1970s. At its peak, in the mid-1970s, Europe had over 23 mb/d of refining capacity (almost one-third of global capacity at the time), with an astonishing 7 mb/d excess compared with European demand for oil products. This gap had arisen because of a frenetic expansion in refinery capacity that started in the late 1960s, all in anticipation of demand growth that failed to materialise (Pinder, 1986). A rise in European natural gas production and the arrival of gas imports from the Soviet Union in the early 1970s gradually reduced demand for fuel oil, which was the most important product of European refineries at the time. The oil price shocks of the 1970s also held back oil consumption, while prompting policy efforts on efficiency and diversification (such as the wider deployment of nuclear power) that switched demand away from oil-derived fuels.

**Figure 16.12 ▷ European refining capacity, demand and oil production in the New Policies Scenario**




Sources: BP (2013) and OPEC (1982).

By the mid-1980s, European countries had shed some 5 mb/d of capacity and increased utilisation rates from 65% to a more sustainable 75%. The current refining capacity of France, Italy and the United Kingdom is only half of its peak in the 1970s. Although this was a dramatic turn for the industry, it could have been even more severe had it not been for the rise of North Sea oil production, which helped to reduce reliance on imported crude oil from nearly 100% in the beginning of the 1970s to less than 60% in the mid-1990s.

*North America*

Almost all OECD countries see declining or relatively flat oil demand in the New Policies Scenario, but North America (the United States, Canada, and Mexico) is the only region where the oil production rises significantly. The robust availability of local crude for a large refining sector and the availability of cheaper natural gas for refinery fuel mean that this region becomes an important product exporter to the rest of the world in the projections. North America is already supplying Europe and South America with middle distillates and, by mid-2020s, it also switches from net gasoline imports to net gasoline exports.

The share of imported crude in refinery intake in North America has historically been low compared to Europe, but reliance on imports started to rise in the 1980s as domestic output fell increasingly far behind rising oil consumption. For around ten years, from the mid-1990s, refineries in the United States were more reliant on imported crude even than their European counterparts, whose access to crude was temporarily bolstered by North Sea output (Figure 16.11). Since 2007 the picture has switched again, with the import reliance of the US refining sector declining, a trend that is expected to continue throughout the projection period.

Not all refineries in North America are in a position to benefit from rising domestic oil output. In the projections, crude and condensate output in this region plateaus at 15.5 mb/d, while refinery capacity is over 20 mb/d. In the United States, which has the lion's share of the region's refining capacity at over 17 mb/d, crude and condensate output peaks at 8.4 mb/d in the second half of 2020s.[12] This, with domestic infrastructure constraints, means that some refineries along the east and west coasts of the continent continue to rely mostly on imported crude (although LTO from the Bakken play is already reaching both the east coast and west coasts [PADD 1 and PADD 5]).[13] These import-dependent refineries are squeezed from two directions in the projections: by competition from other refiners for available crude, both domestic and imported and by competition in domestic product markets from better-placed refiners in the Gulf Coast and midcontinent. For this reason, lower refinery runs are projected in the North American region, to the tune of 2.5 mb/d by 2035, with capacity rationalisation most likely in the periphery of the system along the United States and Canadian east coast and the US west coast.

Increasing production in North America does present certain challenges, even to those domestic refiners with reasonably easy access to it. All of the increase in crude supply comes from Canadian oil sands and LTO in the United States, the most vivid regional example of the bifurcation in crude supply described at the start of this chapter. These two types of feedstocks both require special facilities to extract best value from the crude: cokers and topping units respectively.[14] If a refinery has been constructed mostly to process heavy crude oil, it can still process very light crudes, but at lower utilisation rates as it may not have the necessary scale of downstream equipment for evacuating and treating the very light components (such as LPG and light naphthas) that make up a higher proportion of the

12. NGLs in North America bypass the refining sector and are therefore not included in crude oil supply volumes.

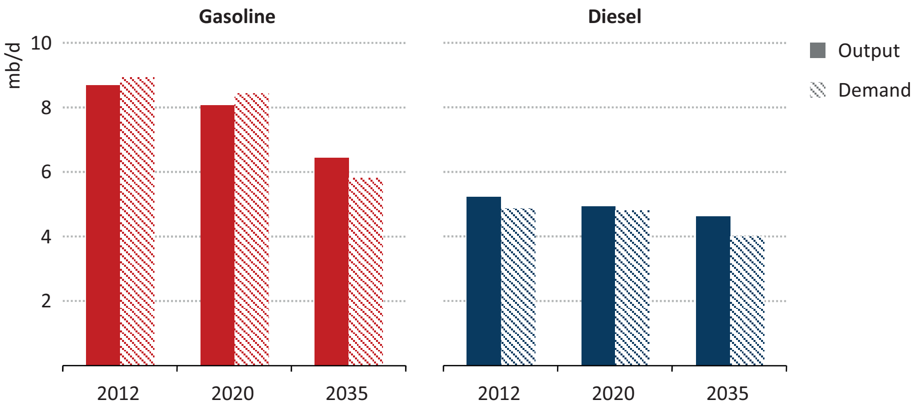
13. The US Department of Energy splits US territories into five Petroleum Administration for Defence Districts, (PADD), for petroleum analysis purposes. PADD 1 is generally the US east coast, and PADD 5 is the US west coast with Hawaii and Alaska.

14. Cokers break extra-heavy oil into lighter products such as diesel and gasoline. Topping units boil off gaseous overheads of extra light crude oil and condensate before they enter main refining operations.

very light crudes. The short-term dilemma facing the owners of highly complex refineries is whether to under-utilise capacity, using cheaper domestic crude or continue importing (more expensive) heavy crude at international prices.

Over the coming years, it is anticipated that the North American refining industry adjusts to cater to the new balance of feedstocks. There is a growing interest in processing local light crude, with refiners and midstream operators announcing plans to add condensate splitters, topping units, pipelines, storage units to existing refineries or construct greenfield facilities in the Gulf Coast to refine lighter crudes and export the products. In the absence of any indications to the contrary, it is assumed that the existing ban on crude oil exports in the United States will remain in place. But we also see that these planned investments, once made, are set to diminish the economic case for exports. At the same time, some of the more complex refineries are expected to continue importing heavier crudes from other countries in the American continent or the Middle East.

**Figure 16.13 ▷ North American gasoline and diesel balances in the New Policies Scenario**



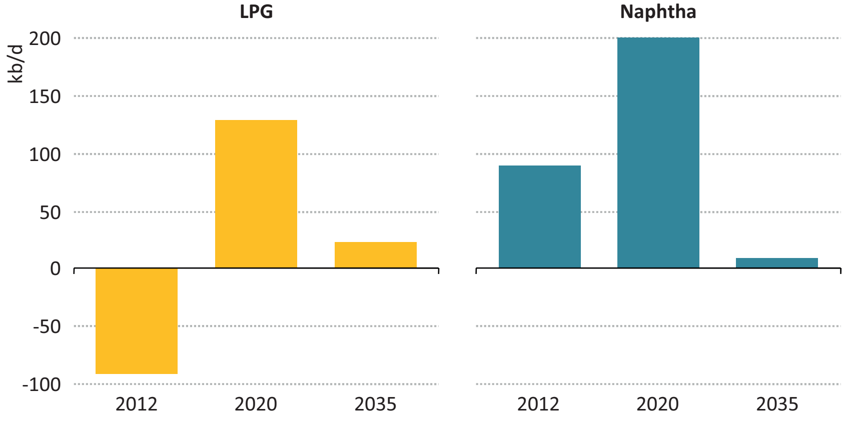

Canadian extra-heavy oil is refined mostly in the United States in the *Outlook*, exported there as syncrude (synthetic crude produced from bitumen in upgraders), diluted bitumen (dilbit)[15] or pure bitumen. This results in fewer straight-run middle distillates, but the impact on diesel output is offset in the projections by the installation of more hydrocrackers (increasing diesel yields and bringing down currently high gasoline yields). Even with these lower gasoline yields, which decline by around seven percentage points to 39% by 2035, the gasoline balance for the North American region still switches into surplus, as the decline in demand outstrips the reduction in supply (Figure 16.13), although the current debate in the United States about a possible revision of the Renewable Fuel Standard could affect the long-term projections for ethanol and gasoline balances (see Chapter 6). In addition to the switch in gasoline to diesel yields, another

15. Dilbit, which is a mixture of bitumen and diluents such as natural gasoline or butanes, is difficult to refine, yielding relatively lower volumes of middle distillates but higher proportions of heavy residue and gases. This consideration is taken into account in projecting refinery yields.

boost to diesel output comes from stand-alone oligomerisation projects that start by the end of this decade, reaching 70 kb/d of output capacity by 2035 and utilising propane to produce middle distillates.

A final aspect of the product outlook for North America is the way that the increase in production of NGLs and lighter crude oils affects the balances of LPG and naphtha. Although these are eventually absorbed by an increase in feedstock demand from the petrochemical industry, this takes time. In the interim, around 2020, North America becomes a significant net exporter of LPG and naphtha (Figure 16.14).

**Figure 16.14 ▷ North American trade of LPG and naphtha in the New Policies Scenario**



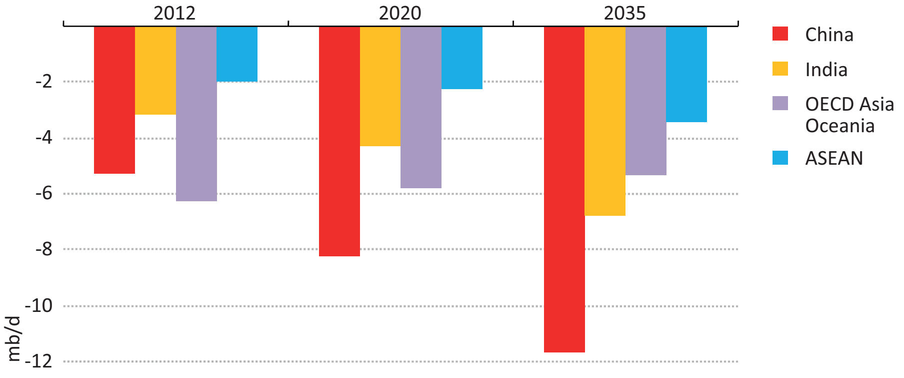

Note: Positive balances denote exports; negative balances denote imports.

The crude oil balance of North America shows the most dramatic improvement of any of the regions analysed. By 2035, North America's net import requirement for crude oil drops to just 400 kb/d, down from 6 mb/d in 2012. Half of this decline takes place before 2020, during which time the net import requirement already falls to less than 3 mb/d. This fall does not mean that crude oil trade with the rest of the world dries up to the same extent. It is more likely that some North American crude, such as Canadian production, will find its way to refiners in Asia, while the United States will continue importing a variety of crudes from different international sources, mostly due to individual refinery preferences for specific crudes, especially in cases where refineries are owned by foreign large oil-producing nations such as Venezuela or Saudi Arabia. There is also the possibility that some Mexican exports may be re-routed to markets outside the region.

### *Asia*

Asia is the destination for the largest share of crude oil traded internationally. In 2012, over 17 mb/d of crude oil from other regions went to the major refining centres of Asia – India, China, Japan, Korea, Singapore and Chinese Taipei. In the New Policies Scenario, this figure rises to 28 mb/d by 2035, to feed the expansion in refining capacity (notably in China and India) and to compensate for the decline in regional oil output (2.5 mb/d across Asia as a whole). The Asian region is, though, far from homogenous and the refining sectors of different countries evolve in different ways.

**Figure 16.15 ▷ Crude oil trade in selected Asian countries and regions in the New Policies Scenario**



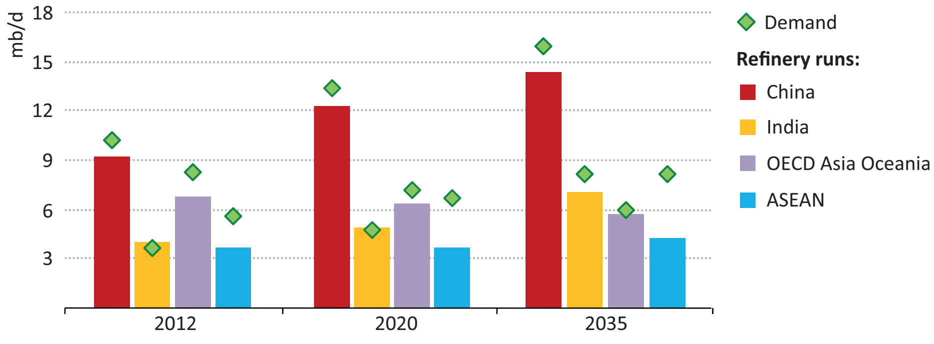

Note: Negative balances denote imports.

The projections take into account a loss of 0.7 mb/d of refining capacity in Asia, mostly in Japan, (where already mandated shutdowns account for 500 kb/d), a planned shutdown in Chinese Taipei and in Australia, where oil majors have started to exit refinery operations. Continued pressure on refining margins and utilisation rates is seen in many of the OECD markets, where demand is declining, although the Korean refining industry is anticipated to be relatively resilient because of its strong integration with petrochemicals and its ability to export valuable middle distillates. By contrast, Japanese refinery runs decline, in part due to the announced government initiative to discontinue the use of excess topping units (to increase the complexity of the remaining capacity), but also because demand in Japan declines by 1.8 mb/d to 2035, or by 2% annually, a faster rate than elsewhere in the OECD. In ASEAN countries, 450 kb/d of capacity is added and utilisation rates rise.

Capacity additions in China and India exceed those of any other country in the region and in the world, reflecting the strong growth in demand for oil products in both countries. In India, current refinery capacity (4.4 mb/d) is increased by 500 kb/d over the period to 2020 and a further 2.2 mb/d by 2035. China's refinery capacity, currently 11.7 mb/d, rises by 3.2 mb/d over the period to 2020 and another 1.5 mb/d by the end of the projection period.[16] Together, China and India more than double their crude oil imports, reaching a combined import volume of 18.5 mb/d in 2035.

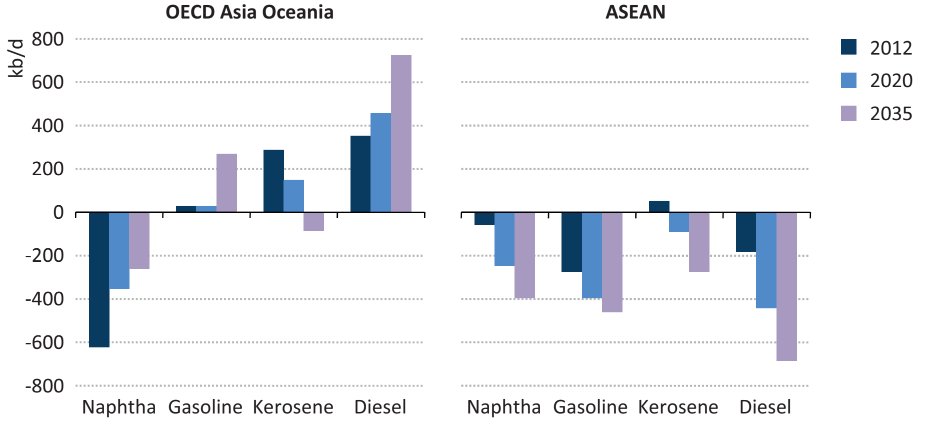
16. Our starting point for total Chinese capacity does not include teapot refineries that use fuel oil as feedstock and hence are not crude consumers. It also lowers the nameplate capacity of small-scale independent refiners that have operated at just 20-30% utilisation rates. Chinese fuel-oil teapot refineries are expected to gradually shut down by 2020, losing market share to newly built capacity.

**Figure 16.16** ▹ **Refinery runs and demand in selected Asian countries and regions in the New Policies Scenario**




These capacity additions lag behind the increases in oil product demand in both countries (which rises by 4.5 mb/d to 2035 in India and by 5.8 mb/d in China). India remains a significant exporter of oil products in the medium term, but this situation is reversed in the latter part of the projection period as it becomes the single largest source of global oil consumption growth. By 2035, India is a net importer of oil products. China continues to rely on net product imports throughout the period to 2035, as rising demand absorbs all of the output from newly built refinery capacity. Combined net product imports of China and India are around 1 mb/d in 2035.

**Figure 16.17** ▹ **Oil product trade balance in selected Asian regions in the New Policies Scenario**




Note: Positive balances denote exports; negative balances denote imports.

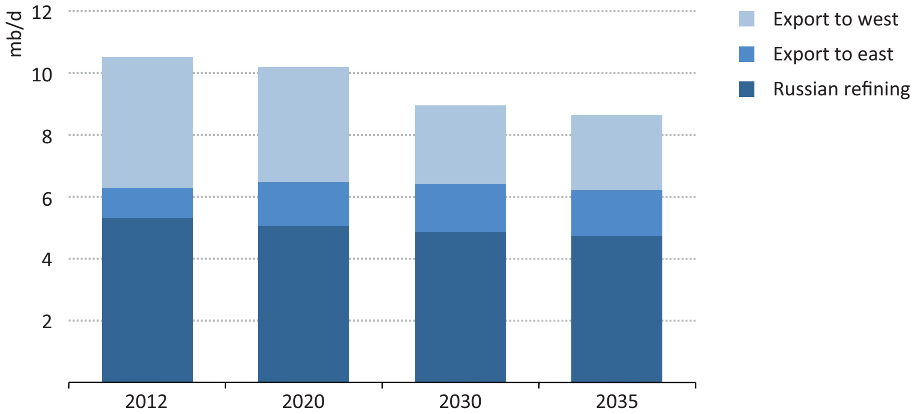
The outlook for OECD Asia Oceania and for ASEAN shows some significant changes in total product balances (Figure 16.17). The OECD grouping manages to increase exports over the period, as its own domestic demand declines, freeing up product to supply to the large and growing demand centres elsewhere in Asia. In ASEAN, growing refinery runs do not keep pace with the increase in consumption, leading to an increase in imports of both crude and products.

### *Russia*

As well as being a major exporter of crude oil, Russia is currently the largest net exporter of refined products, exporting large volumes of diesel, naphtha and fuel oil and importing only some gasoline from Belarus.[17] Judging by the pronouncements of other oil-exporting countries, this appears to be a model that many would like to emulate, but in the projections only the Middle East does so, in aggregate. In the *Outlook*, the composition of Russia's product exports changes over time, with a falling share of fuel oil and a higher share of more valuable transport fuels.

The post-Soviet resurgence of oil production in the mid-2000s initially resulted in an increase in exports of crude oil, but a change in the system of export duties subsequently created more favourable conditions for refining at home. The intention had been to incentivise investment in refinery upgrades, but what happened in practice was that crude runs in old refineries rose again, mostly at simple refineries with high fuel oil yields, and numerous small and very simple teapot refineries appeared along the oil export pipelines. As a result, instead of increasing export only of higher margin products, Russia became a very large exporter of relatively low-value fuel oil: Russian fuel oil exports were 1 mb/d in 2012, larger than the crude oil exports of countries like Oman and Qatar.

**Figure 16.18 ▷ Allocation of Russian crude oil and condensate production in the New Policies Scenario**

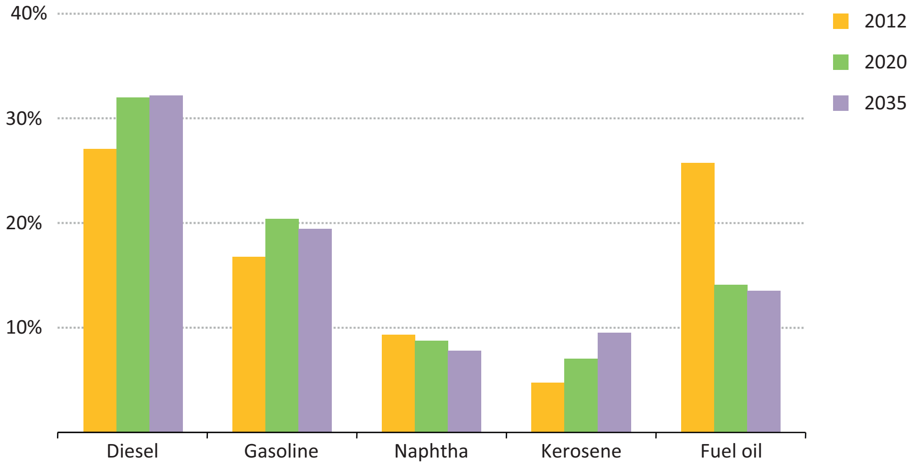



Over the projection period, Russian crude oil and condensate production declines from about 10.6 mb/d in 2012 to 9 mb/d in 2035. This decrease has to be felt somewhere; either in crude exports (to east or west) or in the amount of crude flowing to domestic refineries.

17. If LPG exports are added to the mix, then the Middle East catches up with Russia as an exporter of total oil products, but Russia is a larger exporter of refined products.

Almost all of Russia's refineries, except two in the far east, feed from the pipelines that also supply the western export routes. Since east-bound crude oil exports are set to rise, for strategic as well as commercial reasons, the supply of crude to the western part of the system is expected to be affected, with Russian refiners winning out against crude exports.

**Figure 16.19 ▷ Main oil product yields in Russian refineries in the New Policies Scenario**

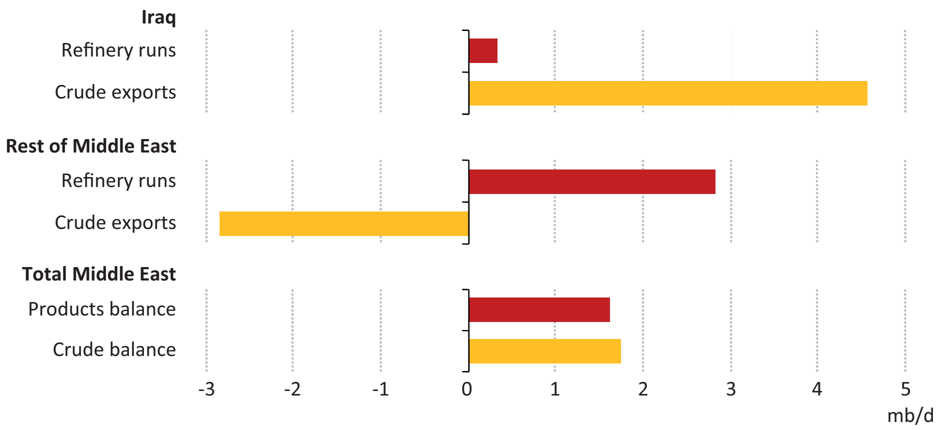



In practice, fiscal policy will play a major role in the allocation of crude between exports and domestic refining and in the composition of Russian product exports. The process of re-balancing oil export taxes that started in 2011 will take a few years to complete, but is expected to disadvantage the least efficient refiners by discouraging fuel oil exports (and reducing refinery runs as a result). Fuel oil exports reduced also because capacity is upgraded at bigger and more complex refineries, increasing the output of more valuable transport fuels, such as diesel, gasoline and kerosene (Figure 16.19). This investment helps to maintain Russia's diesel exports despite the decline in refinery runs, to balance the growing domestic market for gasoline and kerosene, and to meet assumed higher quality standards that are introduced for transport fuels. Russia's exports of transport fuels do not change significantly over the projection period, but those of naphtha and fuel oil decline to below half of their current volumes.

### *Middle East*

The Middle East adds about 3.4 mb/d of refining capacity over the projection period, an increase of almost 45% over its refining capacity today. As a result, the 4.7 mb/d increase in crude and condensate output over the period to 2035 results in only a 1.7 mb/d growth in crude exports. That the Middle East sees any increase in crude exports in the projections is because of Iraq, where the increase in crude production of 4.5 mb/d over the period to 2035 is almost entirely available for export, offsetting a net decline in crude availability from other Middle Eastern countries (Figure 16.20).

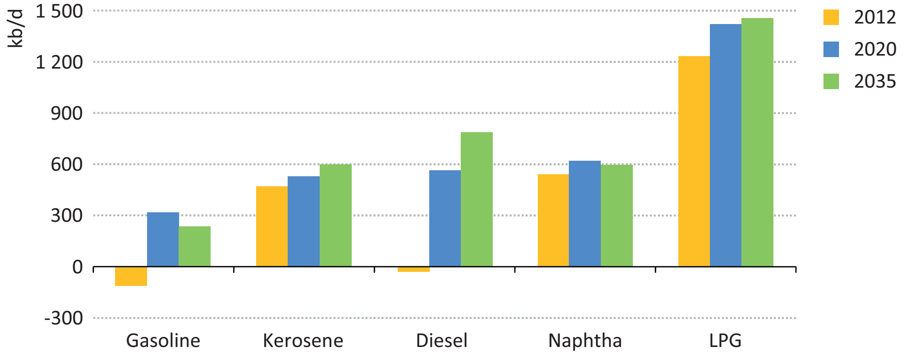
**Figure 16.20** ▷ **Changes in refinery runs and exports in Iraq and the rest of the Middle East in the New Policies Scenario, 2012-2035**




Note: The figures for crude export are for crude and condensate only and exclude trade in the non-refinable portions of NGLs, which are included in total product exports.

This overview of the period to 2035 masks a very significant development in the medium term. Three-quarters of the new refinery capacity assumed to be built in the Middle East is added before 2020, outpacing growth in oil output from the region. This contributes to a decline of some 2.3 mb/d in crude oil and condensate exports from the Middle East by 2020 (before these recover later), forcing many Asian buyers to look further afield for crude supplies, to West Africa, Brazil and the Caspian, thus encroaching on Europe's traditional supply sources and potentially increasing the pressure on Europe's refining industry.

**Figure 16.21** ▷ **Middle East trade of selected oil products in the New Policies Scenario**



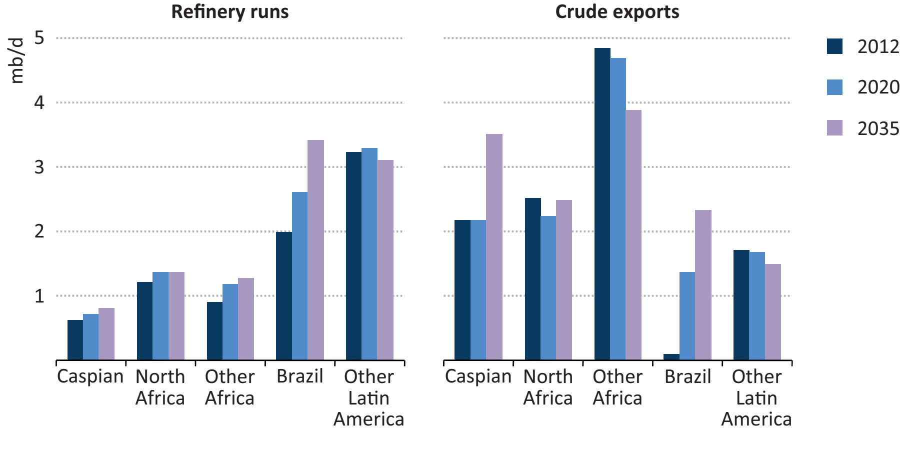

Note: Positive balances denote exports; negative balances denote imports.

Some 80% of the additional capacity in the Middle East is used to supply incremental domestic demand by 2035, but the region also emerges as a major net exporter of oil products, adding diesel and gasoline to its usual exports of petrochemical feedstocks and kerosene (Figure 16.21). Net LPG and naphtha exports are constrained by higher feedstock demand in the region's petrochemical sector, but – in a much more significant turnaround – the Middle East switches from net imports of gasoline and diesel to net exports within the next several years.

### *Other crude exporters*

In the projections, most of the other crude oil exporting regions do not achieve product demand self-sufficiency, let alone net product exports. In our judgement, the financial burden of sustaining and expanding upstream operations and the need for oil revenues for other social and economic purposes will severely constrain their ability to finance increasingly large refinery construction projects. The main exception is Brazil, which succeeds in constructing enough refinery capacity to catch up with product demand by around 2020 (see Chapter 10). With Brazil adding almost 1.5 mb/d of new refinery capacity over the projection period as a whole, its 3.7 mb/d rise in oil production results in only a net 2.2 mb/d addition to crude oil exports. The rest of South America, which – thanks mainly to Venezuelan volumes – is a net oil exporting region, nonetheless remains a net importer of products, as capacity additions in Colombia are more than offset by the assumed eventual closure of the Isla refinery on Curaçao. The region (excluding Brazil) sees a steady growth in dependence on imported diesel, from 470 kb/d to almost 800 kb/d, providing an outlet for North American diesel exports.

**Figure 16.22 ▷ Crude export and refinery runs in selected crude oil-exporting countries and regions in the New Policies Scenario**



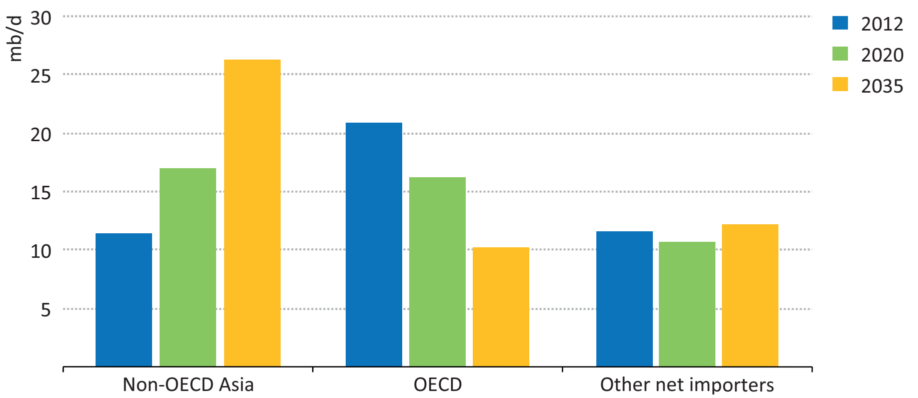

The Caspian is another region where crude output increases significantly, driven by higher output from Kazakhstan. Crude oil exports in 2035 reach 3.5 mb/d from 2.2 mb/d currently. With only one new refinery assumed to be built, in Kazakhstan, the region remains a small net product importer, supplied by Russia. It is assumed that the crude oil pipeline from Kazakhstan to China is expanded to 400 kb/d, as planned, and further to 800 kb/d by 2035, but the remaining increase in production is conveyed via other routes, notably the expanded CPC pipeline to the Black Sea and shipments via the Russian network. The export direction of a post-2020 expansion in Kazakhstan output, which should come primarily from further development phases of the Kashagan field, is open to question: the producing consortium has expressed a preference for westward routes, including via Caspian trans-shipments and the South Caucasus, but the arrival in the consortium of CNPC could shift this orientation eastwards.

West African crude oil production declines in the *Outlook* from 5.6 mb/d to 4.7 mb/d. Some 300 kb/d of refining capacity is projected to come online in the 2020s in Angola, Nigeria and Equatorial Guinea, which will meet a part of incremental product demand. However, the region remains a net importer of diesel and gasoline. East Africa sees refining capacity additions in Uganda and, possibly, South Sudan. However, it does not achieve product self-sufficiency and imports of gasoline and diesel are projected to continue. In the projections, we do not assume any net refinery capacity additions in North Africa (despite the announcements of a number of projects by governments and oil companies in the region). It remains a net product importer while crude exports from Algeria and Libya are partly offset by imports into Egypt, Tunisia and Morocco.

## Oil trade

The changing geography of oil production and consumption brings with it a fundamental re-ordering of global oil trade over the coming decades. Although the growth in inter-regional oil trade (from 44 mb/d in 2012 to 49 mb/d in 2035) is broadly proportional to the growth in global oil supply, the direction of trade flows in 2035 represents a dramatic departure from the patterns seen today, a shift that has implications for the way that countries co-operate to ensure security of oil supply.

**Figure 16.23 ▷ Net oil imports in selected regions in the New Policies Scenario**



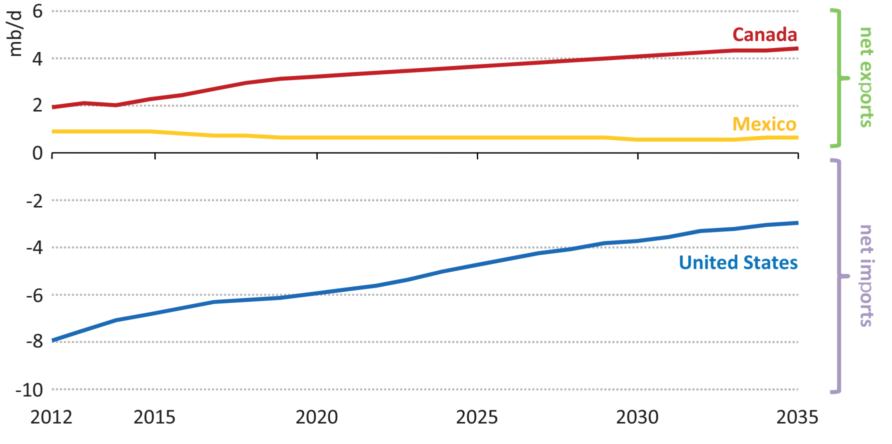

Aggregate figures for net oil imports reveal how the destination of global oil trade moves away from OECD countries towards the emerging demand centres of Asia (Figure 16.23).[18]

18. In previous *Outlooks* we referred to oil trade in net terms as the difference between total production and total demand in any given country or region; this section starts with an analysis on this basis, before proceeding to separate treatment of crude oil and oil products.

The combined net requirement for imports among non-OECD Asian countries grows by almost 15 mb/d over the period to 2035 to reach 27 mb/d, more than half of total inter-regional trade. Most of this increase comes from China (where imports grow by almost 7 mb/d), India (by 4.8 mb/d) and ASEAN (by 3 mb/d). China is in the process of overtaking the United States to become the largest net oil-importing country and its net import levels also overtake those of the European Union around 2020.

The countries of the OECD – traditionally the largest importers of oil – all see their imports decline. Their combined share of total inter-regional trade declines from around 50% today to only 20% in 2035. The fall in net oil imports is modest in European and Asian OECD countries, but is very pronounced in North America, where a 5.1 mb/d net import requirement in 2012 turns into a 1.7 mb/d net oil export position by 2035 (Figure 16.24). This 6.8 mb/d turnaround in North America is attributable in part to increased oil production (which rises by 3.8 mb/d), but also to reduced oil consumption (which falls by 3 mb/d); the net decline in North America almost exactly counter-balances the increase in Chinese net imports.

**Figure 16.24 ▷ Net oil trade in North America in the New Policies Scenario**

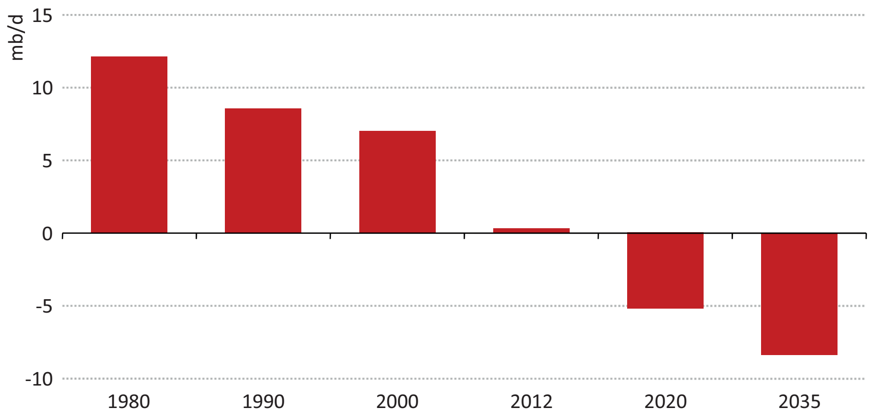



Examining only trade in crude oil (which accounts for the dominant share of total trade), many of the same themes are apparent.[19] Over the coming decades, the main crude oil flows shift decisively from the Atlantic basin (where Europe is left as the only substantial import market) to the "East of Suez" region, as the combined Middle East and Asian region is traditionally referred to in trading analysis. The latter region, taken as a whole, used to be a big net exporter of crude oil to the rest of the world, mainly from the Middle East to Europe and North America. In 2000, for example, the East of Suez region exported 7 mb/d in net terms (Figure 16.25). With increasing refinery capacity additions in this region (reflecting rising demand for oil products), this net contribution to the rest of the world started to fall. By 2012, the East of Suez region was roughly in balance, meaning that

19. For trading analysis purposes, crude oil includes also the condensate part of NGLs.

Middle East net crude oil exports were just matching total Asian imports. In practice, of course, the Middle East exports oil to regions outside Asia as well, including to European and North American refineries; but Asia also receives roughly equivalent volumes from other sources, such as Russia, the Caspian region and West Africa.

**Figure 16.25 ▹ Combined crude oil trade balance of Middle East and Asia in the New Policies Scenario**

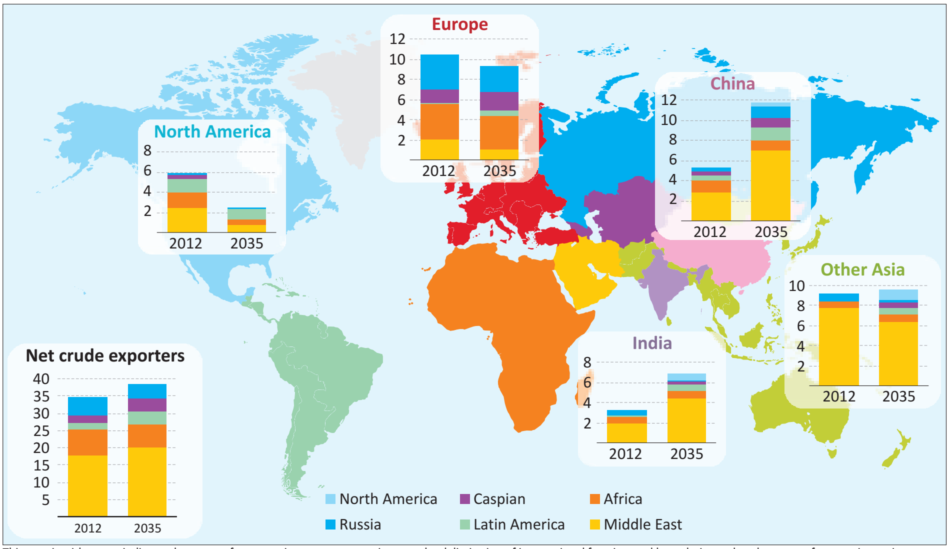



Note: Positive numbers denote net exports; negative numbers denote net imports.

Over the period to 2035, crude oil exports from the Middle East rise only modestly, as the region adds refining capacity, absorbing most of the growth in its production. Asian refinery capacity also increases substantially, while its crude output declines, pushing up its crude oil import needs even further and driving the East of Suez region into deficit. Meanwhile, North American crude oil imports decline dramatically, with the rise in production of LTO and Canadian oil sands, and falling demand for oil products. The consequence is that crude oil from other exporting regions is drawn to the East of Suez region on an unprecedented scale, with a net crude requirement in 2035 of over 8 mb/d.

Since some Middle Eastern crude exports are still expected to go westwards (mainly to Europe, albeit in reduced volumes compared with today), flows of crude oil from the rest of the world to the East of Suez region are projected to be even greater, at more than 9 mb/d by 2035. Direct imports into Asian markets, either via pipelines from Russia or Kazakhstan or through ports in Russia's far east, are assumed to rise to some 2.3 mb/d (based on current and planned infrastructure projects). This still leaves another 7 mb/d to be shipped by tankers through Russia's European ports, West Africa, Latin America and Canada (Figure 16.26). Overall, inter-regional crude oil trade increases by 3.6 mb/d, or about 10%, between 2012 and 2035. However, we estimate that tanker trade (volumes of oil-on-water) is set to increase by around 18%, as average shipping distances lengthen.

**Figure 16.26 ▷ Crude oil imports by region and source in the New Policies Scenario** (mb/d)




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.

The volume of oil products traded internationally increases from 8.7 mb/d in 2012 to 9.7 mb/d in 2035. In the case of diesel, the East of Suez region continues to export to Europe, Latin America and Africa, with Russia and, increasingly, North America making up the difference. For gasoline, the East of Suez region switches from being more or less self-sufficient to becoming a net importer, with imports reaching about 600 kb/d, coming mainly from the Atlantic basin. Similarly, Middle Eastern LPG exports are not sufficient to meet growing needs in Asia, and thus the East of Suez region relies increasingly on supplies from North America, Russia and North Africa. Naphtha and fuel oil continue to be shipped from Europe and Russia to Asian markets, albeit in smaller volumes than at present. Most Middle Eastern kerosene exports go to Asia.

The projections imply that, in 2035, the share of oil products in inter-regional oil trade is around 20%, roughly the same figure as today. This finding, however, is very sensitive to assumptions about the volume and location of refinery additions, in particular the extent to which major oil producers build refinery capacity in order specifically to target product exports. In the New Policies Scenario, we make a generally cautious assessment of the prospects for this type of refinery additions. Most new refinery capacity in this scenario is concentrated in countries and regions experiencing strong demand growth; only a relatively small amount, mainly projects under construction or considered highly likely to go ahead in the Middle East, is oriented towards product exports.

The opening of this export-oriented refining capacity in the Middle East temporarily pushes the share of products up towards one-quarter of global oil trade around 2020, before this trend is reversed in the latter part of the projections as the capacity in question is increasingly required to meet growing demand from within the Middle East itself. But the structure of oil trade would evolve very differently if more refineries were built in the Middle East, North Africa, West Africa, or Brazil, than what is assumed in the New Policies Scenario, or if Russia were to continue to de facto prioritise domestic refinery runs over crude oil exports. Increased competition from these regions in product supply markets would imply a new round of rationalisation of refining capacity among the importing countries, notably in OECD countries. If refining were to become more of an export industry, this would also expand a debate (that is already visible in some importing countries) about the security-of-supply implications of increased reliance on oil product streams transported over larger distances. The higher risks of disruption implicit in longer supply chains would require importers to build additional storage capacity and, in some cases, to alter the balance in their strategic inventories between crude oil and products.

With or without a shift towards trade in oil products, the projections already point to a need for a reappraisal of oil security and how best to achieve it. By 2035, the two largest crude oil-importing countries in the world are China (11.7 mb/d) and India (6.8 mb/d), while the share of the United States in inter-regional crude oil trade declines from 27% today to 15%. As oil import needs rise across Asia, so the countries concerned are developing their capacity to deal with the possibility of oil supply interruptions. Changing patterns of global oil trade have implications for the volumes of oil flowing through certain strategic choke points in the oil supply system. For example, flows of crude oil through the Malacca Straits are projected to rise from around 13 mb/d in 2012 to 17.5 mb/d in 2035.

Countries that rely increasingly on imports will have a heightened interest in engaging actively in efforts to ensure the security of such international shipping routes. More broadly, all oil importers share a strong interest in mitigating the risk of an interruption in supplies – wherever it might take place – because of the potential impact on prices and economies globally. Increasingly, building oil stocks and contributing to plans for their co-ordinated use are becoming essential features of national and regional strategies to secure long-term oil needs. Oil (and gas) trade can underpin a strengthening of political relationships between the main importers and the main oil exporters. There has already been reference in some quarters to a sea-change in the politics of oil, its implications are best explored jointly by all those engaged in the trade.

# ANNEXES

## *World Energy Outlook links*

**General information**
*www.worldenergyoutlook.org*

**Tables for Scenario Projections (Annex A)**
*www.worldenergyoutlook.org/annexa/*
User ID: WEO2013AnnexA
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**Factsheets**
*www.worldenergyoutlook.org/media/weowebsite/2013/factsheets.pdf*

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*www.worldenergyoutlook.org/energyclimatemap/*

**Southeast Asia Energy Outlook**
*www.worldenergyoutlook.org/southeastasiaenergyoutlook/*

# Tables for Scenario Projections

## Definitional 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 fuel combustion in the Current Policies, New Policies and 450 Scenarios. The following regions/countries 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, 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 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 2011 are based on IEA statistics, published in *Energy Balances of OECD Countries, Energy Balances of non-OECD Countries* and *$CO_2$ Emissions from Fuel Combustion*. Historical data for *electrical capacity* is supplemented from the Platts World Electric Power Plants Database (December 2012 version) and the International Atomic Energy Agency PRIS database.

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 power generation 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 electrical capacity is the net result of existing capacity plus additions less retirements. Total $CO_2$ includes emissions from other energy sector in addition to the power generation 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 for oil. Gas use in international bunkers is not itemised separately. $CO_2$ emissions do not include emissions from industrial waste and non-renewable municipal waste.

## New Policies Scenario

| | Production | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Oil supply and production (mb/d)** | | | | | | | | | |
| **World supply** | **66.9** | **86.8** | **95.4** | **97.8** | **99.5** | **101.4** | **100** | **100** | **0.7** |
| Processing gains | 1.3 | 2.1 | 2.6 | 2.8 | 3.1 | 3.3 | 2 | 3 | 1.9 |
| **World production** | **65.6** | **84.7** | **92.8** | **95.0** | **96.5** | **98.1** | **98** | **97** | **0.6** |
| *Crude oil* | *59.6* | *68.5* | *67.7* | *66.6* | *65.5* | *65.4* | *79* | *64* | *-0.2* |
| *Natural gas liquids* | *5.6* | *12.2* | *14.8* | *15.9* | *16.8* | *17.7* | *14* | *17* | *1.6* |
| *Unconventional oil* | *0.4* | *3.9* | *10.4* | *12.5* | *14.2* | *15.0* | *5* | *15* | *5.8* |
| **OECD** | **19.0** | **19.0** | **23.2** | **23.1** | **22.8** | **22.4** | **22** | **22** | **0.7** |
| Americas | 13.9 | 14.6 | 19.3 | 19.8 | 19.9 | 19.6 | 17 | 19 | 1.2 |
| Europe | 4.3 | 3.8 | 3.1 | 2.6 | 2.2 | 2.0 | 4 | 2 | -2.6 |
| Asia Oceania | 0.7 | 0.6 | 0.7 | 0.7 | 0.7 | 0.7 | 1 | 1 | 0.9 |
| **Non-OECD** | **46.7** | **65.7** | **69.6** | **71.8** | **73.7** | **75.7** | **76** | **75** | **0.6** |
| E. Europe/Eurasia | 11.7 | 13.7 | 13.7 | 13.7 | 13.9 | 14.2 | 16 | 14 | 0.2 |
| Asia | 6.0 | 7.7 | 7.7 | 7.4 | 6.8 | 6.0 | 9 | 6 | -1.1 |
| Middle East | 17.7 | 27.6 | 28.6 | 30.3 | 32.0 | 34.4 | 32 | 34 | 0.9 |
| Africa | 6.7 | 9.2 | 10.2 | 10.0 | 9.8 | 10.1 | 11 | 10 | 0.4 |
| Latin America | 4.5 | 7.5 | 9.4 | 10.5 | 11.0 | 11.0 | 9 | 11 | 1.6 |
| **Natural gas production (bcm)** | | | | | | | | | |
| **World** | **2 059** | **3 384** | **3 957** | **4 322** | **4 646** | **4 976** | **100** | **100** | **1.6** |
| *Unconventional gas* | *70* | *560* | *832* | *999* | *1 165* | *1 328* | *17* | *27* | *3.7* |
| **OECD** | **881** | **1 195** | **1 358** | **1 403** | **1 430** | **1 483** | **35** | **30** | **0.9** |
| Americas | 643 | 859 | 1 000 | 1 041 | 1 063 | 1 114 | 25 | 22 | 1.1 |
| Europe | 211 | 277 | 249 | 237 | 225 | 215 | 8 | 4 | -1.1 |
| Asia Oceania | 28 | 59 | 109 | 125 | 143 | 155 | 2 | 3 | 4.1 |
| **Non-OECD** | **1 178** | **2 188** | **2 599** | **2 919** | **3 216** | **3 492** | **65** | **70** | **2.0** |
| E. Europe/Eurasia | 831 | 882 | 911 | 986 | 1 094 | 1 164 | 26 | 23 | 1.2 |
| Asia | 130 | 419 | 566 | 625 | 694 | 769 | 12 | 15 | 2.6 |
| Middle East | 92 | 519 | 624 | 720 | 766 | 823 | 15 | 17 | 1.9 |
| Africa | 64 | 200 | 280 | 333 | 378 | 428 | 6 | 9 | 3.2 |
| Latin America | 60 | 168 | 218 | 255 | 285 | 308 | 5 | 6 | 2.6 |
| **Coal production (Mtce)** | | | | | | | | | |
| **World** | **3 194** | **5 498** | **6 003** | **6 160** | **6 255** | **6 326** | **100** | **100** | **0.6** |
| *Steam coal* | *2 227* | *4 289* | *4 689* | *4 883* | *5 024* | *5 152* | *78* | *81* | *0.8* |
| *Coking coal* | *571* | *896* | *993* | *981* | *958* | *929* | *16* | *15* | *0.2* |
| **OECD** | **1 533** | **1 397** | **1 430** | **1 384** | **1 343** | **1 300** | **25** | **21** | **-0.3** |
| Americas | 836 | 826 | 797 | 768 | 728 | 700 | 15 | 11 | -0.7 |
| Europe | 526 | 248 | 218 | 180 | 151 | 123 | 5 | 2 | -2.9 |
| Asia Oceania | 171 | 323 | 415 | 435 | 464 | 478 | 6 | 8 | 1.6 |
| **Non-OECD** | **1 661** | **4 101** | **4 573** | **4 776** | **4 912** | **5 026** | **75** | **79** | **0.9** |
| E. Europe/Eurasia | 533 | 429 | 448 | 437 | 433 | 432 | 8 | 7 | 0.0 |
| Asia | 952 | 3 377 | 3 755 | 3 945 | 4 069 | 4 162 | 61 | 66 | 0.9 |
| Middle East | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1.1 |
| Africa | 150 | 209 | 244 | 259 | 264 | 277 | 4 | 4 | 1.2 |
| Latin America | 25 | 85 | 125 | 134 | 146 | 155 | 2 | 2 | 2.5 |

| | Production | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Oil supply and production (mb/d)** | | | | | | | | | | |
| **World supply** | **97.1** | **106.2** | **111.0** | **91.1** | **83.4** | **78.2** | **100** | **100** | **1.0** | **-0.4** |
| Processing gains | 2.6 | 3.3 | 3.6 | 2.5 | 2.6 | 2.5 | 3 | 3 | 2.3 | 0.8 |
| **World production** | **94.4** | **102.9** | **107.4** | **88.6** | **80.8** | **75.7** | **97** | **97** | **1.0** | **-0.5** |
| *Crude oil* | *68.6* | *69.5* | *71.4* | *65.1* | *55.4* | *50.8* | *64* | *65* | *0.2* | *-1.2* |
| *Natural gas liquids* | *15.2* | *17.7* | *18.9* | *13.7* | *14.1* | *13.6* | *17* | *17* | *1.8* | *0.5* |
| *Unconventional oil* | *10.6* | *15.7* | *17.1* | *9.8* | *11.4* | *11.3* | *15* | *14* | *6.3* | *4.5* |
| **OECD** | **23.7** | **24.4** | **24.6** | **22.1** | **19.3** | **17.4** | **22** | **22** | **1.1** | **-0.4** |
| Americas | 19.7 | 21.3 | 21.5 | 18.4 | 16.7 | 15.1 | 19 | 19 | 1.6 | 0.1 |
| Europe | 3.2 | 2.4 | 2.2 | 3.0 | 2.0 | 1.7 | 2 | 2 | -2.2 | -3.3 |
| Asia Oceania | 0.7 | 0.8 | 0.8 | 0.7 | 0.6 | 0.6 | 1 | 1 | 1.5 | 0.1 |
| **Non-OECD** | **70.8** | **78.5** | **82.8** | **66.5** | **61.5** | **58.3** | **75** | **75** | **1.0** | **-0.5** |
| E. Europe/Eurasia | 13.9 | 15.0 | 15.6 | 13.0 | 11.5 | 10.8 | 14 | 14 | 0.5 | -1.0 |
| Asia | 7.9 | 7.2 | 6.4 | 7.4 | 6.1 | 5.1 | 6 | 6 | -0.7 | -1.7 |
| Middle East | 29.1 | 34.0 | 37.5 | 27.0 | 26.5 | 26.1 | 34 | 33 | 1.3 | -0.2 |
| Africa | 10.3 | 10.3 | 10.9 | 10.0 | 8.6 | 8.0 | 10 | 10 | 0.7 | -0.6 |
| Latin America | 9.7 | 12.0 | 12.4 | 9.0 | 8.9 | 8.3 | 11 | 11 | 2.1 | 0.4 |
| **Natural gas production (bcm)** | | | | | | | | | | |
| **World** | **4 032** | **4 842** | **5 278** | **3 806** | **4 073** | **4 054** | **100** | **100** | **1.9** | **0.8** |
| *Unconventional gas* | *847* | *1 211* | *1 419* | *813* | *1 056* | *1 092* | *27* | *27* | *4.0* | *2.8* |
| **OECD** | **1 377** | **1 470** | **1 585** | **1 334** | **1 346** | **1 237** | **30** | **31** | **1.2** | **0.1** |
| Americas | 1 012 | 1 091 | 1 196 | 987 | 996 | 892 | 23 | 22 | 1.4 | 0.2 |
| Europe | 249 | 225 | 215 | 245 | 221 | 211 | 4 | 5 | -1.1 | -1.1 |
| Asia Oceania | 116 | 154 | 174 | 102 | 129 | 135 | 3 | 3 | 4.6 | 3.5 |
| **Non-OECD** | **2 655** | **3 371** | **3 693** | **2 472** | **2 728** | **2 817** | **70** | **69** | **2.2** | **1.1** |
| E. Europe/Eurasia | 933 | 1 176 | 1 276 | 860 | 885 | 887 | 24 | 22 | 1.5 | 0.0 |
| Asia | 569 | 698 | 774 | 559 | 671 | 746 | 15 | 18 | 2.6 | 2.4 |
| Middle East | 644 | 810 | 879 | 596 | 624 | 618 | 17 | 15 | 2.2 | 0.7 |
| Africa | 283 | 385 | 437 | 271 | 328 | 339 | 8 | 8 | 3.3 | 2.2 |
| Latin America | 227 | 301 | 327 | 186 | 219 | 226 | 6 | 6 | 2.8 | 1.2 |
| **Coal production (Mtce)** | | | | | | | | | | |
| **World** | **6 404** | **7 361** | **7 764** | **5 307** | **3 897** | **3 619** | **100** | **100** | **1.4** | **-1.7** |
| *Steam coal* | *5 049* | *6 021* | *6 440* | *4 067* | *2 916* | *2 712* | *83* | *75* | *1.7* | *-1.9* |
| *Coking coal* | *1 025* | *1 028* | *1 017* | *959* | *856* | *810* | *13* | *22* | *0.5* | *-0.4* |
| **OECD** | **1 536** | **1 634** | **1 697** | **1 215** | **651** | **691** | **22** | **19** | **0.8** | **-2.9** |
| Americas | 833 | 852 | 885 | 660 | 303 | 368 | 11 | 10 | 0.3 | -3.3 |
| Europe | 224 | 177 | 165 | 198 | 102 | 69 | 2 | 2 | -1.7 | -5.2 |
| Asia Oceania | 479 | 605 | 647 | 356 | 245 | 254 | 8 | 7 | 2.9 | -1.0 |
| **Non-OECD** | **4 868** | **5 726** | **6 066** | **4 092** | **3 246** | **2 928** | **78** | **81** | **1.6** | **-1.4** |
| E. Europe/Eurasia | 481 | 514 | 534 | 416 | 321 | 281 | 7 | 8 | 0.9 | -1.7 |
| Asia | 3 994 | 4 723 | 4 992 | 3 333 | 2 622 | 2 345 | 64 | 65 | 1.6 | -1.5 |
| Middle East | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1.3 | 0.8 |
| Africa | 255 | 306 | 338 | 235 | 203 | 203 | 4 | 6 | 2.0 | -0.1 |
| Latin America | 137 | 182 | 201 | 108 | 99 | 97 | 3 | 3 | 3.6 | 0.5 |

## **World:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **8 769** | **13 070** | **15 025** | **15 877** | **16 623** | **17 387** | **100** | **100** | **1.2** |
| Coal | 2 230 | 3 773 | 4 202 | 4 312 | 4 379 | 4 428 | 29 | 25 | 0.7 |
| Oil | 3 231 | 4 108 | 4 470 | 4 548 | 4 602 | 4 661 | 31 | 27 | 0.5 |
| Gas | 1 668 | 2 787 | 3 273 | 3 576 | 3 846 | 4 119 | 21 | 24 | 1.6 |
| Nuclear | 526 | 674 | 886 | 979 | 1 053 | 1 119 | 5 | 6 | 2.1 |
| Hydro | 184 | 300 | 392 | 430 | 467 | 501 | 2 | 3 | 2.2 |
| Bioenergy | 893 | 1 300 | 1 493 | 1 604 | 1 719 | 1 847 | 10 | 11 | 1.5 |
| Other renewables | 36 | 127 | 309 | 426 | 559 | 711 | 1 | 4 | 7.4 |
| **Power generation** | **2 984** | **4 980** | **5 840** | **6 307** | **6 752** | **7 242** | **100** | **100** | **1.6** |
| Coal | 1 225 | 2 365 | 2 597 | 2 690 | 2 772 | 2 846 | 47 | 39 | 0.8 |
| Oil | 376 | 283 | 220 | 185 | 158 | 147 | 6 | 2 | -2.7 |
| Gas | 581 | 1 121 | 1 259 | 1 377 | 1 478 | 1 596 | 23 | 22 | 1.5 |
| Nuclear | 526 | 674 | 886 | 979 | 1 053 | 1 119 | 14 | 15 | 2.1 |
| Hydro | 184 | 300 | 392 | 430 | 467 | 501 | 6 | 7 | 2.2 |
| Bioenergy | 59 | 136 | 226 | 283 | 346 | 420 | 3 | 6 | 4.8 |
| Other renewables | 32 | 101 | 260 | 363 | 479 | 613 | 2 | 8 | 7.8 |
| **Other energy sector** | **899** | **1 460** | **1 591** | **1 641** | **1 676** | **1 710** | **100** | **100** | **0.7** |
| *Electricity* | *183* | *321* | *382* | *418* | *453* | *489* | *22* | *29* | *1.8* |
| **TFC** | **6 281** | **8 876** | **10 371** | **10 981** | **11 500** | **12 001** | **100** | **100** | **1.3** |
| Coal | 770 | 901 | 1 060 | 1 074 | 1 061 | 1 038 | 10 | 9 | 0.6 |
| Oil | 2 610 | 3 614 | 4 065 | 4 205 | 4 316 | 4 415 | 41 | 37 | 0.8 |
| Gas | 944 | 1 376 | 1 670 | 1 819 | 1 955 | 2 082 | 15 | 17 | 1.7 |
| Electricity | 833 | 1 580 | 2 025 | 2 258 | 2 475 | 2 699 | 18 | 22 | 2.3 |
| Heat | 335 | 281 | 307 | 315 | 319 | 320 | 3 | 3 | 0.5 |
| Bioenergy | 785 | 1 099 | 1 196 | 1 246 | 1 297 | 1 348 | 12 | 11 | 0.9 |
| Other renewables | 4 | 25 | 49 | 63 | 79 | 98 | 0 | 1 | 5.8 |
| **Industry** | **1 813** | **2 548** | **3 096** | **3 284** | **3 409** | **3 528** | **100** | **100** | **1.4** |
| Coal | 475 | 727 | 848 | 852 | 836 | 814 | 29 | 23 | 0.5 |
| Oil | 328 | 324 | 355 | 359 | 355 | 348 | 13 | 10 | 0.3 |
| Gas | 359 | 502 | 624 | 683 | 734 | 783 | 20 | 22 | 1.9 |
| Electricity | 380 | 671 | 885 | 979 | 1 055 | 1 134 | 26 | 32 | 2.2 |
| Heat | 153 | 126 | 143 | 148 | 149 | 148 | 5 | 4 | 0.7 |
| Bioenergy | 119 | 198 | 241 | 262 | 280 | 299 | 8 | 8 | 1.7 |
| Other renewables | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 2.7 |
| **Transport** | **1 581** | **2 444** | **2 832** | **2 993** | **3 153** | **3 319** | **100** | **100** | **1.3** |
| Oil | 1 485 | 2 264 | 2 572 | 2 681 | 2 781 | 2 878 | 93 | 87 | 1.0 |
| *Of which: Bunkers* | *201* | *360* | *402* | *428* | *454* | *482* | *15* | *15* | *1.2* |
| Electricity | 21 | 25 | 35 | 42 | 51 | 63 | 1 | 2 | 3.9 |
| Biofuels | 6 | 59 | 101 | 128 | 159 | 192 | 2 | 6 | 5.1 |
| Other fuels | 69 | 96 | 124 | 141 | 162 | 186 | 4 | 6 | 2.8 |
| **Buildings** | **2 228** | **2 886** | **3 213** | **3 379** | **3 537** | **3 688** | **100** | **100** | **1.0** |
| Coal | 240 | 118 | 117 | 111 | 104 | 95 | 4 | 3 | -0.9 |
| Oil | 325 | 324 | 318 | 303 | 286 | 271 | 11 | 7 | -0.7 |
| Gas | 431 | 597 | 689 | 738 | 781 | 815 | 21 | 22 | 1.3 |
| Electricity | 402 | 839 | 1 044 | 1 168 | 1 292 | 1 417 | 29 | 38 | 2.2 |
| Heat | 173 | 149 | 158 | 162 | 165 | 167 | 5 | 5 | 0.5 |
| Bioenergy | 654 | 835 | 841 | 839 | 837 | 832 | 29 | 23 | -0.0 |
| Other renewables | 4 | 24 | 46 | 59 | 73 | 91 | 1 | 2 | 5.7 |
| **Other** | **659** | **999** | **1 231** | **1 325** | **1 401** | **1 465** | **100** | **100** | **1.6** |

# **World:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **15 359** | **17 572** | **18 646** | **14 316** | **14 589** | **14 908** | **100** | **100** | **1.5** | **0.5** |
| Coal | 4 483 | 5 152 | 5 435 | 3 715 | 2 728 | 2 533 | 29 | 17 | 1.5 | -1.6 |
| Oil | 4 546 | 4 901 | 5 094 | 4 264 | 3 842 | 3 577 | 27 | 24 | 0.9 | -0.6 |
| Gas | 3 335 | 4 007 | 4 369 | 3 148 | 3 372 | 3 357 | 23 | 23 | 1.9 | 0.8 |
| Nuclear | 866 | 990 | 1 020 | 924 | 1 348 | 1 521 | 5 | 10 | 1.7 | 3.5 |
| Hydro | 379 | 442 | 471 | 401 | 512 | 550 | 3 | 4 | 1.9 | 2.6 |
| Bioenergy | 1 472 | 1 639 | 1 729 | 1 522 | 1 961 | 2 205 | 9 | 15 | 1.2 | 2.2 |
| Other renewables | 278 | 441 | 528 | 342 | 827 | 1 164 | 3 | 8 | 6.1 | 9.7 |
| **Power generation** | **6 045** | **7 281** | **7 909** | **5 434** | **5 685** | **6 087** | **100** | **100** | **1.9** | **0.8** |
| Coal | 2 829 | 3 431 | 3 703 | 2 170 | 1 265 | 1 117 | 47 | 18 | 1.9 | -3.1 |
| Oil | 225 | 169 | 161 | 195 | 112 | 93 | 2 | 2 | -2.3 | -4.5 |
| Gas | 1 296 | 1 566 | 1 744 | 1 220 | 1 285 | 1 211 | 22 | 20 | 1.9 | 0.3 |
| Nuclear | 866 | 990 | 1 020 | 924 | 1 348 | 1 521 | 13 | 25 | 1.7 | 3.5 |
| Hydro | 379 | 442 | 471 | 401 | 512 | 550 | 6 | 9 | 1.9 | 2.6 |
| Bioenergy | 218 | 307 | 358 | 236 | 441 | 576 | 5 | 9 | 4.1 | 6.2 |
| Other renewables | 232 | 375 | 451 | 287 | 722 | 1 018 | 6 | 17 | 6.4 | 10.1 |
| **Other energy sector** | **1 618** | **1 758** | **1 829** | **1 539** | **1 506** | **1 486** | **100** | **100** | **0.9** | **0.1** |
| *Electricity* | *393* | *485* | *531* | *362* | *388* | *405* | *29* | *27* | *2.1* | *1.0* |
| **TFC** | **10 547** | **12 043** | **12 736** | **9 983** | **10 334** | **10 442** | **100** | **100** | **1.5** | **0.7** |
| Coal | 1 095 | 1 138 | 1 135 | 1 013 | 961 | 927 | 9 | 9 | 1.0 | 0.1 |
| Oil | 4 138 | 4 614 | 4 846 | 3 889 | 3 621 | 3 408 | 38 | 33 | 1.2 | -0.2 |
| Gas | 1 692 | 2 008 | 2 151 | 1 593 | 1 709 | 1 758 | 17 | 17 | 1.9 | 1.0 |
| Electricity | 2 082 | 2 629 | 2 895 | 1 921 | 2 207 | 2 371 | 23 | 23 | 2.6 | 1.7 |
| Heat | 312 | 334 | 340 | 297 | 288 | 282 | 3 | 3 | 0.8 | 0.0 |
| Bioenergy | 1 183 | 1 255 | 1 292 | 1 215 | 1 444 | 1 551 | 10 | 15 | 0.7 | 1.4 |
| Other renewables | 45 | 66 | 77 | 55 | 104 | 145 | 1 | 1 | 4.7 | 7.6 |
| **Industry** | **3 179** | **3 616** | **3 793** | **2 939** | **3 060** | **3 109** | **100** | **100** | **1.7** | **0.8** |
| Coal | 875 | 894 | 886 | 811 | 759 | 731 | 23 | 24 | 0.8 | 0.0 |
| Oil | 365 | 379 | 379 | 332 | 305 | 290 | 10 | 9 | 0.7 | -0.5 |
| Gas | 639 | 779 | 844 | 593 | 652 | 674 | 22 | 22 | 2.2 | 1.2 |
| Electricity | 912 | 1 130 | 1 232 | 832 | 931 | 982 | 32 | 32 | 2.6 | 1.6 |
| Heat | 145 | 156 | 158 | 136 | 129 | 123 | 4 | 4 | 1.0 | -0.1 |
| Bioenergy | 243 | 277 | 293 | 235 | 278 | 295 | 8 | 9 | 1.6 | 1.7 |
| Other renewables | 1 | 1 | 1 | 1 | 6 | 13 | 0 | 0 | 2.7 | 14.7 |
| **Transport** | **2 859** | **3 322** | **3 577** | **2 724** | **2 713** | **2 663** | **100** | **100** | **1.6** | **0.4** |
| Oil | 2 618 | 3 012 | 3 226 | 2 448 | 2 214 | 2 022 | 90 | 76 | 1.5 | -0.5 |
| *Of which: Bunkers* | *404* | *466* | *501* | *389* | *402* | *404* | *14* | *15* | *1.4* | *0.5* |
| Electricity | 34 | 45 | 51 | 38 | 78 | 125 | 1 | 5 | 3.0 | 6.9 |
| Biofuels | 87 | 128 | 153 | 124 | 291 | 366 | 4 | 14 | 4.1 | 7.9 |
| Other fuels | 120 | 137 | 148 | 114 | 130 | 150 | 4 | 6 | 1.8 | 1.9 |
| **Buildings** | **3 270** | **3 680** | **3 867** | **3 100** | **3 198** | **3 251** | **100** | **100** | **1.2** | **0.5** |
| Coal | 122 | 116 | 111 | 110 | 84 | 73 | 3 | 2 | -0.3 | -2.0 |
| Oil | 330 | 315 | 305 | 301 | 246 | 223 | 8 | 7 | -0.3 | -1.5 |
| Gas | 700 | 812 | 859 | 654 | 659 | 649 | 22 | 20 | 1.5 | 0.4 |
| Electricity | 1 074 | 1 374 | 1 521 | 992 | 1 124 | 1 182 | 39 | 36 | 2.5 | 1.4 |
| Heat | 161 | 172 | 177 | 155 | 155 | 154 | 5 | 5 | 0.7 | 0.1 |
| Bioenergy | 840 | 830 | 823 | 837 | 839 | 845 | 21 | 26 | -0.1 | 0.1 |
| Other renewables | 43 | 61 | 71 | 50 | 92 | 124 | 2 | 4 | 4.6 | 7.1 |
| **Other** | **1 240** | **1 425** | **1 499** | **1 220** | **1 363** | **1 419** | **100** | **100** | **1.7** | **1.5** |

## **World:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **11 818** | **22 113** | **27 999** | **31 121** | **34 058** | **37 087** | **100** | **100** | **2.2** |
| Coal | 4 426 | 9 139 | 10 618 | 11 236 | 11 797 | 12 312 | 41 | 33 | 1.2 |
| Oil | 1 332 | 1 062 | 801 | 676 | 591 | 556 | 5 | 1 | -2.7 |
| Gas | 1 730 | 4 847 | 5 983 | 6 860 | 7 589 | 8 313 | 22 | 22 | 2.3 |
| Nuclear | 2 013 | 2 584 | 3 400 | 3 757 | 4 038 | 4 294 | 12 | 12 | 2.1 |
| Hydro | 2 144 | 3 490 | 4 555 | 5 003 | 5 428 | 5 827 | 16 | 16 | 2.2 |
| Bioenergy | 131 | 424 | 762 | 975 | 1 204 | 1 477 | 2 | 4 | 5.3 |
| Wind | 4 | 434 | 1 326 | 1 795 | 2 269 | 2 774 | 2 | 7 | 8.0 |
| Geothermal | 36 | 69 | 128 | 180 | 238 | 299 | 0 | 1 | 6.3 |
| Solar PV | 0 | 61 | 379 | 555 | 747 | 951 | 0 | 3 | 12.1 |
| CSP | 1 | 2 | 43 | 76 | 137 | 245 | 0 | 1 | 21.7 |
| Marine | 1 | 1 | 3 | 7 | 18 | 39 | 0 | 0 | 19.3 |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **5 456** | **7 308** | **8 121** | **8 922** | **9 760** | **100** | **100** | **2.5** |
| Coal | 1 739 | 2 147 | 2 264 | 2 393 | 2 503 | 32 | 26 | 1.5 |
| Oil | 439 | 362 | 317 | 288 | 274 | 8 | 3 | -1.9 |
| Gas | 1 414 | 1 854 | 2 058 | 2 247 | 2 462 | 26 | 25 | 2.3 |
| Nuclear | 391 | 471 | 512 | 545 | 578 | 7 | 6 | 1.6 |
| Hydro | 1 060 | 1 361 | 1 493 | 1 617 | 1 731 | 19 | 18 | 2.1 |
| Bioenergy | 93 | 154 | 190 | 226 | 266 | 2 | 3 | 4.5 |
| Wind | 238 | 612 | 797 | 960 | 1 130 | 4 | 12 | 6.7 |
| Geothermal | 11 | 19 | 27 | 35 | 43 | 0 | 0 | 5.9 |
| Solar PV | 69 | 312 | 437 | 564 | 690 | 1 | 7 | 10.1 |
| CSP | 2 | 14 | 23 | 40 | 70 | 0 | 1 | 16.7 |
| Marine | 1 | 1 | 3 | 6 | 14 | 0 | 0 | 14.7 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **20 948** | **31 161** | **34 595** | **35 722** | **36 493** | **37 242** | **100** | **100** | **0.7** |
| Coal | 8 323 | 13 761 | 15 280 | 15 580 | 15 653 | 15 651 | 44 | 42 | 0.5 |
| Oil | 8 819 | 11 079 | 11 948 | 12 137 | 12 283 | 12 459 | 36 | 33 | 0.5 |
| Gas | 3 806 | 6 322 | 7 367 | 8 005 | 8 557 | 9 133 | 20 | 25 | 1.5 |
| **Power generation** | **7 468** | **12 954** | **13 985** | **14 457** | **14 792** | **15 180** | **100** | **100** | **0.7** |
| Coal | 4 915 | 9 436 | 10 340 | 10 652 | 10 844 | 11 000 | 73 | 72 | 0.6 |
| Oil | 1 194 | 888 | 692 | 580 | 495 | 461 | 7 | 3 | -2.7 |
| Gas | 1 359 | 2 630 | 2 952 | 3 225 | 3 452 | 3 719 | 20 | 24 | 1.5 |
| **TFC** | **12 475** | **16 669** | **18 926** | **19 546** | **19 967** | **20 317** | **100** | **100** | **0.8** |
| Coal | 3 269 | 4 027 | 4 613 | 4 602 | 4 490 | 4 341 | 24 | 21 | 0.3 |
| Oil | 7 070 | 9 559 | 10 605 | 10 915 | 11 157 | 11 380 | 57 | 56 | 0.7 |
| *Transport* | *4 396* | *6 760* | *7 675* | *8 006* | *8 307* | *8 598* | *41* | *42* | *1.0* |
| *Of which: Bunkers* | *619* | *1 112* | *1 241* | *1 318* | *1 399* | *1 485* | *7* | *7* | *1.2* |
| Gas | 2 136 | 3 083 | 3 708 | 4 030 | 4 321 | 4 595 | 18 | 23 | 1.7 |

## World: Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **28 789** | **36 224** | **39 853** | **26 554** | **30 182** | **32 295** | **100** | **100** | **2.5** | **1.6** |
| Coal | 11 582 | 14 694 | 16 131 | 9 004 | 5 482 | 4 660 | 40 | 14 | 2.4 | -2.8 |
| Oil | 819 | 640 | 614 | 705 | 396 | 323 | 2 | 1 | -2.3 | -4.8 |
| Gas | 6 222 | 8 127 | 9 173 | 5 771 | 6 507 | 5 993 | 23 | 19 | 2.7 | 0.9 |
| Nuclear | 3 322 | 3 797 | 3 914 | 3 546 | 5 171 | 5 837 | 10 | 18 | 1.7 | 3.5 |
| Hydro | 4 412 | 5 145 | 5 478 | 4 667 | 5 953 | 6 394 | 14 | 20 | 1.9 | 2.6 |
| Bioenergy | 734 | 1 066 | 1 250 | 797 | 1 555 | 2 056 | 3 | 6 | 4.6 | 6.8 |
| Wind | 1 195 | 1 907 | 2 251 | 1 441 | 3 365 | 4 337 | 6 | 13 | 7.1 | 10.1 |
| Geothermal | 114 | 181 | 217 | 142 | 330 | 436 | 1 | 1 | 4.9 | 8.0 |
| Solar PV | 352 | 571 | 680 | 422 | 1 030 | 1 389 | 2 | 4 | 10.6 | 13.9 |
| CSP | 35 | 85 | 122 | 56 | 370 | 806 | 0 | 2 | 18.2 | 27.9 |
| Marine | 3 | 11 | 24 | 3 | 25 | 64 | 0 | 0 | 16.8 | 21.8 |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **7 339** | **9 009** | **9 813** | **7 201** | **8 931** | **9 980** | **100** | **100** | **2.5** | **2.5** |
| Coal | 2 275 | 2 799 | 3 033 | 1 965 | 1 529 | 1 464 | 31 | 15 | 2.3 | -0.7 |
| Oil | 366 | 301 | 290 | 357 | 264 | 241 | 3 | 2 | -1.7 | -2.5 |
| Gas | 1 901 | 2 355 | 2 600 | 1 788 | 2 090 | 2 225 | 26 | 22 | 2.6 | 1.9 |
| Nuclear | 460 | 513 | 527 | 488 | 692 | 792 | 5 | 8 | 1.2 | 3.0 |
| Hydro | 1 316 | 1 526 | 1 620 | 1 399 | 1 788 | 1 918 | 17 | 19 | 1.8 | 2.5 |
| Bioenergy | 149 | 204 | 230 | 160 | 281 | 355 | 2 | 4 | 3.8 | 5.7 |
| Wind | 551 | 812 | 926 | 663 | 1 368 | 1 684 | 9 | 17 | 5.8 | 8.5 |
| Geothermal | 17 | 27 | 32 | 21 | 49 | 63 | 0 | 1 | 4.6 | 7.6 |
| Solar PV | 290 | 443 | 511 | 342 | 760 | 990 | 5 | 10 | 8.7 | 11.7 |
| CSP | 11 | 25 | 35 | 17 | 102 | 224 | 0 | 2 | 13.4 | 22.5 |
| Marine | 1 | 4 | 9 | 1 | 9 | 23 | 0 | 0 | 12.3 | 17.1 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **36 059** | **40 825** | **43 111** | **31 693** | **24 663** | **21 568** | **100** | **100** | **1.4** | **-1.5** |
| Coal | 16 374 | 18 702 | 19 621 | 13 296 | 7 616 | 5 671 | 46 | 26 | 1.5 | -3.6 |
| Oil | 12 177 | 13 205 | 13 793 | 11 338 | 9 948 | 9 091 | 32 | 42 | 0.9 | -0.8 |
| Gas | 7 508 | 8 918 | 9 697 | 7 059 | 7 100 | 6 806 | 22 | 32 | 1.8 | 0.3 |
| **Power generation** | **15 016** | **17 744** | **19 123** | **12 068** | **6 853** | **5 034** | **100** | **100** | **1.6** | **-3.9** |
| Coal | 11 272 | 13 546 | 14 539 | 8 598 | 3 677 | 2 194 | 76 | 44 | 1.8 | -5.9 |
| Oil | 707 | 532 | 504 | 615 | 354 | 293 | 3 | 6 | -2.3 | -4.5 |
| Gas | 3 038 | 3 666 | 4 079 | 2 856 | 2 823 | 2 547 | 21 | 51 | 1.8 | -0.1 |
| **TFC** | **19 339** | **21 277** | **22 124** | **18 014** | **16 458** | **15 325** | **100** | **100** | **1.2** | **-0.3** |
| Coal | 4 761 | 4 805 | 4 734 | 4 392 | 3 694 | 3 263 | 21 | 21 | 0.7 | -0.9 |
| Oil | 10 819 | 12 029 | 12 638 | 10 099 | 9 121 | 8 400 | 57 | 55 | 1.2 | -0.5 |
| *Transport* | *7 813* | *8 993* | *9 632* | *7 307* | *6 622* | *6 059* | *44* | *40* | *1.5* | *-0.5* |
| *Of which: Bunkers* | *1 246* | *1 436* | *1 544* | *1 203* | *1 243* | *1 251* | *7* | *8* | *1.4* | *0.5* |
| Gas | 3 759 | 4 443 | 4 753 | 3 523 | 3 643 | 3 661 | 21 | 24 | 1.8 | 0.7 |

## **OECD:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **4 522** | **5 304** | **5 486** | **5 474** | **5 457** | **5 465** | **100** | **100** | **0.1** |
| Coal | 1 080 | 1 063 | 1 029 | 958 | 883 | 809 | 20 | 15 | -1.1 |
| Oil | 1 870 | 1 919 | 1 807 | 1 696 | 1 582 | 1 478 | 36 | 27 | -1.1 |
| Gas | 843 | 1 317 | 1 408 | 1 467 | 1 507 | 1 555 | 25 | 28 | 0.7 |
| Nuclear | 451 | 544 | 599 | 598 | 611 | 629 | 10 | 12 | 0.6 |
| Hydro | 102 | 119 | 128 | 132 | 136 | 139 | 2 | 3 | 0.6 |
| Bioenergy | 147 | 269 | 352 | 401 | 453 | 509 | 5 | 9 | 2.7 |
| Other renewables | 29 | 72 | 163 | 222 | 284 | 346 | 1 | 6 | 6.7 |
| **Power generation** | **1 719** | **2 227** | **2 343** | **2 372** | **2 408** | **2 453** | **100** | **100** | **0.4** |
| Coal | 759 | 853 | 809 | 743 | 676 | 604 | 38 | 25 | -1.4 |
| Oil | 154 | 79 | 38 | 28 | 23 | 21 | 4 | 1 | -5.3 |
| Gas | 176 | 483 | 504 | 534 | 553 | 579 | 22 | 24 | 0.8 |
| Nuclear | 451 | 544 | 599 | 598 | 611 | 629 | 24 | 26 | 0.6 |
| Hydro | 102 | 119 | 128 | 132 | 136 | 139 | 5 | 6 | 0.6 |
| Bioenergy | 53 | 86 | 117 | 136 | 156 | 176 | 4 | 7 | 3.1 |
| Other renewables | 25 | 63 | 146 | 200 | 253 | 305 | 3 | 12 | 6.8 |
| **Other energy sector** | **400** | **431** | **437** | **439** | **438** | **447** | **100** | **100** | **0.2** |
| *Electricity* | *106* | *128* | *132* | *134* | *135* | *137* | *30* | *31* | *0.3* |
| **TFC** | **3 109** | **3 649** | **3 801** | **3 797** | **3 780** | **3 772** | **100** | **100** | **0.1** |
| Coal | 235 | 122 | 124 | 118 | 110 | 103 | 3 | 3 | -0.7 |
| Oil | 1 593 | 1 746 | 1 697 | 1 606 | 1 508 | 1 414 | 48 | 37 | -0.9 |
| Gas | 589 | 729 | 782 | 802 | 815 | 825 | 20 | 22 | 0.5 |
| Electricity | 552 | 801 | 885 | 922 | 954 | 989 | 22 | 26 | 0.9 |
| Heat | 43 | 59 | 62 | 64 | 65 | 67 | 2 | 2 | 0.5 |
| Bioenergy | 94 | 183 | 233 | 264 | 297 | 332 | 5 | 9 | 2.5 |
| Other renewables | 4 | 9 | 16 | 22 | 30 | 41 | 0 | 1 | 6.4 |
| **Industry** | **829** | **834** | **880** | **881** | **871** | **866** | **100** | **100** | **0.2** |
| Coal | 160 | 99 | 99 | 94 | 88 | 82 | 12 | 9 | -0.8 |
| Oil | 169 | 112 | 106 | 99 | 92 | 85 | 13 | 10 | -1.1 |
| Gas | 226 | 266 | 276 | 273 | 266 | 259 | 32 | 30 | -0.1 |
| Electricity | 222 | 261 | 286 | 291 | 293 | 297 | 31 | 34 | 0.5 |
| Heat | 15 | 24 | 23 | 23 | 22 | 22 | 3 | 3 | -0.4 |
| Bioenergy | 37 | 72 | 90 | 100 | 109 | 120 | 9 | 14 | 2.2 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 2.5 |
| **Transport** | **940** | **1 182** | **1 170** | **1 124** | **1 085** | **1 055** | **100** | **100** | **-0.5** |
| Oil | 914 | 1 107 | 1 069 | 1 002 | 935 | 873 | 94 | 83 | -1.0 |
| Electricity | 8 | 9 | 12 | 14 | 18 | 25 | 1 | 2 | 4.2 |
| Biofuels | 0 | 42 | 62 | 75 | 91 | 108 | 4 | 10 | 4.0 |
| Other fuels | 19 | 24 | 27 | 34 | 41 | 50 | 2 | 5 | 3.1 |
| **Buildings** | **986** | **1 208** | **1 302** | **1 345** | **1 384** | **1 422** | **100** | **100** | **0.7** |
| Coal | 71 | 20 | 19 | 18 | 17 | 16 | 2 | 1 | -0.9 |
| Oil | 209 | 151 | 132 | 117 | 102 | 90 | 13 | 6 | -2.2 |
| Gas | 304 | 404 | 441 | 457 | 469 | 477 | 33 | 34 | 0.7 |
| Electricity | 316 | 523 | 579 | 607 | 634 | 659 | 43 | 46 | 1.0 |
| Heat | 27 | 35 | 39 | 41 | 43 | 45 | 3 | 3 | 1.0 |
| Bioenergy | 56 | 67 | 78 | 85 | 91 | 98 | 6 | 7 | 1.6 |
| Other renewables | 4 | 9 | 15 | 20 | 27 | 38 | 1 | 3 | 6.3 |
| **Other** | **353** | **425** | **448** | **448** | **440** | **429** | **100** | **100** | **0.0** |

## **OECD:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **5 545** | **5 699** | **5 809** | **5 290** | **4 937** | **4 867** | **100** | **100** | **0.4** | **-0.4** |
| Coal | 1 067 | 1 060 | 1 051 | 885 | 447 | 439 | 18 | 9 | -0.0 | -3.6 |
| Oil | 1 836 | 1 716 | 1 673 | 1 742 | 1 318 | 1 112 | 29 | 23 | -0.6 | -2.2 |
| Gas | 1 436 | 1 568 | 1 649 | 1 364 | 1 342 | 1 233 | 28 | 25 | 0.9 | -0.3 |
| Nuclear | 592 | 587 | 585 | 614 | 714 | 737 | 10 | 15 | 0.3 | 1.3 |
| Hydro | 127 | 134 | 136 | 131 | 144 | 149 | 2 | 3 | 0.6 | 0.9 |
| Bioenergy | 338 | 407 | 448 | 375 | 573 | 670 | 8 | 14 | 2.1 | 3.9 |
| Other renewables | 148 | 227 | 266 | 180 | 398 | 529 | 5 | 11 | 5.6 | 8.6 |
| **Power generation** | **2 369** | **2 510** | **2 591** | **2 234** | **2 171** | **2 237** | **100** | **100** | **0.6** | **0.0** |
| Coal | 842 | 837 | 824 | 673 | 259 | 257 | 32 | 11 | -0.1 | -4.9 |
| Oil | 39 | 25 | 23 | 33 | 15 | 13 | 1 | 1 | -5.0 | -7.4 |
| Gas | 522 | 582 | 626 | 501 | 507 | 413 | 24 | 18 | 1.1 | -0.7 |
| Nuclear | 592 | 587 | 585 | 614 | 714 | 737 | 23 | 33 | 0.3 | 1.3 |
| Hydro | 127 | 134 | 136 | 131 | 144 | 149 | 5 | 7 | 0.6 | 0.9 |
| Bioenergy | 113 | 143 | 160 | 123 | 176 | 206 | 6 | 9 | 2.7 | 3.7 |
| Other renewables | 133 | 202 | 236 | 161 | 356 | 463 | 9 | 21 | 5.7 | 8.7 |
| **Other energy sector** | **440** | **455** | **480** | **424** | **399** | **392** | **100** | **100** | **0.5** | **-0.4** |
| *Electricity* | *134* | *142* | *147* | *127* | *121* | *120* | *31* | *31* | *0.6* | *-0.3* |
| **TFC** | **3 845** | **3 953** | **4 013** | **3 687** | **3 452** | **3 351** | **100** | **100** | **0.4** | **-0.4** |
| Coal | 128 | 120 | 115 | 119 | 99 | 90 | 3 | 3 | -0.2 | -1.3 |
| Oil | 1 727 | 1 643 | 1 611 | 1 640 | 1 258 | 1 065 | 40 | 32 | -0.3 | -2.0 |
| Gas | 791 | 840 | 857 | 744 | 705 | 688 | 21 | 21 | 0.7 | -0.2 |
| Electricity | 897 | 994 | 1 042 | 855 | 894 | 922 | 26 | 28 | 1.1 | 0.6 |
| Heat | 63 | 68 | 71 | 60 | 58 | 58 | 2 | 2 | 0.8 | -0.0 |
| Bioenergy | 224 | 264 | 287 | 251 | 396 | 462 | 7 | 14 | 1.9 | 3.9 |
| Other renewables | 15 | 24 | 30 | 19 | 42 | 66 | 1 | 2 | 5.0 | 8.5 |
| **Industry** | **896** | **911** | **915** | **844** | **797** | **781** | **100** | **100** | **0.4** | **-0.3** |
| Coal | 102 | 95 | 91 | 95 | 78 | 72 | 10 | 9 | -0.3 | -1.3 |
| Oil | 109 | 100 | 95 | 100 | 81 | 73 | 10 | 9 | -0.7 | -1.7 |
| Gas | 281 | 284 | 283 | 261 | 230 | 219 | 31 | 28 | 0.3 | -0.8 |
| Electricity | 292 | 308 | 315 | 278 | 275 | 277 | 34 | 35 | 0.8 | 0.3 |
| Heat | 23 | 22 | 22 | 22 | 20 | 19 | 2 | 2 | -0.3 | -0.9 |
| Bioenergy | 89 | 102 | 109 | 88 | 112 | 120 | 12 | 15 | 1.7 | 2.1 |
| Other renewables | 0 | 0 | 1 | 0 | 1 | 1 | 0 | 0 | 2.5 | 2.8 |
| **Transport** | **1 183** | **1 169** | **1 181** | **1 147** | **974** | **891** | **100** | **100** | **-0.0** | **-1.2** |
| Oil | 1 091 | 1 050 | 1 045 | 1 031 | 731 | 576 | 88 | 65 | -0.2 | -2.7 |
| Electricity | 11 | 14 | 16 | 13 | 36 | 61 | 1 | 7 | 2.2 | 8.2 |
| Biofuels | 56 | 74 | 86 | 76 | 169 | 206 | 7 | 23 | 3.1 | 6.9 |
| Other fuels | 25 | 30 | 35 | 26 | 39 | 48 | 3 | 5 | 1.6 | 3.0 |
| **Buildings** | **1 317** | **1 433** | **1 487** | **1 252** | **1 253** | **1 261** | **100** | **100** | **0.9** | **0.2** |
| Coal | 20 | 20 | 19 | 19 | 15 | 14 | 1 | 1 | -0.1 | -1.6 |
| Oil | 136 | 114 | 103 | 123 | 80 | 64 | 7 | 5 | -1.6 | -3.5 |
| Gas | 446 | 486 | 500 | 419 | 398 | 382 | 34 | 30 | 0.9 | -0.2 |
| Electricity | 585 | 662 | 701 | 555 | 575 | 575 | 47 | 46 | 1.2 | 0.4 |
| Heat | 40 | 46 | 49 | 37 | 38 | 39 | 3 | 3 | 1.4 | 0.5 |
| Bioenergy | 76 | 83 | 87 | 82 | 107 | 126 | 6 | 10 | 1.1 | 2.7 |
| Other renewables | 14 | 22 | 28 | 17 | 39 | 62 | 2 | 5 | 4.9 | 8.5 |
| **Other** | **449** | **440** | **430** | **444** | **429** | **417** | **100** | **100** | **0.1** | **-0.1** |

## **OECD:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **7 629** | **10 796** | **11 827** | **12 273** | **12 670** | **13 104** | **100** | **100** | **0.8** |
| Coal | 3 093 | 3 618 | 3 529 | 3 290 | 3 044 | 2 775 | 34 | 21 | -1.1 |
| Oil | 697 | 345 | 149 | 112 | 92 | 84 | 3 | 1 | -5.7 |
| Gas | 770 | 2 630 | 2 855 | 3 109 | 3 245 | 3 398 | 24 | 26 | 1.1 |
| Nuclear | 1 729 | 2 087 | 2 300 | 2 294 | 2 346 | 2 412 | 19 | 18 | 0.6 |
| Hydro | 1 182 | 1 388 | 1 490 | 1 538 | 1 578 | 1 615 | 13 | 12 | 0.6 |
| Bioenergy | 124 | 295 | 425 | 501 | 580 | 664 | 3 | 5 | 3.4 |
| Wind | 4 | 328 | 738 | 968 | 1 196 | 1 428 | 3 | 11 | 6.3 |
| Geothermal | 29 | 44 | 84 | 117 | 150 | 177 | 0 | 1 | 5.9 |
| Solar PV | 0 | 58 | 226 | 295 | 360 | 427 | 1 | 3 | 8.7 |
| CSP | 1 | 2 | 28 | 43 | 62 | 86 | 0 | 1 | 16.5 |
| Marine | 1 | 1 | 3 | 7 | 17 | 37 | 0 | 0 | 19.1 |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **2 791** | **3 204** | **3 382** | **3 548** | **3 733** | **100** | **100** | **1.2** |
| Coal | 665 | 624 | 581 | 546 | 516 | 24 | 14 | -1.1 |
| Oil | 215 | 129 | 104 | 94 | 87 | 8 | 2 | -3.7 |
| Gas | 842 | 1 019 | 1 099 | 1 148 | 1 206 | 30 | 32 | 1.5 |
| Nuclear | 319 | 319 | 311 | 314 | 322 | 11 | 9 | 0.0 |
| Hydro | 461 | 494 | 509 | 522 | 532 | 17 | 14 | 0.6 |
| Bioenergy | 62 | 83 | 95 | 107 | 118 | 2 | 3 | 2.7 |
| Wind | 153 | 321 | 407 | 484 | 559 | 5 | 15 | 5.5 |
| Geothermal | 7 | 12 | 17 | 22 | 25 | 0 | 1 | 5.5 |
| Solar PV | 64 | 192 | 244 | 288 | 330 | 2 | 9 | 7.1 |
| CSP | 2 | 9 | 13 | 18 | 24 | 0 | 1 | 11.9 |
| Marine | 1 | 1 | 2 | 6 | 13 | 0 | 0 | 14.5 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **11 110** | **12 223** | **11 870** | **11 366** | **10 750** | **10 179** | **100** | **100** | **-0.8** |
| Coal | 4 148 | 4 075 | 3 886 | 3 571 | 3 190 | 2 795 | 33 | 27 | -1.6 |
| Oil | 5 034 | 5 078 | 4 717 | 4 404 | 4 094 | 3 821 | 42 | 38 | -1.2 |
| Gas | 1 928 | 3 070 | 3 267 | 3 391 | 3 466 | 3 563 | 25 | 35 | 0.6 |
| **Power generation** | **3 961** | **4 839** | **4 562** | **4 314** | **3 987** | **3 677** | **100** | **100** | **-1.1** |
| Coal | 3 063 | 3 455 | 3 256 | 2 970 | 2 626 | 2 269 | 71 | 62 | -1.7 |
| Oil | 487 | 249 | 120 | 91 | 74 | 67 | 5 | 2 | -5.3 |
| Gas | 411 | 1 135 | 1 185 | 1 253 | 1 287 | 1 341 | 23 | 36 | 0.7 |
| **TFC** | **6 555** | **6 698** | **6 625** | **6 376** | **6 100** | **5 836** | **100** | **100** | **-0.6** |
| Coal | 1 021 | 533 | 538 | 512 | 480 | 449 | 8 | 8 | -0.7 |
| Oil | 4 185 | 4 481 | 4 284 | 4 016 | 3 740 | 3 484 | 67 | 60 | -1.0 |
| *Transport* | *2 681* | *3 267* | *3 152* | *2 954* | *2 756* | *2 576* | *49* | *44* | *-1.0* |
| Gas | 1 349 | 1 683 | 1 803 | 1 848 | 1 879 | 1 902 | 25 | 33 | 0.5 |

# OECD: Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **11 990** | **13 218** | **13 835** | **11 415** | **11 801** | **12 123** | **100** | **100** | **1.0** | **0.5** |
| Coal | 3 681 | 3 819 | 3 835 | 2 961 | 1 128 | 1 116 | 28 | 9 | 0.2 | -4.8 |
| Oil | 153 | 99 | 92 | 126 | 56 | 44 | 1 | 0 | -5.4 | -8.2 |
| Gas | 2 979 | 3 445 | 3 710 | 2 813 | 2 964 | 2 307 | 27 | 19 | 1.4 | -0.5 |
| Nuclear | 2 273 | 2 251 | 2 246 | 2 355 | 2 739 | 2 826 | 16 | 23 | 0.3 | 1.3 |
| Hydro | 1 476 | 1 554 | 1 586 | 1 523 | 1 673 | 1 730 | 11 | 14 | 0.6 | 0.9 |
| Bioenergy | 408 | 531 | 599 | 443 | 674 | 803 | 4 | 7 | 3.0 | 4.3 |
| Wind | 701 | 1 037 | 1 201 | 819 | 1 727 | 2 121 | 9 | 17 | 5.6 | 8.1 |
| Geothermal | 73 | 112 | 128 | 89 | 183 | 223 | 1 | 2 | 4.5 | 7.0 |
| Solar PV | 216 | 309 | 352 | 247 | 454 | 561 | 3 | 5 | 7.8 | 9.9 |
| CSP | 27 | 51 | 64 | 34 | 181 | 332 | 0 | 3 | 15.1 | 23.3 |
| Marine | 3 | 10 | 22 | 3 | 23 | 59 | 0 | 0 | 16.6 | 21.4 |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **3 217** | **3 573** | **3 749** | **3 192** | **3 667** | **3 971** | **100** | **100** | **1.2** | **1.5** |
| Coal | 644 | 646 | 649 | 596 | 341 | 304 | 17 | 8 | -0.1 | -3.2 |
| Oil | 130 | 96 | 90 | 129 | 90 | 81 | 2 | 2 | -3.5 | -4.0 |
| Gas | 1 049 | 1 207 | 1 277 | 963 | 1 078 | 1 112 | 34 | 28 | 1.8 | 1.2 |
| Nuclear | 315 | 301 | 299 | 326 | 365 | 387 | 8 | 10 | -0.3 | 0.8 |
| Hydro | 490 | 513 | 522 | 506 | 555 | 573 | 14 | 14 | 0.5 | 0.9 |
| Bioenergy | 80 | 99 | 108 | 86 | 121 | 139 | 3 | 4 | 2.3 | 3.4 |
| Wind | 307 | 428 | 483 | 355 | 676 | 798 | 13 | 20 | 4.9 | 7.1 |
| Geothermal | 11 | 16 | 18 | 13 | 26 | 32 | 0 | 1 | 4.2 | 6.6 |
| Solar PV | 183 | 248 | 275 | 208 | 358 | 430 | 7 | 11 | 6.2 | 8.2 |
| CSP | 8 | 15 | 19 | 10 | 49 | 94 | 1 | 2 | 10.7 | 18.4 |
| Marine | 1 | 4 | 8 | 1 | 8 | 21 | 0 | 1 | 12.0 | 16.7 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **12 191** | **12 056** | **12 015** | **10 962** | **7 222** | **5 883** | **100** | **100** | **-0.1** | **-3.0** |
| Coal | 4 050 | 3 934 | 3 802 | 3 279 | 1 029 | 652 | 32 | 11 | -0.3 | -7.4 |
| Oil | 4 810 | 4 511 | 4 427 | 4 527 | 3 279 | 2 674 | 37 | 45 | -0.6 | -2.6 |
| Gas | 3 331 | 3 611 | 3 786 | 3 156 | 2 915 | 2 558 | 32 | 43 | 0.9 | -0.8 |
| **Power generation** | **4 754** | **4 769** | **4 756** | **3 955** | **1 683** | **1 095** | **100** | **100** | **-0.1** | **-6.0** |
| Coal | 3 403 | 3 327 | 3 221 | 2 676 | 557 | 249 | 68 | 23 | -0.3 | -10.4 |
| Oil | 124 | 79 | 73 | 105 | 49 | 40 | 2 | 4 | -5.0 | -7.3 |
| Gas | 1 227 | 1 363 | 1 462 | 1 174 | 1 076 | 806 | 31 | 74 | 1.1 | -1.4 |
| **TFC** | **6 751** | **6 603** | **6 546** | **6 347** | **5 004** | **4 320** | **100** | **100** | **-0.1** | **-1.8** |
| Coal | 554 | 521 | 500 | 513 | 400 | 341 | 8 | 8 | -0.3 | -1.8 |
| Oil | 4 373 | 4 146 | 4 070 | 4 122 | 3 017 | 2 461 | 62 | 57 | -0.4 | -2.5 |
| *Transport* | *3 216* | *3 096* | *3 082* | *3 040* | *2 155* | *1 698* | *47* | *39* | *-0.2* | *-2.7* |
| Gas | 1 823 | 1 936 | 1 976 | 1 711 | 1 587 | 1 518 | 30 | 35 | 0.7 | -0.4 |

## **OECD Americas:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **2 260** | **2 663** | **2 811** | **2 819** | **2 826** | **2 850** | **100** | **100** | **0.3** |
| Coal | 490 | 514 | 500 | 478 | 454 | 442 | 19 | 16 | -0.6 |
| Oil | 920 | 984 | 978 | 922 | 864 | 808 | 37 | 28 | -0.8 |
| Gas | 518 | 713 | 784 | 809 | 832 | 855 | 27 | 30 | 0.8 |
| Nuclear | 180 | 241 | 258 | 265 | 272 | 277 | 9 | 10 | 0.6 |
| Hydro | 52 | 65 | 65 | 66 | 68 | 70 | 2 | 2 | 0.3 |
| Bioenergy | 82 | 118 | 158 | 185 | 216 | 251 | 4 | 9 | 3.2 |
| Other renewables | 19 | 28 | 69 | 94 | 119 | 147 | 1 | 5 | 7.2 |
| **Power generation** | **852** | **1 079** | **1 155** | **1 181** | **1 206** | **1 238** | **100** | **100** | **0.6** |
| Coal | 420 | 466 | 449 | 426 | 403 | 385 | 43 | 31 | -0.8 |
| Oil | 47 | 23 | 14 | 10 | 8 | 7 | 2 | 1 | -5.0 |
| Gas | 95 | 232 | 268 | 278 | 288 | 299 | 22 | 24 | 1.1 |
| Nuclear | 180 | 241 | 258 | 265 | 272 | 277 | 22 | 22 | 0.6 |
| Hydro | 52 | 65 | 65 | 66 | 68 | 70 | 6 | 6 | 0.3 |
| Bioenergy | 41 | 25 | 38 | 47 | 58 | 68 | 2 | 5 | 4.3 |
| Other renewables | 19 | 26 | 65 | 88 | 110 | 132 | 2 | 11 | 7.0 |
| **Other energy sector** | **192** | **208** | **214** | **220** | **226** | **237** | **100** | **100** | **0.5** |
| *Electricity* | *56* | *66* | *69* | *71* | *73* | *74* | *31* | *31* | *0.5* |
| **TFC** | **1 548** | **1 847** | **1 958** | **1 956** | **1 951** | **1 954** | **100** | **100** | **0.2** |
| Coal | 61 | 30 | 31 | 30 | 28 | 25 | 2 | 1 | -0.7 |
| Oil | 809 | 924 | 940 | 892 | 839 | 790 | 50 | 40 | -0.7 |
| Gas | 362 | 398 | 421 | 429 | 435 | 439 | 22 | 22 | 0.4 |
| Electricity | 272 | 393 | 436 | 456 | 476 | 497 | 21 | 25 | 1.0 |
| Heat | 3 | 7 | 6 | 6 | 5 | 5 | 0 | 0 | -1.7 |
| Bioenergy | 41 | 93 | 120 | 137 | 159 | 183 | 5 | 9 | 2.9 |
| Other renewables | 0 | 2 | 4 | 6 | 9 | 15 | 0 | 1 | 9.1 |
| **Industry** | **361** | **380** | **408** | **408** | **404** | **402** | **100** | **100** | **0.2** |
| Coal | 51 | 28 | 29 | 27 | 25 | 23 | 7 | 6 | -0.8 |
| Oil | 60 | 46 | 46 | 44 | 41 | 39 | 12 | 10 | -0.7 |
| Gas | 138 | 153 | 159 | 156 | 151 | 145 | 40 | 36 | -0.2 |
| Electricity | 94 | 107 | 118 | 120 | 121 | 123 | 28 | 31 | 0.6 |
| Heat | 1 | 6 | 5 | 5 | 4 | 4 | 2 | 1 | -1.3 |
| Bioenergy | 17 | 40 | 52 | 57 | 62 | 68 | 11 | 17 | 2.2 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.7 |
| **Transport** | **562** | **707** | **712** | **684** | **662** | **650** | **100** | **100** | **-0.4** |
| Oil | 543 | 660 | 651 | 607 | 564 | 525 | 93 | 81 | -1.0 |
| Electricity | 1 | 1 | 2 | 3 | 6 | 11 | 0 | 2 | 9.8 |
| Biofuels | - | 27 | 38 | 47 | 60 | 74 | 4 | 11 | 4.2 |
| Other fuels | 18 | 19 | 22 | 27 | 33 | 40 | 3 | 6 | 3.2 |
| **Buildings** | **461** | **570** | **611** | **632** | **652** | **671** | **100** | **100** | **0.7** |
| Coal | 10 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | -4.7 |
| Oil | 64 | 49 | 42 | 37 | 32 | 28 | 9 | 4 | -2.4 |
| Gas | 184 | 208 | 220 | 225 | 229 | 231 | 37 | 34 | 0.4 |
| Electricity | 176 | 283 | 314 | 331 | 347 | 361 | 50 | 54 | 1.0 |
| Heat | 2 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | -3.9 |
| Bioenergy | 24 | 25 | 29 | 31 | 35 | 38 | 4 | 6 | 1.8 |
| Other renewables | 0 | 2 | 3 | 5 | 8 | 13 | 0 | 2 | 8.9 |
| **Other** | **164** | **189** | **227** | **232** | **233** | **231** | **100** | **100** | **0.8** |

## **OECD Americas:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **2 836** | **2 953** | **3 035** | **2 711** | **2 530** | **2 511** | **100** | **100** | **0.5** | **-0.2** |
| Coal | 516 | 550 | 571 | 413 | 176 | 222 | 19 | 9 | 0.4 | -3.4 |
| Oil | 995 | 954 | 941 | 951 | 728 | 608 | 31 | 24 | -0.2 | -2.0 |
| Gas | 793 | 838 | 876 | 773 | 778 | 690 | 29 | 27 | 0.9 | -0.1 |
| Nuclear | 258 | 263 | 258 | 259 | 301 | 319 | 9 | 13 | 0.3 | 1.2 |
| Hydro | 64 | 68 | 69 | 65 | 69 | 71 | 2 | 3 | 0.3 | 0.4 |
| Bioenergy | 152 | 190 | 214 | 176 | 298 | 352 | 7 | 14 | 2.5 | 4.7 |
| Other renewables | 59 | 91 | 105 | 74 | 179 | 251 | 3 | 10 | 5.7 | 9.6 |
| **Power generation** | **1 164** | **1 249** | **1 296** | **1 094** | **1 046** | **1 101** | **100** | **100** | **0.8** | **0.1** |
| Coal | 462 | 493 | 505 | 365 | 132 | 174 | 39 | 16 | 0.3 | -4.0 |
| Oil | 14 | 8 | 7 | 12 | 6 | 5 | 1 | 0 | -4.8 | -6.6 |
| Gas | 274 | 284 | 302 | 281 | 303 | 225 | 23 | 20 | 1.1 | -0.1 |
| Nuclear | 258 | 263 | 258 | 259 | 301 | 319 | 20 | 29 | 0.3 | 1.2 |
| Hydro | 64 | 68 | 69 | 65 | 69 | 71 | 5 | 6 | 0.3 | 0.4 |
| Bioenergy | 36 | 50 | 59 | 42 | 71 | 84 | 5 | 8 | 3.7 | 5.2 |
| Other renewables | 55 | 84 | 96 | 70 | 166 | 224 | 7 | 20 | 5.6 | 9.4 |
| **Other energy sector** | **215** | **236** | **258** | **208** | **206** | **205** | **100** | **100** | **0.9** | **-0.1** |
| *Electricity* | *70* | *76* | *78* | *67* | *64* | *65* | *30* | *32* | *0.7* | *-0.0* |
| **TFC** | **1 979** | **2 041** | **2 082** | **1 908** | **1 793** | **1 737** | **100** | **100** | **0.5** | **-0.3** |
| Coal | 33 | 31 | 30 | 29 | 23 | 21 | 1 | 1 | -0.0 | -1.5 |
| Oil | 957 | 930 | 926 | 915 | 707 | 594 | 44 | 34 | 0.0 | -1.8 |
| Gas | 423 | 439 | 444 | 399 | 374 | 365 | 21 | 21 | 0.4 | -0.4 |
| Electricity | 440 | 488 | 513 | 420 | 443 | 460 | 25 | 26 | 1.1 | 0.7 |
| Heat | 7 | 6 | 5 | 6 | 5 | 4 | 0 | 0 | -1.2 | -2.0 |
| Bioenergy | 116 | 139 | 155 | 133 | 228 | 267 | 7 | 15 | 2.2 | 4.5 |
| Other renewables | 3 | 7 | 10 | 4 | 14 | 27 | 0 | 2 | 7.3 | 11.9 |
| **Industry** | **416** | **423** | **425** | **386** | **359** | **351** | **100** | **100** | **0.5** | **-0.3** |
| Coal | 30 | 28 | 27 | 26 | 20 | 19 | 6 | 5 | -0.2 | -1.7 |
| Oil | 47 | 45 | 44 | 43 | 36 | 34 | 10 | 10 | -0.2 | -1.2 |
| Gas | 162 | 161 | 158 | 149 | 128 | 121 | 37 | 35 | 0.1 | -1.0 |
| Electricity | 120 | 126 | 130 | 111 | 105 | 104 | 30 | 30 | 0.8 | -0.1 |
| Heat | 6 | 5 | 5 | 5 | 4 | 4 | 1 | 1 | -0.7 | -1.6 |
| Bioenergy | 51 | 58 | 62 | 52 | 65 | 69 | 15 | 20 | 1.8 | 2.2 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.7 | 0.7 |
| **Transport** | **721** | **719** | **734** | **706** | **615** | **562** | **100** | **100** | **0.2** | **-1.0** |
| Oil | 665 | 646 | 649 | 634 | 452 | 350 | 88 | 62 | -0.1 | -2.6 |
| Electricity | 1 | 2 | 2 | 3 | 17 | 36 | 0 | 6 | 2.8 | 15.5 |
| Biofuels | 35 | 48 | 57 | 49 | 115 | 138 | 8 | 25 | 3.1 | 7.0 |
| Other fuels | 19 | 22 | 26 | 21 | 31 | 38 | 4 | 7 | 1.3 | 2.9 |
| **Buildings** | **615** | **667** | **692** | **590** | **594** | **601** | **100** | **100** | **0.8** | **0.2** |
| Coal | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | -1.2 | -12.3 |
| Oil | 44 | 37 | 33 | 40 | 25 | 19 | 5 | 3 | -1.6 | -3.8 |
| Gas | 221 | 234 | 237 | 210 | 194 | 184 | 34 | 31 | 0.5 | -0.5 |
| Electricity | 316 | 357 | 378 | 304 | 318 | 317 | 55 | 53 | 1.2 | 0.5 |
| Heat | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | -3.8 | -4.5 |
| Bioenergy | 28 | 32 | 33 | 31 | 43 | 55 | 5 | 9 | 1.3 | 3.4 |
| Other renewables | 3 | 6 | 9 | 4 | 12 | 25 | 1 | 4 | 7.1 | 11.8 |
| **Other** | **227** | **232** | **231** | **225** | **225** | **223** | **100** | **100** | **0.8** | **0.7** |

## **OECD Americas:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **3 819** | **5 324** | **5 872** | **6 132** | **6 379** | **6 647** | **100** | **100** | **0.9** |
| Coal | 1 796 | 2 006 | 1 963 | 1 891 | 1 821 | 1 768 | 38 | 27 | -0.5 |
| Oil | 211 | 102 | 60 | 42 | 34 | 29 | 2 | 0 | -5.1 |
| Gas | 406 | 1 277 | 1 547 | 1 663 | 1 748 | 1 821 | 24 | 27 | 1.5 |
| Nuclear | 687 | 925 | 989 | 1 016 | 1 043 | 1 064 | 17 | 16 | 0.6 |
| Hydro | 602 | 755 | 752 | 773 | 791 | 808 | 14 | 12 | 0.3 |
| Bioenergy | 91 | 95 | 152 | 193 | 238 | 284 | 2 | 4 | 4.7 |
| Wind | 3 | 133 | 296 | 382 | 472 | 578 | 2 | 9 | 6.3 |
| Geothermal | 21 | 24 | 51 | 67 | 80 | 91 | 0 | 1 | 5.6 |
| Solar PV | 0 | 6 | 46 | 79 | 116 | 154 | 0 | 2 | 14.8 |
| CSP | 1 | 1 | 16 | 25 | 34 | 44 | 0 | 1 | 17.7 |
| Marine | 0 | 0 | 0 | 1 | 3 | 5 | 0 | 0 | 24.6 |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **1 332** | **1 474** | **1 559** | **1 633** | **1 722** | **100** | **100** | **1.1** |
| Coal | 357 | 327 | 311 | 291 | 281 | 27 | 16 | -1.0 |
| Oil | 91 | 57 | 48 | 43 | 39 | 7 | 2 | -3.5 |
| Gas | 486 | 565 | 602 | 628 | 657 | 36 | 38 | 1.3 |
| Nuclear | 123 | 127 | 131 | 134 | 137 | 9 | 8 | 0.5 |
| Hydro | 194 | 205 | 211 | 216 | 220 | 15 | 13 | 0.5 |
| Bioenergy | 19 | 29 | 36 | 43 | 50 | 1 | 3 | 4.1 |
| Wind | 53 | 118 | 150 | 179 | 212 | 4 | 12 | 5.9 |
| Geothermal | 4 | 8 | 10 | 11 | 13 | 0 | 1 | 4.9 |
| Solar PV | 5 | 33 | 54 | 77 | 100 | 0 | 6 | 13.3 |
| CSP | 0 | 5 | 8 | 10 | 13 | 0 | 1 | 14.7 |
| Marine | 0 | 0 | 0 | 1 | 2 | 0 | 0 | 20.2 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **5 575** | **6 294** | **6 286** | **6 073** | **5 811** | **5 584** | **100** | **100** | **-0.5** |
| Coal | 1 916 | 1 976 | 1 892 | 1 797 | 1 656 | 1 534 | 31 | 27 | -1.1 |
| Oil | 2 469 | 2 670 | 2 590 | 2 422 | 2 258 | 2 108 | 42 | 38 | -1.0 |
| Gas | 1 189 | 1 648 | 1 803 | 1 855 | 1 896 | 1 943 | 26 | 35 | 0.7 |
| **Power generation** | **2 015** | **2 459** | **2 422** | **2 343** | **2 222** | **2 126** | **100** | **100** | **-0.6** |
| Coal | 1 643 | 1 837 | 1 750 | 1 662 | 1 530 | 1 417 | 75 | 67 | -1.1 |
| Oil | 150 | 78 | 47 | 33 | 26 | 23 | 3 | 1 | -5.0 |
| Gas | 222 | 543 | 625 | 648 | 666 | 686 | 22 | 32 | 1.0 |
| **TFC** | **3 213** | **3 450** | **3 471** | **3 332** | **3 185** | **3 047** | **100** | **100** | **-0.5** |
| Coal | 270 | 128 | 131 | 123 | 115 | 106 | 4 | 3 | -0.8 |
| Oil | 2 115 | 2 404 | 2 372 | 2 222 | 2 071 | 1 933 | 70 | 63 | -0.9 |
| *Transport* | *1 585* | *1 933* | *1 906* | *1 779* | *1 651* | *1 537* | *56* | *50* | *-0.9* |
| Gas | 829 | 919 | 969 | 986 | 999 | 1 008 | 27 | 33 | 0.4 |

# **OECD Americas:** Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **5 926** | **6 557** | **6 880** | **5 663** | **5 897** | **6 099** | **100** | **100** | **1.1** | **0.6** |
| Coal | 2 023 | 2 244 | 2 324 | 1 626 | 620 | 811 | 34 | 13 | 0.6 | -3.7 |
| Oil | 62 | 36 | 31 | 53 | 23 | 19 | 0 | 0 | -4.8 | -6.7 |
| Gas | 1 587 | 1 706 | 1 823 | 1 608 | 1 871 | 1 371 | 27 | 22 | 1.5 | 0.3 |
| Nuclear | 989 | 1 008 | 992 | 994 | 1 154 | 1 223 | 14 | 20 | 0.3 | 1.2 |
| Hydro | 750 | 786 | 802 | 760 | 806 | 823 | 12 | 14 | 0.3 | 0.4 |
| Bioenergy | 145 | 210 | 245 | 166 | 291 | 354 | 4 | 6 | 4.0 | 5.6 |
| Wind | 268 | 381 | 439 | 333 | 748 | 913 | 6 | 15 | 5.1 | 8.4 |
| Geothermal | 42 | 60 | 65 | 51 | 95 | 117 | 1 | 2 | 4.2 | 6.8 |
| Solar PV | 45 | 96 | 121 | 55 | 165 | 222 | 2 | 4 | 13.7 | 16.6 |
| CSP | 15 | 30 | 34 | 17 | 119 | 238 | 0 | 4 | 16.4 | 26.2 |
| Marine | 0 | 2 | 4 | 0 | 4 | 8 | 0 | 0 | 23.1 | 26.9 |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **1 476** | **1 627** | **1 705** | **1 452** | **1 674** | **1 840** | **100** | **100** | **1.0** | **1.4** |
| Coal | 340 | 361 | 367 | 313 | 167 | 165 | 22 | 9 | 0.1 | -3.2 |
| Oil | 57 | 43 | 39 | 56 | 41 | 37 | 2 | 2 | -3.5 | -3.7 |
| Gas | 570 | 614 | 646 | 533 | 616 | 637 | 38 | 35 | 1.2 | 1.1 |
| Nuclear | 127 | 130 | 127 | 128 | 148 | 156 | 7 | 8 | 0.2 | 1.0 |
| Hydro | 204 | 214 | 218 | 207 | 220 | 225 | 13 | 12 | 0.5 | 0.6 |
| Bioenergy | 28 | 38 | 44 | 31 | 51 | 61 | 3 | 3 | 3.5 | 4.9 |
| Wind | 107 | 145 | 164 | 133 | 275 | 326 | 10 | 18 | 4.8 | 7.9 |
| Geothermal | 6 | 9 | 9 | 8 | 14 | 16 | 1 | 1 | 3.5 | 6.0 |
| Solar PV | 32 | 64 | 79 | 38 | 110 | 146 | 5 | 8 | 12.2 | 15.1 |
| CSP | 5 | 9 | 10 | 5 | 31 | 67 | 1 | 4 | 13.7 | 23.0 |
| Marine | 0 | 1 | 1 | 0 | 1 | 3 | 0 | 0 | 18.6 | 22.6 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **6 429** | **6 512** | **6 599** | **5 831** | **3 719** | **3 024** | **100** | **100** | **0.2** | **-3.0** |
| Coal | 1 961 | 2 065 | 2 084 | 1 545 | 237 | 170 | 32 | 6 | 0.2 | -9.7 |
| Oil | 2 644 | 2 534 | 2 518 | 2 510 | 1 838 | 1 480 | 38 | 49 | -0.2 | -2.4 |
| Gas | 1 824 | 1 913 | 1 996 | 1 776 | 1 644 | 1 375 | 30 | 45 | 0.8 | -0.8 |
| **Power generation** | **2 501** | **2 614** | **2 675** | **2 112** | **782** | **518** | **100** | **100** | **0.4** | **-6.3** |
| Coal | 1 813 | 1 924 | 1 949 | 1 414 | 144 | 96 | 73 | 18 | 0.2 | -11.6 |
| Oil | 48 | 27 | 24 | 41 | 19 | 15 | 1 | 3 | -4.8 | -6.6 |
| Gas | 640 | 662 | 701 | 656 | 619 | 407 | 26 | 79 | 1.1 | -1.2 |
| **TFC** | **3 533** | **3 478** | **3 475** | **3 341** | **2 620** | **2 232** | **100** | **100** | **0.0** | **-1.8** |
| Coal | 137 | 129 | 123 | 120 | 85 | 67 | 4 | 3 | -0.1 | -2.6 |
| Oil | 2 424 | 2 342 | 2 333 | 2 305 | 1 700 | 1 369 | 67 | 61 | -0.1 | -2.3 |
| *Transport* | *1 947* | *1 893* | *1 901* | *1 856* | *1 324* | *1 027* | *55* | *46* | *-0.1* | *-2.6* |
| Gas | 973 | 1 008 | 1 019 | 916 | 835 | 796 | 29 | 36 | 0.4 | -0.6 |

## **United States:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **1 915** | **2 189** | **2 281** | **2 264** | **2 246** | **2 242** | **100** | **100** | **0.1** |
| Coal | 460 | 479 | 460 | 437 | 419 | 411 | 22 | 18 | -0.6 |
| Oil | 757 | 787 | 782 | 728 | 670 | 614 | 36 | 27 | -1.0 |
| Gas | 438 | 569 | 614 | 630 | 640 | 646 | 26 | 29 | 0.5 |
| Nuclear | 159 | 214 | 229 | 233 | 237 | 241 | 10 | 11 | 0.5 |
| Hydro | 23 | 28 | 25 | 26 | 27 | 27 | 1 | 1 | -0.1 |
| Bioenergy | 62 | 91 | 124 | 147 | 173 | 203 | 4 | 9 | 3.4 |
| Other renewables | 15 | 21 | 46 | 63 | 80 | 101 | 1 | 4 | 6.8 |
| **Power generation** | **750** | **916** | **965** | **978** | **992** | **1 011** | **100** | **100** | **0.4** |
| Coal | 396 | 436 | 414 | 392 | 375 | 362 | 48 | 36 | -0.8 |
| Oil | 27 | 9 | 5 | 4 | 3 | 3 | 1 | 0 | -4.5 |
| Gas | 90 | 190 | 218 | 227 | 233 | 237 | 21 | 23 | 0.9 |
| Nuclear | 159 | 214 | 229 | 233 | 237 | 241 | 23 | 24 | 0.5 |
| Hydro | 23 | 28 | 25 | 26 | 27 | 27 | 3 | 3 | -0.1 |
| Bioenergy | 40 | 21 | 31 | 38 | 46 | 54 | 2 | 5 | 4.1 |
| Other renewables | 14 | 19 | 43 | 58 | 73 | 88 | 2 | 9 | 6.5 |
| **Other energy sector** | **150** | **157** | **154** | **153** | **151** | **152** | **100** | **100** | **-0.1** |
| *Electricity* | *49* | *49* | *51* | *52* | *53* | *54* | *32* | *35* | *0.4* |
| **TFC** | **1 294** | **1 504** | **1 581** | **1 567** | **1 550** | **1 541** | **100** | **100** | **0.1** |
| Coal | 56 | 25 | 26 | 24 | 22 | 20 | 2 | 1 | -0.8 |
| Oil | 683 | 747 | 752 | 704 | 651 | 602 | 50 | 39 | -0.9 |
| Gas | 303 | 327 | 343 | 348 | 351 | 352 | 22 | 23 | 0.3 |
| Electricity | 226 | 326 | 358 | 372 | 386 | 401 | 22 | 26 | 0.9 |
| Heat | 2 | 7 | 6 | 5 | 4 | 4 | 0 | 0 | -2.1 |
| Bioenergy | 23 | 71 | 94 | 109 | 128 | 149 | 5 | 10 | 3.1 |
| Other renewables | 0 | 2 | 3 | 5 | 8 | 13 | 0 | 1 | 8.9 |
| **Industry** | **284** | **287** | **304** | **300** | **292** | **286** | **100** | **100** | **-0.0** |
| Coal | 46 | 23 | 24 | 22 | 20 | 19 | 8 | 7 | -0.9 |
| Oil | 44 | 30 | 29 | 27 | 24 | 22 | 11 | 8 | -1.3 |
| Gas | 110 | 119 | 122 | 118 | 112 | 106 | 41 | 37 | -0.5 |
| Electricity | 75 | 77 | 83 | 83 | 82 | 82 | 27 | 29 | 0.2 |
| Heat | - | 5 | 5 | 4 | 4 | 3 | 2 | 1 | -1.7 |
| Bioenergy | 9 | 32 | 41 | 45 | 49 | 54 | 11 | 19 | 2.2 |
| Other renewables | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.5 |
| **Transport** | **488** | **589** | **589** | **561** | **538** | **525** | **100** | **100** | **-0.5** |
| Oil | 472 | 546 | 533 | 490 | 446 | 407 | 93 | 78 | -1.2 |
| Electricity | 0 | 1 | 1 | 2 | 5 | 10 | 0 | 2 | 11.9 |
| Biofuels | - | 26 | 36 | 44 | 57 | 70 | 4 | 13 | 4.2 |
| Other fuels | 15 | 17 | 19 | 24 | 30 | 38 | 3 | 7 | 3.5 |
| **Buildings** | **389** | **480** | **511** | **526** | **540** | **554** | **100** | **100** | **0.6** |
| Coal | 10 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | -4.7 |
| Oil | 48 | 34 | 27 | 21 | 16 | 12 | 7 | 2 | -4.4 |
| Gas | 164 | 181 | 190 | 194 | 196 | 197 | 38 | 35 | 0.3 |
| Electricity | 152 | 248 | 273 | 287 | 299 | 310 | 52 | 56 | 0.9 |
| Heat | 2 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | -4.2 |
| Bioenergy | 14 | 13 | 16 | 18 | 20 | 23 | 3 | 4 | 2.5 |
| Other renewables | 0 | 2 | 3 | 4 | 7 | 12 | 0 | 2 | 8.9 |
| **Other** | **133** | **147** | **177** | **180** | **179** | **177** | **100** | **100** | **0.8** |

## **United States:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **2 305** | **2 359** | **2 402** | **2 196** | **2 001** | **1 978** | **100** | **100** | **0.4** | **-0.4** |
| Coal | 475 | 505 | 526 | 377 | 156 | 207 | 22 | 10 | 0.4 | -3.4 |
| Oil | 796 | 748 | 730 | 763 | 566 | 462 | 30 | 23 | -0.3 | -2.2 |
| Gas | 614 | 625 | 637 | 611 | 610 | 521 | 27 | 26 | 0.5 | -0.4 |
| Nuclear | 229 | 232 | 228 | 231 | 264 | 280 | 9 | 14 | 0.3 | 1.1 |
| Hydro | 25 | 26 | 27 | 26 | 28 | 28 | 1 | 1 | -0.1 | 0.1 |
| Bioenergy | 120 | 153 | 174 | 138 | 240 | 281 | 7 | 14 | 2.7 | 4.8 |
| Other renewables | 45 | 70 | 81 | 51 | 137 | 199 | 3 | 10 | 5.8 | 9.8 |
| **Power generation** | **976** | **1 036** | **1 066** | **912** | **855** | **905** | **100** | **100** | **0.6** | **-0.1** |
| Coal | 427 | 455 | 468 | 334 | 118 | 166 | 44 | 18 | 0.3 | -3.9 |
| Oil | 5 | 3 | 3 | 3 | 2 | 1 | 0 | 0 | -4.5 | -7.3 |
| Gas | 218 | 214 | 220 | 236 | 260 | 184 | 21 | 20 | 0.6 | -0.1 |
| Nuclear | 229 | 232 | 228 | 231 | 264 | 280 | 21 | 31 | 0.3 | 1.1 |
| Hydro | 25 | 26 | 27 | 26 | 28 | 28 | 3 | 3 | -0.1 | 0.1 |
| Bioenergy | 30 | 42 | 48 | 35 | 58 | 69 | 5 | 8 | 3.6 | 5.2 |
| Other renewables | 42 | 64 | 73 | 48 | 126 | 175 | 7 | 19 | 5.7 | 9.6 |
| **Other energy sector** | **155** | **156** | **164** | **150** | **138** | **134** | **100** | **100** | **0.2** | **-0.7** |
| *Electricity* | *52* | *55* | *56* | *49* | *47* | *47* | *34* | *35* | *0.6* | *-0.2* |
| **TFC** | **1 597** | **1 625** | **1 649** | **1 539** | **1 423** | **1 368** | **100** | **100** | **0.4** | **-0.4** |
| Coal | 27 | 25 | 24 | 24 | 18 | 16 | 1 | 1 | -0.1 | -1.8 |
| Oil | 766 | 731 | 721 | 735 | 549 | 451 | 44 | 33 | -0.1 | -2.1 |
| Gas | 344 | 352 | 353 | 323 | 297 | 288 | 21 | 21 | 0.3 | -0.5 |
| Electricity | 360 | 395 | 412 | 345 | 361 | 375 | 25 | 27 | 1.0 | 0.6 |
| Heat | 6 | 5 | 5 | 6 | 4 | 4 | 0 | 0 | -1.5 | -2.6 |
| Bioenergy | 90 | 111 | 125 | 103 | 182 | 211 | 8 | 15 | 2.4 | 4.7 |
| Other renewables | 3 | 6 | 9 | 3 | 11 | 23 | 1 | 2 | 7.1 | 11.7 |
| **Industry** | **309** | **305** | **302** | **286** | **257** | **247** | **100** | **100** | **0.2** | **-0.6** |
| Coal | 25 | 23 | 22 | 22 | 17 | 15 | 7 | 6 | -0.2 | -1.9 |
| Oil | 30 | 27 | 26 | 27 | 21 | 19 | 9 | 8 | -0.7 | -2.0 |
| Gas | 124 | 119 | 115 | 113 | 93 | 86 | 38 | 35 | -0.1 | -1.3 |
| Electricity | 85 | 86 | 86 | 78 | 71 | 70 | 28 | 28 | 0.4 | -0.4 |
| Heat | 5 | 4 | 4 | 4 | 3 | 3 | 1 | 1 | -1.1 | -2.1 |
| Bioenergy | 41 | 45 | 49 | 41 | 52 | 54 | 16 | 22 | 1.8 | 2.2 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.5 | 0.5 |
| **Transport** | **596** | **588** | **598** | **585** | **502** | **454** | **100** | **100** | **0.1** | **-1.1** |
| Oil | 545 | 520 | 519 | 522 | 359 | 272 | 87 | 60 | -0.2 | -2.9 |
| Electricity | 1 | 1 | 1 | 2 | 16 | 33 | 0 | 7 | 3.3 | 17.7 |
| Biofuels | 33 | 46 | 55 | 43 | 98 | 114 | 9 | 25 | 3.2 | 6.4 |
| Other fuels | 17 | 20 | 23 | 18 | 28 | 35 | 4 | 8 | 1.4 | 3.2 |
| **Buildings** | **515** | **553** | **572** | **493** | **491** | **496** | **100** | **100** | **0.7** | **0.1** |
| Coal | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | -1.2 | -13.8 |
| Oil | 28 | 20 | 16 | 26 | 13 | 8 | 3 | 2 | -3.2 | -6.0 |
| Gas | 191 | 200 | 202 | 181 | 164 | 154 | 35 | 31 | 0.4 | -0.7 |
| Electricity | 275 | 308 | 325 | 264 | 275 | 273 | 57 | 55 | 1.1 | 0.4 |
| Heat | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | -4.1 | -4.7 |
| Bioenergy | 15 | 18 | 20 | 17 | 28 | 38 | 3 | 8 | 1.8 | 4.7 |
| Other renewables | 3 | 6 | 8 | 3 | 11 | 23 | 1 | 5 | 7.2 | 11.8 |
| **Other** | **177** | **179** | **176** | **175** | **173** | **171** | **100** | **100** | **0.8** | **0.6** |

## **United States:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **3 203** | **4 327** | **4 718** | **4 897** | **5 069** | **5 253** | **100** | **100** | **0.8** |
| Coal | 1 700 | 1 875 | 1 815 | 1 741 | 1 694 | 1 662 | 43 | 32 | -0.5 |
| Oil | 131 | 41 | 21 | 18 | 15 | 13 | 1 | 0 | -4.5 |
| Gas | 382 | 1 045 | 1 262 | 1 357 | 1 410 | 1 443 | 24 | 27 | 1.4 |
| Nuclear | 612 | 821 | 880 | 896 | 910 | 924 | 19 | 18 | 0.5 |
| Hydro | 273 | 322 | 294 | 302 | 310 | 316 | 7 | 6 | -0.1 |
| Bioenergy | 86 | 77 | 123 | 157 | 193 | 232 | 2 | 4 | 4.7 |
| Wind | 3 | 121 | 234 | 289 | 351 | 427 | 3 | 8 | 5.4 |
| Geothermal | 16 | 18 | 32 | 42 | 51 | 59 | 0 | 1 | 5.1 |
| Solar PV | 0 | 5 | 43 | 73 | 105 | 138 | 0 | 3 | 14.6 |
| CSP | 1 | 1 | 14 | 22 | 29 | 37 | 0 | 1 | 16.8 |
| Marine | - | - | - | 0 | 1 | 3 | - | 0 | n.a. |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **1 119** | **1 211** | **1 267** | **1 314** | **1 375** | **100** | **100** | **0.9** |
| Coal | 335 | 304 | 287 | 270 | 263 | 30 | 19 | -1.0 |
| Oil | 67 | 35 | 31 | 28 | 26 | 6 | 2 | -3.9 |
| Gas | 438 | 500 | 526 | 540 | 556 | 39 | 40 | 1.0 |
| Nuclear | 108 | 111 | 113 | 115 | 117 | 10 | 8 | 0.3 |
| Hydro | 101 | 105 | 107 | 109 | 111 | 9 | 8 | 0.4 |
| Bioenergy | 15 | 23 | 28 | 34 | 40 | 1 | 3 | 4.1 |
| Wind | 47 | 94 | 113 | 132 | 154 | 4 | 11 | 5.1 |
| Geothermal | 3 | 5 | 6 | 7 | 8 | 0 | 1 | 4.2 |
| Solar PV | 4 | 29 | 48 | 68 | 88 | 0 | 6 | 13.3 |
| CSP | 0 | 5 | 7 | 9 | 11 | 0 | 1 | 13.9 |
| Marine | - | - | 0 | 1 | 1 | - | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **4 850** | **5 256** | **5 197** | **4 982** | **4 724** | **4 489** | **100** | **100** | **-0.7** |
| Coal | 1 797 | 1 830 | 1 734 | 1 639 | 1 523 | 1 425 | 35 | 32 | -1.0 |
| Oil | 2 042 | 2 111 | 2 040 | 1 888 | 1 729 | 1 583 | 40 | 35 | -1.2 |
| Gas | 1 011 | 1 315 | 1 424 | 1 456 | 1 472 | 1 482 | 25 | 33 | 0.5 |
| **Power generation** | **1 848** | **2 189** | **2 141** | **2 072** | **1 971** | **1 884** | **100** | **100** | **-0.6** |
| Coal | 1 550 | 1 716 | 1 616 | 1 528 | 1 421 | 1 331 | 78 | 71 | -1.1 |
| Oil | 88 | 30 | 16 | 14 | 12 | 10 | 1 | 1 | -4.5 |
| Gas | 210 | 443 | 510 | 530 | 538 | 543 | 20 | 29 | 0.8 |
| **TFC** | **2 730** | **2 801** | **2 785** | **2 643** | **2 490** | **2 348** | **100** | **100** | **-0.7** |
| Coal | 245 | 105 | 108 | 100 | 92 | 84 | 4 | 4 | -0.9 |
| Oil | 1 788 | 1 939 | 1 885 | 1 739 | 1 587 | 1 451 | 69 | 62 | -1.2 |
| *Transport* | *1 376* | *1 599* | *1 559* | *1 435* | *1 306* | *1 193* | *57* | *51* | *-1.2* |
| Gas | 697 | 757 | 792 | 803 | 810 | 813 | 27 | 35 | 0.3 |

## **United States:** Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **4 752** | **5 191** | **5 411** | **4 548** | **4 710** | **4 873** | **100** | **100** | **0.9** | **0.5** |
| Coal | 1 872 | 2 067 | 2 146 | 1 493 | 557 | 774 | 40 | 16 | 0.6 | -3.6 |
| Oil | 21 | 16 | 14 | 15 | 7 | 6 | 0 | 0 | -4.5 | -7.9 |
| Gas | 1 255 | 1 270 | 1 323 | 1 348 | 1 612 | 1 128 | 24 | 23 | 1.0 | 0.3 |
| Nuclear | 880 | 890 | 874 | 885 | 1 013 | 1 076 | 16 | 22 | 0.3 | 1.1 |
| Hydro | 292 | 306 | 312 | 300 | 322 | 330 | 6 | 7 | -0.1 | 0.1 |
| Bioenergy | 120 | 176 | 204 | 137 | 245 | 299 | 4 | 6 | 4.1 | 5.8 |
| Wind | 223 | 302 | 340 | 272 | 623 | 749 | 6 | 15 | 4.4 | 7.9 |
| Geothermal | 32 | 46 | 50 | 33 | 65 | 83 | 1 | 2 | 4.4 | 6.6 |
| Solar PV | 42 | 91 | 115 | 51 | 151 | 199 | 2 | 4 | 13.7 | 16.3 |
| CSP | 14 | 28 | 31 | 15 | 112 | 224 | 1 | 5 | 16.0 | 25.9 |
| Marine | - | 1 | 1 | - | 2 | 5 | 0 | 0 | n.a. | n.a. |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **1 217** | **1 319** | **1 371** | **1 196** | **1 371** | **1 509** | **100** | **100** | **0.9** | **1.3** |
| Coal | 316 | 334 | 339 | 291 | 153 | 154 | 25 | 10 | 0.0 | -3.2 |
| Oil | 35 | 28 | 26 | 34 | 26 | 24 | 2 | 2 | -3.8 | -4.2 |
| Gas | 500 | 515 | 531 | 473 | 543 | 559 | 39 | 37 | 0.8 | 1.0 |
| Nuclear | 111 | 113 | 110 | 112 | 128 | 135 | 8 | 9 | 0.1 | 1.0 |
| Hydro | 104 | 108 | 110 | 107 | 113 | 115 | 8 | 8 | 0.3 | 0.5 |
| Bioenergy | 22 | 31 | 36 | 25 | 43 | 51 | 3 | 3 | 3.7 | 5.2 |
| Wind | 90 | 116 | 128 | 109 | 227 | 264 | 9 | 18 | 4.3 | 7.5 |
| Geothermal | 5 | 7 | 7 | 5 | 9 | 12 | 1 | 1 | 3.6 | 5.7 |
| Solar PV | 29 | 59 | 74 | 35 | 99 | 129 | 5 | 9 | 12.5 | 15.1 |
| CSP | 5 | 8 | 10 | 5 | 29 | 64 | 1 | 4 | 13.3 | 22.7 |
| Marine | - | 0 | 1 | - | 1 | 2 | 0 | 0 | n.a. | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **5 309** | **5 300** | **5 331** | **4 806** | **2 879** | **2 276** | **100** | **100** | **0.1** | **-3.4** |
| Coal | 1 799 | 1 893 | 1 925 | 1 405 | 175 | 134 | 36 | 6 | 0.2 | -10.3 |
| Oil | 2 084 | 1 969 | 1 941 | 1 986 | 1 408 | 1 103 | 36 | 48 | -0.3 | -2.7 |
| Gas | 1 425 | 1 438 | 1 465 | 1 415 | 1 295 | 1 039 | 27 | 46 | 0.5 | -1.0 |
| **Power generation** | **2 201** | **2 287** | **2 338** | **1 860** | **634** | **403** | **100** | **100** | **0.3** | **-6.8** |
| Coal | 1 676 | 1 778 | 1 815 | 1 298 | 102 | 77 | 78 | 19 | 0.2 | -12.1 |
| Oil | 16 | 12 | 10 | 11 | 6 | 5 | 0 | 1 | -4.5 | -7.3 |
| Gas | 509 | 498 | 512 | 551 | 526 | 321 | 22 | 80 | 0.6 | -1.3 |
| **TFC** | **2 836** | **2 741** | **2 716** | **2 685** | **2 038** | **1 700** | **100** | **100** | **-0.1** | **-2.1** |
| Coal | 113 | 105 | 100 | 98 | 66 | 51 | 4 | 3 | -0.2 | -3.0 |
| Oil | 1 929 | 1 824 | 1 802 | 1 842 | 1 305 | 1 021 | 66 | 60 | -0.3 | -2.6 |
| *Transport* | *1 594* | *1 523* | *1 518* | *1 527* | *1 052* | *797* | *56* | *47* | *-0.2* | *-2.9* |
| Gas | 795 | 812 | 814 | 745 | 667 | 628 | 30 | 37 | 0.3 | -0.8 |

## **OECD Europe:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **1 630** | **1 778** | **1 763** | **1 741** | **1 719** | **1 709** | **100** | **100** | **-0.2** |
| Coal | 452 | 312 | 285 | 245 | 211 | 177 | 18 | 10 | -2.3 |
| Oil | 615 | 589 | 521 | 488 | 452 | 422 | 33 | 25 | -1.4 |
| Gas | 260 | 432 | 442 | 468 | 481 | 498 | 24 | 29 | 0.6 |
| Nuclear | 205 | 236 | 226 | 213 | 212 | 210 | 13 | 12 | -0.5 |
| Hydro | 38 | 43 | 52 | 53 | 55 | 56 | 2 | 3 | 1.0 |
| Bioenergy | 54 | 130 | 166 | 184 | 200 | 217 | 7 | 13 | 2.1 |
| Other renewables | 5 | 36 | 71 | 89 | 108 | 129 | 2 | 8 | 5.5 |
| **Power generation** | **626** | **756** | **759** | **752** | **755** | **764** | **100** | **100** | **0.0** |
| Coal | 279 | 227 | 202 | 168 | 140 | 112 | 30 | 15 | -2.9 |
| Oil | 51 | 20 | 12 | 9 | 7 | 6 | 3 | 1 | -4.7 |
| Gas | 41 | 150 | 142 | 162 | 172 | 187 | 20 | 24 | 0.9 |
| Nuclear | 205 | 236 | 226 | 213 | 212 | 210 | 31 | 28 | -0.5 |
| Hydro | 38 | 43 | 52 | 53 | 55 | 56 | 6 | 7 | 1.0 |
| Bioenergy | 9 | 50 | 65 | 71 | 78 | 85 | 7 | 11 | 2.2 |
| Other renewables | 3 | 29 | 60 | 75 | 91 | 108 | 4 | 14 | 5.6 |
| **Other energy sector** | **151** | **152** | **138** | **131** | **124** | **121** | **100** | **100** | **-0.9** |
| *Electricity* | *39* | *45* | *43* | *43* | *43* | *43* | *30* | *36* | *-0.2* |
| **TFC** | **1 130** | **1 236** | **1 257** | **1 260** | **1 254** | **1 250** | **100** | **100** | **0.0** |
| Coal | 126 | 53 | 52 | 49 | 45 | 42 | 4 | 3 | -0.9 |
| Oil | 523 | 526 | 477 | 450 | 420 | 392 | 43 | 31 | -1.2 |
| Gas | 201 | 259 | 280 | 286 | 290 | 292 | 21 | 23 | 0.5 |
| Electricity | 193 | 266 | 286 | 297 | 305 | 316 | 21 | 25 | 0.7 |
| Heat | 40 | 47 | 51 | 53 | 55 | 56 | 4 | 5 | 0.8 |
| Bioenergy | 46 | 80 | 101 | 112 | 122 | 132 | 6 | 11 | 2.1 |
| Other renewables | 2 | 6 | 10 | 13 | 16 | 20 | 1 | 2 | 5.0 |
| **Industry** | **324** | **295** | **300** | **298** | **293** | **290** | **100** | **100** | **-0.1** |
| Coal | 71 | 33 | 32 | 30 | 28 | 25 | 11 | 9 | -1.1 |
| Oil | 59 | 33 | 29 | 27 | 24 | 22 | 11 | 7 | -1.8 |
| Gas | 78 | 88 | 87 | 85 | 82 | 80 | 30 | 27 | -0.4 |
| Electricity | 88 | 101 | 106 | 107 | 107 | 109 | 34 | 37 | 0.3 |
| Heat | 14 | 16 | 16 | 15 | 15 | 16 | 5 | 5 | -0.0 |
| Bioenergy | 14 | 25 | 29 | 33 | 36 | 39 | 8 | 14 | 2.0 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6.7 |
| **Transport** | **268** | **335** | **325** | **317** | **307** | **297** | **100** | **100** | **-0.5** |
| Oil | 262 | 312 | 291 | 277 | 263 | 248 | 93 | 84 | -0.9 |
| Electricity | 5 | 6 | 7 | 8 | 9 | 10 | 2 | 3 | 2.3 |
| Biofuels | 0 | 14 | 23 | 27 | 30 | 33 | 4 | 11 | 3.7 |
| Other fuels | 1 | 3 | 4 | 4 | 5 | 5 | 1 | 2 | 2.4 |
| **Buildings** | **406** | **464** | **502** | **519** | **534** | **548** | **100** | **100** | **0.7** |
| Coal | 51 | 17 | 17 | 16 | 15 | 15 | 4 | 3 | -0.7 |
| Oil | 97 | 64 | 53 | 46 | 39 | 33 | 14 | 6 | -2.7 |
| Gas | 105 | 153 | 173 | 181 | 188 | 192 | 33 | 35 | 1.0 |
| Electricity | 96 | 154 | 168 | 176 | 184 | 192 | 33 | 35 | 0.9 |
| Heat | 24 | 31 | 35 | 37 | 39 | 41 | 7 | 7 | 1.1 |
| Bioenergy | 30 | 40 | 46 | 50 | 53 | 56 | 9 | 10 | 1.4 |
| Other renewables | 2 | 6 | 10 | 13 | 16 | 20 | 1 | 4 | 5.0 |
| **Other** | **133** | **142** | **130** | **126** | **120** | **114** | **100** | **100** | **-0.9** |

## **OECD Europe:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **1 788** | **1 807** | **1 828** | **1 704** | **1 576** | **1 540** | **100** | **100** | **0.1** | **-0.6** |
| Coal | 301 | 262 | 246 | 259 | 138 | 108 | 13 | 7 | -1.0 | -4.3 |
| Oil | 532 | 489 | 473 | 496 | 364 | 312 | 26 | 20 | -0.9 | -2.6 |
| Gas | 458 | 523 | 553 | 419 | 391 | 371 | 30 | 24 | 1.0 | -0.6 |
| Nuclear | 219 | 200 | 193 | 228 | 252 | 244 | 11 | 16 | -0.8 | 0.1 |
| Hydro | 51 | 54 | 55 | 53 | 59 | 61 | 3 | 4 | 1.0 | 1.4 |
| Bioenergy | 160 | 184 | 198 | 170 | 228 | 259 | 11 | 17 | 1.8 | 2.9 |
| Other renewables | 68 | 95 | 111 | 78 | 145 | 184 | 6 | 12 | 4.8 | 7.1 |
| **Power generation** | **771** | **798** | **821** | **734** | **713** | **716** | **100** | **100** | **0.3** | **-0.2** |
| Coal | 216 | 185 | 174 | 178 | 72 | 49 | 21 | 7 | -1.1 | -6.2 |
| Oil | 12 | 7 | 6 | 11 | 5 | 4 | 1 | 1 | -4.7 | -6.6 |
| Gas | 152 | 196 | 218 | 132 | 120 | 108 | 27 | 15 | 1.6 | -1.4 |
| Nuclear | 219 | 200 | 193 | 228 | 252 | 244 | 23 | 34 | -0.8 | 0.1 |
| Hydro | 51 | 54 | 55 | 53 | 59 | 61 | 7 | 9 | 1.0 | 1.4 |
| Bioenergy | 63 | 74 | 81 | 66 | 82 | 94 | 10 | 13 | 2.0 | 2.6 |
| Other renewables | 58 | 81 | 94 | 67 | 124 | 156 | 11 | 22 | 5.0 | 7.3 |
| **Other energy sector** | **139** | **129** | **129** | **134** | **113** | **108** | **100** | **100** | **-0.7** | **-1.4** |
| *Electricity* | *44* | *46* | *48* | *42* | *39* | *39* | *37* | *36* | *0.2* | *-0.7* |
| **TFC** | **1 276** | **1 319** | **1 337** | **1 216** | **1 138** | **1 113** | **100** | **100** | **0.3** | **-0.4** |
| Coal | 54 | 50 | 48 | 50 | 42 | 38 | 4 | 3 | -0.4 | -1.4 |
| Oil | 488 | 457 | 441 | 455 | 338 | 288 | 33 | 26 | -0.7 | -2.5 |
| Gas | 285 | 307 | 314 | 267 | 252 | 244 | 23 | 22 | 0.8 | -0.3 |
| Electricity | 292 | 325 | 341 | 280 | 293 | 301 | 26 | 27 | 1.1 | 0.5 |
| Heat | 51 | 57 | 60 | 48 | 48 | 49 | 4 | 4 | 1.0 | 0.2 |
| Bioenergy | 96 | 110 | 117 | 104 | 145 | 165 | 9 | 15 | 1.6 | 3.1 |
| Other renewables | 10 | 14 | 17 | 11 | 20 | 28 | 1 | 3 | 4.1 | 6.4 |
| **Industry** | **305** | **309** | **309** | **291** | **275** | **270** | **100** | **100** | **0.2** | **-0.4** |
| Coal | 33 | 30 | 28 | 32 | 26 | 23 | 9 | 9 | -0.7 | -1.4 |
| Oil | 30 | 26 | 24 | 28 | 21 | 18 | 8 | 7 | -1.3 | -2.5 |
| Gas | 90 | 89 | 89 | 83 | 73 | 68 | 29 | 25 | 0.0 | -1.1 |
| Electricity | 108 | 114 | 117 | 105 | 106 | 108 | 38 | 40 | 0.6 | 0.3 |
| Heat | 15 | 15 | 15 | 15 | 13 | 13 | 5 | 5 | -0.2 | -0.7 |
| Bioenergy | 29 | 34 | 36 | 28 | 35 | 39 | 12 | 14 | 1.6 | 2.0 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6.7 | 7.5 |
| **Transport** | **329** | **329** | **330** | **312** | **258** | **241** | **100** | **100** | **-0.1** | **-1.4** |
| Oil | 298 | 291 | 288 | 275 | 194 | 160 | 87 | 67 | -0.3 | -2.7 |
| Electricity | 7 | 9 | 10 | 8 | 13 | 18 | 3 | 8 | 2.1 | 4.8 |
| Biofuels | 21 | 25 | 28 | 26 | 47 | 56 | 8 | 23 | 3.0 | 6.1 |
| Other fuels | 4 | 4 | 5 | 3 | 4 | 6 | 1 | 2 | 2.0 | 2.7 |
| **Buildings** | **510** | **559** | **582** | **484** | **486** | **490** | **100** | **100** | **0.9** | **0.2** |
| Coal | 18 | 17 | 17 | 16 | 14 | 13 | 3 | 3 | -0.0 | -1.3 |
| Oil | 55 | 44 | 39 | 49 | 30 | 23 | 7 | 5 | -2.0 | -4.2 |
| Gas | 177 | 198 | 206 | 165 | 160 | 156 | 35 | 32 | 1.3 | 0.1 |
| Electricity | 172 | 196 | 210 | 162 | 168 | 170 | 36 | 35 | 1.3 | 0.4 |
| Heat | 35 | 41 | 44 | 33 | 35 | 36 | 8 | 7 | 1.5 | 0.6 |
| Bioenergy | 45 | 48 | 50 | 48 | 59 | 65 | 9 | 13 | 0.9 | 2.1 |
| Other renewables | 9 | 14 | 16 | 10 | 20 | 27 | 3 | 6 | 4.1 | 6.4 |
| **Other** | **131** | **121** | **116** | **129** | **118** | **112** | **100** | **100** | **-0.9** | **-1.0** |

## **OECD Europe:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **2 683** | **3 613** | **3 836** | **3 952** | **4 054** | **4 178** | **100** | **100** | **0.6** |
| Coal | 1 040 | 931 | 856 | 716 | 598 | 479 | 26 | 11 | -2.7 |
| Oil | 216 | 70 | 36 | 29 | 22 | 20 | 2 | 0 | -5.1 |
| Gas | 168 | 806 | 726 | 850 | 910 | 984 | 22 | 24 | 0.8 |
| Nuclear | 787 | 905 | 866 | 819 | 814 | 806 | 25 | 19 | -0.5 |
| Hydro | 446 | 504 | 600 | 621 | 635 | 647 | 14 | 15 | 1.0 |
| Bioenergy | 21 | 155 | 212 | 236 | 258 | 284 | 4 | 7 | 2.5 |
| Wind | 1 | 182 | 390 | 499 | 600 | 700 | 5 | 17 | 5.8 |
| Geothermal | 4 | 11 | 16 | 20 | 24 | 29 | 0 | 1 | 4.0 |
| Solar PV | 0 | 45 | 125 | 147 | 162 | 176 | 1 | 4 | 5.8 |
| CSP | - | 1 | 10 | 14 | 22 | 31 | 0 | 1 | 14.1 |
| Marine | 1 | 1 | 1 | 3 | 8 | 23 | 0 | 1 | 16.9 |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **1 015** | **1 195** | **1 260** | **1 322** | **1 389** | **100** | **100** | **1.3** |
| Coal | 203 | 183 | 157 | 144 | 131 | 20 | 9 | -1.8 |
| Oil | 65 | 42 | 32 | 29 | 28 | 6 | 2 | -3.5 |
| Gas | 233 | 282 | 316 | 336 | 362 | 23 | 26 | 1.9 |
| Nuclear | 131 | 125 | 117 | 116 | 114 | 13 | 8 | -0.6 |
| Hydro | 198 | 216 | 223 | 228 | 232 | 20 | 17 | 0.7 |
| Bioenergy | 36 | 44 | 47 | 50 | 52 | 4 | 4 | 1.6 |
| Wind | 94 | 184 | 226 | 262 | 296 | 9 | 21 | 4.9 |
| Geothermal | 2 | 2 | 3 | 3 | 4 | 0 | 0 | 3.9 |
| Solar PV | 52 | 115 | 134 | 144 | 152 | 5 | 11 | 4.6 |
| CSP | 1 | 3 | 4 | 7 | 9 | 0 | 1 | 8.9 |
| Marine | 0 | 1 | 1 | 3 | 9 | 0 | 1 | 16.1 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **3 965** | **3 747** | **3 493** | **3 294** | **3 072** | **2 885** | **100** | **100** | **-1.1** |
| Coal | 1 714 | 1 198 | 1 090 | 923 | 770 | 624 | 32 | 22 | -2.7 |
| Oil | 1 673 | 1 556 | 1 385 | 1 295 | 1 197 | 1 119 | 42 | 39 | -1.4 |
| Gas | 578 | 994 | 1 018 | 1 076 | 1 105 | 1 142 | 27 | 40 | 0.6 |
| **Power generation** | **1 399** | **1 355** | **1 205** | **1 089** | **968** | **871** | **100** | **100** | **-1.8** |
| Coal | 1 140 | 940 | 834 | 682 | 546 | 418 | 69 | 48 | -3.3 |
| Oil | 164 | 63 | 38 | 29 | 22 | 20 | 5 | 2 | -4.7 |
| Gas | 95 | 352 | 333 | 377 | 400 | 433 | 26 | 50 | 0.9 |
| **TFC** | **2 388** | **2 208** | **2 127** | **2 055** | **1 967** | **1 880** | **100** | **100** | **-0.7** |
| Coal | 535 | 227 | 225 | 212 | 196 | 181 | 10 | 10 | -0.9 |
| Oil | 1 394 | 1 383 | 1 257 | 1 182 | 1 101 | 1 024 | 63 | 54 | -1.2 |
| *Transport* | *774* | *936* | *872* | *831* | *787* | *743* | *42* | *40* | *-1.0* |
| Gas | 460 | 598 | 645 | 662 | 670 | 675 | 27 | 36 | 0.5 |

## **OECD Europe:** Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **3 913** | **4 313** | **4 527** | **3 738** | **3 858** | **3 952** | **100** | **100** | **0.9** | **0.4** |
| Coal | 919 | 819 | 800 | 747 | 249 | 154 | 18 | 4 | -0.6 | -7.2 |
| Oil | 37 | 23 | 21 | 30 | 13 | 11 | 0 | 0 | -5.0 | -7.5 |
| Gas | 793 | 1 085 | 1 199 | 666 | 565 | 436 | 26 | 11 | 1.7 | -2.5 |
| Nuclear | 839 | 769 | 739 | 876 | 967 | 937 | 16 | 24 | -0.8 | 0.1 |
| Hydro | 591 | 626 | 637 | 615 | 684 | 709 | 14 | 18 | 1.0 | 1.4 |
| Bioenergy | 206 | 246 | 270 | 214 | 286 | 333 | 6 | 8 | 2.3 | 3.2 |
| Wind | 384 | 561 | 646 | 422 | 804 | 997 | 14 | 25 | 5.4 | 7.3 |
| Geothermal | 14 | 19 | 22 | 18 | 30 | 37 | 0 | 1 | 2.8 | 5.1 |
| Solar PV | 118 | 144 | 155 | 133 | 194 | 225 | 3 | 6 | 5.3 | 6.9 |
| CSP | 10 | 18 | 25 | 15 | 52 | 78 | 1 | 2 | 13.1 | 18.6 |
| Marine | 1 | 5 | 14 | 1 | 12 | 35 | 0 | 1 | 14.4 | 19.0 |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **1 206** | **1 356** | **1 434** | **1 207** | **1 395** | **1 506** | **100** | **100** | **1.4** | **1.7** |
| Coal | 186 | 160 | 161 | 171 | 91 | 70 | 11 | 5 | -0.9 | -4.3 |
| Oil | 42 | 29 | 27 | 42 | 29 | 27 | 2 | 2 | -3.6 | -3.6 |
| Gas | 305 | 397 | 432 | 276 | 303 | 316 | 30 | 21 | 2.6 | 1.3 |
| Nuclear | 121 | 109 | 105 | 126 | 135 | 141 | 7 | 9 | -0.9 | 0.3 |
| Hydro | 213 | 225 | 229 | 221 | 245 | 254 | 16 | 17 | 0.6 | 1.0 |
| Bioenergy | 43 | 48 | 50 | 44 | 54 | 60 | 4 | 4 | 1.4 | 2.2 |
| Wind | 182 | 250 | 279 | 199 | 342 | 403 | 19 | 27 | 4.6 | 6.2 |
| Geothermal | 2 | 3 | 3 | 3 | 4 | 5 | 0 | 0 | 2.8 | 5.0 |
| Solar PV | 108 | 129 | 136 | 120 | 171 | 194 | 9 | 13 | 4.1 | 5.6 |
| CSP | 3 | 5 | 7 | 4 | 15 | 23 | 1 | 2 | 8.0 | 13.2 |
| Marine | 0 | 2 | 5 | 1 | 4 | 14 | 0 | 1 | 13.7 | 18.2 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **3 630** | **3 494** | **3 449** | **3 246** | **2 214** | **1 830** | **100** | **100** | **-0.3** | **-2.9** |
| Coal | 1 158 | 981 | 906 | 973 | 427 | 271 | 26 | 15 | -1.2 | -6.0 |
| Oil | 1 419 | 1 310 | 1 273 | 1 312 | 921 | 764 | 37 | 42 | -0.8 | -2.9 |
| Gas | 1 054 | 1 203 | 1 270 | 961 | 865 | 795 | 37 | 43 | 1.0 | -0.9 |
| **Power generation** | **1 288** | **1 217** | **1 203** | **1 065** | **517** | **352** | **100** | **100** | **-0.5** | **-5.5** |
| Coal | 894 | 737 | 675 | 725 | 239 | 115 | 56 | 32 | -1.4 | -8.4 |
| Oil | 39 | 23 | 20 | 34 | 15 | 12 | 2 | 3 | -4.6 | -6.6 |
| Gas | 355 | 458 | 508 | 306 | 264 | 226 | 42 | 64 | 1.5 | -1.8 |
| **TFC** | **2 181** | **2 137** | **2 105** | **2 025** | **1 588** | **1 387** | **100** | **100** | **-0.2** | **-1.9** |
| Coal | 232 | 215 | 205 | 218 | 166 | 138 | 10 | 10 | -0.4 | -2.0 |
| Oil | 1 289 | 1 211 | 1 173 | 1 191 | 851 | 707 | 56 | 51 | -0.7 | -2.8 |
| *Transport* | *893* | *870* | *861* | *824* | *581* | *480* | *41* | *35* | *-0.3* | *-2.7* |
| Gas | 659 | 710 | 726 | 616 | 571 | 542 | 35 | 39 | 0.8 | -0.4 |

## **European Union:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **1 642** | **1 659** | **1 614** | **1 584** | **1 556** | **1 541** | **100** | **100** | **-0.3** |
| Coal | 456 | 286 | 249 | 210 | 175 | 145 | 17 | 9 | -2.8 |
| Oil | 607 | 549 | 473 | 437 | 399 | 367 | 33 | 24 | -1.7 |
| Gas | 297 | 404 | 407 | 430 | 442 | 455 | 24 | 30 | 0.5 |
| Nuclear | 207 | 236 | 226 | 213 | 213 | 212 | 14 | 14 | -0.5 |
| Hydro | 25 | 27 | 33 | 34 | 34 | 35 | 2 | 2 | 1.1 |
| Bioenergy | 47 | 129 | 166 | 183 | 199 | 215 | 8 | 14 | 2.2 |
| Other renewables | 3 | 28 | 61 | 77 | 94 | 112 | 2 | 7 | 6.0 |
| **Power generation** | **646** | **711** | **694** | **683** | **680** | **687** | **100** | **100** | **-0.1** |
| Coal | 287 | 218 | 184 | 149 | 120 | 96 | 31 | 14 | -3.4 |
| Oil | 62 | 21 | 12 | 9 | 7 | 6 | 3 | 1 | -4.9 |
| Gas | 55 | 135 | 122 | 140 | 149 | 161 | 19 | 23 | 0.7 |
| Nuclear | 207 | 236 | 226 | 213 | 213 | 212 | 33 | 31 | -0.5 |
| Hydro | 25 | 27 | 33 | 34 | 34 | 35 | 4 | 5 | 1.1 |
| Bioenergy | 8 | 49 | 63 | 69 | 74 | 81 | 7 | 12 | 2.1 |
| Other renewables | 3 | 25 | 55 | 69 | 83 | 98 | 4 | 14 | 5.8 |
| **Other energy sector** | **151** | **138** | **123** | **118** | **110** | **109** | **100** | **100** | **-1.0** |
| *Electricity* | *39* | *42* | *38* | *37* | *37* | *37* | *30* | *34* | *-0.5* |
| **TFC** | **1 132** | **1 150** | **1 149** | **1 146** | **1 135** | **1 125** | **100** | **100** | **-0.1** |
| Coal | 123 | 40 | 38 | 35 | 32 | 29 | 4 | 3 | -1.4 |
| Oil | 503 | 488 | 430 | 400 | 368 | 337 | 42 | 30 | -1.5 |
| Gas | 226 | 251 | 269 | 275 | 278 | 280 | 22 | 25 | 0.5 |
| Electricity | 186 | 239 | 251 | 259 | 266 | 274 | 21 | 24 | 0.6 |
| Heat | 54 | 49 | 52 | 54 | 56 | 58 | 4 | 5 | 0.7 |
| Bioenergy | 38 | 80 | 103 | 114 | 124 | 134 | 7 | 12 | 2.2 |
| Other renewables | 1 | 3 | 6 | 8 | 11 | 14 | 0 | 1 | 7.1 |
| **Industry** | **343** | **270** | **270** | **268** | **263** | **259** | **100** | **100** | **-0.2** |
| Coal | 69 | 26 | 25 | 23 | 21 | 18 | 10 | 7 | -1.5 |
| Oil | 58 | 32 | 27 | 25 | 23 | 20 | 12 | 8 | -1.9 |
| Gas | 97 | 83 | 82 | 81 | 77 | 75 | 31 | 29 | -0.4 |
| Electricity | 85 | 89 | 91 | 92 | 92 | 92 | 33 | 35 | 0.1 |
| Heat | 19 | 15 | 15 | 15 | 15 | 15 | 6 | 6 | -0.2 |
| Bioenergy | 14 | 25 | 29 | 33 | 36 | 39 | 9 | 15 | 2.0 |
| Other renewables | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1.3 |
| **Transport** | **259** | **318** | **302** | **290** | **275** | **262** | **100** | **100** | **-0.8** |
| Oil | 253 | 296 | 267 | 249 | 231 | 212 | 93 | 81 | -1.4 |
| Electricity | 5 | 6 | 7 | 8 | 9 | 10 | 2 | 4 | 2.1 |
| Biofuels | 0 | 14 | 24 | 28 | 32 | 35 | 4 | 13 | 3.9 |
| Other fuels | 1 | 3 | 4 | 4 | 5 | 5 | 1 | 2 | 2.3 |
| **Buildings** | **396** | **432** | **461** | **476** | **490** | **502** | **100** | **100** | **0.6** |
| Coal | 51 | 11 | 11 | 10 | 9 | 8 | 3 | 2 | -1.5 |
| Oil | 90 | 57 | 47 | 41 | 35 | 30 | 13 | 6 | -2.7 |
| Gas | 108 | 147 | 165 | 172 | 178 | 182 | 34 | 36 | 0.9 |
| Electricity | 91 | 140 | 149 | 155 | 162 | 168 | 33 | 33 | 0.8 |
| Heat | 34 | 33 | 37 | 39 | 41 | 43 | 8 | 9 | 1.0 |
| Bioenergy | 24 | 39 | 47 | 51 | 54 | 57 | 9 | 11 | 1.6 |
| Other renewables | 1 | 3 | 6 | 8 | 11 | 14 | 1 | 3 | 7.2 |
| **Other** | **133** | **130** | **116** | **112** | **107** | **101** | **100** | **100** | **-1.0** |

## **European Union:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **1 635** | **1 636** | **1 649** | **1 562** | **1 442** | **1 408** | **100** | **100** | **-0.0** | **-0.7** |
| Coal | 263 | 222 | 201 | 229 | 122 | 96 | 12 | 7 | -1.5 | -4.5 |
| Oil | 484 | 435 | 417 | 450 | 320 | 272 | 25 | 19 | -1.1 | -2.9 |
| Gas | 421 | 480 | 510 | 384 | 361 | 346 | 31 | 25 | 1.0 | -0.6 |
| Nuclear | 219 | 199 | 194 | 229 | 252 | 243 | 12 | 17 | -0.8 | 0.1 |
| Hydro | 33 | 34 | 34 | 33 | 36 | 37 | 2 | 3 | 1.1 | 1.4 |
| Bioenergy | 159 | 183 | 196 | 169 | 225 | 255 | 12 | 18 | 1.8 | 2.9 |
| Other renewables | 58 | 83 | 96 | 68 | 125 | 159 | 6 | 11 | 5.3 | 7.5 |
| **Power generation** | **703** | **719** | **738** | **675** | **659** | **660** | **100** | **100** | **0.2** | **-0.3** |
| Coal | 196 | 163 | 147 | 166 | 71 | 50 | 20 | 8 | -1.6 | -6.0 |
| Oil | 12 | 7 | 6 | 11 | 5 | 4 | 1 | 1 | -4.8 | -6.6 |
| Gas | 130 | 171 | 194 | 111 | 106 | 100 | 26 | 15 | 1.5 | -1.3 |
| Nuclear | 219 | 199 | 194 | 229 | 252 | 243 | 26 | 37 | -0.8 | 0.1 |
| Hydro | 33 | 34 | 34 | 33 | 36 | 37 | 5 | 6 | 1.1 | 1.4 |
| Bioenergy | 61 | 71 | 77 | 64 | 78 | 88 | 10 | 13 | 1.9 | 2.5 |
| Other renewables | 53 | 74 | 85 | 61 | 110 | 137 | 12 | 21 | 5.2 | 7.4 |
| **Other energy sector** | **125** | **115** | **116** | **120** | **101** | **97** | **100** | **100** | **-0.7** | **-1.4** |
| *Electricity* | *39* | *40* | *41* | *37* | *34* | *33* | *35* | *34* | *-0.1* | *-0.9* |
| **TFC** | **1 166** | **1 194** | **1 205** | **1 111** | **1 033** | **1 009** | **100** | **100** | **0.2** | **-0.5** |
| Coal | 39 | 34 | 32 | 37 | 30 | 27 | 3 | 3 | -1.0 | -1.7 |
| Oil | 441 | 403 | 385 | 410 | 294 | 247 | 32 | 24 | -1.0 | -2.8 |
| Gas | 275 | 295 | 301 | 257 | 241 | 233 | 25 | 23 | 0.8 | -0.3 |
| Electricity | 256 | 283 | 296 | 246 | 256 | 263 | 25 | 26 | 0.9 | 0.4 |
| Heat | 52 | 58 | 61 | 50 | 50 | 50 | 5 | 5 | 0.9 | 0.1 |
| Bioenergy | 97 | 112 | 119 | 105 | 147 | 167 | 10 | 17 | 1.7 | 3.1 |
| Other renewables | 5 | 9 | 11 | 6 | 15 | 22 | 1 | 2 | 5.9 | 9.0 |
| **Industry** | **275** | **276** | **276** | **262** | **247** | **242** | **100** | **100** | **0.1** | **-0.5** |
| Coal | 26 | 22 | 20 | 24 | 20 | 17 | 7 | 7 | -1.1 | -1.7 |
| Oil | 28 | 25 | 23 | 26 | 20 | 17 | 8 | 7 | -1.4 | -2.6 |
| Gas | 85 | 84 | 83 | 78 | 68 | 63 | 30 | 26 | -0.0 | -1.2 |
| Electricity | 93 | 98 | 99 | 91 | 92 | 93 | 36 | 39 | 0.5 | 0.2 |
| Heat | 14 | 14 | 14 | 14 | 13 | 13 | 5 | 5 | -0.3 | -0.8 |
| Bioenergy | 29 | 34 | 36 | 28 | 35 | 39 | 13 | 16 | 1.7 | 2.0 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1.3 | 1.7 |
| **Transport** | **306** | **297** | **295** | **289** | **233** | **216** | **100** | **100** | **-0.3** | **-1.6** |
| Oil | 275 | 259 | 253 | 252 | 170 | 137 | 86 | 64 | -0.7 | -3.1 |
| Electricity | 7 | 8 | 9 | 7 | 12 | 16 | 3 | 7 | 2.0 | 4.3 |
| Biofuels | 21 | 25 | 28 | 26 | 48 | 58 | 10 | 27 | 3.0 | 6.1 |
| Other fuels | 3 | 4 | 5 | 3 | 4 | 5 | 2 | 2 | 1.9 | 2.5 |
| **Buildings** | **469** | **513** | **533** | **445** | **448** | **451** | **100** | **100** | **0.9** | **0.2** |
| Coal | 11 | 10 | 9 | 10 | 8 | 7 | 2 | 2 | -1.0 | -1.9 |
| Oil | 49 | 40 | 35 | 44 | 27 | 21 | 7 | 5 | -2.0 | -4.1 |
| Gas | 169 | 189 | 196 | 157 | 152 | 147 | 37 | 33 | 1.2 | 0.0 |
| Electricity | 152 | 173 | 184 | 144 | 149 | 151 | 34 | 33 | 1.1 | 0.3 |
| Heat | 38 | 44 | 47 | 35 | 37 | 38 | 9 | 8 | 1.4 | 0.5 |
| Bioenergy | 45 | 50 | 52 | 49 | 60 | 66 | 10 | 15 | 1.1 | 2.2 |
| Other renewables | 5 | 9 | 11 | 6 | 14 | 21 | 2 | 5 | 6.0 | 9.1 |
| **Other** | **116** | **107** | **102** | **115** | **105** | **99** | **100** | **100** | **-1.0** | **-1.1** |

## **European Union:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **2 577** | **3 257** | **3 357** | **3 443** | **3 516** | **3 610** | **100** | **100** | **0.4** |
| Coal | 1 051 | 884 | 764 | 622 | 501 | 397 | 27 | 11 | -3.3 |
| Oil | 224 | 74 | 37 | 28 | 22 | 20 | 2 | 1 | -5.3 |
| Gas | 193 | 696 | 577 | 696 | 749 | 801 | 21 | 22 | 0.6 |
| Nuclear | 795 | 907 | 866 | 817 | 817 | 812 | 28 | 22 | -0.5 |
| Hydro | 290 | 311 | 379 | 390 | 397 | 404 | 10 | 11 | 1.1 |
| Bioenergy | 20 | 153 | 206 | 228 | 248 | 272 | 5 | 8 | 2.4 |
| Wind | 1 | 179 | 382 | 485 | 576 | 660 | 6 | 18 | 5.6 |
| Geothermal | 3 | 6 | 10 | 13 | 16 | 20 | 0 | 1 | 5.2 |
| Solar PV | 0 | 45 | 125 | 147 | 160 | 172 | 1 | 5 | 5.8 |
| CSP | - | 1 | 10 | 14 | 22 | 31 | 0 | 1 | 14.1 |
| Marine | 1 | 1 | 1 | 3 | 8 | 23 | 0 | 1 | 16.9 |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **942** | **1 092** | **1 146** | **1 194** | **1 247** | **100** | **100** | **1.2** |
| Coal | 200 | 173 | 146 | 130 | 118 | 21 | 9 | -2.2 |
| Oil | 65 | 40 | 30 | 27 | 26 | 7 | 2 | -3.8 |
| Gas | 216 | 253 | 283 | 298 | 317 | 23 | 25 | 1.6 |
| Nuclear | 131 | 125 | 117 | 116 | 115 | 14 | 9 | -0.5 |
| Hydro | 147 | 158 | 163 | 166 | 169 | 16 | 14 | 0.6 |
| Bioenergy | 35 | 43 | 46 | 48 | 50 | 4 | 4 | 1.5 |
| Wind | 94 | 182 | 222 | 254 | 282 | 10 | 23 | 4.7 |
| Geothermal | 1 | 1 | 2 | 2 | 3 | 0 | 0 | 5.1 |
| Solar PV | 52 | 115 | 133 | 143 | 150 | 6 | 12 | 4.5 |
| CSP | 1 | 3 | 4 | 7 | 9 | 0 | 1 | 9.0 |
| Marine | 0 | 1 | 1 | 3 | 9 | 0 | 1 | 16.1 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **4 057** | **3 499** | **3 157** | **2 943** | **2 702** | **2 515** | **100** | **100** | **-1.4** |
| Coal | 1 738 | 1 111 | 957 | 789 | 629 | 499 | 32 | 20 | -3.3 |
| Oil | 1 656 | 1 464 | 1 269 | 1 169 | 1 063 | 977 | 42 | 39 | -1.7 |
| Gas | 663 | 925 | 931 | 985 | 1 010 | 1 039 | 26 | 41 | 0.5 |
| **Power generation** | **1 497** | **1 285** | **1 082** | **961** | **831** | **741** | **100** | **100** | **-2.3** |
| Coal | 1 172 | 905 | 759 | 606 | 463 | 349 | 70 | 47 | -3.9 |
| Oil | 197 | 66 | 38 | 29 | 22 | 20 | 5 | 3 | -4.9 |
| Gas | 128 | 315 | 285 | 327 | 346 | 372 | 25 | 50 | 0.7 |
| **TFC** | **2 385** | **2 044** | **1 929** | **1 847** | **1 750** | **1 655** | **100** | **100** | **-0.9** |
| Coal | 529 | 178 | 171 | 158 | 143 | 129 | 9 | 8 | -1.3 |
| Oil | 1 340 | 1 289 | 1 142 | 1 058 | 968 | 884 | 63 | 53 | -1.6 |
| *Transport* | *747* | *888* | *802* | *749* | *692* | *638* | *43* | *39* | *-1.4* |
| Gas | 515 | 576 | 617 | 631 | 639 | 643 | 28 | 39 | 0.5 |

## **European Union:** Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **3 425** | **3 746** | **3 918** | **3 275** | **3 370** | **3 446** | **100** | **100** | **0.8** | **0.2** |
| Coal | 818 | 711 | 658 | 686 | 236 | 151 | 17 | 4 | -1.2 | -7.1 |
| Oil | 38 | 23 | 20 | 32 | 14 | 11 | 1 | 0 | -5.2 | -7.7 |
| Gas | 637 | 904 | 1 023 | 515 | 460 | 366 | 26 | 11 | 1.6 | -2.6 |
| Nuclear | 839 | 764 | 745 | 879 | 968 | 933 | 19 | 27 | -0.8 | 0.1 |
| Hydro | 378 | 395 | 401 | 384 | 420 | 435 | 10 | 13 | 1.1 | 1.4 |
| Bioenergy | 201 | 236 | 259 | 209 | 272 | 313 | 7 | 9 | 2.2 | 3.0 |
| Wind | 376 | 534 | 604 | 410 | 726 | 884 | 15 | 26 | 5.2 | 6.9 |
| Geothermal | 9 | 12 | 15 | 13 | 23 | 27 | 0 | 1 | 3.8 | 6.6 |
| Solar PV | 119 | 144 | 155 | 132 | 190 | 219 | 4 | 6 | 5.3 | 6.8 |
| CSP | 10 | 18 | 25 | 14 | 49 | 72 | 1 | 2 | 13.1 | 18.2 |
| Marine | 1 | 5 | 14 | 1 | 12 | 35 | 0 | 1 | 14.4 | 19.0 |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **1 104** | **1 227** | **1 289** | **1 103** | **1 251** | **1 345** | **100** | **100** | **1.3** | **1.5** |
| Coal | 175 | 145 | 140 | 163 | 88 | 68 | 11 | 5 | -1.5 | -4.4 |
| Oil | 40 | 27 | 25 | 40 | 27 | 25 | 2 | 2 | -3.8 | -3.9 |
| Gas | 275 | 356 | 388 | 249 | 269 | 280 | 30 | 21 | 2.5 | 1.1 |
| Nuclear | 121 | 108 | 105 | 126 | 135 | 141 | 8 | 10 | -0.9 | 0.3 |
| Hydro | 158 | 165 | 167 | 160 | 176 | 183 | 13 | 14 | 0.6 | 0.9 |
| Bioenergy | 42 | 47 | 49 | 43 | 52 | 57 | 4 | 4 | 1.4 | 2.0 |
| Wind | 180 | 241 | 264 | 195 | 314 | 363 | 20 | 27 | 4.4 | 5.8 |
| Geothermal | 1 | 2 | 2 | 2 | 3 | 4 | 0 | 0 | 3.8 | 6.5 |
| Solar PV | 109 | 129 | 136 | 120 | 168 | 190 | 11 | 14 | 4.1 | 5.5 |
| CSP | 3 | 5 | 7 | 4 | 14 | 22 | 1 | 2 | 8.0 | 13.0 |
| Marine | 0 | 2 | 5 | 1 | 5 | 14 | 0 | 1 | 13.7 | 18.3 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **3 280** | **3 101** | **3 024** | **2 936** | **1 985** | **1 642** | **100** | **100** | **-0.6** | **-3.1** |
| Coal | 1 013 | 826 | 729 | 861 | 372 | 234 | 24 | 14 | -1.7 | -6.3 |
| Oil | 1 303 | 1 174 | 1 128 | 1 201 | 816 | 667 | 37 | 41 | -1.1 | -3.2 |
| Gas | 964 | 1 100 | 1 167 | 874 | 797 | 741 | 39 | 45 | 1.0 | -0.9 |
| **Power generation** | **1 155** | **1 069** | **1 034** | **963** | **484** | **345** | **100** | **100** | **-0.9** | **-5.3** |
| Coal | 811 | 648 | 564 | 670 | 233 | 122 | 55 | 35 | -1.9 | -8.0 |
| Oil | 39 | 23 | 20 | 35 | 16 | 13 | 2 | 4 | -4.8 | -6.5 |
| Gas | 304 | 398 | 450 | 258 | 235 | 210 | 44 | 61 | 1.5 | -1.7 |
| **TFC** | **1 980** | **1 908** | **1 865** | **1 833** | **1 406** | **1 218** | **100** | **100** | **-0.4** | **-2.1** |
| Coal | 175 | 154 | 142 | 165 | 120 | 97 | 8 | 8 | -0.9 | -2.5 |
| Oil | 1 174 | 1 077 | 1 030 | 1 081 | 746 | 610 | 55 | 50 | -0.9 | -3.1 |
| *Transport* | *826* | *778* | *758* | *757* | *510* | *413* | *41* | *34* | *-0.7* | *-3.1* |
| Gas | 631 | 678 | 693 | 588 | 540 | 511 | 37 | 42 | 0.8 | -0.5 |

## **OECD Asia Oceania:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **631** | **863** | **912** | **914** | **912** | **906** | **100** | **100** | **0.2** |
| Coal | 138 | 237 | 243 | 235 | 218 | 190 | 27 | 21 | -0.9 |
| Oil | 335 | 346 | 308 | 287 | 267 | 247 | 40 | 27 | -1.4 |
| Gas | 66 | 172 | 182 | 190 | 194 | 201 | 20 | 22 | 0.7 |
| Nuclear | 66 | 67 | 116 | 119 | 127 | 141 | 8 | 16 | 3.2 |
| Hydro | 11 | 11 | 12 | 12 | 13 | 14 | 1 | 2 | 0.9 |
| Bioenergy | 10 | 21 | 27 | 32 | 36 | 41 | 2 | 5 | 2.9 |
| Other renewables | 4 | 9 | 24 | 39 | 57 | 71 | 1 | 8 | 9.1 |
| **Power generation** | **241** | **391** | **429** | **439** | **447** | **451** | **100** | **100** | **0.6** |
| Coal | 60 | 159 | 158 | 149 | 133 | 107 | 41 | 24 | -1.6 |
| Oil | 56 | 36 | 12 | 9 | 9 | 8 | 9 | 2 | -5.9 |
| Gas | 40 | 100 | 95 | 95 | 93 | 93 | 26 | 21 | -0.3 |
| Nuclear | 66 | 67 | 116 | 119 | 127 | 141 | 17 | 31 | 3.2 |
| Hydro | 11 | 11 | 12 | 12 | 13 | 14 | 3 | 3 | 0.9 |
| Bioenergy | 3 | 10 | 15 | 17 | 20 | 23 | 3 | 5 | 3.4 |
| Other renewables | 3 | 8 | 22 | 36 | 52 | 65 | 2 | 14 | 9.3 |
| **Other energy sector** | **57** | **71** | **85** | **87** | **88** | **88** | **100** | **100** | **0.9** |
| *Electricity* | *11* | *17* | *19* | *19* | *20* | *20* | *24* | *22* | *0.6* |
| **TFC** | **431** | **566** | **585** | **582** | **575** | **568** | **100** | **100** | **0.0** |
| Coal | 49 | 40 | 40 | 39 | 38 | 36 | 7 | 6 | -0.5 |
| Oil | 261 | 295 | 280 | 265 | 248 | 232 | 52 | 41 | -1.0 |
| Gas | 26 | 72 | 81 | 86 | 90 | 95 | 13 | 17 | 1.2 |
| Electricity | 86 | 143 | 163 | 169 | 173 | 176 | 25 | 31 | 0.9 |
| Heat | 0 | 5 | 5 | 5 | 5 | 6 | 1 | 1 | 0.4 |
| Bioenergy | 7 | 10 | 13 | 14 | 16 | 17 | 2 | 3 | 2.3 |
| Other renewables | 2 | 1 | 2 | 3 | 4 | 6 | 0 | 1 | 7.3 |
| **Industry** | **144** | **159** | **172** | **174** | **174** | **173** | **100** | **100** | **0.4** |
| Coal | 38 | 38 | 38 | 37 | 36 | 34 | 24 | 20 | -0.4 |
| Oil | 51 | 33 | 30 | 29 | 27 | 25 | 21 | 14 | -1.2 |
| Gas | 11 | 25 | 30 | 31 | 33 | 34 | 16 | 20 | 1.3 |
| Electricity | 40 | 53 | 63 | 64 | 65 | 66 | 34 | 38 | 0.9 |
| Heat | - | 2 | 2 | 2 | 2 | 2 | 2 | 1 | -0.6 |
| Bioenergy | 5 | 7 | 9 | 10 | 11 | 13 | 5 | 7 | 2.3 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1.2 |
| **Transport** | **110** | **140** | **133** | **124** | **116** | **109** | **100** | **100** | **-1.0** |
| Oil | 109 | 135 | 127 | 117 | 108 | 100 | 97 | 92 | -1.2 |
| Electricity | 2 | 2 | 3 | 3 | 3 | 4 | 2 | 4 | 2.5 |
| Biofuels | - | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1.0 |
| Other fuels | 0 | 2 | 2 | 3 | 3 | 4 | 1 | 4 | 3.7 |
| **Buildings** | **120** | **174** | **189** | **194** | **198** | **203** | **100** | **100** | **0.6** |
| Coal | 10 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | -1.6 |
| Oil | 47 | 38 | 37 | 34 | 32 | 29 | 22 | 14 | -1.1 |
| Gas | 15 | 43 | 48 | 50 | 52 | 55 | 25 | 27 | 1.0 |
| Electricity | 44 | 86 | 96 | 100 | 103 | 105 | 49 | 52 | 0.9 |
| Heat | 0 | 3 | 3 | 3 | 3 | 3 | 1 | 2 | 1.2 |
| Bioenergy | 2 | 2 | 3 | 3 | 4 | 4 | 1 | 2 | 2.4 |
| Other renewables | 1 | 1 | 2 | 2 | 3 | 5 | 1 | 2 | 7.4 |
| **Other** | **56** | **93** | **91** | **89** | **87** | **83** | **100** | **100** | **-0.5** |

## **OECD Asia Oceania:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **921** | **939** | **946** | **875** | **831** | **816** | **100** | **100** | **0.4** | **-0.2** |
| Coal | 250 | 249 | 234 | 212 | 134 | 109 | 25 | 13 | -0.1 | -3.2 |
| Oil | 310 | 274 | 259 | 295 | 226 | 192 | 27 | 24 | -1.2 | -2.4 |
| Gas | 185 | 207 | 220 | 171 | 173 | 172 | 23 | 21 | 1.0 | 0.0 |
| Nuclear | 116 | 124 | 134 | 126 | 161 | 174 | 14 | 21 | 2.9 | 4.1 |
| Hydro | 12 | 12 | 13 | 13 | 16 | 17 | 1 | 2 | 0.5 | 1.8 |
| Bioenergy | 26 | 33 | 36 | 29 | 47 | 59 | 4 | 7 | 2.3 | 4.4 |
| Other renewables | 22 | 41 | 50 | 28 | 74 | 94 | 5 | 11 | 7.5 | 10.4 |
| **Power generation** | **434** | **463** | **474** | **406** | **412** | **419** | **100** | **100** | **0.8** | **0.3** |
| Coal | 164 | 160 | 145 | 130 | 56 | 34 | 31 | 8 | -0.4 | -6.3 |
| Oil | 12 | 9 | 9 | 10 | 5 | 4 | 2 | 1 | -5.4 | -8.5 |
| Gas | 97 | 102 | 106 | 88 | 84 | 80 | 22 | 19 | 0.2 | -0.9 |
| Nuclear | 116 | 124 | 134 | 126 | 161 | 174 | 28 | 41 | 2.9 | 4.1 |
| Hydro | 12 | 12 | 13 | 13 | 16 | 17 | 3 | 4 | 0.5 | 1.8 |
| Bioenergy | 14 | 18 | 21 | 15 | 23 | 28 | 4 | 7 | 2.9 | 4.3 |
| Other renewables | 20 | 38 | 46 | 24 | 67 | 83 | 10 | 20 | 7.8 | 10.4 |
| **Other energy sector** | **86** | **91** | **92** | **83** | **80** | **79** | **100** | **100** | **1.1** | **0.5** |
| *Electricity* | *19* | *21* | *21* | *18* | *17* | *17* | *23* | *21* | *0.9* | *-0.1* |
| **TFC** | **591** | **593** | **594** | **564** | **520** | **501** | **100** | **100** | **0.2** | **-0.5** |
| Coal | 41 | 39 | 38 | 39 | 34 | 31 | 6 | 6 | -0.2 | -1.0 |
| Oil | 282 | 256 | 244 | 270 | 213 | 183 | 41 | 36 | -0.8 | -2.0 |
| Gas | 82 | 94 | 100 | 78 | 79 | 79 | 17 | 16 | 1.4 | 0.4 |
| Electricity | 166 | 181 | 188 | 155 | 159 | 161 | 32 | 32 | 1.1 | 0.5 |
| Heat | 5 | 6 | 6 | 5 | 5 | 5 | 1 | 1 | 0.4 | 0.1 |
| Bioenergy | 12 | 14 | 15 | 14 | 24 | 30 | 3 | 6 | 1.7 | 4.6 |
| Other renewables | 2 | 3 | 4 | 4 | 8 | 11 | 1 | 2 | 5.0 | 9.8 |
| **Industry** | **175** | **180** | **181** | **168** | **162** | **160** | **100** | **100** | **0.5** | **0.0** |
| Coal | 39 | 37 | 36 | 37 | 32 | 30 | 20 | 19 | -0.2 | -1.0 |
| Oil | 31 | 28 | 27 | 29 | 23 | 21 | 15 | 13 | -0.9 | -1.8 |
| Gas | 30 | 34 | 36 | 29 | 30 | 30 | 20 | 19 | 1.5 | 0.8 |
| Electricity | 64 | 67 | 69 | 62 | 63 | 64 | 38 | 40 | 1.0 | 0.8 |
| Heat | 2 | 2 | 2 | 2 | 2 | 2 | 1 | 1 | -0.6 | -0.8 |
| Bioenergy | 9 | 10 | 11 | 9 | 11 | 13 | 6 | 8 | 1.7 | 2.3 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1.2 | 1.2 |
| **Transport** | **133** | **121** | **117** | **129** | **100** | **88** | **100** | **100** | **-0.7** | **-1.9** |
| Oil | 128 | 113 | 109 | 122 | 85 | 65 | 93 | 74 | -0.9 | -3.0 |
| Electricity | 3 | 3 | 4 | 3 | 5 | 7 | 3 | 8 | 2.2 | 5.3 |
| Biofuels | 1 | 1 | 1 | 1 | 7 | 11 | 1 | 13 | 0.4 | 12.8 |
| Other fuels | 2 | 3 | 4 | 2 | 4 | 4 | 3 | 5 | 3.7 | 4.0 |
| **Buildings** | **192** | **206** | **213** | **177** | **172** | **171** | **100** | **100** | **0.8** | **-0.1** |
| Coal | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | -1.1 | -2.1 |
| Oil | 37 | 33 | 31 | 33 | 25 | 21 | 14 | 12 | -0.9 | -2.4 |
| Gas | 48 | 55 | 58 | 45 | 43 | 43 | 27 | 25 | 1.2 | -0.0 |
| Electricity | 98 | 109 | 114 | 89 | 89 | 88 | 53 | 51 | 1.2 | 0.1 |
| Heat | 3 | 3 | 3 | 3 | 3 | 3 | 2 | 2 | 1.2 | 0.8 |
| Bioenergy | 3 | 3 | 4 | 3 | 5 | 5 | 2 | 3 | 1.8 | 3.7 |
| Other renewables | 1 | 2 | 3 | 3 | 7 | 10 | 1 | 6 | 4.6 | 10.3 |
| **Other** | **91** | **87** | **83** | **90** | **85** | **82** | **100** | **100** | **-0.5** | **-0.5** |

## **OECD Asia Oceania:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **1 127** | **1 859** | **2 119** | **2 189** | **2 236** | **2 278** | **100** | **100** | **0.8** |
| Coal | 257 | 681 | 710 | 683 | 625 | 528 | 37 | 23 | -1.1 |
| Oil | 270 | 173 | 53 | 41 | 36 | 34 | 9 | 2 | -6.5 |
| Gas | 197 | 547 | 582 | 596 | 586 | 593 | 29 | 26 | 0.3 |
| Nuclear | 255 | 256 | 445 | 459 | 489 | 542 | 14 | 24 | 3.2 |
| Hydro | 133 | 130 | 138 | 144 | 152 | 159 | 7 | 7 | 0.9 |
| Bioenergy | 12 | 44 | 61 | 72 | 84 | 96 | 2 | 4 | 3.3 |
| Wind | - | 13 | 53 | 87 | 123 | 151 | 1 | 7 | 10.7 |
| Geothermal | 4 | 9 | 17 | 31 | 46 | 57 | 0 | 2 | 8.1 |
| Solar PV | 0 | 7 | 54 | 69 | 83 | 98 | 0 | 4 | 11.7 |
| CSP | - | 0 | 2 | 4 | 6 | 11 | 0 | 0 | 39.1 |
| Marine | - | - | 2 | 4 | 6 | 10 | - | 0 | n.a. |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **443** | **535** | **563** | **594** | **622** | **100** | **100** | **1.4** |
| Coal | 106 | 114 | 113 | 112 | 104 | 24 | 17 | -0.1 |
| Oil | 58 | 30 | 23 | 22 | 20 | 13 | 3 | -4.3 |
| Gas | 123 | 172 | 181 | 184 | 187 | 28 | 30 | 1.8 |
| Nuclear | 66 | 67 | 63 | 64 | 71 | 15 | 11 | 0.3 |
| Hydro | 69 | 74 | 76 | 78 | 81 | 16 | 13 | 0.7 |
| Bioenergy | 7 | 10 | 12 | 14 | 16 | 2 | 3 | 3.2 |
| Wind | 5 | 19 | 31 | 43 | 51 | 1 | 8 | 9.8 |
| Geothermal | 1 | 2 | 5 | 7 | 8 | 0 | 1 | 8.2 |
| Solar PV | 7 | 45 | 56 | 67 | 77 | 2 | 12 | 10.5 |
| CSP | 0 | 1 | 1 | 2 | 3 | 0 | 0 | 30.9 |
| Marine | - | 1 | 1 | 2 | 3 | - | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **1 570** | **2 181** | **2 091** | **1 998** | **1 868** | **1 710** | **100** | **100** | **-1.0** |
| Coal | 517 | 901 | 904 | 851 | 764 | 637 | 41 | 37 | -1.4 |
| Oil | 892 | 852 | 741 | 688 | 639 | 595 | 39 | 35 | -1.5 |
| Gas | 161 | 429 | 446 | 460 | 465 | 478 | 20 | 28 | 0.5 |
| **Power generation** | **548** | **1 026** | **936** | **883** | **797** | **680** | **100** | **100** | **-1.7** |
| Coal | 280 | 678 | 673 | 626 | 550 | 434 | 66 | 64 | -1.8 |
| Oil | 174 | 108 | 36 | 29 | 26 | 25 | 11 | 4 | -5.9 |
| Gas | 94 | 240 | 227 | 228 | 222 | 222 | 23 | 33 | -0.3 |
| **TFC** | **954** | **1 039** | **1 026** | **989** | **947** | **909** | **100** | **100** | **-0.6** |
| Coal | 217 | 178 | 182 | 177 | 169 | 161 | 17 | 18 | -0.4 |
| Oil | 676 | 694 | 655 | 612 | 569 | 528 | 67 | 58 | -1.1 |
| *Transport* | *321* | *398* | *374* | *344* | *318* | *295* | *38* | *32* | *-1.2* |
| Gas | 61 | 166 | 189 | 200 | 210 | 220 | 16 | 24 | 1.2 |

## **OECD Asia Oceania:** Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **2 152** | **2 347** | **2 428** | **2 015** | **2 046** | **2 072** | **100** | **100** | **1.1** | **0.5** |
| Coal | 739 | 756 | 712 | 589 | 259 | 151 | 29 | 7 | 0.2 | -6.1 |
| Oil | 54 | 41 | 40 | 43 | 19 | 15 | 2 | 1 | -5.9 | -9.8 |
| Gas | 600 | 653 | 687 | 539 | 528 | 500 | 28 | 24 | 1.0 | -0.4 |
| Nuclear | 445 | 475 | 515 | 485 | 618 | 666 | 21 | 32 | 3.0 | 4.1 |
| Hydro | 135 | 143 | 147 | 148 | 182 | 197 | 6 | 9 | 0.5 | 1.8 |
| Bioenergy | 57 | 75 | 85 | 63 | 97 | 116 | 3 | 6 | 2.8 | 4.1 |
| Wind | 49 | 95 | 116 | 64 | 174 | 212 | 5 | 10 | 9.5 | 12.3 |
| Geothermal | 16 | 33 | 40 | 20 | 57 | 69 | 2 | 3 | 6.6 | 9.0 |
| Solar PV | 53 | 69 | 76 | 60 | 95 | 114 | 3 | 5 | 10.5 | 12.4 |
| CSP | 2 | 4 | 6 | 3 | 10 | 17 | 0 | 1 | 35.3 | 41.6 |
| Marine | 2 | 3 | 5 | 2 | 8 | 16 | 0 | 1 | n.a. | n.a. |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **535** | **590** | **611** | **533** | **598** | **626** | **100** | **100** | **1.3** | **1.4** |
| Coal | 117 | 124 | 120 | 112 | 84 | 69 | 20 | 11 | 0.5 | -1.8 |
| Oil | 31 | 24 | 24 | 30 | 20 | 18 | 4 | 3 | -3.7 | -4.8 |
| Gas | 174 | 195 | 200 | 154 | 159 | 159 | 33 | 25 | 2.0 | 1.1 |
| Nuclear | 67 | 63 | 68 | 72 | 82 | 90 | 11 | 14 | 0.1 | 1.3 |
| Hydro | 72 | 75 | 76 | 77 | 89 | 94 | 12 | 15 | 0.4 | 1.3 |
| Bioenergy | 10 | 12 | 14 | 11 | 16 | 19 | 2 | 3 | 2.7 | 4.0 |
| Wind | 18 | 33 | 40 | 24 | 58 | 69 | 7 | 11 | 8.7 | 11.1 |
| Geothermal | 2 | 5 | 6 | 3 | 9 | 10 | 1 | 2 | 6.6 | 9.1 |
| Solar PV | 43 | 56 | 61 | 49 | 77 | 90 | 10 | 14 | 9.4 | 11.2 |
| CSP | 0 | 1 | 1 | 1 | 2 | 4 | 0 | 1 | 27.4 | 33.3 |
| Marine | 1 | 1 | 1 | 1 | 2 | 5 | 0 | 1 | n.a. | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **2 132** | **2 050** | **1 968** | **1 885** | **1 290** | **1 029** | **100** | **100** | **-0.4** | **-3.1** |
| Coal | 931 | 889 | 811 | 761 | 365 | 211 | 41 | 21 | -0.4 | -5.9 |
| Oil | 748 | 667 | 637 | 705 | 519 | 430 | 32 | 42 | -1.2 | -2.8 |
| Gas | 453 | 494 | 520 | 419 | 406 | 388 | 26 | 38 | 0.8 | -0.4 |
| **Power generation** | **965** | **938** | **878** | **778** | **384** | **225** | **100** | **100** | **-0.6** | **-6.1** |
| Coal | 696 | 666 | 597 | 537 | 175 | 39 | 68 | 17 | -0.5 | -11.2 |
| Oil | 37 | 29 | 28 | 30 | 16 | 13 | 3 | 6 | -5.4 | -8.5 |
| Gas | 232 | 243 | 253 | 211 | 193 | 173 | 29 | 77 | 0.2 | -1.3 |
| **TFC** | **1 037** | **988** | **966** | **981** | **796** | **700** | **100** | **100** | **-0.3** | **-1.6** |
| Coal | 185 | 177 | 171 | 176 | 149 | 135 | 18 | 19 | -0.2 | -1.2 |
| Oil | 661 | 593 | 564 | 626 | 466 | 384 | 58 | 55 | -0.9 | -2.4 |
| *Transport* | *376* | *333* | *320* | *360* | *250* | *190* | *33* | *27* | *-0.9* | *-3.0* |
| Gas | 191 | 218 | 231 | 180 | 181 | 181 | 24 | 26 | 1.4 | 0.3 |

## **Japan:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **439** | **461** | **470** | **458** | **450** | **443** | **100** | **100** | **-0.2** |
| Coal | 77 | 107 | 110 | 107 | 105 | 98 | 23 | 22 | -0.4 |
| Oil | 250 | 206 | 171 | 156 | 142 | 131 | 45 | 30 | -1.9 |
| Gas | 44 | 100 | 99 | 102 | 101 | 103 | 22 | 23 | 0.1 |
| Nuclear | 53 | 27 | 57 | 50 | 45 | 45 | 6 | 10 | 2.3 |
| Hydro | 8 | 7 | 8 | 8 | 9 | 9 | 2 | 2 | 1.1 |
| Bioenergy | 5 | 10 | 13 | 15 | 17 | 19 | 2 | 4 | 2.5 |
| Other renewables | 3 | 4 | 12 | 21 | 31 | 38 | 1 | 9 | 10.1 |
| **Power generation** | **174** | **201** | **216** | **217** | **220** | **223** | **100** | **100** | **0.4** |
| Coal | 25 | 58 | 60 | 59 | 59 | 55 | 29 | 25 | -0.3 |
| Oil | 51 | 30 | 8 | 6 | 6 | 5 | 15 | 2 | -6.9 |
| Gas | 33 | 68 | 62 | 63 | 60 | 59 | 34 | 26 | -0.6 |
| Nuclear | 53 | 27 | 57 | 50 | 45 | 45 | 13 | 20 | 2.3 |
| Hydro | 8 | 7 | 8 | 8 | 9 | 9 | 4 | 4 | 1.1 |
| Bioenergy | 2 | 7 | 10 | 12 | 13 | 15 | 4 | 7 | 2.9 |
| Other renewables | 1 | 3 | 11 | 19 | 29 | 35 | 2 | 15 | 10.5 |
| **Other energy sector** | **38** | **36** | **40** | **38** | **35** | **33** | **100** | **100** | **-0.4** |
| *Electricity* | *7* | *9* | *10* | *10* | *10* | *10* | *24* | *29* | *0.4* |
| **TFC** | **299** | **314** | **315** | **306** | **298** | **293** | **100** | **100** | **-0.3** |
| Coal | 32 | 26 | 27 | 26 | 25 | 24 | 8 | 8 | -0.3 |
| Oil | 184 | 168 | 154 | 141 | 129 | 119 | 53 | 41 | -1.4 |
| Gas | 15 | 35 | 39 | 41 | 43 | 46 | 11 | 16 | 1.1 |
| Electricity | 64 | 81 | 91 | 92 | 93 | 95 | 26 | 32 | 0.7 |
| Heat | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1.5 |
| Bioenergy | 3 | 3 | 3 | 4 | 4 | 4 | 1 | 1 | 1.2 |
| Other renewables | 1 | 1 | 1 | 1 | 2 | 3 | 0 | 1 | 7.3 |
| **Industry** | **102** | **85** | **88** | **87** | **85** | **83** | **100** | **100** | **-0.1** |
| Coal | 30 | 26 | 26 | 25 | 24 | 24 | 30 | 28 | -0.3 |
| Oil | 37 | 24 | 22 | 20 | 19 | 17 | 28 | 21 | -1.3 |
| Gas | 4 | 8 | 9 | 10 | 11 | 12 | 10 | 14 | 1.4 |
| Electricity | 29 | 24 | 28 | 28 | 27 | 27 | 28 | 32 | 0.5 |
| Heat | - | - | - | - | - | - | - | - | n.a. |
| Bioenergy | 3 | 3 | 3 | 4 | 4 | 4 | 4 | 5 | 1.2 |
| Other renewables | - | - | - | - | - | - | - | - | n.a. |
| **Transport** | **72** | **76** | **67** | **59** | **53** | **48** | **100** | **100** | **-1.9** |
| Oil | 70 | 74 | 65 | 57 | 50 | 45 | 98 | 94 | -2.0 |
| Electricity | 1 | 2 | 2 | 2 | 2 | 3 | 2 | 6 | 2.4 |
| Biofuels | - | - | - | - | - | - | - | - | n.a. |
| Other fuels | - | - | 0 | 0 | 0 | 0 | - | 0 | n.a. |
| **Buildings** | **84** | **113** | **121** | **123** | **125** | **128** | **100** | **100** | **0.5** |
| Coal | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0.9 |
| Oil | 36 | 30 | 29 | 28 | 26 | 24 | 26 | 19 | -0.8 |
| Gas | 11 | 27 | 29 | 31 | 32 | 34 | 24 | 27 | 1.0 |
| Electricity | 34 | 55 | 61 | 62 | 64 | 65 | 49 | 51 | 0.7 |
| Heat | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1.5 |
| Bioenergy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -0.8 |
| Other renewables | 1 | 1 | 1 | 1 | 2 | 3 | 0 | 2 | 7.5 |
| **Other** | **41** | **41** | **39** | **37** | **35** | **33** | **100** | **100** | **-0.9** |

## **Japan:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **474** | **462** | **461** | **445** | **403** | **390** | **100** | **100** | **-0.0** | **-0.7** |
| Coal | 113 | 116 | 114 | 91 | 54 | 46 | 25 | 12 | 0.3 | -3.5 |
| Oil | 173 | 148 | 140 | 162 | 119 | 102 | 30 | 26 | -1.6 | -2.9 |
| Gas | 100 | 108 | 111 | 90 | 85 | 82 | 24 | 21 | 0.5 | -0.8 |
| Nuclear | 57 | 45 | 45 | 66 | 72 | 72 | 10 | 19 | 2.3 | 4.3 |
| Hydro | 8 | 8 | 8 | 8 | 10 | 11 | 2 | 3 | 0.7 | 1.8 |
| Bioenergy | 13 | 15 | 17 | 14 | 20 | 23 | 4 | 6 | 2.0 | 3.3 |
| Other renewables | 11 | 20 | 25 | 14 | 43 | 55 | 6 | 14 | 8.3 | 11.8 |
| **Power generation** | **219** | **226** | **233** | **201** | **200** | **203** | **100** | **100** | **0.6** | **0.0** |
| Coal | 63 | 69 | 69 | 43 | 13 | 8 | 29 | 4 | 0.7 | -8.0 |
| Oil | 8 | 6 | 7 | 6 | 2 | 2 | 3 | 1 | -6.2 | -11.4 |
| Gas | 63 | 66 | 67 | 56 | 51 | 47 | 29 | 23 | -0.1 | -1.5 |
| Nuclear | 57 | 45 | 45 | 66 | 72 | 72 | 19 | 36 | 2.3 | 4.3 |
| Hydro | 8 | 8 | 8 | 8 | 10 | 11 | 4 | 5 | 0.7 | 1.8 |
| Bioenergy | 9 | 12 | 13 | 10 | 14 | 16 | 6 | 8 | 2.5 | 3.2 |
| Other renewables | 10 | 19 | 24 | 12 | 38 | 47 | 10 | 23 | 8.8 | 12.0 |
| **Other energy sector** | **40** | **36** | **35** | **38** | **31** | **28** | **100** | **100** | **-0.2** | **-1.0** |
| *Electricity* | *10* | *10* | *10* | *9* | *8* | *8* | *30* | *28* | *0.7* | *-0.4* |
| **TFC** | **318** | **308** | **306** | **300** | **264** | **251** | **100** | **100** | **-0.1** | **-0.9** |
| Coal | 27 | 26 | 26 | 26 | 22 | 21 | 8 | 8 | -0.1 | -1.0 |
| Oil | 155 | 134 | 126 | 147 | 110 | 95 | 41 | 38 | -1.2 | -2.4 |
| Gas | 39 | 44 | 47 | 36 | 36 | 36 | 15 | 14 | 1.2 | 0.1 |
| Electricity | 92 | 98 | 101 | 85 | 84 | 84 | 33 | 34 | 0.9 | 0.2 |
| Heat | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1.5 | 1.0 |
| Bioenergy | 3 | 3 | 3 | 4 | 6 | 7 | 1 | 3 | 0.5 | 3.5 |
| Other renewables | 1 | 1 | 1 | 2 | 5 | 8 | 0 | 3 | 3.7 | 11.2 |
| **Industry** | **89** | **88** | **87** | **86** | **79** | **77** | **100** | **100** | **0.1** | **-0.4** |
| Coal | 26 | 26 | 25 | 25 | 21 | 20 | 29 | 26 | -0.1 | -1.0 |
| Oil | 22 | 20 | 19 | 20 | 16 | 15 | 21 | 19 | -1.0 | -2.0 |
| Gas | 9 | 11 | 12 | 9 | 10 | 10 | 14 | 13 | 1.4 | 0.8 |
| Electricity | 28 | 28 | 28 | 28 | 27 | 27 | 32 | 36 | 0.6 | 0.5 |
| Heat | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Bioenergy | 3 | 3 | 3 | 3 | 4 | 4 | 4 | 6 | 0.5 | 1.6 |
| Other renewables | - | - | - | - | - | - | - | - | n.a. | n.a. |
| **Transport** | **68** | **56** | **53** | **65** | **45** | **38** | **100** | **100** | **-1.5** | **-2.8** |
| Oil | 66 | 53 | 50 | 63 | 40 | 31 | 95 | 83 | -1.6 | -3.5 |
| Electricity | 2 | 2 | 3 | 2 | 3 | 5 | 5 | 12 | 2.0 | 4.4 |
| Biofuels | - | - | - | - | 1 | 2 | - | 5 | n.a. | n.a. |
| Other fuels | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | n.a. | n.a. |
| **Buildings** | **122** | **130** | **134** | **111** | **106** | **104** | **100** | **100** | **0.7** | **-0.3** |
| Coal | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1.0 | 0.2 |
| Oil | 29 | 27 | 26 | 26 | 20 | 17 | 19 | 17 | -0.6 | -2.2 |
| Gas | 29 | 33 | 35 | 27 | 26 | 26 | 26 | 25 | 1.1 | -0.1 |
| Electricity | 62 | 68 | 71 | 55 | 53 | 53 | 53 | 50 | 1.0 | -0.2 |
| Heat | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1.5 | 1.0 |
| Bioenergy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -1.0 | 12.0 |
| Other renewables | 1 | 1 | 1 | 2 | 5 | 7 | 1 | 7 | 3.9 | 11.7 |
| **Other** | **39** | **35** | **33** | **39** | **34** | **32** | **100** | **100** | **-0.9** | **-1.0** |

## **Japan:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **836** | **1 043** | **1 169** | **1 187** | **1 200** | **1 217** | **100** | **100** | **0.6** |
| Coal | 117 | 281 | 295 | 295 | 295 | 276 | 27 | 23 | -0.1 |
| Oil | 248 | 153 | 40 | 31 | 27 | 26 | 15 | 2 | -7.1 |
| Gas | 167 | 374 | 401 | 413 | 400 | 398 | 36 | 33 | 0.3 |
| Nuclear | 202 | 102 | 220 | 191 | 174 | 174 | 10 | 14 | 2.3 |
| Hydro | 89 | 83 | 91 | 95 | 101 | 108 | 8 | 9 | 1.1 |
| Bioenergy | 11 | 37 | 48 | 55 | 61 | 68 | 4 | 6 | 2.6 |
| Wind | - | 5 | 22 | 38 | 55 | 67 | 0 | 5 | 11.8 |
| Geothermal | 2 | 3 | 6 | 13 | 21 | 26 | 0 | 2 | 9.9 |
| Solar PV | 0 | 5 | 47 | 57 | 64 | 72 | 0 | 6 | 11.6 |
| CSP | - | - | - | - | - | - | - | - | n.a. |
| Marine | - | - | - | 0 | 1 | 3 | - | 0 | n.a. |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **282** | **329** | **341** | **353** | **364** | **100** | **100** | **1.1** |
| Coal | 47 | 48 | 47 | 48 | 46 | 17 | 13 | -0.1 |
| Oil | 51 | 24 | 18 | 17 | 16 | 18 | 4 | -4.7 |
| Gas | 76 | 112 | 120 | 121 | 122 | 27 | 33 | 2.0 |
| Nuclear | 46 | 38 | 29 | 24 | 24 | 16 | 7 | -2.7 |
| Hydro | 48 | 51 | 53 | 55 | 57 | 17 | 16 | 0.7 |
| Bioenergy | 6 | 8 | 9 | 10 | 11 | 2 | 3 | 2.6 |
| Wind | 2 | 9 | 15 | 21 | 25 | 1 | 7 | 10.1 |
| Geothermal | 1 | 1 | 2 | 4 | 4 | 0 | 1 | 9.2 |
| Solar PV | 5 | 39 | 47 | 54 | 59 | 2 | 16 | 10.9 |
| CSP | - | - | - | - | - | - | - | n.a. |
| Marine | - | - | 0 | 0 | 1 | - | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **1 061** | **1 178** | **1 081** | **1 036** | **989** | **940** | **100** | **100** | **-0.9** |
| Coal | 291 | 400 | 410 | 401 | 391 | 368 | 34 | 39 | -0.3 |
| Oil | 655 | 529 | 426 | 383 | 348 | 320 | 45 | 34 | -2.1 |
| Gas | 115 | 249 | 245 | 252 | 250 | 252 | 21 | 27 | 0.1 |
| **Power generation** | **363** | **515** | **442** | **432** | **418** | **395** | **100** | **100** | **-1.1** |
| Coal | 128 | 259 | 266 | 261 | 255 | 237 | 50 | 60 | -0.4 |
| Oil | 157 | 92 | 24 | 18 | 17 | 16 | 18 | 4 | -7.0 |
| Gas | 78 | 164 | 152 | 153 | 146 | 143 | 32 | 36 | -0.6 |
| **TFC** | **653** | **622** | **595** | **563** | **534** | **510** | **100** | **100** | **-0.8** |
| Coal | 147 | 125 | 127 | 124 | 119 | 116 | 20 | 23 | -0.3 |
| Oil | 470 | 415 | 378 | 343 | 313 | 287 | 67 | 56 | -1.5 |
| *Transport* | *208* | *218* | *192* | *167* | *148* | *134* | *35* | *26* | *-2.0* |
| Gas | 35 | 82 | 91 | 96 | 101 | 107 | 13 | 21 | 1.1 |

## **Japan:** Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **1 186** | **1 263** | **1 302** | **1 090** | **1 074** | **1 074** | **100** | **100** | **0.9** | **0.1** |
| Coal | 313 | 349 | 352 | 216 | 65 | 35 | 27 | 3 | 0.9 | -8.3 |
| Oil | 41 | 31 | 32 | 30 | 11 | 8 | 2 | 1 | -6.4 | -11.6 |
| Gas | 410 | 448 | 455 | 361 | 339 | 315 | 35 | 29 | 0.8 | -0.7 |
| Nuclear | 220 | 174 | 174 | 252 | 277 | 278 | 13 | 26 | 2.3 | 4.3 |
| Hydro | 88 | 94 | 98 | 96 | 118 | 128 | 8 | 12 | 0.7 | 1.8 |
| Bioenergy | 44 | 55 | 62 | 48 | 64 | 72 | 5 | 7 | 2.2 | 2.8 |
| Wind | 20 | 41 | 52 | 31 | 97 | 116 | 4 | 11 | 10.6 | 14.4 |
| Geothermal | 5 | 12 | 17 | 6 | 27 | 35 | 1 | 3 | 7.9 | 11.2 |
| Solar PV | 45 | 57 | 61 | 51 | 73 | 82 | 5 | 8 | 10.9 | 12.2 |
| CSP | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Marine | - | 0 | 0 | - | 1 | 6 | 0 | 1 | n.a. | n.a. |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **329** | **354** | **362** | **325** | **356** | **366** | **100** | **100** | **1.1** | **1.1** |
| Coal | 50 | 56 | 57 | 47 | 33 | 29 | 16 | 8 | 0.8 | -2.0 |
| Oil | 25 | 20 | 20 | 24 | 16 | 14 | 5 | 4 | -3.9 | -5.4 |
| Gas | 112 | 128 | 126 | 94 | 98 | 94 | 35 | 26 | 2.1 | 0.9 |
| Nuclear | 38 | 24 | 24 | 42 | 38 | 40 | 7 | 11 | -2.7 | -0.6 |
| Hydro | 50 | 52 | 53 | 53 | 60 | 63 | 15 | 17 | 0.4 | 1.2 |
| Bioenergy | 7 | 9 | 10 | 8 | 11 | 12 | 3 | 3 | 2.2 | 2.9 |
| Wind | 8 | 16 | 20 | 13 | 34 | 39 | 5 | 11 | 9.2 | 12.3 |
| Geothermal | 1 | 2 | 3 | 1 | 5 | 6 | 1 | 2 | 7.2 | 10.5 |
| Solar PV | 38 | 47 | 50 | 42 | 61 | 67 | 14 | 18 | 10.1 | 11.5 |
| CSP | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Marine | - | 0 | 0 | - | 0 | 2 | 0 | 1 | n.a. | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **1 104** | **1 078** | **1 058** | **951** | **644** | **538** | **100** | **100** | **-0.4** | **-3.2** |
| Coal | 426 | 445 | 438 | 328 | 160 | 114 | 41 | 21 | 0.4 | -5.1 |
| Oil | 430 | 366 | 346 | 399 | 279 | 233 | 33 | 43 | -1.8 | -3.4 |
| Gas | 248 | 267 | 274 | 224 | 205 | 191 | 26 | 35 | 0.4 | -1.1 |
| **Power generation** | **458** | **484** | **481** | **344** | **166** | **113** | **100** | **100** | **-0.3** | **-6.1** |
| Coal | 280 | 303 | 300 | 189 | 41 | 4 | 62 | 3 | 0.6 | -16.2 |
| Oil | 25 | 19 | 20 | 18 | 7 | 5 | 4 | 4 | -6.2 | -11.5 |
| Gas | 154 | 161 | 161 | 137 | 118 | 104 | 34 | 92 | -0.1 | -1.9 |
| **TFC** | **601** | **556** | **540** | **564** | **445** | **396** | **100** | **100** | **-0.6** | **-1.9** |
| Coal | 129 | 125 | 122 | 122 | 104 | 96 | 23 | 24 | -0.1 | -1.1 |
| Oil | 382 | 328 | 308 | 357 | 257 | 215 | 57 | 54 | -1.2 | -2.7 |
| *Transport* | *194* | *157* | *147* | *184* | *118* | *92* | *27* | *23* | *-1.6* | *-3.5* |
| Gas | 91 | 103 | 110 | 85 | 84 | 84 | 20 | 21 | 1.2 | 0.1 |

## **Non-OECD:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **4 047** | **7 406** | **9 136** | **9 972** | **10 709** | **11 435** | **100** | **100** | **1.8** |
| Coal | 1 150 | 2 711 | 3 173 | 3 354 | 3 495 | 3 619 | 37 | 32 | 1.2 |
| Oil | 1 161 | 1 829 | 2 261 | 2 425 | 2 566 | 2 701 | 25 | 24 | 1.6 |
| Gas | 825 | 1 470 | 1 864 | 2 107 | 2 335 | 2 560 | 20 | 22 | 2.3 |
| Nuclear | 74 | 130 | 287 | 382 | 441 | 491 | 2 | 4 | 5.7 |
| Hydro | 83 | 181 | 264 | 298 | 331 | 362 | 2 | 3 | 2.9 |
| Bioenergy | 746 | 1 031 | 1 141 | 1 203 | 1 266 | 1 337 | 14 | 12 | 1.1 |
| Other renewables | 8 | 55 | 146 | 204 | 275 | 365 | 1 | 3 | 8.2 |
| **Power generation** | **1 265** | **2 753** | **3 498** | **3 935** | **4 344** | **4 789** | **100** | **100** | **2.3** |
| Coal | 466 | 1 512 | 1 788 | 1 947 | 2 096 | 2 242 | 55 | 47 | 1.7 |
| Oil | 222 | 204 | 182 | 156 | 134 | 126 | 7 | 3 | -2.0 |
| Gas | 406 | 638 | 755 | 842 | 926 | 1 017 | 23 | 21 | 2.0 |
| Nuclear | 74 | 130 | 287 | 382 | 441 | 491 | 5 | 10 | 5.7 |
| Hydro | 83 | 181 | 264 | 298 | 331 | 362 | 7 | 8 | 2.9 |
| Bioenergy | 7 | 50 | 109 | 147 | 190 | 244 | 2 | 5 | 6.8 |
| Other renewables | 8 | 39 | 113 | 163 | 226 | 308 | 1 | 6 | 9.0 |
| **Other energy sector** | **499** | **1 029** | **1 154** | **1 202** | **1 239** | **1 263** | **100** | **100** | **0.9** |
| *Electricity* | *78* | *193* | *250* | *284* | *318* | *352* | *19* | *28* | *2.5* |
| **TFC** | **2 971** | **4 867** | **6 167** | **6 753** | **7 263** | **7 742** | **100** | **100** | **2.0** |
| Coal | 535 | 779 | 936 | 956 | 951 | 935 | 16 | 12 | 0.8 |
| Oil | 816 | 1 508 | 1 965 | 2 171 | 2 354 | 2 519 | 31 | 33 | 2.2 |
| Gas | 355 | 647 | 886 | 1 015 | 1 136 | 1 253 | 13 | 16 | 2.8 |
| Electricity | 281 | 780 | 1 140 | 1 336 | 1 521 | 1 710 | 16 | 22 | 3.3 |
| Heat | 293 | 222 | 245 | 251 | 253 | 254 | 5 | 3 | 0.6 |
| Bioenergy | 691 | 916 | 962 | 982 | 1 000 | 1 015 | 19 | 13 | 0.4 |
| Other renewables | 0 | 16 | 33 | 41 | 49 | 57 | 0 | 1 | 5.4 |
| **Industry** | **984** | **1 714** | **2 216** | **2 403** | **2 538** | **2 662** | **100** | **100** | **1.8** |
| Coal | 315 | 628 | 749 | 758 | 747 | 731 | 37 | 27 | 0.6 |
| Oil | 158 | 212 | 249 | 260 | 263 | 264 | 12 | 10 | 0.9 |
| Gas | 133 | 236 | 348 | 411 | 468 | 524 | 14 | 20 | 3.4 |
| Electricity | 158 | 410 | 599 | 688 | 762 | 837 | 24 | 31 | 3.0 |
| Heat | 138 | 102 | 120 | 125 | 127 | 126 | 6 | 5 | 0.9 |
| Bioenergy | 82 | 126 | 151 | 162 | 171 | 179 | 7 | 7 | 1.5 |
| Other renewables | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3.2 |
| **Transport** | **440** | **901** | **1 258** | **1 438** | **1 611** | **1 777** | **100** | **100** | **2.9** |
| Oil | 370 | 796 | 1 101 | 1 252 | 1 392 | 1 522 | 88 | 86 | 2.7 |
| Electricity | 13 | 16 | 23 | 28 | 33 | 38 | 2 | 2 | 3.8 |
| Biofuels | 6 | 17 | 38 | 53 | 68 | 84 | 2 | 5 | 6.9 |
| Other fuels | 50 | 72 | 96 | 105 | 118 | 133 | 8 | 7 | 2.6 |
| **Buildings** | **1 242** | **1 677** | **1 911** | **2 034** | **2 153** | **2 267** | **100** | **100** | **1.3** |
| Coal | 170 | 98 | 97 | 93 | 87 | 79 | 6 | 3 | -0.9 |
| Oil | 116 | 173 | 187 | 185 | 184 | 181 | 10 | 8 | 0.2 |
| Gas | 126 | 192 | 248 | 282 | 312 | 338 | 11 | 15 | 2.4 |
| Electricity | 86 | 316 | 466 | 560 | 658 | 758 | 19 | 33 | 3.7 |
| Heat | 146 | 114 | 119 | 121 | 122 | 122 | 7 | 5 | 0.3 |
| Bioenergy | 598 | 768 | 763 | 754 | 745 | 734 | 46 | 32 | -0.2 |
| Other renewables | 0 | 15 | 31 | 39 | 46 | 53 | 1 | 2 | 5.3 |
| **Other** | **306** | **574** | **782** | **878** | **961** | **1 036** | **100** | **100** | **2.5** |

## **Non-OECD:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **9 410** | **11 406** | **12 334** | **8 634** | **9 228** | **9 602** | **100** | **100** | **2.1** | **1.1** |
| Coal | 3 416 | 4 092 | 4 383 | 2 830 | 2 280 | 2 095 | 36 | 22 | 2.0 | -1.1 |
| Oil | 2 305 | 2 719 | 2 919 | 2 133 | 2 123 | 2 062 | 24 | 21 | 2.0 | 0.5 |
| Gas | 1 899 | 2 438 | 2 719 | 1 781 | 2 025 | 2 120 | 22 | 22 | 2.6 | 1.5 |
| Nuclear | 274 | 403 | 435 | 311 | 634 | 785 | 4 | 8 | 5.2 | 7.8 |
| Hydro | 253 | 309 | 335 | 270 | 368 | 401 | 3 | 4 | 2.6 | 3.4 |
| Bioenergy | 1 134 | 1 232 | 1 281 | 1 147 | 1 370 | 1 504 | 10 | 16 | 0.9 | 1.6 |
| Other renewables | 130 | 214 | 262 | 162 | 428 | 635 | 2 | 7 | 6.8 | 10.8 |
| **Power generation** | **3 676** | **4 771** | **5 318** | **3 200** | **3 513** | **3 850** | **100** | **100** | **2.8** | **1.4** |
| Coal | 1 987 | 2 594 | 2 880 | 1 497 | 1 006 | 860 | 54 | 22 | 2.7 | -2.3 |
| Oil | 186 | 145 | 138 | 162 | 97 | 80 | 3 | 2 | -1.6 | -3.8 |
| Gas | 773 | 984 | 1 118 | 719 | 778 | 799 | 21 | 21 | 2.4 | 0.9 |
| Nuclear | 274 | 403 | 435 | 311 | 634 | 785 | 8 | 20 | 5.2 | 7.8 |
| Hydro | 253 | 309 | 335 | 270 | 368 | 401 | 6 | 10 | 2.6 | 3.4 |
| Bioenergy | 105 | 165 | 197 | 114 | 265 | 369 | 4 | 10 | 5.9 | 8.7 |
| Other renewables | 99 | 172 | 216 | 126 | 366 | 555 | 4 | 14 | 7.4 | 11.7 |
| **Other energy sector** | **1 177** | **1 302** | **1 349** | **1 115** | **1 107** | **1 094** | **100** | **100** | **1.1** | **0.3** |
| *Electricity* | *259* | *343* | *384* | *235* | *267* | *285* | *28* | *26* | *2.9* | *1.6* |
| **TFC** | **6 298** | **7 624** | **8 219** | **5 904** | **6 458** | **6 652** | **100** | **100** | **2.2** | **1.3** |
| Coal | 967 | 1 017 | 1 019 | 895 | 862 | 837 | 12 | 13 | 1.1 | 0.3 |
| Oil | 2 008 | 2 505 | 2 733 | 1 860 | 1 962 | 1 940 | 33 | 29 | 2.5 | 1.1 |
| Gas | 900 | 1 168 | 1 294 | 846 | 1 000 | 1 065 | 16 | 16 | 2.9 | 2.1 |
| Electricity | 1 185 | 1 635 | 1 853 | 1 066 | 1 313 | 1 449 | 23 | 22 | 3.7 | 2.6 |
| Heat | 250 | 266 | 270 | 237 | 230 | 223 | 3 | 3 | 0.8 | 0.0 |
| Bioenergy | 959 | 991 | 1 005 | 964 | 1 029 | 1 058 | 12 | 16 | 0.4 | 0.6 |
| Other renewables | 30 | 41 | 46 | 36 | 63 | 80 | 1 | 1 | 4.5 | 6.9 |
| **Industry** | **2 283** | **2 705** | **2 877** | **2 095** | **2 263** | **2 327** | **100** | **100** | **2.2** | **1.3** |
| Coal | 773 | 799 | 795 | 716 | 681 | 659 | 28 | 28 | 1.0 | 0.2 |
| Oil | 257 | 279 | 284 | 232 | 224 | 217 | 10 | 9 | 1.2 | 0.1 |
| Gas | 357 | 495 | 561 | 332 | 421 | 455 | 20 | 20 | 3.7 | 2.8 |
| Electricity | 621 | 822 | 916 | 553 | 656 | 705 | 32 | 30 | 3.4 | 2.3 |
| Heat | 122 | 134 | 136 | 114 | 109 | 104 | 5 | 4 | 1.2 | 0.1 |
| Bioenergy | 154 | 176 | 184 | 147 | 166 | 175 | 6 | 8 | 1.6 | 1.4 |
| Other renewables | 0 | 0 | 0 | 1 | 6 | 12 | 0 | 1 | 3.2 | 19.6 |
| **Transport** | **1 271** | **1 687** | **1 893** | **1 185** | **1 316** | **1 333** | **100** | **100** | **3.1** | **1.6** |
| Oil | 1 124 | 1 496 | 1 679 | 1 028 | 1 081 | 1 043 | 89 | 78 | 3.2 | 1.1 |
| Electricity | 23 | 31 | 35 | 24 | 42 | 64 | 2 | 5 | 3.4 | 6.0 |
| Biofuels | 31 | 53 | 66 | 47 | 105 | 129 | 3 | 10 | 5.8 | 8.9 |
| Other fuels | 94 | 107 | 112 | 85 | 87 | 97 | 6 | 7 | 1.9 | 1.2 |
| **Buildings** | **1 953** | **2 248** | **2 380** | **1 848** | **1 946** | **1 990** | **100** | **100** | **1.5** | **0.7** |
| Coal | 102 | 96 | 92 | 91 | 69 | 59 | 4 | 3 | -0.3 | -2.1 |
| Oil | 194 | 201 | 202 | 179 | 165 | 160 | 8 | 8 | 0.6 | -0.3 |
| Gas | 254 | 326 | 359 | 235 | 261 | 267 | 15 | 13 | 2.6 | 1.4 |
| Electricity | 488 | 711 | 820 | 437 | 549 | 607 | 34 | 31 | 4.1 | 2.8 |
| Heat | 122 | 127 | 128 | 118 | 116 | 115 | 5 | 6 | 0.5 | 0.0 |
| Bioenergy | 765 | 747 | 737 | 755 | 732 | 720 | 31 | 36 | -0.2 | -0.3 |
| Other renewables | 29 | 39 | 43 | 33 | 53 | 63 | 2 | 3 | 4.4 | 6.0 |
| **Other** | **791** | **985** | **1 069** | **776** | **934** | **1 001** | **100** | **100** | **2.6** | **2.3** |

## **Non-OECD:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **4 189** | **11 317** | **16 172** | **18 848** | **21 389** | **23 983** | **100** | **100** | **3.2** |
| Coal | 1 333 | 5 522 | 7 089 | 7 947 | 8 754 | 9 537 | 49 | 40 | 2.3 |
| Oil | 635 | 717 | 652 | 564 | 499 | 472 | 6 | 2 | -1.7 |
| Gas | 960 | 2 217 | 3 128 | 3 751 | 4 345 | 4 915 | 20 | 20 | 3.4 |
| Nuclear | 283 | 497 | 1 100 | 1 463 | 1 692 | 1 881 | 4 | 8 | 5.7 |
| Hydro | 963 | 2 102 | 3 065 | 3 465 | 3 850 | 4 212 | 19 | 18 | 2.9 |
| Bioenergy | 8 | 130 | 337 | 474 | 624 | 812 | 1 | 3 | 7.9 |
| Wind | 0 | 106 | 588 | 827 | 1 074 | 1 346 | 1 | 6 | 11.2 |
| Geothermal | 8 | 25 | 45 | 63 | 88 | 123 | 0 | 1 | 6.9 |
| Solar PV | 0 | 3 | 153 | 260 | 387 | 524 | 0 | 2 | 23.2 |
| CSP | - | 0 | 15 | 33 | 75 | 159 | 0 | 1 | 64.7 |
| Marine | - | 0 | 0 | 0 | 1 | 2 | 0 | 0 | 24.2 |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **2 665** | **4 104** | **4 739** | **5 374** | **6 028** | **100** | **100** | **3.5** |
| Coal | 1 074 | 1 523 | 1 684 | 1 847 | 1 987 | 40 | 33 | 2.6 |
| Oil | 224 | 233 | 213 | 194 | 187 | 8 | 3 | -0.7 |
| Gas | 572 | 835 | 959 | 1 099 | 1 256 | 21 | 21 | 3.3 |
| Nuclear | 72 | 152 | 201 | 231 | 256 | 3 | 4 | 5.4 |
| Hydro | 599 | 867 | 984 | 1 095 | 1 199 | 22 | 20 | 2.9 |
| Bioenergy | 31 | 72 | 95 | 120 | 148 | 1 | 2 | 6.8 |
| Wind | 85 | 291 | 389 | 476 | 571 | 3 | 9 | 8.3 |
| Geothermal | 4 | 7 | 10 | 13 | 18 | 0 | 0 | 6.5 |
| Solar PV | 5 | 119 | 193 | 276 | 360 | 0 | 6 | 19.8 |
| CSP | 0 | 5 | 10 | 22 | 45 | 0 | 1 | 29.6 |
| Marine | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 22.7 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **9 220** | **17 826** | **21 481** | **23 032** | **24 337** | **25 570** | **100** | **100** | **1.5** |
| Coal | 4 175 | 9 686 | 11 394 | 12 009 | 12 463 | 12 856 | 54 | 50 | 1.2 |
| Oil | 3 166 | 4 889 | 5 990 | 6 414 | 6 790 | 7 153 | 27 | 28 | 1.6 |
| Gas | 1 878 | 3 251 | 4 097 | 4 608 | 5 083 | 5 561 | 18 | 22 | 2.3 |
| **Power generation** | **3 506** | **8 115** | **9 423** | **10 143** | **10 805** | **11 504** | **100** | **100** | **1.5** |
| Coal | 1 852 | 5 981 | 7 084 | 7 682 | 8 218 | 8 732 | 74 | 76 | 1.6 |
| Oil | 706 | 639 | 572 | 490 | 421 | 394 | 8 | 3 | -2.0 |
| Gas | 948 | 1 495 | 1 768 | 1 971 | 2 165 | 2 378 | 18 | 21 | 2.0 |
| **TFC** | **5 301** | **8 859** | **11 058** | **11 847** | **12 462** | **12 988** | **100** | **100** | **1.6** |
| Coal | 2 248 | 3 494 | 4 075 | 4 090 | 4 009 | 3 893 | 39 | 30 | 0.5 |
| Oil | 2 267 | 3 966 | 5 080 | 5 580 | 6 018 | 6 411 | 45 | 49 | 2.0 |
| *Transport* | *1 096* | *2 381* | *3 282* | *3 733* | *4 152* | *4 538* | *27* | *35* | *2.7* |
| Gas | 787 | 1 399 | 1 903 | 2 177 | 2 435 | 2 684 | 16 | 21 | 2.8 |

## **Non-OECD:** Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **16 799** | **23 007** | **26 018** | **15 139** | **18 381** | **20 173** | **100** | **100** | **3.5** | **2.4** |
| Coal | 7 901 | 10 876 | 12 296 | 6 043 | 4 354 | 3 544 | 47 | 18 | 3.4 | -1.8 |
| Oil | 666 | 541 | 522 | 578 | 340 | 278 | 2 | 1 | -1.3 | -3.9 |
| Gas | 3 242 | 4 682 | 5 463 | 2 958 | 3 543 | 3 686 | 21 | 18 | 3.8 | 2.1 |
| Nuclear | 1 049 | 1 546 | 1 668 | 1 191 | 2 431 | 3 011 | 6 | 15 | 5.2 | 7.8 |
| Hydro | 2 936 | 3 591 | 3 891 | 3 144 | 4 280 | 4 665 | 15 | 23 | 2.6 | 3.4 |
| Bioenergy | 325 | 535 | 650 | 354 | 881 | 1 253 | 2 | 6 | 7.0 | 9.9 |
| Wind | 493 | 870 | 1 050 | 622 | 1 638 | 2 215 | 4 | 11 | 10.0 | 13.5 |
| Geothermal | 41 | 69 | 89 | 52 | 147 | 213 | 0 | 1 | 5.5 | 9.4 |
| Solar PV | 136 | 262 | 328 | 174 | 575 | 829 | 1 | 4 | 20.8 | 25.6 |
| CSP | 9 | 33 | 58 | 22 | 189 | 474 | 0 | 2 | 57.9 | 72.4 |
| Marine | 0 | 1 | 2 | 0 | 2 | 6 | 0 | 0 | 23.6 | 29.8 |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **4 122** | **5 436** | **6 064** | **4 009** | **5 264** | **6 009** | **100** | **100** | **3.5** | **3.4** |
| Coal | 1 632 | 2 154 | 2 384 | 1 369 | 1 188 | 1 161 | 39 | 19 | 3.4 | 0.3 |
| Oil | 236 | 205 | 200 | 228 | 173 | 160 | 3 | 3 | -0.5 | -1.4 |
| Gas | 852 | 1 148 | 1 323 | 825 | 1 012 | 1 114 | 22 | 19 | 3.6 | 2.8 |
| Nuclear | 145 | 212 | 227 | 162 | 327 | 405 | 4 | 7 | 4.9 | 7.5 |
| Hydro | 827 | 1 012 | 1 098 | 893 | 1 233 | 1 346 | 18 | 22 | 2.6 | 3.4 |
| Bioenergy | 70 | 105 | 122 | 74 | 160 | 216 | 2 | 4 | 5.9 | 8.5 |
| Wind | 245 | 384 | 443 | 308 | 692 | 885 | 7 | 15 | 7.1 | 10.3 |
| Geothermal | 6 | 11 | 13 | 8 | 22 | 32 | 0 | 1 | 5.2 | 9.0 |
| Solar PV | 107 | 195 | 236 | 134 | 403 | 559 | 4 | 9 | 17.8 | 22.1 |
| CSP | 3 | 10 | 16 | 7 | 53 | 130 | 0 | 2 | 24.2 | 35.4 |
| Marine | 0 | 0 | 1 | 0 | 1 | 2 | 0 | 0 | 21.9 | 28.4 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **22 622** | **27 333** | **29 550** | **19 522** | **16 188** | **14 421** | **100** | **100** | **2.1** | **-0.9** |
| Coal | 12 324 | 14 768 | 15 819 | 10 017 | 6 587 | 5 020 | 54 | 35 | 2.1 | -2.7 |
| Oil | 6 121 | 7 259 | 7 821 | 5 609 | 5 426 | 5 166 | 26 | 36 | 2.0 | 0.2 |
| Gas | 4 176 | 5 306 | 5 910 | 3 896 | 4 175 | 4 236 | 20 | 29 | 2.5 | 1.1 |
| **Power generation** | **10 262** | **12 975** | **14 367** | **8 114** | **5 171** | **3 939** | **100** | **100** | **2.4** | **-3.0** |
| Coal | 7 869 | 10 218 | 11 318 | 5 921 | 3 120 | 1 945 | 79 | 49 | 2.7 | -4.6 |
| Oil | 583 | 453 | 431 | 510 | 304 | 252 | 3 | 6 | -1.6 | -3.8 |
| Gas | 1 811 | 2 303 | 2 617 | 1 683 | 1 747 | 1 741 | 18 | 44 | 2.4 | 0.6 |
| **TFC** | **11 341** | **13 238** | **14 032** | **10 459** | **10 201** | **9 742** | **100** | **100** | **1.9** | **0.4** |
| Coal | 4 207 | 4 284 | 4 234 | 3 878 | 3 294 | 2 922 | 30 | 30 | 0.8 | -0.7 |
| Oil | 5 200 | 6 447 | 7 023 | 4 775 | 4 860 | 4 688 | 50 | 48 | 2.4 | 0.7 |
| *Transport* | *3 351* | *4 461* | *5 005* | *3 065* | *3 223* | *3 110* | *36* | *32* | *3.1* | *1.1* |
| Gas | 1 935 | 2 506 | 2 775 | 1 805 | 2 047 | 2 131 | 20 | 22 | 2.9 | 1.8 |

# **E. Europe/Eurasia:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **1 539** | **1 159** | **1 228** | **1 273** | **1 318** | **1 373** | **100** | **100** | **0.7** |
| Coal | 367 | 230 | 234 | 236 | 236 | 242 | 20 | 18 | 0.2 |
| Oil | 469 | 229 | 242 | 245 | 244 | 244 | 20 | 18 | 0.3 |
| Gas | 602 | 577 | 601 | 620 | 644 | 670 | 50 | 49 | 0.6 |
| Nuclear | 59 | 77 | 93 | 102 | 112 | 117 | 7 | 9 | 1.8 |
| Hydro | 23 | 24 | 28 | 30 | 32 | 34 | 2 | 2 | 1.4 |
| Bioenergy | 17 | 20 | 25 | 29 | 35 | 43 | 2 | 3 | 3.2 |
| Other renewables | 0 | 1 | 5 | 10 | 15 | 22 | 0 | 2 | 14.1 |
| **Power generation** | **742** | **575** | **593** | **610** | **629** | **660** | **100** | **100** | **0.6** |
| Coal | 197 | 143 | 144 | 145 | 143 | 147 | 25 | 22 | 0.1 |
| Oil | 125 | 21 | 16 | 13 | 11 | 10 | 4 | 2 | -2.8 |
| Gas | 333 | 302 | 299 | 300 | 303 | 310 | 53 | 47 | 0.1 |
| Nuclear | 59 | 77 | 93 | 102 | 112 | 117 | 13 | 18 | 1.8 |
| Hydro | 23 | 24 | 28 | 30 | 32 | 34 | 4 | 5 | 1.4 |
| Bioenergy | 4 | 6 | 8 | 11 | 14 | 20 | 1 | 3 | 5.0 |
| Other renewables | 0 | 1 | 5 | 10 | 15 | 21 | 0 | 3 | 15.0 |
| **Other energy sector** | **198** | **198** | **187** | **192** | **197** | **201** | **100** | **100** | **0.1** |
| *Electricity* | *35* | *40* | *43* | *45* | *47* | *50* | *20* | *25* | *1.0* |
| **TFC** | **1 074** | **724** | **811** | **849** | **884** | **919** | **100** | **100** | **1.0** |
| Coal | 114 | 46 | 53 | 54 | 54 | 54 | 6 | 6 | 0.7 |
| Oil | 281 | 173 | 200 | 208 | 214 | 218 | 24 | 24 | 1.0 |
| Gas | 261 | 230 | 255 | 269 | 283 | 299 | 32 | 32 | 1.1 |
| Electricity | 126 | 106 | 124 | 134 | 144 | 156 | 15 | 17 | 1.6 |
| Heat | 279 | 156 | 163 | 165 | 167 | 169 | 22 | 18 | 0.3 |
| Bioenergy | 13 | 14 | 17 | 18 | 20 | 22 | 2 | 2 | 2.1 |
| Other renewables | - | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 6.6 |
| **Industry** | **397** | **214** | **242** | **253** | **263** | **275** | **100** | **100** | **1.1** |
| Coal | 56 | 35 | 41 | 43 | 43 | 44 | 16 | 16 | 1.0 |
| Oil | 52 | 19 | 21 | 22 | 22 | 23 | 9 | 8 | 0.9 |
| Gas | 86 | 55 | 61 | 64 | 66 | 69 | 26 | 25 | 1.0 |
| Electricity | 75 | 47 | 56 | 60 | 65 | 71 | 22 | 26 | 1.7 |
| Heat | 127 | 57 | 61 | 63 | 64 | 65 | 27 | 24 | 0.6 |
| Bioenergy | 0 | 2 | 2 | 2 | 2 | 3 | 1 | 1 | 2.2 |
| Other renewables | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.6 |
| **Transport** | **172** | **148** | **169** | **178** | **185** | **191** | **100** | **100** | **1.1** |
| Oil | 123 | 99 | 117 | 124 | 128 | 131 | 67 | 68 | 1.1 |
| Electricity | 12 | 10 | 11 | 12 | 14 | 15 | 6 | 8 | 1.9 |
| Biofuels | 0 | 0 | 1 | 1 | 2 | 2 | 0 | 1 | 7.9 |
| Other fuels | 37 | 38 | 40 | 41 | 42 | 44 | 26 | 23 | 0.5 |
| **Buildings** | **383** | **271** | **288** | **299** | **309** | **319** | **100** | **100** | **0.7** |
| Coal | 56 | 10 | 10 | 9 | 9 | 9 | 4 | 3 | -0.6 |
| Oil | 36 | 19 | 19 | 18 | 17 | 16 | 7 | 5 | -0.6 |
| Gas | 111 | 92 | 99 | 105 | 111 | 117 | 34 | 37 | 1.0 |
| Electricity | 26 | 45 | 51 | 54 | 58 | 61 | 17 | 19 | 1.3 |
| Heat | 143 | 93 | 96 | 97 | 98 | 99 | 34 | 31 | 0.2 |
| Bioenergy | 12 | 11 | 13 | 14 | 16 | 17 | 4 | 5 | 1.6 |
| Other renewables | - | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 6.0 |
| **Other** | **122** | **93** | **112** | **118** | **126** | **134** | **100** | **100** | **1.6** |

# E. Europe/Eurasia: Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **1 249** | **1 373** | **1 445** | **1 182** | **1 181** | **1 201** | **100** | **100** | **0.9** | **0.1** |
| Coal | 242 | 258 | 269 | 215 | 174 | 158 | 19 | 13 | 0.6 | -1.6 |
| Oil | 245 | 252 | 257 | 234 | 216 | 205 | 18 | 17 | 0.5 | -0.4 |
| Gas | 615 | 686 | 731 | 565 | 533 | 523 | 51 | 44 | 1.0 | -0.4 |
| Nuclear | 91 | 106 | 109 | 103 | 136 | 151 | 8 | 13 | 1.4 | 2.8 |
| Hydro | 28 | 31 | 33 | 30 | 39 | 41 | 2 | 3 | 1.2 | 2.2 |
| Bioenergy | 24 | 30 | 34 | 28 | 57 | 80 | 2 | 7 | 2.2 | 6.0 |
| Other renewables | 5 | 10 | 13 | 7 | 27 | 42 | 1 | 4 | 11.8 | 17.2 |
| **Power generation** | **603** | **655** | **693** | **574** | **577** | **601** | **100** | **100** | **0.8** | **0.2** |
| Coal | 150 | 160 | 167 | 129 | 89 | 73 | 24 | 12 | 0.6 | -2.8 |
| Oil | 16 | 11 | 10 | 16 | 10 | 10 | 2 | 2 | -2.8 | -3.1 |
| Gas | 306 | 325 | 346 | 281 | 247 | 235 | 50 | 39 | 0.6 | -1.0 |
| Nuclear | 91 | 106 | 109 | 103 | 136 | 151 | 16 | 25 | 1.4 | 2.8 |
| Hydro | 28 | 31 | 33 | 30 | 39 | 41 | 5 | 7 | 1.2 | 2.2 |
| Bioenergy | 8 | 12 | 15 | 9 | 31 | 50 | 2 | 8 | 3.7 | 9.1 |
| Other renewables | 4 | 10 | 13 | 7 | 26 | 41 | 2 | 7 | 12.7 | 18.2 |
| **Other energy sector** | **190** | **204** | **212** | **182** | **177** | **175** | **100** | **100** | **0.3** | **-0.5** |
| *Electricity* | *44* | *50* | *54* | *41* | *42* | *43* | *26* | *24* | *1.3* | *0.3* |
| **TFC** | **828** | **925** | **974** | **779** | **781** | **782** | **100** | **100** | **1.2** | **0.3** |
| Coal | 54 | 57 | 58 | 51 | 49 | 49 | 6 | 6 | 1.0 | 0.2 |
| Oil | 203 | 223 | 232 | 193 | 189 | 182 | 24 | 23 | 1.2 | 0.2 |
| Gas | 262 | 299 | 318 | 238 | 234 | 234 | 33 | 30 | 1.4 | 0.1 |
| Electricity | 128 | 155 | 170 | 118 | 128 | 134 | 17 | 17 | 2.0 | 1.0 |
| Heat | 165 | 173 | 176 | 159 | 154 | 152 | 18 | 19 | 0.5 | -0.1 |
| Bioenergy | 16 | 18 | 18 | 19 | 26 | 30 | 2 | 4 | 1.3 | 3.3 |
| Other renewables | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 4.0 | 8.7 |
| **Industry** | **247** | **276** | **291** | **231** | **236** | **241** | **100** | **100** | **1.3** | **0.5** |
| Coal | 42 | 45 | 46 | 40 | 40 | 40 | 16 | 16 | 1.2 | 0.5 |
| Oil | 21 | 23 | 24 | 20 | 20 | 21 | 8 | 9 | 1.1 | 0.4 |
| Gas | 64 | 72 | 75 | 58 | 60 | 61 | 26 | 25 | 1.3 | 0.5 |
| Electricity | 57 | 69 | 76 | 53 | 57 | 60 | 26 | 25 | 2.0 | 1.1 |
| Heat | 61 | 65 | 67 | 58 | 57 | 56 | 23 | 23 | 0.7 | -0.1 |
| Bioenergy | 2 | 2 | 2 | 2 | 3 | 3 | 1 | 1 | 1.6 | 2.9 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.6 | 0.6 |
| **Transport** | **170** | **189** | **198** | **159** | **149** | **142** | **100** | **100** | **1.2** | **-0.2** |
| Oil | 118 | 133 | 140 | 113 | 111 | 105 | 70 | 74 | 1.4 | 0.2 |
| Electricity | 11 | 13 | 15 | 11 | 14 | 16 | 7 | 11 | 1.7 | 2.1 |
| Biofuels | 0 | 0 | 0 | 1 | 2 | 3 | 0 | 2 | 0.2 | 9.6 |
| Other fuels | 40 | 42 | 44 | 34 | 22 | 18 | 22 | 13 | 0.5 | -3.1 |
| **Buildings** | **298** | **331** | **346** | **278** | **275** | **273** | **100** | **100** | **1.0** | **0.0** |
| Coal | 10 | 10 | 10 | 9 | 8 | 8 | 3 | 3 | 0.0 | -1.1 |
| Oil | 20 | 19 | 19 | 18 | 15 | 14 | 5 | 5 | -0.0 | -1.2 |
| Gas | 104 | 120 | 129 | 93 | 91 | 89 | 37 | 33 | 1.4 | -0.1 |
| Electricity | 53 | 64 | 69 | 49 | 49 | 50 | 20 | 18 | 1.8 | 0.4 |
| Heat | 98 | 103 | 104 | 95 | 93 | 92 | 30 | 34 | 0.5 | -0.0 |
| Bioenergy | 13 | 14 | 15 | 14 | 17 | 19 | 4 | 7 | 1.2 | 2.2 |
| Other renewables | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 2.8 | 8.3 |
| **Other** | **113** | **129** | **138** | **110** | **120** | **126** | **100** | **100** | **1.7** | **1.3** |

## **E. Europe/Eurasia:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **1 894** | **1 716** | **1 957** | **2 099** | **2 249** | **2 421** | **100** | **100** | **1.4** |
| Coal | 429 | 412 | 446 | 461 | 472 | 504 | 24 | 21 | 0.9 |
| Oil | 270 | 39 | 24 | 16 | 11 | 11 | 2 | 0 | -5.2 |
| Gas | 702 | 681 | 776 | 830 | 882 | 929 | 40 | 38 | 1.3 |
| Nuclear | 226 | 294 | 355 | 391 | 427 | 449 | 17 | 19 | 1.8 |
| Hydro | 267 | 283 | 323 | 345 | 370 | 397 | 16 | 16 | 1.4 |
| Bioenergy | 0 | 4 | 13 | 20 | 34 | 57 | 0 | 2 | 12.0 |
| Wind | - | 3 | 14 | 23 | 33 | 47 | 0 | 2 | 11.8 |
| Geothermal | 0 | 1 | 4 | 9 | 13 | 19 | 0 | 1 | 16.2 |
| Solar PV | - | 0 | 3 | 4 | 6 | 8 | 0 | 0 | 17.9 |
| CSP | - | - | - | - | - | - | - | - | n.a. |
| Marine | - | - | - | - | 0 | 0 | - | 0 | n.a. |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **423** | **466** | **492** | **517** | **554** | **100** | **100** | **1.1** |
| Coal | 110 | 107 | 106 | 103 | 103 | 26 | 19 | -0.3 |
| Oil | 23 | 17 | 12 | 8 | 8 | 6 | 1 | -4.4 |
| Gas | 150 | 177 | 190 | 203 | 220 | 35 | 40 | 1.6 |
| Nuclear | 43 | 50 | 55 | 59 | 62 | 10 | 11 | 1.5 |
| Hydro | 92 | 102 | 108 | 115 | 122 | 22 | 22 | 1.2 |
| Bioenergy | 2 | 3 | 4 | 6 | 10 | 0 | 2 | 7.9 |
| Wind | 2 | 7 | 10 | 14 | 20 | 1 | 4 | 9.5 |
| Geothermal | 0 | 1 | 1 | 2 | 3 | 0 | 0 | 15.3 |
| Solar PV | 0 | 3 | 4 | 5 | 7 | 0 | 1 | 12.8 |
| CSP | - | - | - | - | - | - | - | n.a. |
| Marine | - | - | - | 0 | 0 | - | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **3 988** | **2 711** | **2 829** | **2 878** | **2 911** | **2 978** | **100** | **100** | **0.4** |
| Coal | 1 335 | 840 | 875 | 883 | 875 | 889 | 31 | 30 | 0.2 |
| Oil | 1 247 | 582 | 622 | 629 | 632 | 636 | 21 | 21 | 0.4 |
| Gas | 1 405 | 1 290 | 1 332 | 1 367 | 1 405 | 1 453 | 48 | 49 | 0.5 |
| **Power generation** | **1 976** | **1 375** | **1 356** | **1 353** | **1 345** | **1 375** | **100** | **100** | **0.0** |
| Coal | 799 | 598 | 602 | 606 | 598 | 614 | 43 | 45 | 0.1 |
| Oil | 399 | 67 | 52 | 42 | 35 | 33 | 5 | 2 | -2.8 |
| Gas | 778 | 710 | 702 | 705 | 711 | 728 | 52 | 53 | 0.1 |
| **TFC** | **1 898** | **1 199** | **1 330** | **1 379** | **1 417** | **1 452** | **100** | **100** | **0.8** |
| Coal | 525 | 229 | 260 | 264 | 263 | 263 | 19 | 18 | 0.6 |
| Oil | 782 | 464 | 518 | 536 | 547 | 554 | 39 | 38 | 0.7 |
| *Transport* | *365* | *293* | *345* | *364* | *377* | *385* | *24* | *27* | *1.1* |
| Gas | 591 | 505 | 552 | 579 | 606 | 635 | 42 | 44 | 1.0 |

## **E. Europe/Eurasia:** Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **2 018** | **2 406** | **2 626** | **1 876** | **1 991** | **2 081** | **100** | **100** | **1.8** | **0.8** |
| Coal | 466 | 518 | 552 | 392 | 268 | 218 | 21 | 10 | 1.2 | -2.6 |
| Oil | 25 | 11 | 11 | 24 | 10 | 8 | 0 | 0 | -5.3 | -6.5 |
| Gas | 826 | 1 044 | 1 176 | 681 | 538 | 452 | 45 | 22 | 2.3 | -1.7 |
| Nuclear | 348 | 406 | 415 | 394 | 523 | 578 | 16 | 28 | 1.5 | 2.9 |
| Hydro | 323 | 359 | 381 | 346 | 452 | 481 | 14 | 23 | 1.2 | 2.2 |
| Bioenergy | 12 | 27 | 38 | 14 | 89 | 159 | 1 | 8 | 10.1 | 17.0 |
| Wind | 14 | 28 | 38 | 15 | 81 | 138 | 1 | 7 | 10.9 | 17.0 |
| Geothermal | 3 | 8 | 11 | 6 | 21 | 32 | 0 | 2 | 13.5 | 18.8 |
| Solar PV | 2 | 4 | 5 | 4 | 10 | 15 | 0 | 1 | 15.9 | 20.9 |
| CSP | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Marine | - | 0 | 0 | - | 0 | 0 | 0 | 0 | n.a. | n.a. |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **476** | **531** | **568** | **457** | **500** | **552** | **100** | **100** | **1.2** | **1.1** |
| Coal | 110 | 111 | 111 | 101 | 75 | 63 | 20 | 11 | 0.0 | -2.3 |
| Oil | 17 | 8 | 8 | 17 | 8 | 8 | 1 | 1 | -4.5 | -4.5 |
| Gas | 185 | 221 | 245 | 160 | 145 | 154 | 43 | 28 | 2.1 | 0.1 |
| Nuclear | 49 | 56 | 57 | 56 | 73 | 81 | 10 | 15 | 1.2 | 2.7 |
| Hydro | 102 | 112 | 117 | 108 | 137 | 145 | 21 | 26 | 1.0 | 1.9 |
| Bioenergy | 3 | 5 | 7 | 3 | 15 | 27 | 1 | 5 | 6.3 | 12.4 |
| Wind | 7 | 13 | 17 | 8 | 34 | 56 | 3 | 10 | 8.8 | 14.5 |
| Geothermal | 0 | 1 | 1 | 1 | 3 | 4 | 0 | 1 | 12.5 | 17.7 |
| Solar PV | 3 | 4 | 5 | 4 | 9 | 13 | 1 | 2 | 10.9 | 15.8 |
| CSP | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Marine | - | 0 | 0 | - | 0 | 0 | 0 | 0 | n.a. | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **2 902** | **3 114** | **3 255** | **2 644** | **2 208** | **2 008** | **100** | **100** | **0.8** | **-1.2** |
| Coal | 907 | 960 | 992 | 795 | 558 | 451 | 30 | 22 | 0.7 | -2.6 |
| Oil | 631 | 659 | 679 | 601 | 551 | 517 | 21 | 26 | 0.6 | -0.5 |
| Gas | 1 365 | 1 495 | 1 585 | 1 247 | 1 099 | 1 039 | 49 | 52 | 0.9 | -0.9 |
| **Power generation** | **1 399** | **1 469** | **1 545** | **1 244** | **915** | **788** | **100** | **100** | **0.5** | **-2.3** |
| Coal | 628 | 670 | 699 | 534 | 332 | 247 | 45 | 31 | 0.7 | -3.6 |
| Oil | 53 | 36 | 34 | 52 | 34 | 31 | 2 | 4 | -2.8 | -3.1 |
| Gas | 717 | 764 | 813 | 658 | 548 | 510 | 53 | 65 | 0.6 | -1.4 |
| **TFC** | **1 360** | **1 492** | **1 553** | **1 262** | **1 171** | **1 106** | **100** | **100** | **1.1** | **-0.3** |
| Coal | 266 | 277 | 279 | 249 | 215 | 195 | 18 | 18 | 0.8 | -0.7 |
| Oil | 526 | 573 | 594 | 500 | 478 | 450 | 38 | 41 | 1.0 | -0.1 |
| *Transport* | *348* | *392* | *411* | *333* | *327* | *309* | *26* | *28* | *1.4* | *0.2* |
| Gas | 568 | 642 | 680 | 513 | 478 | 460 | 44 | 42 | 1.2 | -0.4 |

## **Russia:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **880** | **718** | **755** | **779** | **806** | **841** | **100** | **100** | **0.7** |
| Coal | 191 | 116 | 116 | 119 | 120 | 122 | 16 | 15 | 0.2 |
| Oil | 264 | 143 | 147 | 147 | 145 | 145 | 20 | 17 | 0.0 |
| Gas | 367 | 391 | 405 | 414 | 430 | 447 | 54 | 53 | 0.6 |
| Nuclear | 31 | 45 | 59 | 64 | 68 | 73 | 6 | 9 | 2.0 |
| Hydro | 14 | 14 | 16 | 17 | 19 | 21 | 2 | 2 | 1.6 |
| Bioenergy | 12 | 7 | 9 | 11 | 13 | 18 | 1 | 2 | 4.1 |
| Other renewables | 0 | 0 | 3 | 7 | 10 | 15 | 0 | 2 | 15.7 |
| **Power generation** | **444** | **391** | **408** | **419** | **432** | **454** | **100** | **100** | **0.6** |
| Coal | 105 | 73 | 78 | 82 | 85 | 89 | 19 | 20 | 0.8 |
| Oil | 62 | 17 | 14 | 11 | 9 | 9 | 4 | 2 | -2.7 |
| Gas | 228 | 237 | 233 | 231 | 231 | 234 | 61 | 52 | -0.1 |
| Nuclear | 31 | 45 | 59 | 64 | 68 | 73 | 12 | 16 | 2.0 |
| Hydro | 14 | 14 | 16 | 17 | 19 | 21 | 4 | 5 | 1.6 |
| Bioenergy | 4 | 4 | 6 | 7 | 10 | 14 | 1 | 3 | 5.0 |
| Other renewables | 0 | 0 | 3 | 7 | 10 | 15 | 0 | 3 | 15.7 |
| **Other energy sector** | **127** | **124** | **109** | **109** | **111** | **113** | **100** | **100** | **-0.4** |
| *Electricity* | *21* | *26* | *28* | *30* | *32* | *34* | *21* | *31* | *1.2* |
| **TFC** | **625** | **444** | **495** | **515** | **536** | **557** | **100** | **100** | **1.0** |
| Coal | 55 | 16 | 17 | 17 | 15 | 14 | 4 | 3 | -0.4 |
| Oil | 145 | 101 | 117 | 121 | 125 | 127 | 23 | 23 | 0.9 |
| Gas | 143 | 138 | 156 | 165 | 176 | 188 | 31 | 34 | 1.3 |
| Electricity | 71 | 63 | 74 | 80 | 87 | 94 | 14 | 17 | 1.7 |
| Heat | 203 | 124 | 127 | 128 | 129 | 130 | 28 | 23 | 0.2 |
| Bioenergy | 8 | 2 | 3 | 3 | 4 | 4 | 1 | 1 | 1.9 |
| Other renewables | - | - | 0 | 0 | 0 | 0 | - | 0 | n.a. |
| **Industry** | **209** | **128** | **143** | **148** | **154** | **160** | **100** | **100** | **0.9** |
| Coal | 15 | 11 | 13 | 13 | 12 | 11 | 9 | 7 | -0.1 |
| Oil | 25 | 10 | 11 | 12 | 12 | 13 | 8 | 8 | 0.9 |
| Gas | 30 | 31 | 36 | 38 | 40 | 42 | 24 | 26 | 1.2 |
| Electricity | 41 | 29 | 34 | 37 | 40 | 43 | 22 | 27 | 1.7 |
| Heat | 98 | 46 | 48 | 49 | 50 | 51 | 36 | 32 | 0.4 |
| Bioenergy | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1.0 |
| Other renewables | - | - | - | - | - | - | - | - | n.a. |
| **Transport** | **116** | **98** | **113** | **118** | **122** | **125** | **100** | **100** | **1.0** |
| Oil | 73 | 59 | 70 | 74 | 76 | 77 | 60 | 61 | 1.1 |
| Electricity | 9 | 8 | 9 | 10 | 11 | 12 | 8 | 10 | 2.0 |
| Biofuels | - | - | - | - | - | - | - | - | n.a. |
| Other fuels | 34 | 31 | 33 | 34 | 35 | 36 | 32 | 29 | 0.6 |
| **Buildings** | **228** | **153** | **162** | **167** | **172** | **178** | **100** | **100** | **0.6** |
| Coal | 40 | 4 | 4 | 3 | 3 | 3 | 3 | 2 | -1.6 |
| Oil | 12 | 8 | 8 | 7 | 6 | 6 | 5 | 3 | -1.4 |
| Gas | 57 | 42 | 46 | 49 | 53 | 57 | 27 | 32 | 1.3 |
| Electricity | 15 | 25 | 29 | 31 | 33 | 35 | 16 | 19 | 1.4 |
| Heat | 98 | 72 | 74 | 74 | 74 | 75 | 47 | 42 | 0.1 |
| Bioenergy | 7 | 2 | 2 | 2 | 3 | 3 | 1 | 2 | 1.6 |
| Other renewables | - | - | 0 | 0 | 0 | 0 | - | 0 | n.a. |
| **Other** | **72** | **64** | **77** | **82** | **88** | **94** | **100** | **100** | **1.7** |

## **Russia:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **771** | **845** | **891** | **730** | **716** | **729** | **100** | **100** | **0.9** | **0.1** |
| Coal | 121 | 132 | 135 | 106 | 78 | 74 | 15 | 10 | 0.6 | -1.8 |
| Oil | 148 | 150 | 152 | 143 | 130 | 124 | 17 | 17 | 0.2 | -0.6 |
| Gas | 415 | 459 | 491 | 380 | 344 | 328 | 55 | 45 | 0.9 | -0.7 |
| Nuclear | 59 | 67 | 70 | 68 | 89 | 97 | 8 | 13 | 1.8 | 3.2 |
| Hydro | 16 | 18 | 20 | 17 | 24 | 25 | 2 | 3 | 1.4 | 2.3 |
| Bioenergy | 9 | 12 | 14 | 11 | 31 | 48 | 2 | 7 | 2.8 | 8.3 |
| Other renewables | 3 | 7 | 9 | 5 | 19 | 31 | 1 | 4 | 13.3 | 19.3 |
| **Power generation** | **417** | **452** | **478** | **398** | **397** | **416** | **100** | **100** | **0.8** | **0.3** |
| Coal | 82 | 95 | 100 | 69 | 47 | 46 | 21 | 11 | 1.3 | -1.9 |
| Oil | 14 | 9 | 9 | 13 | 9 | 8 | 2 | 2 | -2.6 | -2.8 |
| Gas | 237 | 247 | 261 | 219 | 185 | 168 | 55 | 40 | 0.4 | -1.4 |
| Nuclear | 59 | 67 | 70 | 68 | 89 | 97 | 15 | 23 | 1.8 | 3.2 |
| Hydro | 16 | 18 | 20 | 17 | 24 | 25 | 4 | 6 | 1.4 | 2.3 |
| Bioenergy | 6 | 8 | 10 | 6 | 24 | 40 | 2 | 10 | 3.5 | 9.5 |
| Other renewables | 3 | 7 | 9 | 5 | 19 | 31 | 2 | 8 | 13.3 | 19.3 |
| **Other energy sector** | **111** | **117** | **120** | **105** | **97** | **94** | **100** | **100** | **-0.1** | **-1.1** |
| *Electricity* | *29* | *34* | *37* | *28* | *28* | *29* | *31* | *31* | *1.5* | *0.5* |
| **TFC** | **506** | **565** | **596** | **476** | **468** | **466** | **100** | **100** | **1.2** | **0.2** |
| Coal | 18 | 17 | 16 | 17 | 14 | 13 | 3 | 3 | -0.0 | -0.8 |
| Oil | 119 | 130 | 135 | 114 | 110 | 106 | 23 | 23 | 1.2 | 0.2 |
| Gas | 160 | 187 | 201 | 146 | 140 | 140 | 34 | 30 | 1.6 | 0.1 |
| Electricity | 77 | 94 | 104 | 71 | 76 | 81 | 17 | 17 | 2.1 | 1.1 |
| Heat | 129 | 135 | 137 | 124 | 120 | 118 | 23 | 25 | 0.4 | -0.2 |
| Bioenergy | 3 | 3 | 4 | 4 | 7 | 8 | 1 | 2 | 1.5 | 5.2 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. | n.a. |
| **Industry** | **146** | **162** | **170** | **137** | **137** | **139** | **100** | **100** | **1.2** | **0.3** |
| Coal | 13 | 12 | 11 | 13 | 11 | 10 | 7 | 7 | 0.0 | -0.6 |
| Oil | 12 | 13 | 13 | 11 | 11 | 12 | 8 | 8 | 1.1 | 0.5 |
| Gas | 38 | 43 | 45 | 35 | 36 | 37 | 27 | 27 | 1.5 | 0.8 |
| Electricity | 35 | 43 | 47 | 32 | 34 | 36 | 28 | 26 | 2.1 | 1.0 |
| Heat | 49 | 51 | 52 | 46 | 44 | 43 | 31 | 31 | 0.5 | -0.3 |
| Bioenergy | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0.9 | 2.8 |
| Other renewables | - | - | - | - | - | - | - | - | n.a. | n.a. |
| **Transport** | **113** | **124** | **130** | **104** | **92** | **85** | **100** | **100** | **1.2** | **-0.6** |
| Oil | 71 | 78 | 82 | 69 | 67 | 63 | 63 | 75 | 1.3 | 0.3 |
| Electricity | 9 | 11 | 12 | 9 | 12 | 13 | 9 | 16 | 1.9 | 2.2 |
| Biofuels | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Other fuels | 33 | 35 | 36 | 26 | 13 | 8 | 28 | 10 | 0.6 | -5.3 |
| **Buildings** | **169** | **188** | **198** | **158** | **155** | **154** | **100** | **100** | **1.1** | **0.0** |
| Coal | 4 | 4 | 4 | 4 | 3 | 3 | 2 | 2 | -0.4 | -1.7 |
| Oil | 8 | 8 | 8 | 7 | 6 | 5 | 4 | 3 | -0.4 | -2.1 |
| Gas | 49 | 59 | 65 | 44 | 44 | 44 | 33 | 29 | 1.8 | 0.2 |
| Electricity | 30 | 37 | 40 | 28 | 27 | 27 | 20 | 18 | 2.0 | 0.3 |
| Heat | 75 | 78 | 79 | 73 | 72 | 71 | 40 | 46 | 0.4 | -0.1 |
| Bioenergy | 2 | 2 | 2 | 3 | 4 | 4 | 1 | 3 | 1.1 | 3.1 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. | n.a. |
| **Other** | **78** | **91** | **98** | **76** | **84** | **89** | **100** | **100** | **1.8** | **1.4** |

## **Russia:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **1 082** | **1 053** | **1 211** | **1 301** | **1 403** | **1 521** | **100** | **100** | **1.5** |
| Coal | 157 | 164 | 194 | 217 | 238 | 265 | 16 | 17 | 2.0 |
| Oil | 129 | 27 | 16 | 10 | 6 | 6 | 3 | 0 | -6.2 |
| Gas | 512 | 519 | 575 | 602 | 632 | 660 | 49 | 43 | 1.0 |
| Nuclear | 118 | 173 | 226 | 243 | 261 | 278 | 16 | 18 | 2.0 |
| Hydro | 166 | 166 | 185 | 202 | 221 | 241 | 16 | 16 | 1.6 |
| Bioenergy | 0 | 3 | 8 | 12 | 22 | 39 | 0 | 3 | 11.7 |
| Wind | - | 0 | 3 | 7 | 11 | 15 | 0 | 1 | 39.7 |
| Geothermal | 0 | 1 | 4 | 7 | 11 | 16 | 0 | 1 | 15.3 |
| Solar PV | - | - | 0 | 1 | 1 | 1 | - | 0 | n.a. |
| CSP | - | - | - | - | - | - | - | - | n.a. |
| Marine | - | - | - | - | - | - | - | - | n.a. |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **238** | **260** | **274** | **290** | **315** | **100** | **100** | **1.2** |
| Coal | 52 | 47 | 47 | 45 | 47 | 22 | 15 | -0.4 |
| Oil | 6 | 5 | 3 | 2 | 1 | 2 | 0 | -5.5 |
| Gas | 106 | 120 | 127 | 136 | 146 | 45 | 46 | 1.3 |
| Nuclear | 25 | 32 | 34 | 36 | 38 | 11 | 12 | 1.7 |
| Hydro | 48 | 52 | 56 | 61 | 66 | 20 | 21 | 1.4 |
| Bioenergy | 1 | 2 | 3 | 4 | 7 | 1 | 2 | 6.9 |
| Wind | 0 | 1 | 3 | 4 | 6 | 0 | 2 | 28.2 |
| Geothermal | 0 | 0 | 1 | 1 | 2 | 0 | 1 | 14.5 |
| Solar PV | - | 0 | 1 | 1 | 1 | - | 0 | n.a. |
| CSP | - | - | - | - | - | - | - | n.a. |
| Marine | - | - | - | - | - | - | - | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **2 179** | **1 635** | **1 708** | **1 734** | **1 757** | **1 797** | **100** | **100** | **0.4** |
| Coal | 687 | 411 | 441 | 455 | 460 | 471 | 25 | 26 | 0.6 |
| Oil | 625 | 350 | 370 | 369 | 366 | 365 | 21 | 20 | 0.2 |
| Gas | 866 | 873 | 897 | 910 | 931 | 961 | 53 | 53 | 0.4 |
| **Power generation** | **1 162** | **923** | **923** | **929** | **934** | **958** | **100** | **100** | **0.2** |
| Coal | 432 | 313 | 333 | 351 | 363 | 381 | 34 | 40 | 0.8 |
| Oil | 198 | 54 | 44 | 35 | 29 | 28 | 6 | 3 | -2.7 |
| Gas | 532 | 556 | 547 | 542 | 542 | 549 | 60 | 57 | -0.1 |
| **TFC** | **960** | **651** | **724** | **745** | **763** | **779** | **100** | **100** | **0.8** |
| Coal | 253 | 91 | 102 | 98 | 91 | 84 | 14 | 11 | -0.3 |
| Oil | 389 | 263 | 293 | 301 | 305 | 307 | 40 | 39 | 0.6 |
| *Transport* | *217* | *174* | *207* | *217* | *223* | *226* | *27* | *29* | *1.1* |
| Gas | 318 | 297 | 330 | 347 | 367 | 388 | 46 | 50 | 1.1 |

## **Russia:** Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **1 252** | **1 513** | **1 666** | **1 168** | **1 237** | **1 299** | **100** | **100** | **1.9** | **0.9** |
| Coal | 204 | 254 | 274 | 166 | 111 | 119 | 16 | 9 | 2.2 | -1.3 |
| Oil | 16 | 6 | 6 | 16 | 6 | 6 | 0 | 0 | -6.3 | -6.2 |
| Gas | 608 | 748 | 842 | 506 | 364 | 266 | 51 | 20 | 2.0 | -2.8 |
| Nuclear | 226 | 257 | 267 | 261 | 339 | 373 | 16 | 29 | 1.8 | 3.3 |
| Hydro | 185 | 215 | 231 | 201 | 276 | 289 | 14 | 22 | 1.4 | 2.3 |
| Bioenergy | 8 | 17 | 24 | 9 | 71 | 126 | 1 | 10 | 9.5 | 17.2 |
| Wind | 3 | 9 | 12 | 4 | 51 | 91 | 1 | 7 | 38.4 | 50.5 |
| Geothermal | 3 | 7 | 9 | 5 | 17 | 27 | 1 | 2 | 12.7 | 17.9 |
| Solar PV | 0 | 0 | 0 | 1 | 2 | 3 | 0 | 0 | n.a. | n.a. |
| CSP | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Marine | - | - | - | - | - | 0 | - | 0 | n.a. | n.a. |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **266** | **301** | **325** | **255** | **281** | **314** | **100** | **100** | **1.3** | **1.2** |
| Coal | 49 | 49 | 49 | 43 | 31 | 27 | 15 | 8 | -0.2 | -2.7 |
| Oil | 5 | 2 | 1 | 5 | 2 | 1 | 0 | 0 | -5.9 | -5.6 |
| Gas | 124 | 147 | 163 | 108 | 89 | 92 | 50 | 29 | 1.8 | -0.6 |
| Nuclear | 32 | 35 | 36 | 37 | 47 | 51 | 11 | 16 | 1.5 | 3.0 |
| Hydro | 52 | 60 | 64 | 56 | 75 | 79 | 20 | 25 | 1.2 | 2.1 |
| Bioenergy | 2 | 3 | 5 | 2 | 12 | 21 | 1 | 7 | 5.1 | 11.9 |
| Wind | 1 | 4 | 5 | 2 | 21 | 37 | 2 | 12 | 27.6 | 38.4 |
| Geothermal | 0 | 1 | 1 | 1 | 2 | 4 | 0 | 1 | 12.0 | 17.1 |
| Solar PV | 0 | 1 | 1 | 1 | 2 | 3 | 0 | 1 | n.a. | n.a. |
| CSP | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Marine | - | - | - | - | - | 0 | - | 0 | n.a. | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **1 754** | **1 884** | **1 970** | **1 600** | **1 266** | **1 137** | **100** | **100** | **0.8** | **-1.5** |
| Coal | 463 | 510 | 524 | 401 | 245 | 203 | 27 | 18 | 1.0 | -2.9 |
| Oil | 374 | 381 | 389 | 360 | 324 | 303 | 20 | 27 | 0.4 | -0.6 |
| Gas | 917 | 994 | 1 056 | 839 | 697 | 631 | 54 | 56 | 0.8 | -1.3 |
| **Power generation** | **952** | **1 016** | **1 069** | **855** | **602** | **524** | **100** | **100** | **0.6** | **-2.3** |
| Coal | 351 | 406 | 427 | 297 | 170 | 143 | 40 | 27 | 1.3 | -3.2 |
| Oil | 44 | 29 | 28 | 43 | 28 | 27 | 3 | 5 | -2.6 | -2.8 |
| Gas | 557 | 580 | 613 | 514 | 404 | 354 | 57 | 68 | 0.4 | -1.9 |
| **TFC** | **741** | **806** | **837** | **687** | **616** | **570** | **100** | **100** | **1.1** | **-0.6** |
| Coal | 105 | 97 | 91 | 98 | 71 | 56 | 11 | 10 | -0.0 | -2.0 |
| Oil | 296 | 319 | 329 | 285 | 269 | 253 | 39 | 44 | 0.9 | -0.2 |
| *Transport* | *208* | *230* | *240* | *202* | *197* | *187* | *29* | *33* | *1.3* | *0.3* |
| Gas | 340 | 390 | 417 | 305 | 276 | 261 | 50 | 46 | 1.4 | -0.5 |

## **Non-OECD Asia:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **1 578** | **4 324** | **5 548** | **6 107** | **6 584** | **7 045** | **100** | **100** | **2.1** |
| Coal | 694 | 2 349 | 2 782 | 2 947 | 3 082 | 3 193 | 54 | 45 | 1.3 |
| Oil | 318 | 899 | 1 182 | 1 305 | 1 416 | 1 518 | 21 | 22 | 2.2 |
| Gas | 69 | 337 | 552 | 674 | 784 | 899 | 8 | 13 | 4.2 |
| Nuclear | 10 | 44 | 176 | 250 | 291 | 330 | 1 | 5 | 8.8 |
| Hydro | 24 | 84 | 141 | 160 | 177 | 192 | 2 | 3 | 3.5 |
| Bioenergy | 457 | 563 | 593 | 608 | 625 | 651 | 13 | 9 | 0.6 |
| Other renewables | 7 | 48 | 122 | 163 | 208 | 262 | 1 | 4 | 7.3 |
| **Power generation** | **328** | **1 667** | **2 264** | **2 611** | **2 924** | **3 250** | **100** | **100** | **2.8** |
| Coal | 226 | 1 299 | 1 556 | 1 709 | 1 857 | 1 994 | 78 | 61 | 1.8 |
| Oil | 45 | 43 | 29 | 24 | 20 | 17 | 3 | 1 | -3.8 |
| Gas | 16 | 131 | 190 | 235 | 277 | 331 | 8 | 10 | 4.0 |
| Nuclear | 10 | 44 | 176 | 250 | 291 | 330 | 3 | 10 | 8.8 |
| Hydro | 24 | 84 | 141 | 160 | 177 | 192 | 5 | 6 | 3.5 |
| Bioenergy | 0 | 34 | 79 | 107 | 136 | 171 | 2 | 5 | 7.0 |
| Other renewables | 7 | 33 | 92 | 126 | 166 | 214 | 2 | 7 | 8.1 |
| **Other energy sector** | **166** | **588** | **681** | **700** | **713** | **721** | **100** | **100** | **0.9** |
| *Electricity* | *26* | *110* | *150* | *175* | *200* | *224* | *19* | *31* | *3.0* |
| **TFC** | **1 209** | **2 745** | **3 611** | **3 979** | **4 285** | **4 567** | **100** | **100** | **2.1** |
| Coal | 395 | 702 | 848 | 864 | 857 | 840 | 26 | 18 | 0.8 |
| Oil | 240 | 793 | 1 081 | 1 215 | 1 337 | 1 450 | 29 | 32 | 2.5 |
| Gas | 31 | 161 | 304 | 379 | 444 | 502 | 6 | 11 | 4.9 |
| Electricity | 83 | 490 | 763 | 908 | 1 040 | 1 173 | 18 | 26 | 3.7 |
| Heat | 14 | 66 | 82 | 86 | 86 | 85 | 2 | 2 | 1.1 |
| Bioenergy | 445 | 518 | 503 | 490 | 478 | 469 | 19 | 10 | -0.4 |
| Other renewables | 0 | 15 | 30 | 36 | 42 | 48 | 1 | 1 | 4.9 |
| **Industry** | **402** | **1 139** | **1 520** | **1 648** | **1 729** | **1 796** | **100** | **100** | **1.9** |
| Coal | 239 | 569 | 679 | 685 | 672 | 655 | 50 | 36 | 0.6 |
| Oil | 53 | 112 | 132 | 136 | 136 | 134 | 10 | 7 | 0.8 |
| Gas | 8 | 62 | 132 | 169 | 201 | 229 | 5 | 13 | 5.6 |
| Electricity | 51 | 297 | 458 | 532 | 593 | 652 | 26 | 36 | 3.3 |
| Heat | 11 | 45 | 59 | 63 | 63 | 61 | 4 | 3 | 1.3 |
| Bioenergy | 39 | 53 | 60 | 63 | 64 | 65 | 5 | 4 | 0.8 |
| Other renewables | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3.2 |
| **Transport** | **111** | **405** | **627** | **743** | **858** | **974** | **100** | **100** | **3.7** |
| Oil | 97 | 376 | 566 | 666 | 762 | 856 | 93 | 88 | 3.5 |
| Electricity | 1 | 6 | 11 | 15 | 18 | 22 | 1 | 2 | 5.9 |
| Biofuels | - | 3 | 13 | 19 | 27 | 37 | 1 | 4 | 11.7 |
| Other fuels | 12 | 21 | 38 | 43 | 50 | 59 | 5 | 6 | 4.4 |
| **Buildings** | **580** | **880** | **1 002** | **1 063** | **1 122** | **1 176** | **100** | **100** | **1.2** |
| Coal | 111 | 84 | 83 | 79 | 74 | 66 | 9 | 6 | -1.0 |
| Oil | 33 | 99 | 106 | 104 | 102 | 99 | 11 | 8 | -0.0 |
| Gas | 5 | 39 | 75 | 97 | 116 | 131 | 4 | 11 | 5.2 |
| Electricity | 22 | 161 | 258 | 320 | 384 | 448 | 18 | 38 | 4.4 |
| Heat | 3 | 21 | 23 | 24 | 24 | 24 | 2 | 2 | 0.5 |
| Bioenergy | 406 | 462 | 428 | 404 | 382 | 361 | 53 | 31 | -1.0 |
| Other renewables | 0 | 15 | 29 | 35 | 41 | 46 | 2 | 4 | 4.9 |
| **Other** | **117** | **322** | **462** | **525** | **576** | **621** | **100** | **100** | **2.8** |

## **Non-OECD Asia:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **5 773** | **7 130** | **7 728** | **5 208** | **5 595** | **5 865** | **100** | **100** | **2.4** | **1.3** |
| Coal | 3 013 | 3 638 | 3 901 | 2 466 | 1 967 | 1 804 | 50 | 31 | 2.1 | -1.1 |
| Oil | 1 211 | 1 515 | 1 654 | 1 127 | 1 198 | 1 189 | 21 | 20 | 2.6 | 1.2 |
| Gas | 556 | 789 | 906 | 547 | 766 | 863 | 12 | 15 | 4.2 | 4.0 |
| Nuclear | 165 | 265 | 294 | 190 | 444 | 570 | 4 | 10 | 8.3 | 11.3 |
| Hydro | 131 | 158 | 170 | 146 | 204 | 220 | 2 | 4 | 3.0 | 4.1 |
| Bioenergy | 589 | 601 | 610 | 598 | 699 | 769 | 8 | 13 | 0.3 | 1.3 |
| Other renewables | 108 | 164 | 192 | 134 | 317 | 450 | 2 | 8 | 5.9 | 9.7 |
| **Power generation** | **2 418** | **3 280** | **3 683** | **2 031** | **2 267** | **2 529** | **100** | **100** | **3.4** | **1.8** |
| Coal | 1 747 | 2 325 | 2 591 | 1 289 | 853 | 733 | 70 | 29 | 2.9 | -2.4 |
| Oil | 29 | 20 | 16 | 28 | 14 | 11 | 0 | 0 | -3.9 | -5.7 |
| Gas | 189 | 269 | 323 | 194 | 299 | 358 | 9 | 14 | 3.9 | 4.3 |
| Nuclear | 165 | 265 | 294 | 190 | 444 | 570 | 8 | 23 | 8.3 | 11.3 |
| Hydro | 131 | 158 | 170 | 146 | 204 | 220 | 5 | 9 | 3.0 | 4.1 |
| Bioenergy | 77 | 116 | 136 | 84 | 190 | 257 | 4 | 10 | 6.0 | 8.8 |
| Other renewables | 80 | 127 | 152 | 101 | 262 | 381 | 4 | 15 | 6.5 | 10.7 |
| **Other energy sector** | **700** | **760** | **782** | **658** | **634** | **621** | **100** | **100** | **1.2** | **0.2** |
| *Electricity* | *157* | *219* | *248* | *140* | *164* | *178* | *32* | *29* | *3.5* | *2.0* |
| **TFC** | **3 708** | **4 544** | **4 901** | **3 458** | **3 836** | **3 963** | **100** | **100** | **2.4** | **1.5** |
| Coal | 876 | 918 | 916 | 809 | 776 | 751 | 19 | 19 | 1.1 | 0.3 |
| Oil | 1 111 | 1 438 | 1 590 | 1 030 | 1 134 | 1 139 | 32 | 29 | 2.9 | 1.5 |
| Gas | 308 | 454 | 514 | 296 | 406 | 442 | 10 | 11 | 5.0 | 4.3 |
| Electricity | 799 | 1 130 | 1 284 | 709 | 891 | 990 | 26 | 25 | 4.1 | 3.0 |
| Heat | 85 | 93 | 93 | 79 | 76 | 71 | 2 | 2 | 1.4 | 0.3 |
| Bioenergy | 502 | 474 | 463 | 503 | 499 | 502 | 9 | 13 | -0.5 | -0.1 |
| Other renewables | 28 | 37 | 40 | 33 | 55 | 69 | 1 | 2 | 4.1 | 6.5 |
| **Industry** | **1 572** | **1 858** | **1 963** | **1 430** | **1 544** | **1 577** | **100** | **100** | **2.3** | **1.4** |
| Coal | 701 | 719 | 713 | 649 | 612 | 589 | 36 | 37 | 0.9 | 0.1 |
| Oil | 137 | 146 | 146 | 121 | 114 | 107 | 7 | 7 | 1.1 | -0.2 |
| Gas | 136 | 216 | 251 | 128 | 192 | 211 | 13 | 13 | 6.0 | 5.2 |
| Electricity | 476 | 641 | 716 | 420 | 507 | 546 | 36 | 35 | 3.7 | 2.6 |
| Heat | 61 | 69 | 70 | 56 | 53 | 48 | 4 | 3 | 1.8 | 0.3 |
| Bioenergy | 61 | 66 | 68 | 57 | 61 | 63 | 3 | 4 | 1.0 | 0.7 |
| Other renewables | 0 | 0 | 0 | 1 | 6 | 12 | 0 | 1 | 3.2 | 19.7 |
| **Transport** | **639** | **910** | **1 045** | **599** | **720** | **751** | **100** | **100** | **4.0** | **2.6** |
| Oil | 582 | 832 | 956 | 534 | 604 | 598 | 91 | 80 | 4.0 | 2.0 |
| Electricity | 11 | 16 | 19 | 12 | 26 | 44 | 2 | 6 | 5.4 | 9.0 |
| Biofuels | 10 | 19 | 26 | 17 | 47 | 63 | 3 | 8 | 10.1 | 14.2 |
| Other fuels | 36 | 42 | 43 | 36 | 42 | 45 | 4 | 6 | 3.0 | 3.2 |
| **Buildings** | **1 028** | **1 180** | **1 244** | **968** | **1 003** | **1 023** | **100** | **100** | **1.5** | **0.6** |
| Coal | 87 | 82 | 77 | 77 | 57 | 47 | 6 | 5 | -0.3 | -2.3 |
| Oil | 111 | 114 | 113 | 101 | 90 | 87 | 9 | 8 | 0.5 | -0.6 |
| Gas | 76 | 117 | 134 | 71 | 95 | 102 | 11 | 10 | 5.3 | 4.1 |
| Electricity | 276 | 425 | 495 | 241 | 312 | 350 | 40 | 34 | 4.8 | 3.3 |
| Heat | 24 | 24 | 24 | 23 | 23 | 23 | 2 | 2 | 0.5 | 0.4 |
| Bioenergy | 428 | 384 | 363 | 424 | 379 | 360 | 29 | 35 | -1.0 | -1.0 |
| Other renewables | 27 | 35 | 38 | 31 | 47 | 54 | 3 | 5 | 4.1 | 5.6 |
| **Other** | **469** | **595** | **648** | **461** | **568** | **612** | **100** | **100** | **3.0** | **2.7** |

# **Non-OECD Asia:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **1 271** | **6 956** | **10 609** | **12 583** | **14 403** | **16 235** | **100** | **100** | **3.6** |
| Coal | 729 | 4 825 | 6 264 | 7 074 | 7 851 | 8 574 | 69 | 53 | 2.4 |
| Oil | 162 | 150 | 95 | 77 | 65 | 56 | 2 | 0 | -4.0 |
| Gas | 59 | 641 | 1 004 | 1 294 | 1 582 | 1 914 | 9 | 12 | 4.7 |
| Nuclear | 39 | 167 | 675 | 958 | 1 118 | 1 268 | 2 | 8 | 8.8 |
| Hydro | 274 | 972 | 1 645 | 1 860 | 2 059 | 2 229 | 14 | 14 | 3.5 |
| Bioenergy | 1 | 82 | 244 | 343 | 442 | 565 | 1 | 3 | 8.4 |
| Wind | 0 | 96 | 512 | 711 | 904 | 1 094 | 1 | 7 | 10.7 |
| Geothermal | 7 | 19 | 31 | 42 | 56 | 73 | 0 | 0 | 5.7 |
| Solar PV | 0 | 3 | 131 | 210 | 296 | 389 | 0 | 2 | 22.5 |
| CSP | - | 0 | 7 | 13 | 29 | 71 | 0 | 0 | 59.2 |
| Marine | - | 0 | 0 | 0 | 1 | 2 | 0 | 0 | 24.0 |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **1 600** | **2 715** | **3 203** | **3 665** | **4 109** | **100** | **100** | **4.0** |
| Coal | 916 | 1 347 | 1 497 | 1 654 | 1 781 | 57 | 43 | 2.8 |
| Oil | 65 | 62 | 59 | 55 | 51 | 4 | 1 | -1.0 |
| Gas | 167 | 277 | 346 | 419 | 508 | 10 | 12 | 4.8 |
| Nuclear | 23 | 91 | 130 | 151 | 172 | 1 | 4 | 8.7 |
| Hydro | 324 | 514 | 584 | 650 | 706 | 20 | 17 | 3.3 |
| Bioenergy | 18 | 50 | 68 | 84 | 102 | 1 | 2 | 7.4 |
| Wind | 79 | 263 | 348 | 415 | 479 | 5 | 12 | 7.8 |
| Geothermal | 3 | 5 | 6 | 9 | 11 | 0 | 0 | 5.3 |
| Solar PV | 4 | 104 | 161 | 220 | 280 | 0 | 7 | 19.3 |
| CSP | 0 | 2 | 4 | 8 | 18 | 0 | 0 | 35.3 |
| Marine | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 22.4 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **3 556** | **11 457** | **14 202** | **15 366** | **16 362** | **17 261** | **100** | **100** | **1.7** |
| Coal | 2 560 | 8 438 | 10 017 | 10 596 | 11 055 | 11 427 | 74 | 66 | 1.3 |
| Oil | 863 | 2 276 | 2 962 | 3 273 | 3 559 | 3 827 | 20 | 22 | 2.2 |
| Gas | 133 | 744 | 1 223 | 1 498 | 1 747 | 2 007 | 6 | 12 | 4.2 |
| **Power generation** | **1 067** | **5 549** | **6 669** | **7 330** | **7 964** | **8 578** | **100** | **100** | **1.8** |
| Coal | 886 | 5 107 | 6 132 | 6 706 | 7 253 | 7 749 | 92 | 90 | 1.8 |
| Oil | 144 | 136 | 92 | 76 | 63 | 54 | 2 | 1 | -3.8 |
| Gas | 37 | 305 | 444 | 549 | 648 | 775 | 6 | 9 | 4.0 |
| **TFC** | **2 332** | **5 473** | **7 014** | **7 503** | **7 855** | **8 140** | **100** | **100** | **1.7** |
| Coal | 1 614 | 3 136 | 3 668 | 3 671 | 3 585 | 3 466 | 57 | 43 | 0.4 |
| Oil | 660 | 1 993 | 2 690 | 3 012 | 3 305 | 3 581 | 36 | 44 | 2.5 |
| *Transport* | *290* | *1 121* | *1 687* | *1 987* | *2 275* | *2 555* | *20* | *31* | *3.5* |
| Gas | 58 | 344 | 656 | 820 | 964 | 1 093 | 6 | 13 | 4.9 |

## **Non-OECD Asia:** Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **11 106** | **15 663** | **17 802** | **9 857** | **12 256** | **13 569** | **100** | **100** | **4.0** | **2.8** |
| Coal | 7 049 | 9 871 | 11 193 | 5 304 | 3 808 | 3 095 | 63 | 23 | 3.6 | -1.8 |
| Oil | 95 | 62 | 51 | 90 | 43 | 33 | 0 | 0 | -4.4 | -6.2 |
| Gas | 1 005 | 1 521 | 1 835 | 1 037 | 1 748 | 2 117 | 10 | 16 | 4.5 | 5.1 |
| Nuclear | 635 | 1 019 | 1 127 | 728 | 1 705 | 2 187 | 6 | 16 | 8.3 | 11.3 |
| Hydro | 1 523 | 1 834 | 1 974 | 1 701 | 2 372 | 2 561 | 11 | 19 | 3.0 | 4.1 |
| Bioenergy | 235 | 373 | 443 | 260 | 626 | 867 | 2 | 6 | 7.3 | 10.3 |
| Wind | 417 | 728 | 866 | 544 | 1 332 | 1 704 | 5 | 13 | 9.6 | 12.7 |
| Geothermal | 29 | 44 | 53 | 37 | 97 | 138 | 0 | 1 | 4.3 | 8.5 |
| Solar PV | 116 | 205 | 245 | 146 | 438 | 606 | 1 | 4 | 20.1 | 24.7 |
| CSP | 1 | 6 | 12 | 9 | 84 | 257 | 0 | 2 | 47.9 | 68.0 |
| Marine | 0 | 1 | 2 | 0 | 2 | 4 | 0 | 0 | 23.4 | 27.1 |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **2 719** | **3 708** | **4 149** | **2 647** | **3 568** | **4 050** | **100** | **100** | **4.1** | **3.9** |
| Coal | 1 451 | 1 947 | 2 162 | 1 203 | 1 048 | 1 034 | 52 | 26 | 3.6 | 0.5 |
| Oil | 62 | 55 | 50 | 61 | 53 | 48 | 1 | 1 | -1.0 | -1.2 |
| Gas | 281 | 421 | 506 | 297 | 440 | 506 | 12 | 12 | 4.7 | 4.7 |
| Nuclear | 86 | 138 | 153 | 96 | 226 | 290 | 4 | 7 | 8.1 | 11.1 |
| Hydro | 475 | 576 | 622 | 533 | 755 | 819 | 15 | 20 | 2.8 | 3.9 |
| Bioenergy | 49 | 73 | 83 | 53 | 114 | 149 | 2 | 4 | 6.4 | 9.1 |
| Wind | 217 | 334 | 378 | 280 | 575 | 687 | 9 | 17 | 6.7 | 9.4 |
| Geothermal | 5 | 7 | 8 | 6 | 15 | 21 | 0 | 1 | 4.1 | 8.2 |
| Solar PV | 92 | 157 | 184 | 115 | 320 | 428 | 4 | 11 | 17.2 | 21.4 |
| CSP | 0 | 2 | 3 | 3 | 22 | 67 | 0 | 2 | 25.6 | 43.0 |
| Marine | 0 | 0 | 1 | 0 | 1 | 1 | 0 | 0 | 21.7 | 25.5 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **15 181** | **18 793** | **20 396** | **12 771** | **10 284** | **8 999** | **100** | **100** | **2.4** | **-1.0** |
| Coal | 10 904 | 13 195 | 14 155 | 8 759 | 5 750 | 4 379 | 69 | 49 | 2.2 | -2.7 |
| Oil | 3 045 | 3 844 | 4 221 | 2 802 | 2 898 | 2 823 | 21 | 31 | 2.6 | 0.9 |
| Gas | 1 232 | 1 755 | 2 021 | 1 210 | 1 637 | 1 796 | 10 | 20 | 4.3 | 3.7 |
| **Power generation** | **7 420** | **9 808** | **10 944** | **5 612** | **3 355** | **2 428** | **100** | **100** | **2.9** | **-3.4** |
| Coal | 6 885 | 9 116 | 10 135 | 5 072 | 2 642 | 1 629 | 93 | 67 | 2.9 | -4.7 |
| Oil | 92 | 63 | 52 | 87 | 45 | 34 | 0 | 1 | -3.9 | -5.6 |
| Gas | 443 | 629 | 756 | 453 | 668 | 765 | 7 | 32 | 3.9 | 3.9 |
| **TFC** | **7 226** | **8 404** | **8 858** | **6 666** | **6 513** | **6 192** | **100** | **100** | **2.0** | **0.5** |
| Coal | 3 790 | 3 835 | 3 774 | 3 487 | 2 950 | 2 612 | 43 | 42 | 0.8 | -0.8 |
| Oil | 2 772 | 3 585 | 3 967 | 2 542 | 2 708 | 2 662 | 45 | 43 | 2.9 | 1.2 |
| *Transport* | *1 737* | *2 482* | *2 853* | *1 594* | *1 804* | *1 787* | *32* | *29* | *4.0* | *2.0* |
| Gas | 665 | 984 | 1 117 | 636 | 855 | 918 | 13 | 15 | 5.0 | 4.2 |

## **China:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **879** | **2 743** | **3 519** | **3 786** | **3 945** | **4 060** | **100** | **100** | **1.6** |
| Coal | 533 | 1 866 | 2 118 | 2 166 | 2 166 | 2 135 | 68 | 53 | 0.6 |
| Oil | 122 | 446 | 615 | 667 | 702 | 726 | 16 | 18 | 2.0 |
| Gas | 13 | 110 | 257 | 331 | 393 | 442 | 4 | 11 | 6.0 |
| Nuclear | - | 23 | 136 | 195 | 222 | 248 | 1 | 6 | 10.5 |
| Hydro | 11 | 60 | 105 | 113 | 118 | 122 | 2 | 3 | 3.0 |
| Bioenergy | 200 | 216 | 213 | 216 | 222 | 237 | 8 | 6 | 0.4 |
| Other renewables | 0 | 21 | 74 | 98 | 122 | 150 | 1 | 4 | 8.5 |
| **Power generation** | **181** | **1 127** | **1 533** | **1 735** | **1 874** | **1 997** | **100** | **100** | **2.4** |
| Coal | 153 | 994 | 1 137 | 1 213 | 1 262 | 1 287 | 88 | 64 | 1.1 |
| Oil | 16 | 5 | 5 | 5 | 5 | 4 | 0 | 0 | -1.0 |
| Gas | 1 | 23 | 59 | 84 | 108 | 131 | 2 | 7 | 7.5 |
| Nuclear | - | 23 | 136 | 195 | 222 | 248 | 2 | 12 | 10.5 |
| Hydro | 11 | 60 | 105 | 113 | 118 | 122 | 5 | 6 | 3.0 |
| Bioenergy | - | 16 | 45 | 61 | 76 | 95 | 1 | 5 | 7.8 |
| Other renewables | 0 | 6 | 46 | 65 | 84 | 109 | 1 | 5 | 12.5 |
| **Other energy sector** | **100** | **457** | **517** | **514** | **506** | **493** | **100** | **100** | **0.3** |
| *Electricity* | *15* | *73* | *95* | *106* | *115* | *122* | *16* | *25* | *2.2* |
| **TFC** | **669** | **1 643** | **2 188** | **2 359** | **2 462** | **2 526** | **100** | **100** | **1.8** |
| Coal | 318 | 553 | 640 | 626 | 592 | 550 | 34 | 22 | -0.0 |
| Oil | 87 | 403 | 568 | 624 | 665 | 697 | 25 | 28 | 2.3 |
| Gas | 9 | 71 | 172 | 218 | 252 | 274 | 4 | 11 | 5.8 |
| Electricity | 41 | 336 | 531 | 619 | 683 | 738 | 20 | 29 | 3.3 |
| Heat | 13 | 65 | 81 | 85 | 85 | 84 | 4 | 3 | 1.0 |
| Bioenergy | 200 | 201 | 168 | 155 | 146 | 142 | 12 | 6 | -1.4 |
| Other renewables | 0 | 15 | 28 | 33 | 38 | 41 | 1 | 2 | 4.4 |
| **Industry** | **245** | **785** | **1 033** | **1 087** | **1 095** | **1 084** | **100** | **100** | **1.4** |
| Coal | 181 | 434 | 485 | 461 | 423 | 381 | 55 | 35 | -0.5 |
| Oil | 21 | 56 | 62 | 61 | 56 | 52 | 7 | 5 | -0.3 |
| Gas | 2 | 22 | 71 | 95 | 109 | 117 | 3 | 11 | 7.2 |
| Electricity | 30 | 229 | 355 | 408 | 443 | 472 | 29 | 44 | 3.1 |
| Heat | 11 | 45 | 59 | 62 | 62 | 61 | 6 | 6 | 1.3 |
| Bioenergy | - | - | - | - | - | - | - | - | n.a. |
| Other renewables | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3.2 |
| **Transport** | **35** | **213** | **360** | **412** | **458** | **499** | **100** | **100** | **3.6** |
| Oil | 25 | 195 | 321 | 367 | 403 | 433 | 92 | 87 | 3.4 |
| Electricity | 1 | 4 | 9 | 12 | 15 | 18 | 2 | 4 | 6.5 |
| Biofuels | - | 1 | 5 | 8 | 13 | 18 | 1 | 4 | 12.1 |
| Other fuels | 10 | 13 | 25 | 25 | 27 | 29 | 6 | 6 | 3.4 |
| **Buildings** | **314** | **476** | **541** | **568** | **587** | **599** | **100** | **100** | **1.0** |
| Coal | 96 | 70 | 69 | 65 | 60 | 52 | 15 | 9 | -1.2 |
| Oil | 7 | 54 | 53 | 48 | 42 | 36 | 11 | 6 | -1.7 |
| Gas | 2 | 28 | 57 | 76 | 90 | 101 | 6 | 17 | 5.5 |
| Electricity | 6 | 90 | 150 | 181 | 207 | 228 | 19 | 38 | 4.0 |
| Heat | 2 | 20 | 22 | 23 | 23 | 23 | 4 | 4 | 0.5 |
| Bioenergy | 200 | 199 | 161 | 143 | 129 | 119 | 42 | 20 | -2.1 |
| Other renewables | 0 | 14 | 27 | 32 | 37 | 40 | 3 | 7 | 4.5 |
| **Other** | **75** | **169** | **254** | **292** | **321** | **345** | **100** | **100** | **3.0** |

## **China:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **3 690** | **4 360** | **4 574** | **3 276** | **3 292** | **3 324** | **100** | **100** | **2.2** | **0.8** |
| Coal | 2 302 | 2 579 | 2 645 | 1 882 | 1 423 | 1 246 | 58 | 37 | 1.5 | -1.7 |
| Oil | 634 | 775 | 824 | 580 | 558 | 520 | 18 | 16 | 2.6 | 0.6 |
| Gas | 255 | 383 | 436 | 261 | 402 | 442 | 10 | 13 | 5.9 | 6.0 |
| Nuclear | 126 | 204 | 225 | 148 | 336 | 426 | 5 | 13 | 10.1 | 13.0 |
| Hydro | 97 | 110 | 116 | 106 | 121 | 125 | 3 | 4 | 2.8 | 3.1 |
| Bioenergy | 211 | 210 | 215 | 219 | 276 | 316 | 5 | 10 | -0.0 | 1.6 |
| Other renewables | 65 | 99 | 114 | 80 | 176 | 249 | 2 | 7 | 7.3 | 10.8 |
| **Power generation** | **1 654** | **2 152** | **2 330** | **1 357** | **1 441** | **1 551** | **100** | **100** | **3.1** | **1.3** |
| Coal | 1 286 | 1 605 | 1 710 | 935 | 605 | 497 | 73 | 32 | 2.3 | -2.9 |
| Oil | 6 | 5 | 5 | 5 | 4 | 3 | 0 | 0 | -0.4 | -2.2 |
| Gas | 57 | 92 | 114 | 65 | 137 | 167 | 5 | 11 | 6.9 | 8.6 |
| Nuclear | 126 | 204 | 225 | 148 | 336 | 426 | 10 | 27 | 10.1 | 13.0 |
| Hydro | 97 | 110 | 116 | 106 | 121 | 125 | 5 | 8 | 2.8 | 3.1 |
| Bioenergy | 45 | 69 | 81 | 48 | 111 | 145 | 3 | 9 | 7.1 | 9.7 |
| Other renewables | 38 | 66 | 80 | 50 | 127 | 189 | 3 | 12 | 11.1 | 15.1 |
| **Other energy sector** | **533** | **541** | **538** | **499** | **448** | **421** | **100** | **100** | **0.7** | **-0.3** |
| *Electricity* | *101* | *129* | *139* | *88* | *94* | *95* | *26* | *23* | *2.7* | *1.1* |
| **TFC** | **2 261** | **2 663** | **2 788** | **2 089** | **2 161** | **2 142** | **100** | **100** | **2.2** | **1.1** |
| Coal | 663 | 639 | 608 | 614 | 535 | 488 | 22 | 23 | 0.4 | -0.5 |
| Oil | 588 | 739 | 797 | 535 | 526 | 497 | 29 | 23 | 2.9 | 0.9 |
| Gas | 172 | 258 | 285 | 170 | 233 | 240 | 10 | 11 | 5.9 | 5.2 |
| Electricity | 561 | 762 | 838 | 491 | 579 | 617 | 30 | 29 | 3.9 | 2.6 |
| Heat | 84 | 92 | 92 | 78 | 74 | 70 | 3 | 3 | 1.4 | 0.3 |
| Bioenergy | 167 | 140 | 134 | 171 | 165 | 171 | 5 | 8 | -1.7 | -0.7 |
| Other renewables | 26 | 33 | 35 | 31 | 49 | 60 | 1 | 3 | 3.6 | 6.0 |
| **Industry** | **1 071** | **1 192** | **1 211** | **975** | **975** | **946** | **100** | **100** | **1.8** | **0.8** |
| Coal | 503 | 457 | 422 | 467 | 384 | 340 | 35 | 36 | -0.1 | -1.0 |
| Oil | 65 | 63 | 60 | 56 | 44 | 35 | 5 | 4 | 0.3 | -1.9 |
| Gas | 72 | 118 | 132 | 71 | 111 | 114 | 11 | 12 | 7.7 | 7.1 |
| Electricity | 370 | 484 | 528 | 324 | 378 | 395 | 44 | 42 | 3.5 | 2.3 |
| Heat | 61 | 69 | 69 | 55 | 52 | 48 | 6 | 5 | 1.8 | 0.3 |
| Bioenergy | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Other renewables | 0 | 0 | 0 | 1 | 6 | 12 | 0 | 1 | 3.2 | 19.7 |
| **Transport** | **369** | **501** | **558** | **341** | **369** | **367** | **100** | **100** | **4.1** | **2.3** |
| Oil | 332 | 456 | 507 | 299 | 293 | 268 | 91 | 73 | 4.1 | 1.3 |
| Electricity | 9 | 14 | 16 | 10 | 22 | 33 | 3 | 9 | 6.0 | 9.1 |
| Biofuels | 4 | 9 | 12 | 8 | 29 | 42 | 2 | 11 | 10.1 | 16.0 |
| Other fuels | 24 | 23 | 22 | 24 | 25 | 24 | 4 | 7 | 2.3 | 2.6 |
| **Buildings** | **563** | **634** | **653** | **520** | **507** | **499** | **100** | **100** | **1.3** | **0.2** |
| Coal | 73 | 66 | 61 | 64 | 45 | 36 | 9 | 7 | -0.6 | -2.8 |
| Oil | 57 | 50 | 44 | 49 | 35 | 30 | 7 | 6 | -0.8 | -2.5 |
| Gas | 58 | 90 | 102 | 55 | 72 | 75 | 16 | 15 | 5.5 | 4.2 |
| Electricity | 165 | 245 | 273 | 140 | 161 | 170 | 42 | 34 | 4.7 | 2.7 |
| Heat | 23 | 23 | 22 | 22 | 22 | 22 | 3 | 4 | 0.4 | 0.3 |
| Bioenergy | 161 | 128 | 117 | 160 | 129 | 121 | 18 | 24 | -2.2 | -2.1 |
| Other renewables | 25 | 32 | 34 | 29 | 42 | 46 | 5 | 9 | 3.7 | 5.1 |
| **Other** | **258** | **335** | **366** | **253** | **310** | **330** | **100** | **100** | **3.3** | **2.8** |

## **China:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **650** | **4 755** | **7 285** | **8 438** | **9 287** | **10 004** | **100** | **100** | **3.1** |
| Coal | 471 | 3 751 | 4 570 | 5 011 | 5 316 | 5 506 | 79 | 55 | 1.6 |
| Oil | 49 | 8 | 7 | 6 | 5 | 5 | 0 | 0 | -1.9 |
| Gas | 3 | 95 | 297 | 442 | 599 | 737 | 2 | 7 | 8.9 |
| Nuclear | - | 86 | 523 | 748 | 852 | 953 | 2 | 10 | 10.5 |
| Hydro | 127 | 699 | 1 221 | 1 309 | 1 368 | 1 416 | 15 | 14 | 3.0 |
| Bioenergy | - | 42 | 152 | 212 | 263 | 326 | 1 | 3 | 8.9 |
| Wind | 0 | 70 | 411 | 556 | 681 | 787 | 1 | 8 | 10.6 |
| Geothermal | - | 0 | 1 | 3 | 7 | 13 | 0 | 0 | 20.4 |
| Solar PV | 0 | 3 | 99 | 142 | 174 | 204 | 0 | 2 | 20.1 |
| CSP | - | 0 | 4 | 9 | 21 | 56 | 0 | 1 | 57.7 |
| Marine | - | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 21.9 |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **1 105** | **1 851** | **2 139** | **2 336** | **2 491** | **100** | **100** | **3.4** |
| Coal | 738 | 987 | 1 082 | 1 144 | 1 172 | 67 | 47 | 1.9 |
| Oil | 11 | 11 | 10 | 10 | 9 | 1 | 0 | -0.8 |
| Gas | 39 | 91 | 121 | 149 | 181 | 4 | 7 | 6.6 |
| Nuclear | 13 | 70 | 101 | 115 | 128 | 1 | 5 | 10.2 |
| Hydro | 230 | 370 | 397 | 416 | 431 | 21 | 17 | 2.7 |
| Bioenergy | 7 | 30 | 41 | 50 | 59 | 1 | 2 | 9.3 |
| Wind | 63 | 210 | 271 | 309 | 337 | 6 | 14 | 7.3 |
| Geothermal | 0 | 0 | 0 | 1 | 2 | 0 | 0 | 19.3 |
| Solar PV | 3 | 80 | 114 | 138 | 157 | 0 | 6 | 17.2 |
| CSP | 0 | 1 | 2 | 5 | 13 | 0 | 1 | 44.3 |
| Marine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20.3 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **2 278** | **7 979** | **9 617** | **10 056** | **10 239** | **10 238** | **100** | **100** | **1.0** |
| Coal | 1 943 | 6 624 | 7 502 | 7 651 | 7 612 | 7 443 | 83 | 73 | 0.5 |
| Oil | 308 | 1 112 | 1 540 | 1 661 | 1 741 | 1 796 | 14 | 18 | 2.0 |
| Gas | 27 | 244 | 574 | 744 | 885 | 999 | 3 | 10 | 6.1 |
| **Power generation** | **651** | **3 991** | **4 651** | **4 984** | **5 197** | **5 312** | **100** | **100** | **1.2** |
| Coal | 597 | 3 919 | 4 495 | 4 772 | 4 930 | 4 991 | 98 | 94 | 1.0 |
| Oil | 52 | 18 | 18 | 16 | 15 | 14 | 0 | 0 | -1.0 |
| Gas | 2 | 54 | 139 | 196 | 252 | 308 | 1 | 6 | 7.5 |
| **TFC** | **1 541** | **3 704** | **4 627** | **4 725** | **4 692** | **4 577** | **100** | **100** | **0.9** |
| Coal | 1 295 | 2 521 | 2 803 | 2 675 | 2 481 | 2 256 | 68 | 49 | -0.5 |
| Oil | 229 | 1 025 | 1 441 | 1 563 | 1 647 | 1 707 | 28 | 37 | 2.2 |
| *Transport* | *73* | *582* | *959* | *1 095* | *1 203* | *1 292* | *16* | *28* | *3.4* |
| Gas | 17 | 158 | 383 | 487 | 564 | 613 | 4 | 13 | 5.8 |

## **China:** Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **7 696** | **10 370** | **11 373** | **6 741** | **7 832** | **8 279** | **100** | **100** | **3.7** | **2.3** |
| Coal | 5 212 | 6 833 | 7 404 | 3 881 | 2 636 | 1 937 | 65 | 23 | 2.9 | -2.7 |
| Oil | 7 | 6 | 6 | 7 | 5 | 5 | 0 | 0 | -1.3 | -2.3 |
| Gas | 283 | 495 | 615 | 342 | 807 | 985 | 5 | 12 | 8.1 | 10.2 |
| Nuclear | 482 | 784 | 864 | 567 | 1 290 | 1 633 | 8 | 20 | 10.1 | 13.0 |
| Hydro | 1 126 | 1 278 | 1 348 | 1 228 | 1 405 | 1 459 | 12 | 18 | 2.8 | 3.1 |
| Bioenergy | 151 | 241 | 282 | 163 | 379 | 499 | 2 | 6 | 8.2 | 10.8 |
| Wind | 347 | 587 | 677 | 439 | 979 | 1 212 | 6 | 15 | 9.9 | 12.6 |
| Geothermal | 1 | 4 | 6 | 2 | 9 | 17 | 0 | 0 | 16.7 | 21.6 |
| Solar PV | 86 | 136 | 160 | 106 | 259 | 341 | 1 | 4 | 18.9 | 22.7 |
| CSP | 1 | 5 | 10 | 7 | 62 | 190 | 0 | 2 | 47.0 | 65.9 |
| Marine | 0 | 0 | 1 | 0 | 1 | 2 | 0 | 0 | 21.7 | 23.9 |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **1 879** | **2 460** | **2 664** | **1 813** | **2 222** | **2 414** | **100** | **100** | **3.7** | **3.3** |
| Coal | 1 087 | 1 379 | 1 476 | 907 | 732 | 667 | 55 | 28 | 2.9 | -0.4 |
| Oil | 11 | 10 | 10 | 11 | 9 | 9 | 0 | 0 | -0.7 | -0.9 |
| Gas | 95 | 153 | 180 | 104 | 186 | 220 | 7 | 9 | 6.6 | 7.5 |
| Nuclear | 65 | 105 | 116 | 74 | 168 | 212 | 4 | 9 | 9.7 | 12.5 |
| Hydro | 341 | 388 | 410 | 373 | 428 | 445 | 15 | 18 | 2.4 | 2.8 |
| Bioenergy | 30 | 46 | 52 | 32 | 68 | 86 | 2 | 4 | 8.7 | 11.0 |
| Wind | 180 | 267 | 291 | 225 | 414 | 474 | 11 | 20 | 6.6 | 8.8 |
| Geothermal | 0 | 1 | 1 | 0 | 1 | 2 | 0 | 0 | 15.8 | 20.4 |
| Solar PV | 70 | 109 | 126 | 85 | 198 | 253 | 5 | 10 | 16.1 | 19.5 |
| CSP | 0 | 1 | 2 | 2 | 15 | 44 | 0 | 2 | 34.6 | 51.7 |
| Marine | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 20.1 | 22.4 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **10 373** | **12 016** | **12 473** | **8 581** | **6 100** | **4 720** | **100** | **100** | **1.9** | **-2.2** |
| Coal | 8 209 | 9 209 | 9 417 | 6 560 | 3 916 | 2 620 | 75 | 56 | 1.5 | -3.8 |
| Oil | 1 596 | 1 948 | 2 075 | 1 438 | 1 327 | 1 201 | 17 | 25 | 2.6 | 0.3 |
| Gas | 568 | 859 | 981 | 583 | 857 | 899 | 8 | 19 | 6.0 | 5.6 |
| **Power generation** | **5 238** | **6 537** | **6 982** | **3 863** | **2 052** | **1 184** | **100** | **100** | **2.4** | **-4.9** |
| Coal | 5 086 | 6 306 | 6 699 | 3 693 | 1 747 | 847 | 96 | 71 | 2.3 | -6.2 |
| Oil | 19 | 17 | 16 | 17 | 13 | 10 | 0 | 1 | -0.4 | -2.2 |
| Gas | 133 | 215 | 266 | 153 | 292 | 327 | 4 | 28 | 6.9 | 7.8 |
| **TFC** | **4 784** | **5 100** | **5 105** | **4 401** | **3 782** | **3 295** | **100** | **100** | **1.3** | **-0.5** |
| Coal | 2 905 | 2 674 | 2 488 | 2 679 | 2 023 | 1 646 | 49 | 50 | -0.1 | -1.8 |
| Oil | 1 495 | 1 850 | 1 981 | 1 343 | 1 253 | 1 139 | 39 | 35 | 2.8 | 0.4 |
| *Transport* | *992* | *1 359* | *1 512* | *893* | *876* | *802* | *30* | *24* | *4.1* | *1.3* |
| Gas | 383 | 576 | 637 | 378 | 507 | 510 | 12 | 15 | 6.0 | 5.0 |

## *India:* New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **317** | **750** | **971** | **1 146** | **1 336** | **1 539** | **100** | **100** | **3.0** |
| Coal | 103 | 326 | 425 | 499 | 588 | 681 | 43 | 44 | 3.1 |
| Oil | 61 | 167 | 224 | 273 | 325 | 380 | 22 | 25 | 3.5 |
| Gas | 11 | 50 | 72 | 94 | 116 | 143 | 7 | 9 | 4.4 |
| Nuclear | 2 | 9 | 21 | 32 | 43 | 53 | 1 | 3 | 7.9 |
| Hydro | 6 | 11 | 15 | 20 | 26 | 32 | 1 | 2 | 4.4 |
| Bioenergy | 133 | 185 | 202 | 208 | 210 | 213 | 25 | 14 | 0.6 |
| Other renewables | 0 | 2 | 12 | 19 | 28 | 38 | 0 | 2 | 12.2 |
| **Power generation** | **70** | **277** | **374** | **458** | **564** | **681** | **100** | **100** | **3.8** |
| Coal | 56 | 216 | 272 | 317 | 382 | 452 | 78 | 66 | 3.1 |
| Oil | 4 | 6 | 5 | 4 | 3 | 2 | 2 | 0 | -4.6 |
| Gas | 3 | 20 | 28 | 41 | 52 | 67 | 7 | 10 | 5.2 |
| Nuclear | 2 | 9 | 21 | 32 | 43 | 53 | 3 | 8 | 7.9 |
| Hydro | 6 | 11 | 15 | 20 | 26 | 32 | 4 | 5 | 4.4 |
| Bioenergy | - | 13 | 21 | 27 | 32 | 40 | 5 | 6 | 4.9 |
| Other renewables | 0 | 2 | 11 | 17 | 25 | 35 | 1 | 5 | 12.5 |
| **Other energy sector** | **20** | **73** | **95** | **112** | **129** | **147** | **100** | **100** | **3.0** |
| *Electricity* | *7* | *24* | *38* | *48* | *60* | *74* | *34* | *50* | *4.7* |
| **TFC** | **252** | **491** | **646** | **760** | **878** | **1 001** | **100** | **100** | **3.0** |
| Coal | 42 | 86 | 124 | 147 | 167 | 186 | 17 | 19 | 3.3 |
| Oil | 53 | 139 | 196 | 246 | 299 | 355 | 28 | 35 | 4.0 |
| Gas | 6 | 27 | 38 | 47 | 57 | 66 | 5 | 7 | 3.8 |
| Electricity | 18 | 67 | 106 | 137 | 175 | 217 | 14 | 22 | 5.0 |
| Heat | - | - | - | - | - | - | - | - | n.a. |
| Bioenergy | 133 | 172 | 181 | 181 | 178 | 173 | 35 | 17 | 0.0 |
| Other renewables | 0 | 0 | 1 | 2 | 2 | 3 | 0 | 0 | 9.6 |
| **Industry** | **70** | **171** | **242** | **288** | **331** | **376** | **100** | **100** | **3.3** |
| Coal | 29 | 78 | 116 | 140 | 160 | 180 | 46 | 48 | 3.6 |
| Oil | 10 | 25 | 34 | 39 | 43 | 47 | 15 | 12 | 2.7 |
| Gas | 0 | 9 | 12 | 14 | 16 | 18 | 5 | 5 | 3.0 |
| Electricity | 9 | 30 | 49 | 63 | 79 | 98 | 17 | 26 | 5.1 |
| Heat | - | - | - | - | - | - | - | - | n.a. |
| Bioenergy | 23 | 30 | 32 | 33 | 33 | 33 | 17 | 9 | 0.5 |
| Other renewables | - | - | - | - | - | - | - | - | n.a. |
| **Transport** | **27** | **58** | **90** | **129** | **174** | **227** | **100** | **100** | **5.8** |
| Oil | 24 | 55 | 81 | 117 | 156 | 200 | 94 | 88 | 5.6 |
| Electricity | 0 | 1 | 2 | 2 | 2 | 3 | 2 | 1 | 3.2 |
| Biofuels | - | 0 | 2 | 3 | 5 | 9 | 0 | 4 | 17.8 |
| Other fuels | 2 | 2 | 5 | 7 | 10 | 15 | 4 | 6 | 7.9 |
| **Buildings** | **137** | **199** | **225** | **240** | **256** | **272** | **100** | **100** | **1.3** |
| Coal | 11 | 8 | 7 | 7 | 6 | 6 | 4 | 2 | -1.5 |
| Oil | 11 | 24 | 30 | 33 | 36 | 39 | 12 | 14 | 2.0 |
| Gas | 0 | 0 | 1 | 2 | 3 | 5 | 0 | 2 | 24.5 |
| Electricity | 4 | 24 | 38 | 52 | 70 | 89 | 12 | 33 | 5.6 |
| Heat | - | - | - | - | - | - | - | - | n.a. |
| Bioenergy | 111 | 142 | 147 | 145 | 139 | 131 | 72 | 48 | -0.4 |
| Other renewables | 0 | 0 | 1 | 2 | 2 | 3 | 0 | 1 | 9.3 |
| **Other** | **17** | **63** | **89** | **103** | **116** | **128** | **100** | **100** | **3.0** |

## **India:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **1 005** | **1 421** | **1 647** | **923** | **1 128** | **1 258** | **100** | **100** | **3.3** | **2.2** |
| Coal | 458 | 687 | 814 | 380 | 351 | 361 | 49 | 29 | 3.9 | 0.4 |
| Oil | 229 | 338 | 400 | 216 | 291 | 315 | 24 | 25 | 3.7 | 2.7 |
| Gas | 72 | 117 | 140 | 74 | 125 | 157 | 9 | 13 | 4.4 | 4.9 |
| Nuclear | 21 | 38 | 45 | 23 | 69 | 94 | 3 | 7 | 7.1 | 10.5 |
| Hydro | 14 | 20 | 23 | 17 | 42 | 49 | 1 | 4 | 3.1 | 6.3 |
| Bioenergy | 201 | 206 | 205 | 200 | 214 | 223 | 12 | 18 | 0.4 | 0.8 |
| Other renewables | 8 | 15 | 18 | 13 | 36 | 59 | 1 | 5 | 8.8 | 14.3 |
| **Power generation** | **397** | **622** | **755** | **347** | **411** | **492** | **100** | **100** | **4.3** | **2.4** |
| Coal | 303 | 471 | 572 | 236 | 160 | 151 | 76 | 31 | 4.1 | -1.5 |
| Oil | 5 | 3 | 2 | 5 | 3 | 2 | 0 | 0 | -3.9 | -5.1 |
| Gas | 27 | 52 | 67 | 32 | 63 | 84 | 9 | 17 | 5.2 | 6.2 |
| Nuclear | 21 | 38 | 45 | 23 | 69 | 94 | 6 | 19 | 7.1 | 10.5 |
| Hydro | 14 | 20 | 23 | 17 | 42 | 49 | 3 | 10 | 3.1 | 6.3 |
| Bioenergy | 20 | 26 | 29 | 22 | 41 | 56 | 4 | 11 | 3.5 | 6.4 |
| Other renewables | 7 | 13 | 16 | 12 | 34 | 56 | 2 | 11 | 8.8 | 14.7 |
| **Other energy sector** | **96** | **135** | **155** | **92** | **116** | **129** | **100** | **100** | **3.2** | **2.4** |
| *Electricity* | *39* | *63* | *78* | *36* | *51* | *61* | *50* | *47* | *4.9* | *3.9* |
| **TFC** | **658** | **907** | **1 037** | **621** | **806** | **887** | **100** | **100** | **3.2** | **2.5** |
| Coal | 126 | 175 | 197 | 115 | 153 | 169 | 19 | 19 | 3.5 | 2.9 |
| Oil | 201 | 313 | 375 | 189 | 269 | 295 | 36 | 33 | 4.2 | 3.2 |
| Gas | 40 | 57 | 64 | 37 | 54 | 64 | 6 | 7 | 3.7 | 3.7 |
| Electricity | 108 | 180 | 222 | 101 | 155 | 189 | 21 | 21 | 5.2 | 4.4 |
| Heat | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Bioenergy | 182 | 180 | 177 | 177 | 173 | 166 | 17 | 19 | 0.1 | -0.1 |
| Other renewables | 1 | 2 | 3 | 1 | 3 | 4 | 0 | 0 | 8.7 | 10.3 |
| **Industry** | **248** | **346** | **394** | **226** | **299** | **334** | **100** | **100** | **3.5** | **2.8** |
| Coal | 119 | 168 | 190 | 108 | 147 | 165 | 48 | 49 | 3.8 | 3.2 |
| Oil | 34 | 44 | 48 | 31 | 37 | 39 | 12 | 12 | 2.8 | 1.9 |
| Gas | 13 | 18 | 20 | 11 | 14 | 15 | 5 | 5 | 3.5 | 2.4 |
| Electricity | 50 | 82 | 102 | 47 | 70 | 83 | 26 | 25 | 5.2 | 4.4 |
| Heat | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Bioenergy | 32 | 34 | 35 | 29 | 31 | 32 | 9 | 10 | 0.6 | 0.3 |
| Other renewables | - | - | - | - | - | - | - | - | n.a. | n.a. |
| **Transport** | **92** | **180** | **233** | **86** | **154** | **182** | **100** | **100** | **5.9** | **4.8** |
| Oil | 84 | 164 | 213 | 78 | 135 | 151 | 91 | 83 | 5.8 | 4.3 |
| Electricity | 2 | 2 | 2 | 2 | 4 | 9 | 1 | 5 | 2.7 | 8.8 |
| Biofuels | 2 | 4 | 7 | 3 | 7 | 9 | 3 | 5 | 16.7 | 17.5 |
| Other fuels | 5 | 9 | 11 | 4 | 8 | 12 | 5 | 7 | 6.6 | 7.2 |
| **Buildings** | **227** | **262** | **279** | **219** | **236** | **242** | **100** | **100** | **1.4** | **0.8** |
| Coal | 7 | 7 | 6 | 7 | 5 | 4 | 2 | 2 | -1.1 | -3.0 |
| Oil | 31 | 39 | 43 | 29 | 33 | 35 | 15 | 14 | 2.4 | 1.5 |
| Gas | 1 | 2 | 4 | 1 | 4 | 6 | 1 | 2 | 23.3 | 25.9 |
| Electricity | 39 | 71 | 89 | 36 | 58 | 69 | 32 | 29 | 5.6 | 4.5 |
| Heat | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Bioenergy | 148 | 141 | 135 | 145 | 134 | 125 | 48 | 52 | -0.2 | -0.5 |
| Other renewables | 1 | 2 | 2 | 1 | 2 | 3 | 1 | 1 | 8.4 | 9.8 |
| **Other** | **91** | **119** | **131** | **89** | **117** | **129** | **100** | **100** | **3.1** | **3.0** |

# **India:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **289** | **1 052** | **1 661** | **2 142** | **2 725** | **3 372** | **100** | **100** | **5.0** |
| Coal | 192 | 715 | 1 059 | 1 271 | 1 566 | 1 893 | 68 | 56 | 4.1 |
| Oil | 10 | 12 | 11 | 9 | 7 | 5 | 1 | 0 | -3.3 |
| Gas | 10 | 109 | 161 | 243 | 321 | 419 | 10 | 12 | 5.8 |
| Nuclear | 6 | 33 | 81 | 125 | 166 | 205 | 3 | 6 | 7.9 |
| Hydro | 72 | 131 | 179 | 237 | 303 | 368 | 12 | 11 | 4.4 |
| Bioenergy | - | 29 | 55 | 72 | 91 | 116 | 3 | 3 | 6.0 |
| Wind | 0 | 24 | 91 | 131 | 171 | 209 | 2 | 6 | 9.5 |
| Geothermal | - | - | 0 | 1 | 1 | 2 | - | 0 | n.a. |
| Solar PV | - | 0 | 23 | 49 | 91 | 142 | 0 | 4 | 35.1 |
| CSP | - | - | 2 | 4 | 7 | 13 | - | 0 | n.a. |
| Marine | - | - | - | 0 | 0 | 1 | - | 0 | n.a. |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **215** | **452** | **561** | **722** | **887** | **100** | **100** | **6.1** |
| Coal | 117 | 247 | 273 | 334 | 395 | 54 | 45 | 5.2 |
| Oil | 8 | 8 | 9 | 8 | 8 | 4 | 1 | 0.1 |
| Gas | 23 | 51 | 70 | 95 | 121 | 11 | 14 | 7.2 |
| Nuclear | 5 | 12 | 18 | 24 | 29 | 2 | 3 | 7.9 |
| Hydro | 42 | 59 | 79 | 100 | 121 | 19 | 14 | 4.5 |
| Bioenergy | 5 | 10 | 12 | 16 | 19 | 2 | 2 | 5.8 |
| Wind | 16 | 48 | 67 | 83 | 98 | 7 | 11 | 7.8 |
| Geothermal | - | 0 | 0 | 0 | 0 | - | 0 | n.a. |
| Solar PV | 0 | 16 | 33 | 60 | 91 | 0 | 10 | 28.4 |
| CSP | - | 1 | 1 | 2 | 4 | - | 0 | n.a. |
| Marine | - | - | 0 | 0 | 0 | - | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **582** | **1 736** | **2 318** | **2 780** | **3 311** | **3 882** | **100** | **100** | **3.4** |
| Coal | 396 | 1 205 | 1 589 | 1 867 | 2 203 | 2 559 | 69 | 66 | 3.2 |
| Oil | 166 | 425 | 578 | 713 | 861 | 1 018 | 24 | 26 | 3.7 |
| Gas | 21 | 105 | 151 | 199 | 247 | 306 | 6 | 8 | 4.5 |
| **Power generation** | **235** | **903** | **1 136** | **1 336** | **1 609** | **1 915** | **100** | **100** | **3.2** |
| Coal | 215 | 837 | 1 054 | 1 228 | 1 478 | 1 751 | 93 | 91 | 3.1 |
| Oil | 11 | 19 | 16 | 13 | 9 | 6 | 2 | 0 | -4.6 |
| Gas | 8 | 47 | 66 | 95 | 122 | 158 | 5 | 8 | 5.2 |
| **TFC** | **330** | **773** | **1 099** | **1 353** | **1 601** | **1 858** | **100** | **100** | **3.7** |
| Coal | 175 | 365 | 531 | 635 | 720 | 802 | 47 | 43 | 3.3 |
| Oil | 146 | 357 | 496 | 630 | 774 | 928 | 46 | 50 | 4.1 |
| *Transport* | *74* | *164* | *245* | *350* | *469* | *602* | *21* | *32* | *5.6* |
| Gas | 9 | 51 | 72 | 89 | 107 | 127 | 7 | 7 | 3.9 |

# **India:** Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **1 701** | **2 824** | **3 483** | **1 590** | **2 387** | **2 901** | **100** | **100** | **5.1** | **4.3** |
| Coal | 1 154 | 1 910 | 2 376 | 919 | 780 | 762 | 68 | 26 | 5.1 | 0.3 |
| Oil | 11 | 8 | 6 | 11 | 7 | 4 | 0 | 0 | -2.9 | -4.1 |
| Gas | 156 | 313 | 403 | 187 | 389 | 518 | 12 | 18 | 5.6 | 6.7 |
| Nuclear | 81 | 144 | 174 | 89 | 264 | 362 | 5 | 12 | 7.1 | 10.5 |
| Hydro | 166 | 234 | 269 | 201 | 486 | 570 | 8 | 20 | 3.1 | 6.3 |
| Bioenergy | 51 | 69 | 79 | 58 | 119 | 176 | 2 | 6 | 4.3 | 7.8 |
| Wind | 61 | 97 | 115 | 92 | 201 | 270 | 3 | 9 | 6.8 | 10.6 |
| Geothermal | 0 | 1 | 1 | 1 | 2 | 4 | 0 | 0 | n.a. | n.a. |
| Solar PV | 21 | 47 | 59 | 29 | 118 | 168 | 2 | 6 | 30.2 | 36.0 |
| CSP | 0 | 0 | 0 | 2 | 21 | 66 | 0 | 2 | n.a. | n.a. |
| Marine | - | 0 | 0 | - | 0 | 1 | 0 | 0 | n.a. | n.a. |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **428** | **659** | **787** | **432** | **722** | **889** | **100** | **100** | **5.5** | **6.1** |
| Coal | 247 | 377 | 454 | 201 | 215 | 251 | 58 | 28 | 5.8 | 3.2 |
| Oil | 8 | 8 | 7 | 8 | 8 | 7 | 1 | 1 | -0.1 | -0.4 |
| Gas | 49 | 83 | 105 | 63 | 106 | 118 | 13 | 13 | 6.6 | 7.1 |
| Nuclear | 12 | 21 | 25 | 13 | 38 | 52 | 3 | 6 | 7.1 | 10.4 |
| Hydro | 55 | 77 | 89 | 67 | 160 | 188 | 11 | 21 | 3.2 | 6.5 |
| Bioenergy | 9 | 12 | 13 | 10 | 20 | 28 | 2 | 3 | 4.1 | 7.5 |
| Wind | 33 | 48 | 55 | 49 | 92 | 116 | 7 | 13 | 5.2 | 8.6 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | n.a. | n.a. |
| Solar PV | 15 | 32 | 39 | 20 | 77 | 107 | 5 | 12 | 24.0 | 29.3 |
| CSP | 0 | 0 | 0 | 1 | 6 | 22 | 0 | 2 | n.a. | n.a. |
| Marine | - | 0 | 0 | - | 0 | 0 | 0 | 0 | n.a. | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **2 460** | **3 728** | **4 445** | **2 120** | **2 183** | **2 264** | **100** | **100** | **4.0** | **1.1** |
| Coal | 1 717 | 2 579 | 3 066 | 1 411 | 1 180 | 1 139 | 69 | 50 | 4.0 | -0.2 |
| Oil | 592 | 902 | 1 079 | 553 | 743 | 797 | 24 | 35 | 4.0 | 2.7 |
| Gas | 151 | 247 | 299 | 156 | 260 | 328 | 7 | 15 | 4.4 | 4.8 |
| **Power generation** | **1 251** | **1 954** | **2 379** | **1 003** | **734** | **706** | **100** | **100** | **4.1** | **-1.0** |
| Coal | 1 171 | 1 822 | 2 215 | 913 | 580 | 508 | 93 | 72 | 4.1 | -2.1 |
| Oil | 16 | 11 | 7 | 16 | 9 | 6 | 0 | 1 | -3.9 | -5.1 |
| Gas | 63 | 122 | 157 | 75 | 145 | 193 | 7 | 27 | 5.2 | 6.1 |
| **TFC** | **1 126** | **1 671** | **1 952** | **1 037** | **1 369** | **1 480** | **100** | **100** | **3.9** | **2.7** |
| Coal | 542 | 752 | 846 | 495 | 595 | 627 | 43 | 42 | 3.6 | 2.3 |
| Oil | 510 | 812 | 984 | 474 | 675 | 736 | 50 | 50 | 4.3 | 3.1 |
| *Transport* | *254* | *493* | *640* | *234* | *405* | *455* | *33* | *31* | *5.8* | *4.3* |
| Gas | 75 | 108 | 122 | 68 | 98 | 117 | 6 | 8 | 3.7 | 3.5 |

## **Middle East:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **212** | **640** | **796** | **886** | **970** | **1 051** | **100** | **100** | **2.1** |
| Coal | 1 | 3 | 4 | 5 | 5 | 5 | 0 | 1 | 2.7 |
| Oil | 137 | 301 | 359 | 375 | 393 | 413 | 47 | 39 | 1.3 |
| Gas | 72 | 334 | 419 | 480 | 537 | 582 | 52 | 55 | 2.3 |
| Nuclear | - | 0 | 5 | 13 | 13 | 15 | 0 | 1 | 23.7 |
| Hydro | 1 | 2 | 2 | 3 | 3 | 4 | 0 | 0 | 3.2 |
| Bioenergy | 0 | 1 | 2 | 3 | 6 | 8 | 0 | 1 | 11.3 |
| Other renewables | 0 | 0 | 3 | 7 | 13 | 23 | 0 | 2 | 22.8 |
| **Power generation** | **61** | **216** | **260** | **286** | **312** | **339** | **100** | **100** | **1.9** |
| Coal | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 7.6 |
| Oil | 27 | 93 | 91 | 79 | 69 | 65 | 43 | 19 | -1.5 |
| Gas | 32 | 120 | 157 | 184 | 212 | 229 | 56 | 67 | 2.7 |
| Nuclear | - | 0 | 5 | 13 | 13 | 15 | 0 | 5 | 23.7 |
| Hydro | 1 | 2 | 2 | 3 | 3 | 4 | 1 | 1 | 3.2 |
| Bioenergy | - | 0 | 1 | 2 | 4 | 7 | 0 | 2 | 36.2 |
| Other renewables | 0 | 0 | 2 | 5 | 10 | 19 | 0 | 6 | 33.5 |
| **Other energy sector** | **22** | **75** | **94** | **103** | **108** | **111** | **100** | **100** | **1.6** |
| *Electricity* | *4* | *14* | *19* | *21* | *24* | *26* | *18* | *23* | *2.7* |
| **TFC** | **148** | **422** | **542** | **613** | **684** | **751** | **100** | **100** | **2.4** |
| Coal | 0 | 2 | 3 | 3 | 3 | 3 | 0 | 0 | 2.4 |
| Oil | 102 | 202 | 260 | 294 | 327 | 357 | 48 | 47 | 2.4 |
| Gas | 30 | 158 | 196 | 218 | 239 | 261 | 38 | 35 | 2.1 |
| Electricity | 15 | 59 | 82 | 95 | 111 | 125 | 14 | 17 | 3.2 |
| Heat | - | - | - | - | - | - | - | - | n.a. |
| Bioenergy | 0 | 1 | 1 | 1 | 1 | 2 | 0 | 0 | 4.6 |
| Other renewables | 0 | 0 | 1 | 2 | 3 | 4 | 0 | 1 | 14.9 |
| **Industry** | **42** | **115** | **142** | **160** | **177** | **195** | **100** | **100** | **2.2** |
| Coal | 0 | 1 | 2 | 2 | 2 | 2 | 1 | 1 | 1.1 |
| Oil | 19 | 32 | 37 | 40 | 42 | 43 | 28 | 22 | 1.3 |
| Gas | 19 | 69 | 86 | 99 | 112 | 126 | 60 | 65 | 2.5 |
| Electricity | 3 | 13 | 17 | 19 | 21 | 24 | 11 | 12 | 2.5 |
| Heat | - | - | - | - | - | - | - | - | n.a. |
| Bioenergy | - | - | - | - | - | - | - | - | n.a. |
| Other renewables | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3.7 |
| **Transport** | **48** | **121** | **164** | **190** | **216** | **239** | **100** | **100** | **2.9** |
| Oil | 48 | 115 | 156 | 180 | 204 | 224 | 95 | 94 | 2.8 |
| Electricity | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.7 |
| Biofuels | - | - | - | - | - | - | - | - | n.a. |
| Other fuels | - | 6 | 9 | 10 | 12 | 15 | 5 | 6 | 4.1 |
| **Buildings** | **33** | **105** | **132** | **146** | **162** | **177** | **100** | **100** | **2.2** |
| Coal | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -1.8 |
| Oil | 18 | 18 | 19 | 19 | 18 | 17 | 17 | 10 | -0.2 |
| Gas | 3 | 43 | 50 | 53 | 56 | 59 | 41 | 33 | 1.3 |
| Electricity | 11 | 43 | 60 | 72 | 84 | 96 | 41 | 54 | 3.4 |
| Heat | - | - | - | - | - | - | - | - | n.a. |
| Bioenergy | 0 | 1 | 1 | 1 | 1 | 2 | 1 | 1 | 4.4 |
| Other renewables | 0 | 0 | 1 | 2 | 2 | 3 | 0 | 2 | 13.9 |
| **Other** | **25** | **81** | **104** | **117** | **129** | **141** | **100** | **100** | **2.3** |

## **Middle East:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **810** | **1 015** | **1 119** | **753** | **813** | **832** | **100** | **100** | **2.4** | **1.1** |
| Coal | 4 | 5 | 6 | 4 | 5 | 5 | 0 | 1 | 2.9 | 2.4 |
| Oil | 366 | 419 | 450 | 334 | 313 | 297 | 40 | 36 | 1.7 | -0.1 |
| Gas | 428 | 564 | 631 | 402 | 442 | 445 | 56 | 54 | 2.7 | 1.2 |
| Nuclear | 4 | 12 | 12 | 5 | 17 | 21 | 1 | 3 | 22.4 | 25.3 |
| Hydro | 2 | 3 | 4 | 3 | 4 | 4 | 0 | 1 | 3.0 | 4.0 |
| Bioenergy | 2 | 4 | 6 | 2 | 8 | 13 | 1 | 2 | 9.9 | 13.4 |
| Other renewables | 2 | 8 | 11 | 4 | 24 | 45 | 1 | 5 | 19.3 | 26.4 |
| **Power generation** | **267** | **334** | **373** | **243** | **258** | **267** | **100** | **100** | **2.3** | **0.9** |
| Coal | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 7.9 | 6.5 |
| Oil | 94 | 78 | 75 | 80 | 52 | 45 | 20 | 17 | -0.9 | -3.0 |
| Gas | 163 | 232 | 268 | 150 | 156 | 145 | 72 | 54 | 3.4 | 0.8 |
| Nuclear | 4 | 12 | 12 | 5 | 17 | 21 | 3 | 8 | 22.4 | 25.3 |
| Hydro | 2 | 3 | 4 | 3 | 4 | 4 | 1 | 2 | 3.0 | 4.0 |
| Bioenergy | 1 | 3 | 4 | 1 | 7 | 11 | 1 | 4 | 34.0 | 39.3 |
| Other renewables | 2 | 6 | 9 | 3 | 21 | 40 | 2 | 15 | 29.2 | 37.7 |
| **Other energy sector** | **95** | **111** | **116** | **92** | **95** | **94** | **100** | **100** | **1.8** | **0.9** |
| *Electricity* | *19* | *25* | *28* | *18* | *20* | *21* | *24* | *22* | *3.0* | *1.8* |
| **TFC** | **550** | **712** | **792** | **514** | **574** | **593** | **100** | **100** | **2.7** | **1.4** |
| Coal | 3 | 3 | 3 | 2 | 3 | 3 | 0 | 0 | 2.6 | 2.2 |
| Oil | 264 | 347 | 386 | 246 | 264 | 261 | 49 | 44 | 2.7 | 1.1 |
| Gas | 198 | 242 | 265 | 187 | 208 | 220 | 33 | 37 | 2.2 | 1.4 |
| Electricity | 84 | 117 | 134 | 77 | 94 | 102 | 17 | 17 | 3.5 | 2.3 |
| Heat | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Bioenergy | 1 | 1 | 2 | 1 | 1 | 2 | 0 | 0 | 4.5 | 4.8 |
| Other renewables | 1 | 2 | 3 | 1 | 3 | 5 | 0 | 1 | 12.9 | 16.2 |
| **Industry** | **144** | **183** | **203** | **134** | **149** | **156** | **100** | **100** | **2.4** | **1.3** |
| Coal | 2 | 2 | 2 | 2 | 2 | 2 | 1 | 1 | 1.3 | 0.9 |
| Oil | 38 | 43 | 45 | 35 | 36 | 36 | 22 | 23 | 1.4 | 0.5 |
| Gas | 87 | 115 | 130 | 81 | 92 | 98 | 64 | 63 | 2.7 | 1.5 |
| Electricity | 18 | 23 | 26 | 16 | 19 | 20 | 13 | 13 | 2.9 | 1.9 |
| Heat | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Bioenergy | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3.7 | 3.7 |
| **Transport** | **167** | **230** | **261** | **153** | **167** | **167** | **100** | **100** | **3.3** | **1.4** |
| Oil | 159 | 220 | 250 | 146 | 155 | 147 | 96 | 88 | 3.3 | 1.0 |
| Electricity | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 1 | 0.4 | 17.0 |
| Biofuels | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Other fuels | 8 | 10 | 11 | 7 | 11 | 18 | 4 | 11 | 2.7 | 5.0 |
| **Buildings** | **135** | **170** | **187** | **126** | **141** | **144** | **100** | **100** | **2.5** | **1.3** |
| Coal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -1.8 | -1.9 |
| Oil | 20 | 20 | 19 | 19 | 17 | 15 | 10 | 10 | 0.2 | -0.8 |
| Gas | 51 | 59 | 63 | 49 | 49 | 48 | 34 | 33 | 1.6 | 0.4 |
| Electricity | 62 | 89 | 101 | 57 | 70 | 75 | 54 | 52 | 3.7 | 2.4 |
| Heat | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Bioenergy | 1 | 1 | 2 | 1 | 1 | 2 | 1 | 1 | 4.3 | 4.6 |
| Other renewables | 0 | 1 | 2 | 1 | 2 | 4 | 1 | 3 | 11.4 | 15.0 |
| **Other** | **104** | **129** | **141** | **101** | **118** | **126** | **100** | **100** | **2.3** | **1.9** |

## **Middle East:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **219** | **845** | **1 169** | **1 358** | **1 565** | **1 757** | **100** | **100** | **3.1** |
| Coal | 0 | 0 | 2 | 3 | 3 | 3 | 0 | 0 | 9.2 |
| Oil | 98 | 320 | 329 | 289 | 267 | 254 | 38 | 14 | -1.0 |
| Gas | 110 | 504 | 769 | 935 | 1 105 | 1 214 | 60 | 69 | 3.7 |
| Nuclear | - | 0 | 20 | 48 | 48 | 59 | 0 | 3 | 23.7 |
| Hydro | 12 | 20 | 29 | 34 | 39 | 43 | 2 | 2 | 3.2 |
| Bioenergy | - | 0 | 4 | 8 | 14 | 23 | 0 | 1 | 36.2 |
| Wind | 0 | 0 | 3 | 10 | 25 | 60 | 0 | 3 | 26.4 |
| Geothermal | - | - | - | - | - | - | - | - | n.a. |
| Solar PV | - | - | 8 | 20 | 41 | 60 | - | 3 | n.a. |
| CSP | - | - | 5 | 10 | 21 | 40 | - | 2 | n.a. |
| Marine | - | - | - | - | - | - | - | - | n.a. |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **239** | **340** | **362** | **404** | **459** | **100** | **100** | **2.8** |
| Coal | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 7.4 |
| Oil | 72 | 84 | 76 | 70 | 67 | 30 | 15 | -0.3 |
| Gas | 152 | 225 | 236 | 261 | 281 | 64 | 61 | 2.6 |
| Nuclear | 1 | 3 | 7 | 7 | 8 | 0 | 2 | 9.2 |
| Hydro | 13 | 18 | 21 | 24 | 25 | 5 | 6 | 2.9 |
| Bioenergy | 0 | 1 | 1 | 2 | 4 | 0 | 1 | 35.7 |
| Wind | 0 | 1 | 4 | 11 | 26 | 0 | 6 | 26.4 |
| Geothermal | - | - | - | - | - | - | - | n.a. |
| Solar PV | - | 5 | 11 | 22 | 32 | - | 7 | n.a. |
| CSP | - | 2 | 3 | 7 | 14 | - | 3 | n.a. |
| Marine | - | - | - | - | - | - | - | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **556** | **1 590** | **1 918** | **2 078** | **2 239** | **2 381** | **100** | **100** | **1.7** |
| Coal | 1 | 9 | 12 | 14 | 14 | 15 | 1 | 1 | 2.1 |
| Oil | 393 | 853 | 997 | 1 040 | 1 084 | 1 134 | 54 | 48 | 1.2 |
| Gas | 162 | 727 | 908 | 1 025 | 1 140 | 1 231 | 46 | 52 | 2.2 |
| **Power generation** | **162** | **573** | **652** | **677** | **711** | **738** | **100** | **100** | **1.1** |
| Coal | 0 | 1 | 2 | 3 | 3 | 3 | 0 | 0 | 3.6 |
| Oil | 86 | 290 | 284 | 245 | 215 | 202 | 51 | 27 | -1.5 |
| Gas | 76 | 281 | 366 | 428 | 493 | 532 | 49 | 72 | 2.7 |
| **TFC** | **347** | **871** | **1 086** | **1 212** | **1 333** | **1 444** | **100** | **100** | **2.1** |
| Coal | 1 | 7 | 9 | 9 | 10 | 10 | 1 | 1 | 1.7 |
| Oil | 282 | 525 | 662 | 742 | 817 | 881 | 60 | 61 | 2.2 |
| *Transport* | *142* | *341* | *461* | *533* | *603* | *663* | *39* | *46* | *2.8* |
| Gas | 64 | 339 | 416 | 461 | 506 | 553 | 39 | 38 | 2.1 |

## **Middle East:** Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **1 200** | **1 659** | **1 882** | **1 109** | **1 332** | **1 434** | **100** | **100** | **3.4** | **2.2** |
| Coal | 2 | 3 | 4 | 2 | 3 | 3 | 0 | 0 | 9.6 | 8.1 |
| Oil | 340 | 305 | 301 | 291 | 197 | 169 | 16 | 12 | -0.3 | -2.6 |
| Gas | 795 | 1 211 | 1 401 | 742 | 820 | 768 | 74 | 54 | 4.4 | 1.8 |
| Nuclear | 17 | 46 | 46 | 20 | 67 | 80 | 2 | 6 | 22.4 | 25.3 |
| Hydro | 28 | 38 | 41 | 30 | 46 | 52 | 2 | 4 | 3.0 | 4.0 |
| Bioenergy | 4 | 9 | 15 | 4 | 23 | 40 | 1 | 3 | 33.9 | 39.2 |
| Wind | 3 | 12 | 23 | 4 | 75 | 135 | 1 | 9 | 21.4 | 30.8 |
| Geothermal | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Solar PV | 7 | 21 | 32 | 9 | 56 | 92 | 2 | 6 | n.a. | n.a. |
| CSP | 4 | 14 | 18 | 6 | 45 | 96 | 1 | 7 | n.a. | n.a. |
| Marine | - | - | - | - | - | 0 | - | 0 | n.a. | n.a. |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **341** | **408** | **450** | **341** | **437** | **513** | **100** | **100** | **2.7** | **3.2** |
| Coal | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 7.7 | 6.4 |
| Oil | 86 | 79 | 79 | 82 | 56 | 49 | 18 | 10 | 0.4 | -1.6 |
| Gas | 225 | 274 | 302 | 226 | 262 | 277 | 67 | 54 | 2.9 | 2.5 |
| Nuclear | 3 | 7 | 7 | 3 | 9 | 11 | 2 | 2 | 8.4 | 10.6 |
| Hydro | 18 | 23 | 25 | 19 | 27 | 30 | 5 | 6 | 2.7 | 3.6 |
| Bioenergy | 1 | 1 | 2 | 1 | 4 | 6 | 1 | 1 | 33.4 | 38.7 |
| Wind | 1 | 5 | 10 | 2 | 33 | 59 | 2 | 11 | 21.5 | 30.8 |
| Geothermal | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Solar PV | 4 | 12 | 18 | 5 | 30 | 50 | 4 | 10 | n.a. | n.a. |
| CSP | 2 | 5 | 6 | 2 | 14 | 30 | 1 | 6 | n.a. | n.a. |
| Marine | - | - | - | - | - | 0 | - | 0 | n.a. | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **1 960** | **2 386** | **2 615** | **1 796** | **1 713** | **1 627** | **100** | **100** | **2.1** | **0.1** |
| Coal | 12 | 15 | 16 | 12 | 13 | 13 | 1 | 1 | 2.3 | 1.4 |
| Oil | 1 019 | 1 172 | 1 260 | 922 | 835 | 773 | 48 | 48 | 1.6 | -0.4 |
| Gas | 928 | 1 199 | 1 340 | 863 | 864 | 841 | 51 | 52 | 2.6 | 0.6 |
| **Power generation** | **675** | **787** | **864** | **601** | **519** | **468** | **100** | **100** | **1.7** | **-0.8** |
| Coal | 2 | 3 | 4 | 2 | 3 | 3 | 0 | 1 | 3.9 | 2.6 |
| Oil | 292 | 241 | 235 | 250 | 163 | 140 | 27 | 30 | -0.9 | -3.0 |
| Gas | 381 | 542 | 626 | 349 | 353 | 325 | 72 | 70 | 3.4 | 0.6 |
| **TFC** | **1 104** | **1 400** | **1 545** | **1 024** | **1 057** | **1 039** | **100** | **100** | **2.4** | **0.7** |
| Coal | 9 | 10 | 11 | 9 | 9 | 9 | 1 | 1 | 1.9 | 1.1 |
| Oil | 675 | 877 | 970 | 624 | 639 | 607 | 63 | 58 | 2.6 | 0.6 |
| *Transport* | *470* | *653* | *741* | *432* | *458* | *437* | *48* | *42* | *3.3* | *1.0* |
| Gas | 420 | 513 | 564 | 392 | 409 | 423 | 36 | 41 | 2.1 | 0.9 |

## **Africa:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **388** | **698** | **836** | **901** | **962** | **1 026** | **100** | **100** | **1.6** |
| Coal | 74 | 107 | 123 | 129 | 131 | 136 | 15 | 13 | 1.0 |
| Oil | 87 | 148 | 180 | 189 | 193 | 199 | 21 | 19 | 1.3 |
| Gas | 30 | 94 | 129 | 143 | 157 | 171 | 13 | 17 | 2.5 |
| Nuclear | 2 | 4 | 3 | 7 | 12 | 14 | 1 | 1 | 5.8 |
| Hydro | 5 | 10 | 15 | 19 | 24 | 31 | 1 | 3 | 5.0 |
| Bioenergy | 190 | 335 | 381 | 404 | 426 | 445 | 48 | 43 | 1.2 |
| Other renewables | 0 | 2 | 6 | 10 | 18 | 31 | 0 | 3 | 13.1 |
| **Power generation** | **68** | **144** | **189** | **212** | **238** | **271** | **100** | **100** | **2.7** |
| Coal | 39 | 63 | 78 | 81 | 83 | 86 | 44 | 32 | 1.3 |
| Oil | 11 | 16 | 18 | 17 | 15 | 15 | 11 | 5 | -0.5 |
| Gas | 11 | 49 | 67 | 72 | 76 | 80 | 34 | 30 | 2.0 |
| Nuclear | 2 | 4 | 3 | 7 | 12 | 14 | 2 | 5 | 5.8 |
| Hydro | 5 | 10 | 15 | 19 | 24 | 31 | 7 | 11 | 5.0 |
| Bioenergy | 0 | 0 | 3 | 7 | 11 | 16 | 0 | 6 | 16.1 |
| Other renewables | 0 | 2 | 5 | 9 | 17 | 29 | 1 | 11 | 13.0 |
| **Other energy sector** | **57** | **90** | **103** | **110** | **116** | **122** | **100** | **100** | **1.3** |
| *Electricity* | *5* | *11* | *15* | *17* | *19* | *22* | *12* | *18* | *2.9* |
| **TFC** | **290** | **523** | **629** | **677** | **721** | **765** | **100** | **100** | **1.6** |
| Coal | 20 | 18 | 20 | 20 | 20 | 20 | 3 | 3 | 0.4 |
| Oil | 71 | 130 | 164 | 177 | 187 | 195 | 25 | 26 | 1.7 |
| Gas | 9 | 28 | 39 | 45 | 50 | 56 | 5 | 7 | 2.9 |
| Electricity | 22 | 49 | 70 | 81 | 94 | 110 | 9 | 14 | 3.4 |
| Heat | - | - | - | - | - | - | - | - | n.a. |
| Bioenergy | 169 | 298 | 336 | 354 | 369 | 382 | 57 | 50 | 1.0 |
| Other renewables | - | 0 | 0 | 1 | 1 | 2 | 0 | 0 | 13.9 |
| **Industry** | **60** | **90** | **115** | **125** | **134** | **142** | **100** | **100** | **1.9** |
| Coal | 14 | 12 | 13 | 13 | 13 | 13 | 13 | 9 | 0.5 |
| Oil | 14 | 15 | 19 | 20 | 21 | 21 | 16 | 15 | 1.5 |
| Gas | 5 | 14 | 19 | 22 | 24 | 26 | 16 | 18 | 2.6 |
| Electricity | 12 | 21 | 27 | 30 | 32 | 35 | 23 | 25 | 2.2 |
| Heat | - | - | - | - | - | - | - | - | n.a. |
| Bioenergy | 16 | 29 | 37 | 41 | 44 | 47 | 32 | 33 | 2.0 |
| Other renewables | - | - | - | - | - | - | - | - | n.a. |
| **Transport** | **38** | **83** | **104** | **114** | **122** | **129** | **100** | **100** | **1.9** |
| Oil | 37 | 81 | 102 | 111 | 119 | 125 | 98 | 97 | 1.8 |
| Electricity | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 2.2 |
| Biofuels | - | - | - | - | - | - | - | - | n.a. |
| Other fuels | 0 | 1 | 1 | 2 | 2 | 3 | 1 | 3 | 4.9 |
| **Buildings** | **177** | **324** | **373** | **398** | **422** | **446** | **100** | **100** | **1.3** |
| Coal | 3 | 4 | 4 | 4 | 4 | 4 | 1 | 1 | -0.4 |
| Oil | 12 | 20 | 24 | 25 | 27 | 28 | 6 | 6 | 1.5 |
| Gas | 1 | 6 | 8 | 9 | 10 | 11 | 2 | 2 | 2.4 |
| Electricity | 9 | 26 | 40 | 48 | 58 | 70 | 8 | 16 | 4.2 |
| Heat | - | - | - | - | - | - | - | - | n.a. |
| Bioenergy | 152 | 267 | 297 | 311 | 323 | 333 | 83 | 75 | 0.9 |
| Other renewables | - | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 10.7 |
| **Other** | **15** | **26** | **36** | **40** | **44** | **47** | **100** | **100** | **2.5** |

# **Africa:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **844** | **987** | **1 060** | **800** | **865** | **900** | **100** | **100** | **1.8** | **1.1** |
| Coal | 126 | 146 | 159 | 116 | 102 | 96 | 15 | 11 | 1.7 | -0.4 |
| Oil | 181 | 200 | 210 | 164 | 150 | 142 | 20 | 16 | 1.5 | -0.2 |
| Gas | 131 | 169 | 189 | 119 | 122 | 118 | 18 | 13 | 3.0 | 1.0 |
| Nuclear | 3 | 7 | 8 | 3 | 19 | 26 | 1 | 3 | 3.7 | 8.7 |
| Hydro | 14 | 22 | 26 | 16 | 26 | 32 | 2 | 4 | 4.2 | 5.1 |
| Bioenergy | 383 | 429 | 448 | 376 | 414 | 429 | 42 | 48 | 1.2 | 1.0 |
| Other renewables | 5 | 14 | 21 | 6 | 33 | 57 | 2 | 6 | 11.3 | 16.1 |
| **Power generation** | **191** | **246** | **282** | **175** | **202** | **227** | **100** | **100** | **2.8** | **1.9** |
| Coal | 79 | 94 | 105 | 71 | 55 | 49 | 37 | 21 | 2.1 | -1.1 |
| Oil | 18 | 14 | 14 | 17 | 12 | 11 | 5 | 5 | -0.6 | -1.8 |
| Gas | 68 | 86 | 95 | 59 | 45 | 34 | 34 | 15 | 2.8 | -1.5 |
| Nuclear | 3 | 7 | 8 | 3 | 19 | 26 | 3 | 12 | 3.7 | 8.7 |
| Hydro | 14 | 22 | 26 | 16 | 26 | 32 | 9 | 14 | 4.2 | 5.1 |
| Bioenergy | 3 | 10 | 13 | 4 | 14 | 20 | 5 | 9 | 15.2 | 17.2 |
| Other renewables | 5 | 13 | 20 | 6 | 31 | 55 | 7 | 24 | 11.3 | 16.1 |
| **Other energy sector** | **104** | **119** | **126** | **101** | **108** | **109** | **100** | **100** | **1.4** | **0.8** |
| *Electricity* | *15* | *19* | *22* | *14* | *16* | *17* | *17* | *15* | *2.9* | *1.8* |
| **TFC** | **634** | **737** | **786** | **604** | **653** | **674** | **100** | **100** | **1.7** | **1.1** |
| Coal | 20 | 21 | 22 | 19 | 19 | 19 | 3 | 3 | 0.8 | 0.2 |
| Oil | 166 | 194 | 208 | 149 | 147 | 142 | 26 | 21 | 2.0 | 0.4 |
| Gas | 40 | 51 | 57 | 38 | 48 | 53 | 7 | 8 | 2.9 | 2.7 |
| Electricity | 70 | 96 | 111 | 66 | 82 | 93 | 14 | 14 | 3.5 | 2.7 |
| Heat | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Bioenergy | 338 | 374 | 387 | 331 | 356 | 364 | 49 | 54 | 1.1 | 0.8 |
| Other renewables | 0 | 1 | 1 | 1 | 1 | 2 | 0 | 0 | 12.3 | 15.1 |
| **Industry** | **119** | **143** | **155** | **110** | **120** | **125** | **100** | **100** | **2.3** | **1.4** |
| Coal | 13 | 14 | 15 | 13 | 12 | 13 | 10 | 10 | 0.9 | 0.3 |
| Oil | 20 | 22 | 23 | 18 | 18 | 17 | 15 | 14 | 2.0 | 0.7 |
| Gas | 20 | 25 | 28 | 19 | 22 | 24 | 18 | 19 | 2.9 | 2.3 |
| Electricity | 28 | 35 | 39 | 25 | 28 | 29 | 25 | 23 | 2.6 | 1.5 |
| Heat | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Bioenergy | 38 | 47 | 50 | 36 | 40 | 42 | 32 | 34 | 2.3 | 1.6 |
| Other renewables | - | - | - | - | - | - | - | - | n.a. | n.a. |
| **Transport** | **104** | **125** | **135** | **94** | **91** | **87** | **100** | **100** | **2.1** | **0.2** |
| Oil | 102 | 123 | 132 | 90 | 85 | 80 | 98 | 91 | 2.0 | -0.1 |
| Electricity | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 2.2 | 4.0 |
| Biofuels | - | - | - | 1 | 2 | 3 | - | 3 | n.a. | n.a. |
| Other fuels | 1 | 2 | 2 | 2 | 3 | 3 | 1 | 4 | 2.4 | 5.0 |
| **Buildings** | **374** | **424** | **447** | **365** | **399** | **415** | **100** | **100** | **1.4** | **1.0** |
| Coal | 4 | 4 | 4 | 4 | 4 | 4 | 1 | 1 | -0.1 | -0.5 |
| Oil | 24 | 28 | 30 | 23 | 24 | 25 | 7 | 6 | 1.7 | 1.0 |
| Gas | 8 | 10 | 11 | 8 | 9 | 10 | 3 | 2 | 2.6 | 1.9 |
| Electricity | 39 | 56 | 66 | 37 | 50 | 58 | 15 | 14 | 4.0 | 3.4 |
| Heat | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Bioenergy | 298 | 325 | 335 | 292 | 311 | 317 | 75 | 76 | 0.9 | 0.7 |
| Other renewables | 0 | 0 | 1 | 0 | 1 | 1 | 0 | 0 | 9.6 | 11.9 |
| **Other** | **37** | **45** | **49** | **36** | **43** | **47** | **100** | **100** | **2.6** | **2.4** |

## **Africa:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **316** | **692** | **976** | **1 136** | **1 312** | **1 526** | **100** | **100** | **3.4** |
| Coal | 165 | 263 | 336 | 360 | 372 | 394 | 38 | 26 | 1.7 |
| Oil | 41 | 71 | 78 | 75 | 66 | 65 | 10 | 4 | -0.3 |
| Gas | 45 | 228 | 343 | 387 | 424 | 464 | 33 | 30 | 3.0 |
| Nuclear | 8 | 14 | 13 | 25 | 47 | 53 | 2 | 3 | 5.8 |
| Hydro | 56 | 111 | 172 | 222 | 283 | 357 | 16 | 23 | 5.0 |
| Bioenergy | 0 | 1 | 11 | 23 | 38 | 54 | 0 | 4 | 18.5 |
| Wind | - | 2 | 8 | 15 | 26 | 42 | 0 | 3 | 12.6 |
| Geothermal | 0 | 2 | 4 | 5 | 9 | 16 | 0 | 1 | 10.3 |
| Solar PV | - | 0 | 7 | 15 | 28 | 43 | 0 | 3 | 24.0 |
| CSP | - | - | 3 | 9 | 19 | 37 | - | 2 | n.a. |
| Marine | - | - | - | - | - | - | - | - | n.a. |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **155** | **234** | **282** | **338** | **409** | **100** | **100** | **4.1** |
| Coal | 42 | 61 | 70 | 79 | 91 | 27 | 22 | 3.2 |
| Oil | 26 | 29 | 28 | 27 | 27 | 17 | 7 | 0.2 |
| Gas | 55 | 87 | 102 | 115 | 130 | 36 | 32 | 3.6 |
| Nuclear | 2 | 2 | 4 | 7 | 7 | 1 | 2 | 5.7 |
| Hydro | 27 | 42 | 54 | 69 | 87 | 18 | 21 | 4.9 |
| Bioenergy | 0 | 2 | 5 | 7 | 10 | 0 | 2 | 16.3 |
| Wind | 1 | 4 | 6 | 11 | 17 | 1 | 4 | 12.7 |
| Geothermal | 0 | 1 | 1 | 1 | 2 | 0 | 1 | 11.4 |
| Solar PV | 0 | 4 | 9 | 17 | 25 | 0 | 6 | 22.8 |
| CSP | - | 1 | 3 | 6 | 11 | - | 3 | n.a. |
| Marine | - | - | - | - | - | - | - | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **544** | **979** | **1 204** | **1 278** | **1 314** | **1 363** | **100** | **100** | **1.4** |
| Coal | 234 | 318 | 379 | 392 | 381 | 379 | 32 | 28 | 0.7 |
| Oil | 248 | 458 | 553 | 586 | 608 | 630 | 47 | 46 | 1.3 |
| Gas | 62 | 203 | 272 | 300 | 325 | 354 | 21 | 26 | 2.3 |
| **Power generation** | **212** | **413** | **514** | **535** | **527** | **537** | **100** | **100** | **1.1** |
| Coal | 152 | 246 | 301 | 314 | 304 | 303 | 60 | 56 | 0.9 |
| Oil | 35 | 51 | 56 | 53 | 47 | 46 | 12 | 9 | -0.5 |
| Gas | 25 | 116 | 157 | 168 | 177 | 188 | 28 | 35 | 2.0 |
| **TFC** | **301** | **526** | **640** | **687** | **725** | **761** | **100** | **100** | **1.5** |
| Coal | 82 | 72 | 77 | 78 | 77 | 77 | 14 | 10 | 0.3 |
| Oil | 201 | 393 | 482 | 518 | 546 | 570 | 75 | 75 | 1.6 |
| *Transport* | *105* | *253* | *311* | *338* | *360* | *379* | *48* | *50* | *1.7* |
| Gas | 18 | 62 | 81 | 91 | 102 | 114 | 12 | 15 | 2.6 |

## **Africa:** Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **986** | **1 331** | **1 539** | **918** | **1 129** | **1 272** | **100** | **100** | **3.4** | **2.6** |
| Coal | 344 | 419 | 475 | 310 | 242 | 204 | 31 | 16 | 2.5 | -1.0 |
| Oil | 78 | 65 | 63 | 74 | 52 | 48 | 4 | 4 | -0.5 | -1.6 |
| Gas | 353 | 475 | 535 | 301 | 257 | 195 | 35 | 15 | 3.6 | -0.7 |
| Nuclear | 13 | 29 | 32 | 13 | 72 | 100 | 2 | 8 | 3.7 | 8.7 |
| Hydro | 169 | 253 | 301 | 182 | 303 | 369 | 20 | 29 | 4.2 | 5.1 |
| Bioenergy | 9 | 32 | 44 | 12 | 48 | 70 | 3 | 5 | 17.6 | 19.8 |
| Wind | 8 | 20 | 28 | 9 | 46 | 91 | 2 | 7 | 10.8 | 16.3 |
| Geothermal | 3 | 8 | 12 | 4 | 14 | 22 | 1 | 2 | 9.1 | 11.8 |
| Solar PV | 6 | 19 | 29 | 9 | 43 | 66 | 2 | 5 | 21.9 | 26.3 |
| CSP | 3 | 11 | 20 | 4 | 51 | 106 | 1 | 8 | n.a. | n.a. |
| Marine | - | - | - | - | 0 | 0 | - | 0 | n.a. | n.a. |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **234** | **328** | **386** | **226** | **326** | **401** | **100** | **100** | **3.9** | **4.0** |
| Coal | 62 | 84 | 98 | 56 | 56 | 55 | 25 | 14 | 3.6 | 1.1 |
| Oil | 29 | 26 | 26 | 28 | 22 | 22 | 7 | 5 | -0.0 | -0.8 |
| Gas | 89 | 122 | 139 | 81 | 93 | 97 | 36 | 24 | 3.9 | 2.4 |
| Nuclear | 2 | 4 | 4 | 2 | 10 | 14 | 1 | 4 | 3.5 | 8.7 |
| Hydro | 41 | 62 | 73 | 45 | 75 | 91 | 19 | 23 | 4.2 | 5.1 |
| Bioenergy | 2 | 6 | 9 | 3 | 9 | 13 | 2 | 3 | 15.5 | 17.5 |
| Wind | 4 | 8 | 12 | 4 | 19 | 38 | 3 | 10 | 10.8 | 16.4 |
| Geothermal | 1 | 1 | 2 | 1 | 2 | 3 | 1 | 1 | 10.5 | 13.0 |
| Solar PV | 4 | 12 | 17 | 6 | 25 | 38 | 4 | 9 | 20.8 | 24.8 |
| CSP | 1 | 3 | 5 | 1 | 15 | 30 | 1 | 8 | n.a. | n.a. |
| Marine | - | - | - | - | 0 | 0 | - | 0 | n.a. | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **1 221** | **1 428** | **1 548** | **1 105** | **887** | **773** | **100** | **100** | **1.9** | **-1.0** |
| Coal | 387 | 446 | 490 | 350 | 178 | 105 | 32 | 14 | 1.8 | -4.5 |
| Oil | 558 | 630 | 667 | 505 | 470 | 446 | 43 | 58 | 1.6 | -0.1 |
| Gas | 276 | 352 | 390 | 250 | 239 | 222 | 25 | 29 | 2.8 | 0.4 |
| **Power generation** | **523** | **609** | **672** | **465** | **258** | **165** | **100** | **100** | **2.0** | **-3.8** |
| Coal | 307 | 363 | 406 | 275 | 115 | 52 | 60 | 31 | 2.1 | -6.3 |
| Oil | 56 | 45 | 44 | 53 | 37 | 33 | 7 | 20 | -0.6 | -1.8 |
| Gas | 160 | 201 | 222 | 137 | 106 | 80 | 33 | 48 | 2.8 | -1.5 |
| **TFC** | **648** | **757** | **808** | **591** | **578** | **558** | **100** | **100** | **1.8** | **0.2** |
| Coal | 80 | 83 | 84 | 75 | 63 | 53 | 10 | 9 | 0.7 | -1.2 |
| Oil | 487 | 570 | 608 | 437 | 422 | 403 | 75 | 72 | 1.8 | 0.1 |
| *Transport* | *311* | *371* | *401* | *273* | *257* | *240* | *50* | *43* | *1.9* | *-0.2* |
| Gas | 82 | 104 | 116 | 79 | 94 | 102 | 14 | 18 | 2.7 | 2.1 |

## **Latin America:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **331** | **586** | **729** | **806** | **876** | **941** | **100** | **100** | **2.0** |
| Coal | 15 | 22 | 31 | 36 | 41 | 43 | 4 | 5 | 2.8 |
| Oil | 150 | 252 | 298 | 311 | 319 | 327 | 43 | 35 | 1.1 |
| Gas | 52 | 129 | 163 | 190 | 213 | 237 | 22 | 25 | 2.6 |
| Nuclear | 2 | 6 | 10 | 10 | 13 | 14 | 1 | 1 | 3.7 |
| Hydro | 30 | 62 | 77 | 86 | 94 | 102 | 10 | 11 | 2.1 |
| Bioenergy | 81 | 112 | 140 | 158 | 175 | 190 | 19 | 20 | 2.2 |
| Other renewables | 1 | 3 | 10 | 15 | 21 | 28 | 1 | 3 | 9.0 |
| **Power generation** | **66** | **152** | **192** | **217** | **242** | **268** | **100** | **100** | **2.4** |
| Coal | 3 | 6 | 10 | 11 | 13 | 13 | 4 | 5 | 3.6 |
| Oil | 14 | 30 | 28 | 24 | 20 | 19 | 20 | 7 | -1.9 |
| Gas | 14 | 36 | 42 | 52 | 59 | 66 | 23 | 25 | 2.6 |
| Nuclear | 2 | 6 | 10 | 10 | 13 | 14 | 4 | 5 | 3.7 |
| Hydro | 30 | 62 | 77 | 86 | 94 | 102 | 41 | 38 | 2.1 |
| Bioenergy | 2 | 10 | 16 | 20 | 25 | 29 | 6 | 11 | 4.7 |
| Other renewables | 1 | 3 | 9 | 13 | 19 | 25 | 2 | 9 | 9.2 |
| **Other energy sector** | **56** | **78** | **88** | **97** | **104** | **108** | **100** | **100** | **1.4** |
| *Electricity* | *8* | *19* | *24* | *26* | *28* | *30* | *25* | *28* | *1.9* |
| **TFC** | **250** | **452** | **574** | **636** | **690** | **740** | **100** | **100** | **2.1** |
| Coal | 6 | 11 | 14 | 16 | 17 | 18 | 3 | 2 | 1.9 |
| Oil | 122 | 210 | 260 | 277 | 289 | 298 | 46 | 40 | 1.5 |
| Gas | 24 | 69 | 92 | 106 | 120 | 136 | 15 | 18 | 2.9 |
| Electricity | 35 | 76 | 102 | 117 | 131 | 145 | 17 | 20 | 2.7 |
| Heat | - | - | - | - | - | - | - | - | n.a. |
| Bioenergy | 63 | 86 | 105 | 119 | 131 | 140 | 19 | 19 | 2.0 |
| Other renewables | - | 0 | 1 | 1 | 2 | 2 | 0 | 0 | 7.3 |
| **Industry** | **85** | **157** | **197** | **217** | **235** | **254** | **100** | **100** | **2.0** |
| Coal | 6 | 11 | 14 | 15 | 17 | 17 | 7 | 7 | 1.9 |
| Oil | 21 | 35 | 40 | 42 | 42 | 42 | 22 | 17 | 0.8 |
| Gas | 15 | 36 | 50 | 57 | 65 | 75 | 23 | 29 | 3.0 |
| Electricity | 16 | 32 | 41 | 46 | 51 | 56 | 21 | 22 | 2.3 |
| Heat | - | - | - | - | - | - | - | - | n.a. |
| Bioenergy | 27 | 42 | 52 | 56 | 61 | 64 | 27 | 25 | 1.8 |
| Other renewables | - | - | - | - | - | - | - | - | n.a. |
| **Transport** | **71** | **145** | **193** | **213** | **230** | **243** | **100** | **100** | **2.2** |
| Oil | 65 | 125 | 160 | 171 | 179 | 186 | 86 | 76 | 1.7 |
| Electricity | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 4.3 |
| Biofuels | 6 | 14 | 25 | 32 | 39 | 44 | 10 | 18 | 4.9 |
| Other fuels | 0 | 6 | 8 | 9 | 11 | 13 | 4 | 5 | 3.1 |
| **Buildings** | **68** | **98** | **116** | **128** | **138** | **149** | **100** | **100** | **1.7** |
| Coal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3.7 |
| Oil | 17 | 17 | 19 | 19 | 20 | 20 | 17 | 13 | 0.7 |
| Gas | 6 | 12 | 15 | 17 | 19 | 20 | 13 | 14 | 2.1 |
| Electricity | 17 | 41 | 57 | 66 | 75 | 83 | 42 | 56 | 2.9 |
| Heat | - | - | - | - | - | - | - | - | n.a. |
| Bioenergy | 27 | 27 | 24 | 23 | 23 | 23 | 27 | 15 | -0.7 |
| Other renewables | - | 0 | 1 | 1 | 2 | 2 | 0 | 2 | 7.3 |
| **Other** | **27** | **53** | **69** | **78** | **86** | **94** | **100** | **100** | **2.4** |

## **Latin America:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **735** | **902** | **982** | **690** | **773** | **804** | **100** | **100** | **2.2** | **1.3** |
| Coal | 32 | 45 | 49 | 29 | 33 | 32 | 5 | 4 | 3.4 | 1.5 |
| Oil | 302 | 334 | 349 | 273 | 245 | 229 | 36 | 28 | 1.4 | -0.4 |
| Gas | 169 | 230 | 263 | 148 | 163 | 170 | 27 | 21 | 3.0 | 1.2 |
| Nuclear | 10 | 12 | 12 | 10 | 17 | 17 | 1 | 2 | 3.3 | 4.7 |
| Hydro | 77 | 95 | 103 | 76 | 95 | 103 | 10 | 13 | 2.2 | 2.2 |
| Bioenergy | 136 | 167 | 182 | 143 | 192 | 212 | 19 | 26 | 2.0 | 2.7 |
| Other renewables | 10 | 18 | 24 | 11 | 28 | 40 | 2 | 5 | 8.4 | 10.8 |
| **Power generation** | **196** | **255** | **288** | **178** | **209** | **225** | **100** | **100** | **2.7** | **1.7** |
| Coal | 10 | 14 | 16 | 8 | 8 | 5 | 5 | 2 | 4.3 | -0.4 |
| Oil | 28 | 22 | 21 | 22 | 8 | 5 | 7 | 2 | -1.5 | -7.5 |
| Gas | 47 | 71 | 86 | 36 | 31 | 26 | 30 | 12 | 3.7 | -1.2 |
| Nuclear | 10 | 12 | 12 | 10 | 17 | 17 | 4 | 8 | 3.3 | 4.7 |
| Hydro | 77 | 95 | 103 | 76 | 95 | 103 | 36 | 46 | 2.2 | 2.2 |
| Bioenergy | 16 | 24 | 28 | 15 | 24 | 31 | 10 | 14 | 4.5 | 4.9 |
| Other renewables | 9 | 17 | 22 | 10 | 26 | 38 | 8 | 17 | 8.6 | 11.1 |
| **Other energy sector** | **89** | **108** | **114** | **83** | **93** | **96** | **100** | **100** | **1.6** | **0.9** |
| *Electricity* | *24* | *30* | *32* | *22* | *25* | *27* | *29* | *28* | *2.2* | *1.3* |
| **TFC** | **578** | **706** | **767** | **548** | **615** | **639** | **100** | **100** | **2.2** | **1.5** |
| Coal | 15 | 18 | 20 | 14 | 15 | 16 | 3 | 3 | 2.3 | 1.4 |
| Oil | 264 | 302 | 317 | 241 | 228 | 216 | 41 | 34 | 1.7 | 0.1 |
| Gas | 93 | 123 | 140 | 86 | 104 | 115 | 18 | 18 | 3.0 | 2.2 |
| Electricity | 104 | 138 | 154 | 96 | 118 | 130 | 20 | 20 | 3.0 | 2.2 |
| Heat | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Bioenergy | 102 | 124 | 134 | 110 | 147 | 160 | 17 | 25 | 1.9 | 2.6 |
| Other renewables | 1 | 2 | 2 | 1 | 2 | 2 | 0 | 0 | 6.7 | 7.3 |
| **Industry** | **200** | **245** | **265** | **189** | **214** | **228** | **100** | **100** | **2.2** | **1.6** |
| Coal | 14 | 18 | 20 | 13 | 15 | 16 | 7 | 7 | 2.3 | 1.4 |
| Oil | 41 | 45 | 45 | 38 | 37 | 36 | 17 | 16 | 1.1 | 0.1 |
| Gas | 50 | 68 | 78 | 47 | 55 | 61 | 29 | 27 | 3.2 | 2.2 |
| Electricity | 42 | 54 | 59 | 39 | 45 | 49 | 22 | 21 | 2.6 | 1.8 |
| Heat | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Bioenergy | 52 | 61 | 64 | 52 | 62 | 67 | 24 | 29 | 1.8 | 1.9 |
| Other renewables | - | - | - | - | - | - | - | - | n.a. | n.a. |
| **Transport** | **191** | **233** | **253** | **180** | **189** | **186** | **100** | **100** | **2.4** | **1.0** |
| Oil | 162 | 188 | 200 | 144 | 126 | 113 | 79 | 61 | 2.0 | -0.4 |
| Electricity | 0 | 1 | 1 | 0 | 1 | 1 | 0 | 1 | 4.1 | 6.7 |
| Biofuels | 21 | 33 | 39 | 28 | 53 | 60 | 16 | 32 | 4.4 | 6.3 |
| Other fuels | 8 | 11 | 13 | 7 | 9 | 12 | 5 | 6 | 3.2 | 3.0 |
| **Buildings** | **117** | **143** | **155** | **111** | **127** | **135** | **100** | **100** | **1.9** | **1.3** |
| Coal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3.8 | 2.9 |
| Oil | 19 | 20 | 21 | 18 | 19 | 19 | 13 | 14 | 0.9 | 0.4 |
| Gas | 16 | 19 | 21 | 15 | 17 | 18 | 14 | 13 | 2.2 | 1.5 |
| Electricity | 58 | 78 | 88 | 53 | 67 | 74 | 57 | 55 | 3.2 | 2.4 |
| Heat | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Bioenergy | 24 | 23 | 23 | 24 | 22 | 22 | 15 | 16 | -0.7 | -0.9 |
| Other renewables | 1 | 2 | 2 | 1 | 2 | 2 | 1 | 2 | 6.7 | 7.1 |
| **Other** | **69** | **86** | **94** | **68** | **84** | **91** | **100** | **100** | **2.4** | **2.3** |

## **Latin America:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **489** | **1 109** | **1 461** | **1 671** | **1 860** | **2 045** | **100** | **100** | **2.6** |
| Coal | 9 | 22 | 41 | 48 | 56 | 61 | 2 | 3 | 4.3 |
| Oil | 64 | 137 | 126 | 108 | 90 | 86 | 12 | 4 | -1.9 |
| Gas | 45 | 162 | 235 | 306 | 351 | 394 | 15 | 19 | 3.8 |
| Nuclear | 10 | 22 | 37 | 40 | 51 | 53 | 2 | 3 | 3.7 |
| Hydro | 354 | 715 | 896 | 1 003 | 1 098 | 1 186 | 65 | 58 | 2.1 |
| Bioenergy | 7 | 43 | 66 | 80 | 96 | 113 | 4 | 6 | 4.2 |
| Wind | - | 4 | 50 | 68 | 85 | 103 | 0 | 5 | 14.7 |
| Geothermal | 1 | 3 | 5 | 7 | 10 | 14 | 0 | 1 | 6.3 |
| Solar PV | - | 0 | 5 | 10 | 17 | 24 | 0 | 1 | 26.4 |
| CSP | - | - | - | 1 | 6 | 11 | - | 1 | n.a. |
| Marine | - | - | - | - | - | - | - | - | n.a. |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **249** | **349** | **400** | **450** | **497** | **100** | **100** | **2.9** |
| Coal | 5 | 8 | 9 | 10 | 11 | 2 | 2 | 2.8 |
| Oil | 38 | 41 | 38 | 34 | 34 | 15 | 7 | -0.5 |
| Gas | 47 | 69 | 85 | 102 | 116 | 19 | 23 | 3.9 |
| Nuclear | 3 | 5 | 6 | 7 | 7 | 1 | 1 | 3.6 |
| Hydro | 143 | 190 | 215 | 237 | 258 | 57 | 52 | 2.5 |
| Bioenergy | 10 | 15 | 17 | 20 | 22 | 4 | 4 | 3.1 |
| Wind | 2 | 15 | 20 | 25 | 29 | 1 | 6 | 11.7 |
| Geothermal | 1 | 1 | 1 | 1 | 2 | 0 | 0 | 5.5 |
| Solar PV | 0 | 4 | 7 | 11 | 16 | 0 | 3 | 29.5 |
| CSP | - | - | 0 | 1 | 3 | - | 1 | n.a. |
| Marine | - | - | - | - | - | - | - | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **576** | **1 088** | **1 329** | **1 431** | **1 511** | **1 587** | **100** | **100** | **1.6** |
| Coal | 44 | 81 | 111 | 125 | 138 | 145 | 7 | 9 | 2.4 |
| Oil | 415 | 720 | 856 | 887 | 907 | 926 | 66 | 58 | 1.0 |
| Gas | 116 | 287 | 362 | 419 | 466 | 516 | 26 | 33 | 2.5 |
| **Power generation** | **90** | **205** | **232** | **248** | **258** | **276** | **100** | **100** | **1.2** |
| Coal | 15 | 28 | 46 | 52 | 60 | 63 | 14 | 23 | 3.4 |
| Oil | 44 | 94 | 87 | 74 | 62 | 59 | 46 | 21 | -1.9 |
| Gas | 32 | 83 | 99 | 121 | 137 | 154 | 40 | 56 | 2.6 |
| **TFC** | **422** | **790** | **988** | **1 066** | **1 132** | **1 191** | **100** | **100** | **1.7** |
| Coal | 26 | 50 | 61 | 68 | 73 | 77 | 6 | 6 | 1.9 |
| Oil | 342 | 591 | 729 | 772 | 803 | 825 | 75 | 69 | 1.4 |
| *Transport* | *193* | *373* | *479* | *511* | *537* | *556* | *47* | *47* | *1.7* |
| Gas | 54 | 150 | 198 | 227 | 256 | 289 | 19 | 24 | 2.8 |

## **Latin America:** Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **1 489** | **1 948** | **2 169** | **1 378** | **1 673** | **1 817** | **100** | **100** | **2.8** | **2.1** |
| Coal | 41 | 64 | 72 | 34 | 33 | 23 | 3 | 1 | 5.0 | 0.1 |
| Oil | 128 | 99 | 97 | 99 | 38 | 21 | 4 | 1 | -1.4 | -7.5 |
| Gas | 264 | 431 | 516 | 197 | 180 | 153 | 24 | 8 | 4.9 | -0.2 |
| Nuclear | 37 | 47 | 48 | 37 | 64 | 66 | 2 | 4 | 3.3 | 4.7 |
| Hydro | 894 | 1 107 | 1 195 | 885 | 1 106 | 1 202 | 55 | 66 | 2.2 | 2.2 |
| Bioenergy | 66 | 94 | 110 | 63 | 95 | 117 | 5 | 6 | 4.0 | 4.3 |
| Wind | 51 | 82 | 95 | 49 | 104 | 147 | 4 | 8 | 14.3 | 16.4 |
| Geothermal | 5 | 9 | 13 | 6 | 15 | 21 | 1 | 1 | 5.8 | 8.0 |
| Solar PV | 5 | 13 | 17 | 6 | 28 | 50 | 1 | 3 | 24.7 | 30.4 |
| CSP | - | 3 | 7 | 2 | 9 | 15 | 0 | 1 | n.a. | n.a. |
| Marine | - | - | - | - | 0 | 2 | - | 0 | n.a. | n.a. |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **352** | **459** | **510** | **338** | **434** | **494** | **100** | **100** | **3.0** | **2.9** |
| Coal | 8 | 11 | 12 | 7 | 8 | 7 | 2 | 1 | 3.3 | 0.9 |
| Oil | 42 | 37 | 37 | 41 | 33 | 33 | 7 | 7 | -0.1 | -0.6 |
| Gas | 71 | 110 | 130 | 61 | 72 | 80 | 25 | 16 | 4.3 | 2.3 |
| Nuclear | 5 | 6 | 6 | 5 | 9 | 9 | 1 | 2 | 3.2 | 4.5 |
| Hydro | 190 | 240 | 261 | 188 | 239 | 261 | 51 | 53 | 2.5 | 2.5 |
| Bioenergy | 15 | 19 | 21 | 15 | 19 | 21 | 4 | 4 | 3.0 | 3.0 |
| Wind | 16 | 24 | 27 | 15 | 31 | 45 | 5 | 9 | 11.3 | 13.7 |
| Geothermal | 1 | 1 | 2 | 1 | 2 | 3 | 0 | 1 | 5.1 | 7.2 |
| Solar PV | 4 | 9 | 12 | 4 | 18 | 31 | 2 | 6 | 28.0 | 33.2 |
| CSP | - | 1 | 2 | 1 | 2 | 4 | 0 | 1 | n.a. | n.a. |
| Marine | - | - | - | - | 0 | 1 | - | 0 | n.a. | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **1 358** | **1 611** | **1 735** | **1 207** | **1 096** | **1 015** | **100** | **100** | **2.0** | **-0.3** |
| Coal | 114 | 153 | 167 | 101 | 88 | 71 | 10 | 7 | 3.0 | -0.5 |
| Oil | 869 | 953 | 995 | 779 | 671 | 606 | 57 | 60 | 1.4 | -0.7 |
| Gas | 375 | 505 | 574 | 327 | 337 | 338 | 33 | 33 | 2.9 | 0.7 |
| **Power generation** | **244** | **302** | **341** | **193** | **125** | **91** | **100** | **100** | **2.1** | **-3.3** |
| Coal | 46 | 67 | 75 | 39 | 28 | 15 | 22 | 17 | 4.2 | -2.4 |
| Oil | 89 | 68 | 66 | 69 | 26 | 14 | 19 | 16 | -1.4 | -7.5 |
| Gas | 110 | 167 | 200 | 85 | 71 | 61 | 59 | 67 | 3.7 | -1.3 |
| **TFC** | **1 003** | **1 185** | **1 269** | **915** | **882** | **846** | **100** | **100** | **2.0** | **0.3** |
| Coal | 63 | 80 | 86 | 58 | 57 | 52 | 7 | 6 | 2.3 | 0.2 |
| Oil | 740 | 842 | 884 | 672 | 614 | 566 | 70 | 67 | 1.7 | -0.2 |
| *Transport* | *485* | *563* | *599* | *432* | *377* | *337* | *47* | *40* | *2.0* | *-0.4* |
| Gas | 200 | 263 | 298 | 185 | 211 | 228 | 24 | 27 | 2.9 | 1.8 |

## **Brazil:** New Policies Scenario

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **TPED** | **138** | **267** | **352** | **398** | **441** | **480** | **100** | **100** | **2.5** |
| Coal | 10 | 15 | 19 | 21 | 23 | 24 | 6 | 5 | 1.9 |
| Oil | 59 | 109 | 141 | 150 | 158 | 165 | 41 | 34 | 1.7 |
| Gas | 3 | 23 | 38 | 52 | 64 | 77 | 9 | 16 | 5.2 |
| Nuclear | 1 | 4 | 6 | 6 | 8 | 8 | 2 | 2 | 2.9 |
| Hydro | 18 | 37 | 44 | 49 | 54 | 58 | 14 | 12 | 1.9 |
| Bioenergy | 48 | 78 | 99 | 113 | 127 | 138 | 29 | 29 | 2.4 |
| Other renewables | - | 1 | 5 | 6 | 9 | 11 | 0 | 2 | 12.4 |
| **Power generation** | **22** | **58** | **82** | **98** | **113** | **128** | **100** | **100** | **3.3** |
| Coal | 2 | 3 | 4 | 5 | 5 | 5 | 5 | 4 | 2.4 |
| Oil | 1 | 3 | 2 | 2 | 2 | 2 | 5 | 2 | -1.7 |
| Gas | 0 | 5 | 10 | 16 | 20 | 25 | 9 | 19 | 6.8 |
| Nuclear | 1 | 4 | 6 | 6 | 8 | 8 | 7 | 6 | 2.9 |
| Hydro | 18 | 37 | 44 | 49 | 54 | 58 | 63 | 46 | 1.9 |
| Bioenergy | 1 | 6 | 11 | 14 | 17 | 20 | 10 | 15 | 5.2 |
| Other renewables | - | 0 | 4 | 6 | 7 | 9 | 0 | 7 | 16.7 |
| **Other energy sector** | **26** | **39** | **48** | **54** | **59** | **61** | **100** | **100** | **2.0** |
| *Electricity* | *3* | *10* | *12* | *14* | *16* | *17* | *25* | *28* | *2.4* |
| **TFC** | **111** | **219** | **287** | **322** | **356** | **388** | **100** | **100** | **2.4** |
| Coal | 4 | 8 | 9 | 10 | 11 | 12 | 4 | 3 | 2.0 |
| Oil | 53 | 100 | 131 | 139 | 147 | 154 | 46 | 40 | 1.8 |
| Gas | 2 | 14 | 22 | 27 | 33 | 41 | 6 | 11 | 4.7 |
| Electricity | 18 | 39 | 53 | 63 | 71 | 79 | 18 | 20 | 3.0 |
| Heat | - | - | - | - | - | - | - | - | n.a. |
| Bioenergy | 34 | 57 | 71 | 82 | 92 | 99 | 26 | 26 | 2.3 |
| Other renewables | - | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 5.0 |
| **Industry** | **40** | **82** | **105** | **119** | **133** | **148** | **100** | **100** | **2.5** |
| Coal | 4 | 8 | 9 | 10 | 11 | 12 | 9 | 8 | 2.0 |
| Oil | 8 | 13 | 15 | 16 | 17 | 17 | 15 | 11 | 1.2 |
| Gas | 1 | 9 | 15 | 19 | 24 | 30 | 12 | 20 | 4.8 |
| Electricity | 10 | 18 | 23 | 26 | 30 | 34 | 22 | 23 | 2.6 |
| Heat | - | - | - | - | - | - | - | - | n.a. |
| Bioenergy | 17 | 35 | 43 | 48 | 52 | 55 | 42 | 38 | 2.0 |
| Other renewables | - | - | - | - | - | - | - | - | n.a. |
| **Transport** | **33** | **74** | **105** | **115** | **124** | **132** | **100** | **100** | **2.4** |
| Oil | 27 | 59 | 81 | 84 | 88 | 92 | 80 | 70 | 1.8 |
| Electricity | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4.6 |
| Biofuels | 6 | 13 | 21 | 27 | 32 | 35 | 17 | 27 | 4.3 |
| Other fuels | 0 | 2 | 3 | 3 | 4 | 4 | 3 | 3 | 3.0 |
| **Buildings** | **23** | **35** | **41** | **47** | **52** | **57** | **100** | **100** | **2.1** |
| Coal | - | - | - | - | - | - | - | - | n.a. |
| Oil | 6 | 7 | 9 | 9 | 10 | 10 | 21 | 18 | 1.5 |
| Gas | 0 | 1 | 1 | 2 | 2 | 2 | 2 | 4 | 6.3 |
| Electricity | 8 | 19 | 28 | 33 | 38 | 42 | 56 | 74 | 3.3 |
| Heat | - | - | - | - | - | - | - | - | n.a. |
| Bioenergy | 9 | 7 | 3 | 2 | 1 | 1 | 21 | 2 | -7.9 |
| Other renewables | - | 0 | 1 | 1 | 1 | 1 | 1 | 2 | 5.0 |
| **Other** | **15** | **27** | **36** | **41** | **46** | **51** | **100** | **100** | **2.6** |

## **Brazil:** Current Policies and 450 Scenarios

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **TPED** | **356** | **455** | **502** | **334** | **392** | **416** | **100** | **100** | **2.7** | **1.9** |
| Coal | 19 | 25 | 28 | 17 | 17 | 17 | 6 | 4 | 2.6 | 0.4 |
| Oil | 143 | 165 | 174 | 129 | 117 | 112 | 35 | 27 | 2.0 | 0.1 |
| Gas | 42 | 71 | 88 | 32 | 43 | 51 | 18 | 12 | 5.8 | 3.4 |
| Nuclear | 6 | 8 | 8 | 6 | 11 | 11 | 2 | 3 | 2.9 | 4.2 |
| Hydro | 44 | 55 | 60 | 44 | 54 | 58 | 12 | 14 | 2.0 | 1.9 |
| Bioenergy | 97 | 122 | 134 | 102 | 142 | 156 | 27 | 37 | 2.3 | 2.9 |
| Other renewables | 5 | 8 | 10 | 5 | 9 | 11 | 2 | 3 | 12.0 | 12.6 |
| **Power generation** | **84** | **120** | **138** | **73** | **95** | **106** | **100** | **100** | **3.7** | **2.5** |
| Coal | 4 | 6 | 7 | 3 | 1 | 1 | 5 | 1 | 3.4 | -6.3 |
| Oil | 2 | 2 | 2 | 1 | 1 | 1 | 2 | 1 | -1.6 | -3.4 |
| Gas | 12 | 25 | 33 | 5 | 5 | 7 | 24 | 7 | 8.2 | 1.3 |
| Nuclear | 6 | 8 | 8 | 6 | 11 | 11 | 6 | 10 | 2.9 | 4.2 |
| Hydro | 44 | 55 | 60 | 44 | 54 | 58 | 43 | 55 | 2.0 | 1.9 |
| Bioenergy | 11 | 16 | 19 | 10 | 15 | 18 | 14 | 17 | 5.0 | 4.8 |
| Other renewables | 4 | 7 | 9 | 4 | 8 | 10 | 6 | 9 | 16.2 | 16.9 |
| **Other energy sector** | **49** | **61** | **65** | **47** | **56** | **57** | **100** | **100** | **2.2** | **1.7** |
| *Electricity* | *12* | *16* | *18* | *11* | *14* | *15* | *28* | *26* | *2.7* | *1.8* |
| **TFC** | **289** | **365** | **402** | **275** | **318** | **338** | **100** | **100** | **2.6** | **1.8** |
| Coal | 9 | 13 | 14 | 9 | 10 | 11 | 4 | 3 | 2.5 | 1.4 |
| Oil | 134 | 154 | 163 | 120 | 108 | 103 | 41 | 31 | 2.0 | 0.1 |
| Gas | 22 | 34 | 43 | 21 | 29 | 34 | 11 | 10 | 4.8 | 3.9 |
| Electricity | 54 | 75 | 85 | 49 | 63 | 70 | 21 | 21 | 3.2 | 2.5 |
| Heat | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Bioenergy | 69 | 88 | 96 | 75 | 107 | 117 | 24 | 35 | 2.2 | 3.0 |
| Other renewables | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 4.8 | 4.8 |
| **Industry** | **108** | **139** | **155** | **102** | **123** | **135** | **100** | **100** | **2.7** | **2.1** |
| Coal | 9 | 13 | 14 | 9 | 10 | 11 | 9 | 8 | 2.6 | 1.4 |
| Oil | 15 | 18 | 19 | 14 | 14 | 15 | 12 | 11 | 1.7 | 0.6 |
| Gas | 15 | 24 | 31 | 14 | 19 | 23 | 20 | 17 | 5.0 | 3.8 |
| Electricity | 24 | 31 | 36 | 22 | 27 | 29 | 23 | 22 | 2.9 | 2.1 |
| Heat | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Bioenergy | 44 | 52 | 56 | 43 | 53 | 57 | 36 | 42 | 2.0 | 2.1 |
| Other renewables | - | - | - | - | - | - | - | - | n.a. | n.a. |
| **Transport** | **104** | **125** | **135** | **99** | **103** | **101** | **100** | **100** | **2.5** | **1.3** |
| Oil | 83 | 93 | 98 | 71 | 52 | 45 | 73 | 45 | 2.1 | -1.1 |
| Electricity | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 1 | 4.4 | 7.2 |
| Biofuels | 18 | 28 | 32 | 25 | 46 | 51 | 24 | 50 | 3.9 | 5.9 |
| Other fuels | 3 | 4 | 4 | 3 | 4 | 5 | 3 | 4 | 3.2 | 3.6 |
| **Buildings** | **42** | **55** | **61** | **38** | **47** | **51** | **100** | **100** | **2.4** | **1.7** |
| Coal | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Oil | 9 | 10 | 11 | 8 | 9 | 10 | 17 | 19 | 1.7 | 1.3 |
| Gas | 1 | 2 | 3 | 1 | 2 | 2 | 4 | 4 | 6.7 | 5.7 |
| Electricity | 28 | 40 | 46 | 25 | 33 | 37 | 75 | 72 | 3.6 | 2.8 |
| Heat | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Bioenergy | 3 | 1 | 1 | 3 | 1 | 1 | 2 | 2 | -7.9 | -7.2 |
| Other renewables | 1 | 1 | 1 | 1 | 1 | 1 | 2 | 3 | 4.8 | 4.8 |
| **Other** | **36** | **46** | **51** | **36** | **45** | **50** | **100** | **100** | **2.6** | **2.6** |

## **Brazil:** New Policies Scenario

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total generation** | **223** | **532** | **725** | **855** | **973** | **1 085** | **100** | **100** | **3.0** |
| Coal | 5 | 13 | 19 | 21 | 23 | 25 | 2 | 2 | 2.9 |
| Oil | 5 | 14 | 10 | 10 | 10 | 10 | 3 | 1 | -1.7 |
| Gas | 0 | 26 | 59 | 100 | 128 | 157 | 5 | 14 | 7.7 |
| Nuclear | 2 | 16 | 23 | 25 | 31 | 31 | 3 | 3 | 2.9 |
| Hydro | 207 | 429 | 516 | 574 | 627 | 676 | 81 | 62 | 1.9 |
| Bioenergy | 4 | 32 | 51 | 61 | 72 | 84 | 6 | 8 | 4.1 |
| Wind | - | 3 | 44 | 59 | 72 | 85 | 1 | 8 | 15.5 |
| Geothermal | - | - | - | - | - | - | - | - | n.a. |
| Solar PV | - | - | 3 | 5 | 8 | 12 | - | 1 | n.a. |
| CSP | - | - | - | - | 2 | 5 | - | 0 | n.a. |
| Marine | - | - | - | - | - | - | - | - | n.a. |

| | Electrical capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total capacity** | **114** | **171** | **202** | **232** | **260** | **100** | **100** | **3.5** |
| Coal | 3 | 4 | 4 | 4 | 5 | 3 | 2 | 2.0 |
| Oil | 7 | 11 | 11 | 11 | 11 | 6 | 4 | 1.7 |
| Gas | 10 | 15 | 24 | 32 | 40 | 9 | 16 | 6.1 |
| Nuclear | 2 | 3 | 3 | 4 | 4 | 2 | 2 | 3.0 |
| Hydro | 82 | 110 | 125 | 138 | 151 | 72 | 58 | 2.6 |
| Bioenergy | 8 | 12 | 14 | 15 | 16 | 7 | 6 | 2.8 |
| Wind | 1 | 13 | 17 | 20 | 23 | 1 | 9 | 12.3 |
| Geothermal | - | - | - | - | - | - | - | n.a. |
| Solar PV | - | 2 | 4 | 6 | 8 | - | 3 | n.a. |
| CSP | - | - | - | 1 | 1 | - | 0 | n.a. |
| Marine | - | - | - | - | - | - | - | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2011 | 2020 | 2025 | 2030 | 2035 | 2011 | 2035 | 2011-35 |
| **Total $CO_2$** | **192** | **409** | **543** | **601** | **653** | **703** | **100** | **100** | **2.3** |
| Coal | 27 | 55 | 69 | 76 | 83 | 89 | 13 | 13 | 2.0 |
| Oil | 159 | 303 | 388 | 409 | 429 | 446 | 74 | 63 | 1.6 |
| Gas | 7 | 51 | 87 | 116 | 141 | 168 | 12 | 24 | 5.1 |
| **Power generation** | **12** | **39** | **54** | **70** | **82** | **94** | **100** | **100** | **3.8** |
| Coal | 8 | 17 | 24 | 26 | 29 | 30 | 44 | 32 | 2.4 |
| Oil | 4 | 10 | 7 | 7 | 7 | 7 | 25 | 7 | -1.6 |
| Gas | 0 | 12 | 23 | 37 | 47 | 58 | 30 | 61 | 6.8 |
| **TFC** | **165** | **344** | **451** | **487** | **524** | **562** | **100** | **100** | **2.1** |
| Coal | 16 | 34 | 40 | 45 | 50 | 54 | 10 | 10 | 1.9 |
| Oil | 144 | 279 | 362 | 382 | 400 | 418 | 81 | 74 | 1.7 |
| *Transport* | *81* | *178* | *243* | *253* | *264* | *276* | *52* | *49* | *1.8* |
| Gas | 5 | 31 | 48 | 60 | 74 | 91 | 9 | 16 | 4.6 |

## **Brazil:** Current Policies and 450 Scenarios

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total generation** | **741** | **1 022** | **1 160** | **670** | **861** | **956** | **100** | **100** | **3.3** | **2.5** |
| Coal | 19 | 27 | 31 | 14 | 6 | 3 | 3 | 0 | 3.9 | -6.2 |
| Oil | 10 | 10 | 10 | 6 | 6 | 6 | 1 | 1 | -1.7 | -3.5 |
| Gas | 75 | 161 | 216 | 26 | 29 | 43 | 19 | 5 | 9.2 | 2.1 |
| Nuclear | 23 | 31 | 31 | 23 | 41 | 42 | 3 | 4 | 2.9 | 4.2 |
| Hydro | 515 | 644 | 696 | 506 | 627 | 676 | 60 | 71 | 2.0 | 1.9 |
| Bioenergy | 51 | 71 | 82 | 48 | 67 | 79 | 7 | 8 | 4.0 | 3.8 |
| Wind | 45 | 70 | 80 | 43 | 73 | 88 | 7 | 9 | 15.1 | 15.6 |
| Geothermal | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Solar PV | 3 | 7 | 10 | 3 | 9 | 14 | 1 | 1 | n.a. | n.a. |
| CSP | - | 1 | 4 | - | 2 | 5 | 0 | 1 | n.a. | n.a. |
| Marine | - | - | - | - | 0 | 1 | - | 0 | n.a. | n.a. |

| | Electrical capacity (GW) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total capacity** | **171** | **237** | **268** | **163** | **217** | **243** | **100** | **100** | **3.6** | **3.2** |
| Coal | 4 | 5 | 5 | 3 | 3 | 3 | 2 | 1 | 2.4 | -0.4 |
| Oil | 11 | 11 | 11 | 11 | 11 | 11 | 4 | 4 | 1.7 | 1.6 |
| Gas | 15 | 34 | 46 | 11 | 18 | 25 | 17 | 10 | 6.6 | 3.9 |
| Nuclear | 3 | 4 | 4 | 3 | 5 | 5 | 2 | 2 | 3.0 | 4.2 |
| Hydro | 110 | 142 | 156 | 107 | 138 | 151 | 58 | 62 | 2.7 | 2.6 |
| Bioenergy | 12 | 15 | 16 | 12 | 14 | 15 | 6 | 6 | 2.8 | 2.4 |
| Wind | 13 | 20 | 22 | 13 | 20 | 23 | 8 | 10 | 12.0 | 12.4 |
| Geothermal | - | - | - | - | - | - | - | - | n.a. | n.a. |
| Solar PV | 2 | 5 | 7 | 2 | 7 | 9 | 3 | 4 | n.a. | n.a. |
| CSP | - | 0 | 1 | - | 1 | 1 | 0 | 1 | n.a. | n.a. |
| Marine | - | - | - | - | 0 | 0 | - | 0 | n.a. | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2030 | 2035 | 2020 | 2030 | 2035 | 2035 | | 2011-35 | |
| | Current Policies Scenario | | | 450 Scenario | | | CPS | 450 | CPS | 450 |
| **Total $CO_2$** | **560** | **702** | **774** | **482** | **435** | **411** | **100** | **100** | **2.7** | **0.0** |
| Coal | 70 | 94 | 105 | 61 | 50 | 42 | 14 | 10 | 2.7 | -1.1 |
| Oil | 396 | 451 | 474 | 350 | 298 | 272 | 61 | 66 | 1.9 | -0.5 |
| Gas | 94 | 157 | 195 | 70 | 87 | 97 | 25 | 24 | 5.7 | 2.7 |
| **Power generation** | **60** | **98** | **122** | **35** | **23** | **24** | **100** | **100** | **4.9** | **-2.0** |
| Coal | 24 | 33 | 38 | 19 | 8 | 4 | 31 | 15 | 3.3 | -6.3 |
| Oil | 7 | 7 | 7 | 4 | 4 | 4 | 5 | 18 | -1.6 | -3.4 |
| Gas | 29 | 58 | 78 | 11 | 11 | 16 | 64 | 67 | 8.2 | 1.3 |
| **TFC** | **460** | **554** | **601** | **411** | **376** | **359** | **100** | **100** | **2.4** | **0.2** |
| Coal | 42 | 56 | 62 | 38 | 38 | 35 | 10 | 10 | 2.5 | 0.2 |
| Oil | 370 | 422 | 446 | 328 | 278 | 255 | 74 | 71 | 2.0 | -0.4 |
| *Transport* | *248* | *279* | *295* | *212* | *157* | *136* | *49* | *38* | *2.1* | *-1.1* |
| Gas | 49 | 76 | 94 | 46 | 60 | 68 | 16 | 19 | 4.7 | 3.3 |

# Policies and measures by scenario

The *World Energy Outlook 2013* (*WEO-2013*) presents projections for three scenarios, which are differentiated primarily by their underlying assumptions about government policies.

The ***Current Policies Scenario*** is based on the implementation of the government policies and measures that had been enacted by mid-2013.

The ***New Policies Scenario*** – our central scenario – takes into account broad policy commitments and plans that have already been implemented to address energy-related challenges as well as those that have been announced, even where the specific measures to implement these commitments have yet to be introduced. It assumes only cautious implementation of current commitments and plans.

The ***450 Scenario*** sets out an energy pathway that is consistent with a 50% chance of meeting the goal of limiting the increase in average global temperature to 2 °C compared with pre-industrial levels. For the period to 2020, the 450 Scenario assumes more vigorous policy action to implement fully the Cancun Agreements than is assumed in the New Policies Scenario. After 2020, OECD countries and other major economies are assumed to set economy-wide emissions targets for 2035 and beyond to collectively ensure an emissions trajectory consistent with stabilisation of the greenhouse-gas concentration at 450 parts per million.

The key policies that are assumed to be adopted in each of the main scenarios of *WEO-2013* 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 they have been adopted in this year's *Outlook*.

## Table B.1 ▷ Cross-cutting policy assumptions by scenario for selected regions

| | Current Policies Scenario | New Policies Scenario | 450 Scenario |
|---|---|---|---|
| **OECD** | | | • Staggered introduction of $CO_2$ prices in all countries.<br>• $100 billion financing provided to non-OECD countries by 2020. |
| United States | • State-level renewable portfolio standards (RPS) that include the option of using energy efficiency as a means of compliance.<br>• Regional Greenhouse Gas Initiative (RGGI): mandatory cap-and-trade scheme covering fossil-fuel power plants in nine northeast states including recycling of revenues for energy efficiency and renewable energy investments.<br>• State-wide cap-and-trade scheme in California with binding commitments. | | • 17% reduction in greenhouse-gas (GHG) emissions by 2020 compared with 2005.<br>• $CO_2$ pricing implemented from 2020. |
| Japan[1] | | | • 25% reduction in GHG emissions by 2020 compared with 1990.<br>• $CO_2$ pricing implemented from 2020. |
| European Union | • EU-level target to reduce GHG emissions by 20% in 2020, relative to 1990.<br>• EU Emissions Trading System.<br>• Renewables to reach a share of 20% in energy demand in 2020. | • Partial implementation of the EU-level target to reduce primary energy consumption by 20% in 2020:<br>  ○ Partial implementation of the EU Energy Efficiency Directive.<br>  ○ National Energy Efficiency Action Plans. | • 30% reduction in GHG emissions by 2020 compared with 1990.<br>• Emissions Trading System strengthened in line with the 2050 roadmap.<br>• Full implementation of the EU Energy Efficiency Directive. |
| Australia and New Zealand | • Australia: Clean Energy Future Package - carbon prices through taxes/emissions trading scheme as of mid-2015.<br>• New Zealand: emissions trading scheme from 2010. | • Australia: 5% reduction in GHG emissions by 2020 compared with 2000.<br>• New Zealand: 10% cut in GHG emissions by 2020 compared with 1990. | • Australia: 25% reduction in GHG emissions by 2020 compared with 2000.<br>• New Zealand: 20% reduction in GHG emissions by 2020 compared with 1990. |
| Korea | • Cap-and-trade scheme from 2015 ($CO_2$ emissions reductions of 4% by 2020 compared with 2005). | • 30% reduction in GHG emissions by 2020 compared with business-as-usual. | • 30% reduction in GHG emissions by 2020 compared with business-as-usual.<br>• Higher $CO_2$ prices. |

[1] Japan is reviewing its basic policies on energy and climate change, some of which are expected to be announced by the end of 2013.

**Table B.1 ▷ Cross-cutting policy assumptions by scenario for selected regions** (continued)

| | Current Policies Scenario | New Policies Scenario | 450 Scenario |
|---|---|---|---|
| **Non-OECD** | • Fossil-fuel subsidies are phased out in countries that already have policies in place to do so. | • 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. | • Finance for domestic mitigation.<br>• Fossil-fuel subsidies are phased out within the next ten years in all net-importer and in net-exporters by 2035.* |
| Russia | • Gradual real increases in residential gas and electricity prices (1% per year) and in gas prices in industry (1.5% per year).<br>• Implementation of 2009 energy efficiency legislation. | • 15% reduction in GHG emissions by 2020 compared with 1990.<br>• 2% per year real rise in residential gas and electricity prices.<br>• Industrial gas prices reach export prices (minus taxes and transport) in 2020.<br>• Partial implementation of the 2010 energy efficiency state programme. | • 25% reduction in GHG emissions by 2020, compared with 1990.<br>• Quicker rise in residential gas and electricity prices.<br>• $CO_2$ pricing from 2020.<br>• More support for nuclear and renewables.<br>• Full implementation of the 2010 energy efficiency state programme. |
| China | • 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. | • 40% reduction in $CO_2$ intensity compared with 2005 by 2020.<br>• $CO_2$ pricing from 2020.<br>• Share of 15% of non-fossil fuel in total supply by 2020.<br>• Energy price reform including more frequent adjustments in oil product prices and Increase in natural gas price by 15% for non-residential users. | • 45% reduction in $CO_2$ intensity by 2020 compared with 2005; higher $CO_2$ pricing.<br>• Reduction of local air pollutants between 2010 and 2015 (reduction of 8% for sulphur dioxide, 10% for nitrogen oxides). |
| India | • Trading of renewable energy certificates.<br>• National solar mission and national mission on enhanced energy efficiency.<br>• 11th Five-Year Plan (2007-2012). | • 20% reduction in $CO_2$ intensity by 2020 compared with 2005. | • 25% reduction in $CO_2$ intensity by 2020 compared with 2005. |
| Brazil | • Implementation of National Energy Efficiency Plan. | • 36% reduction in GHG emissions by 2020 compared with business-as-usual.<br>• Strengthened implementation of National Energy Efficiency Plan. | • 39% reduction in GHG emissions by 2020 compared with business-as-usual.<br>• $CO_2$ pricing from 2020. |

*Except the Middle East where subsidisation rates are assumed to decline to a maximum of 20% by 2035.

Note: Pricing of $CO_2$ emissions is either by an emissions trading scheme (ETS) or taxes.

**Table B.2 ▷ Power sector policies and measures as modelled by scenario in selected regions**

| | Current Policies Scenario | New Policies Scenario | 450 Scenario |
|---|---|---|---|
| **OECD** | | | |
| United States | • State-level renewable portfolio standards (RPS) and support for renewables prolonged over the projection period.<br>• Mercury and Air Toxics Standard.<br>• Clean Air Interstate Rule regulating sulphur dioxide and nitrogen oxides.<br>• Lifetimes of most US nuclear plants extended beyond 60 years.<br>• Funding for CCS (demonstration-scale). | • Extension and strengthening of support for renewables and nuclear, including loan guarantees.<br>• Cautious implementation of carbon pollution standards on new power plants.<br>• Shadow price of carbon assumed from 2015, affecting investment decisions in power generation capacity. | • $CO_2$ pricing implemented from 2020.<br>• Extended support to renewables, nuclear and CCS.<br>• Efficiency and emission standards preventing refurbishment of old inefficient plants.<br>• Full implementation of the carbon pollution standards on existing power plants by 2030. |
| Japan | • Support for renewables generation.<br>• Decommissioning of units 1-4 of Fukushima Daiichi nuclear power plant. | • Shadow price of carbon assumed from 2015, affecting investment decisions in power generation.<br>• Lifetime of nuclear power plants limited to 40 years for plants built up to 1990 and 50 years for all others.<br>• Increased support for renewables generation. | • $CO_2$ pricing implemented from 2020.<br>• Share of low-carbon electricity generation to increase by 2020 and expand further by 2030.<br>• Expansion of renewables support.<br>• Introduction of CCS to coal-fired power generation. |
| European Union | • Climate and Energy Package:<br>○ Emissions Trading System.<br>○ Support for renewables sufficient to reach 20% share of energy demand in 2020.<br>○ Financial support for CCS.<br>• Early retirement of all nuclear plants in Germany by the end of 2022.<br>• Removal of some barriers to combined heat and power (CHP) plants resulting from the Cogeneration Directive 2004. | • Extended and strengthened support to renewables-based electricity generation technologies.<br>• Further removal of barriers to CHP through partial implementation of the Energy Efficiency Directive. | • Emissions Trading System strengthened in line with the 2050 roadmap.<br>• Reinforcement of government support in favour of renewables.<br>• Expanded support measures for CCS. |

Note: CCS = carbon capture and storage.

## Table B.2 ▷ Power sector policies and measures as modelled by scenario in selected regions (continued)

| | Current Policies Scenario | New Policies Scenario | 450 Scenario |
|---|---|---|---|
| **Non-OECD** | | | |
| Russia | • Competitive wholesale electricity market. | • State support to the nuclear and hydropower sectors; a support mechanism for non-hydro renewables introduced from 2014. | • $CO_2$ pricing implemented from 2020.<br>• Stronger support for nuclear power and renewables. |
| China | • Implementation of measures in 12th Five-Year Plan.<br>• Start construction of 40 GW of new nuclear plants by 2015.<br>• Reach 290 GW of installed hydro capacity by 2015.<br>• Reach 100 GW of installed wind capacity by 2015.<br>• 35 GW of solar capacity by 2015.<br>• Priority given to gas use to 2015. | • 12th Five-Year Plan renewables targets for 2015 are exceeded.<br>• 70 to 80 GW of nuclear capacity by 2020.<br>• 200 GW of wind capacity by 2020.<br>• 30 GW of bioenergy capacity by 2020.<br>• $CO_2$ pricing implemented from 2020. | • Higher $CO_2$ pricing.<br>• Enhanced support for renewables.<br>• Continued support to nuclear capacity additions post 2020.<br>• Deployment of CCS from around 2020. |
| India | • Renewable Energy Certificate trade for all eligible grid-connected renewable-based electricity generation technologies.<br>• National solar mission target of 20 GW of solar PV capacity by 2022.<br>• Increased use of supercritical coal technology. | • Renewable energy support policies and targets, including small hydro.<br>• Coal-fired power stations energy efficiency mandates. | • Renewables (excluding large hydro) to reach 15% of installed capacity by 2020.<br>• Expanded support to renewables, nuclear and efficient coal.<br>• Deployment of CCS from around 2020. |
| Brazil | • Power auctions for all fuel types.<br>• Guidance on the fuel mix from the Ten-Year Plan for Energy Expansion. | • Enhanced deployment of renewables technologies through power auctions. | • $CO_2$ pricing implemented from 2020.<br>• Further increases of generation from renewable sources. |

Note: CCS = carbon capture and storage.

## Table B.3 ▷ Transport sector policies and measures as modelled by scenario in selected regions

| | Current Policies Scenario | New Policies Scenario | 450 Scenario |
|---|---|---|---|
| **OECD** | | | **All OECD** |
| United States | • CAFE standards: 35.5 miles per gallon for PLDVs by 2016, and further strengthening thereafter.<br>• Renewables Fuel Standard.<br>• Truck standards for each model year from 2014 to 2018 reduce average on-road fuel consumption by up to 18% in 2018. | • CAFE standards: 54.5 miles per gallon for PLDVs by 2025.<br>• Renewables Fuel Standard.<br>• Truck standards for each model year from 2014 to 2018 reduce average on-road fuel consumption by up to 20% in 2018, and further strengthening thereafter.<br>• Support to natural gas in road freight.<br>• Increase of ethanol blending mandates. | • On-road emission targets for PLDVs in 2035: 60 g $CO_2$/km<br>• Light-commercial vehicles: full technology spill-over from PLDVs.<br>• Medium- and heavy-freight vehicles: 45% more efficient by 2035 than in New Policies Scenario.<br>• Aviation: 50% efficiency improvements by 2035 (compared with 2010) and support for the use of biofuels.<br>• Other sectors (*e.g.* maritime and rail): national policies and measures.<br>• Fuels: retail fuel prices kept at a level similar to New Policies Scenario.<br>• Alternative clean fuels: enhanced support to alternative fuels. |
| Japan | • Fuel economy target for PLDVs: 16.8 kilometres per litre (km/l) by 2015 and 20.3 km/l by 2020.<br>• Average fuel economy target for road freight vehicles: 7.09 km/l by 2015.<br>• Fiscal incentives for hybrid and electric vehicles; subsidies for electric vehicles. | • Target share of next generation vehicles 50% by 2020. | |
| European Union | • $CO_2$ emission standards for PLDVs by 2015 (130 g $CO_2$/km through efficiency measures, additional 10 g $CO_2$/km by alternative fuels).<br>• Support to biofuels. | • Climate and Energy Package: Target to reach 10% of transport energy demand in 2020 by renewable fuels.<br>• More stringent emission target for PLDVs (95 g $CO_2$/km by 2020), and further strengthening after 2020.<br>• Emission target for LCVs (147 g $CO_2$/km by 2020), and further strengthening post 2020.<br>• Enhanced support to alternative fuels. | |

Note: CAFE = Corporate Average Fuel Economy; PLDVs = passenger light-duty vehicles; LCV = light-commercial vehicles.

**Table B.3 ▷ Transport sector policies and measures as modelled by scenario in selected regions** (continued)

| | Current Policies Scenario | New Policies Scenario | 450 Scenario |
|---|---|---|---|
| **Non-OECD** | | | **All non-OECD** |
| China | • Subsidies for hybrid and electric vehicles.<br>• Promotion of fuel-efficient cars.<br>• Ethanol blending mandates 10% in selected provinces.<br>• Upper threshold on PLDV sales in some cities.<br>• Enhance infrastructure for electric vehicle in selected cities. | • Fuel economy target for PLDVs: 6.9 l/100 km by 2015, 5.0 l/100 km by 2020.<br>• Extended subsidies for purchase of alternative-fuel vehicles.<br>• Complete fossil fuel subsidy phase-out within the next ten years. | • On-road emission targets for PLDVs in 2035: 80 g $CO_2$/km<br>• Light-commercial vehicles: full technology spill-over from PLDVs.<br>• Medium- and heavy-freight vehicles: 45% more efficient by 2035 than in New Policies Scenario.<br>• Aviation: 50% efficiency improvements by 2035 (compared with 2010) and support for the use of biofuels.<br>• Other sectors (*e.g.* maritime and rail): national policies and measures.<br>• Fuels: retail fuel prices kept at a level similar to New Policies Scenario.<br>• Alternative clean fuels: enhanced support to alternative fuels. |
| India | • Support for alternative fuel vehicles. | • Extended support for alternative-fuel vehicles.<br>• Proposed automobile fuel efficiency standards to reduce average test-cycle fuel consumption by 1.3% per year between 2010 and 2020.<br>• Increased utilisation of natural gas in road transport.<br>• National Electric Mobility Mission Plan 2020.<br>• All fossil-fuel subsidies are phased out within the next ten years. | |
| Brazil | • Ethanol blending mandates in road transport between 18% and 25%.<br>• Biodiesel blending mandate of 5%. | • Increase of ethanol and biodiesel blending mandates.<br>• Local renewable fuel targets for urban transport.<br>• Concessions to improve port, road, rail and air infrastructure, as per the Accelerated Growth Programme 2011-2014.<br>• Long-term plan for freight transport (PNLT), developed by the Ministry of Transport.<br>• National urban mobility plan (PNMU), developed by the Ministry of Cities | |

Note: PLDVs = passenger light-duty vehicles.

## Table B.4 ▷ Industry sector policies and measures as modelled by scenario in selected regions

| | Current Policies Scenario | New Policies Scenario | 450 Scenario |
|---|---|---|---|
| **OECD** | | | **All OECD** |
| United States | • Better Buildings, Better Plants programme.<br>• Energy Star Program for Industry.<br>• Climate Voluntary Innovative Sector Initiatives: Opportunities Now.<br>• Boiler maximum achievable control technology rule to impose stricter emissions limits on industrial and commercial boilers and process heaters. | • Tax reduction and funding for efficient technologies.<br>• R&D in low-carbon technologies.<br>• Energy Savings and Industrial Competitiveness Act. | • $CO_2$ pricing introduced from 2025 at the latest in all countries.<br>• International sectoral agreements with energy intensity targets for iron and steel, and cement industries.<br>• Enhanced energy efficiency standards.<br>• Policies to support the introduction of CCS in industry. |
| Japan | • Mandatory energy efficiency benchmarking.<br>• Tax credit for investments in energy efficiency.<br>• Mandatory energy management for large business operators.<br>• Top Runner Programme setting minimum energy standards, including for lighting, space heating, and transformers. | • Maintenance and strengthening of top-end/low carbon efficiency standards by:<br>o Higher efficiency CHP systems.<br>o Promotion of state-of-the-art technology and faster replacement of aging equipment. | |
| European Union | • Emissions Trading System.<br>• Eco-Design Directive (including minimum standards for electric motors, pumps, fans, compressors and insulation).<br>• Voluntary energy efficiency agreements in several countries. | • Partial implementation of Energy Efficiency Directive:<br>o Mandatory and regular energy audits for large enterprises.<br>o Incentives for the use of energy management systems.<br>o Encouragement for SMEs to undergo energy audit.<br>o Technical assistance and targeted information for SMEs.<br>o Training programmes for auditors. | |

Note: R&D = research and development; CHP = combined heat and power; CCS = carbon capture and storage.

## Table B.4 ▷ Industry sector policies and measures as modelled by scenario in selected regions (continued)

| | Current Policies Scenario | New Policies Scenario | 450 Scenario |
|---|---|---|---|
| **Non-OECD** | | | **All non-OECD** |
| Russia | • Competitive wholesale electricity market price.<br>• Mandatory energy audits and energy management systems for energy-intensive industries.<br>• Complete phase-out of open hearth furnaces in the iron and steel industry. | • Industrial gas prices reach the equivalent of export prices (minus taxes and transportation) in 2020.<br>• Very cautious implementation of the "Energy saving and increase of energy efficiency for the period till 2020" programme.<br>• Limited phase-out of natural gas subsidy. | • $CO_2$ pricing introduced as of 2020 in Russia, China, Brazil and South Africa.<br>• Wider hosting of international offset projects.<br>• International sectoral agreements with targets for iron and steel, and cement industries.<br>• Enhanced energy efficiency standards.<br>• Policies to support the introduction of CCS in industry. |
| China | • Top 10 000 energy-consuming enterprises programme.<br>• Small plant closures and phasing out of outdated production capacity.<br>• Partial implementation of Industrial Energy Performance Standard.<br>• Ten Key Projects.<br>• Mandatory adoption of coke dry quenching and top-pressure turbines in new iron and steel plants / Support non-blast furnace iron making.<br>• Priority given to gas use to 2015 (12th Five-Year Plan). | • Contain the expansion of energy-intensive industries.<br>• $CO_2$ pricing implemented from 2020.Partial implementation of reduction in industrial energy intensity by 21% during the 12th Five-Year Plan period (2011-2015).<br>• Full implementation of Industrial Energy Performance Standard.<br>• Enhanced use of energy service companies and energy performance contracting.<br>• All fossil-fuel subsidies are phased out within the next ten years. | |
| India | • 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.<br>• Energy Conservation Act:<br>  ○ Mandatory energy audits, appointment of an energy manager in seven energy-intensive industries. | • Further implementation of National Mission for Enhanced Energy Efficiency recommendations including:<br>  ○ Enhancement of cost-effective improvements in energy efficiency in energy-intensive large industries and facilities through tradable certificates (extension of PAT).<br>  ○ Financing mechanism for demand-side management programmes.<br>  ○ Development of fiscal instruments to promote energy efficiency.<br>• All fossil-fuel subsidies are phased out within the next ten years. | |
| Brazil | • PROCEL (National Program for Energy Conversation).<br>• PROESCO (Support for Energy Efficiency Projects). | • Partial implementation of the National Energy Efficiency Plan:<br>  ○ Fiscal and tax incentives for industrial upgrading.<br>  ○ Invest in training efficiency.<br>  ○ Encourage the use of industrial waste.<br>• Extension of PROESCO. | |

Note: CCS = carbon capture and storage.

**Table B.5 ▷ Buildings sector policies and measures as modelled by scenario in selected regions**

| | Current Policies Scenario | New Policies Scenario | 450 Scenario |
|---|---|---|---|
| **OECD** | | | |
| United States | • AHAM-ACEEE Multi-Product Standards Agreement.<br>• Energy Star: federal tax credits for consumer energy efficiency; new appliance efficiency standards.<br>• Energy Improvement and Extension Act of 2008.<br>• Budget proposals 2011 - institute programmes to make commercial buildings 20% more efficient by 2020; tax credit for renewable energy deployment.<br>• Weatherization program: provision of funding for refurbishments of residential 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 PV and solar thermal water heaters.<br>• Mandatory energy requirements in building codes in some states.<br>• Introduction of the Energy Savings and Industrial Competitiveness Act of 2013 strengthening building codes, creating a financing initiative and incentivising the use of efficient motors.<br>• Tightening of efficiency standards for appliances. | • Mandatory energy requirements in building codes in all states by 2020.<br>• Extension of energy efficiency grants to end of projection period.<br>• Zero-energy buildings initiative. |
| Japan | • Top-Runner Programme.<br>• Long-Term Outlook on Energy Supply and Demand (2009): energy savings using demand-side management. | • Extension of the Top Runner Programme to include windows and insulating materials; high-efficiency lighting: 100% in public facilities by 2020; 100% of lighting stock by 2030.<br>• Voluntary buildings labelling; national voluntary equipment labelling programmes.<br>• Net zero-energy buildings by 2030 for all new construction.<br>• Increased introduction of gas and renewable energy.<br>• High-efficiency lighting: 100% in public facilities by 2020; 100% of all lighting by 2030. | • Rigorous and mandatory building energy codes for all new and existing buildings.<br>• Net zero-energy buildings by 2025 for all new construction.<br>• Strengthening of high-efficiency lighting for non-public buildings. |
| European Union | • Energy Performance of Buildings Directive.<br>• Eco-Design and Energy Labelling Directive.<br>• EU-US Energy Star Agreement: energy labelling of appliances. | • Partial implementation of the Energy Efficiency Directive.<br>• Implementation of regulations for vacuum cleaners and computers within the framework of the Ecodesign Directive.<br>• 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.<br>• Mandatory energy labelling for sale or rental of all buildings and some appliances, lighting and equipment.<br>• Further product groups in EcoDesign Directive.<br>• Phase-out of incandescent light bulbs. | • Zero-carbon footprint for all new buildings as of 2015; enhanced energy efficiency in all existing buildings.<br>• Full implementation of the Energy Efficiency Directive.<br>• Accelerated phase-out of incandescent light bulbs.<br>• Mandatory energy conservation standards and labelling requirements for all equipment and appliances, space and water heating and cooling systems by 2020. |

Notes: ACEEE = American Council for an Energy-Efficient Economy; AHAM = Association of Home Appliance Manufacturers.

## Table B.5 ▷ Buildings sector policies and measures as modelled by scenario in selected regions (continued)

| | Current Policies Scenario | New Policies Scenario | 450 Scenario |
|---|---|---|---|
| **Non-OECD** | | | |
| Russia | • Implementation of 2009 energy efficiency legislation.<br>• Voluntary labelling program for electrical products.<br>• Restriction on sale of incandescent light bulbs. | • Gradual above-inflation increase in residential electricity and gas prices.<br>• New building codes, meter installations and refurbishment programmes. Information and awareness on energy efficiency classes for appliances.<br>• Phase-out of incandescent >100 Watt light bulbs.<br>• Limited phase-out of natural gas and electricity subsidies. | • Faster liberalisation of gas and electricity prices.<br>• Extension and reinforcement of all measures included in the 2010 energy efficiency state programme; mandatory building codes by 2030 and phase-out of inefficient equipment and appliances by 2030. |
| China | • Civil Construction Energy Conservation Design Standard.<br>• Appliance standards and labelling programme. | • Energy efficient buildings to account for 30% of all new construction projects by 2020.<br>• 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.<br>• 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.<br>• Energy Price Policy (reform heating price to be based on actual consumption, rather than on living area supplied).<br>• Mandatory energy efficiency labels for appliances and equipment.<br>• Labelling mandatory for new, large commercial and governmental buildings in big cities.<br>• Introduction of energy standards for new buildings & refurbishment of existing dwellings.<br>• Phase-out of incandescent light bulbs production over the next ten years.<br>• All fossil-fuel subsidies are phased out within the next ten years. | • More stringent implementation of Civil Construction Energy Conservation Design Standard.<br>• Mandatory energy efficiency labels for all appliances and also for building shell.<br>• Faster Energy Price Policy reform to set stronger incentives for energy savings.<br>• Partial Implementation of the Building Conservation Plan, which foresees that 95% of new buildings achieve savings of 55%- 65% in space heating compared to 1980, depending on the climate zone. |
| India | • Measures under national solar mission.<br>• Energy Conservation Building Code 2007, with voluntary requirements for commercial and residential buildings. | • Mandatory standards and labels for room air conditioners and refrigerators, voluntary for five other products. (More stringent minimum energy performance standards for air conditioners).<br>• Phase-out of incandescent light bulbs by 2020.<br>• Voluntary Star Ratings for the services sector.<br>• National Action Plan in Climate Change: Measures concerning building sector in the National Mission on Enhanced Energy Efficiency.<br>• Energy Conservation in Building Code made mandatory in eight states and applies among others to building envelope, lighting and hot water.<br>• All fossil-fuel subsidies are phased out within the next ten years. | • Mandatory energy conservation standards and labelling requirements for all equipment and appliances by 2025.<br>• Increased penetration of energy efficient lighting. |
| Brazil | • Labelling programme for household goods, public buildings equipment. | • Implementation of National Energy Efficiency Plan. | |

# Definitions

This annex provides general information on terminology used throughout *WEO-2013* including: units and general conversion factors; definitions on fuels, processes and sectors; regional and country groupings; and, abbreviations and acronyms.

## Units

| | | |
|---|---|---|
| **Area** | Ha | hectare |
| | GHa | giga-hectare (1 hectare x $10^9$) |
| | $km^2$ | square kilometre |
| **Coal** | Mtce | million tonnes of coal equivalent |
| **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** | Mtce | million tonnes of coal equivalent (equals 0.7 Mtoe) |
| | boe | barrels of oil equivalent |
| | toe | tonne of oil equivalent |
| | ktoe | kilotonne 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 | barrels per day |
| | kb/d | thousand barrels per day |
| | mb/d | million barrels per day |
| | Mboe/d | million barrels equivalent per day |
| | mpg | miles per gallon |
| **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 $10^9$) |
| | $GW_{th}$ | gigawatt thermal (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 |

## Currency conversions

| *Exchange rates (2012)* | 1 US Dollar equals: |
|---|---|
| Australian Dollar | 0.97 |
| Brazilian Real | 1.95 |
| British Pound | 0.63 |
| Canadian Dollar | 1.00 |
| Chinese Yuan | 6.31 |
| Euro | 0.78 |
| Indian Rupee | 53.44 |
| Japanese Yen | 79.81 |
| Korean Won | 1 125.93 |
| Russian Ruble | 30.84 |

## Definitions

### *Advanced biofuels*

Advanced biofuels comprise different emerging and novel conversion technologies that are currently in the research and development, pilot or demonstration phase. This definition differs from the one used for "Advanced Biofuels" in US legislation, which is based on a minimum 50% lifecycle greenhouse-gas reduction and which, therefore, includes sugarcane ethanol.

### *Advanced biomass cookstoves*

Advanced biomass cookstoves are biomass gasifier-operated cooking stoves that run on solid biomass, such as wood chips and briquettes. These cooking devices have significantly lower emissions and higher efficiencies than the traditional biomass cookstoves (three-stone fires) currently used largely in developing countries.

### *Agriculture*

Includes all energy used on farms, in forestry and for fishing.

### *Biodiesel*

Biodiesel is a diesel-equivalent, processed fuel made from the transesterification (a chemical process that converts triglycerides in oils) of vegetable oils and animal fats.

### *Bioenergy*

Refers to the energy content in solid, liquid and gaseous products derived from biomass feedstocks and biogas. This includes biofuels for transport and products (*e.g.* wood chips, pellets, black liquor) to produce electricity and heat as well as traditional biomass. Municipal solid waste and industrial waste are also included.

### *Biofuels*

Biofuels are fuels derived from biomass or waste feedstocks and include ethanol and biodiesel. They can be classified as conventional and advanced biofuels according to the technologies used to produce them and their respective maturity.

### *Biogas*

A mixture of methane and carbon dioxide produced by bacterial degradation of organic matter and used as a fuel.

### *Brown coal*

Includes lignite and sub-bituminous coal where lignite is defined as non-agglomerating coal with a gross calorific value less than 4 165 kilocalories per kilogramme (kcal/kg) and sub-bituminous coal is defined as non-agglomerating coal with a gross calorific value between 4 165 - 5 700 kcal/kg.

### *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*

Capacity credit refers to the proportion of capacity that can be reliably expected to generate electricity during times of peak demand in the grid to which it is connected.

### *Clean coal technologies*

Clean coal technologies are designed to enhance the efficiency and the environmental acceptability of coal extraction, preparation and use.

### *Clean cooking facilities*

Cooking facilities which can be used without significant harm to the health of those in the household. This refers primarily to biogas systems, liquefied petroleum gas stoves and advanced biomass cookstoves.

### *Coal*

Coal includes both primary coal (including hard coal and brown coal) and derived fuels (including patent fuel, brown-coal briquettes, coke-oven coke, gas coke, gas-works gas, coke-oven gas, blast-furnace gas and oxygen steel furnace gas). Peat is also included.

### *Coalbed methane*

Methane found in coal seams. Coalbed methane (CBM) is a category of unconventional natural gas.

### *Coal-to-liquids*

Coal-to-liquids (CTL) refers to the transformation of coal into liquid hydrocarbons. It can be achieved through either coal gasification into syngas (a mixture of hydrogen and carbon monoxide), combined 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*

Coking coal is a type of hard coal that can be used in the production of coke, which is capable of supporting a blast furnace charge.

### *Condensates*

Condensates are liquid hydrocarbon mixtures recovered from associated or nonassociated gas reservoirs. They are composed of C5 and higher carbon number hydrocarbons and normally have an API gravity between 50° and 85°.

### *Conventional biofuels*

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.

### *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.

### *Ethanol*

Although ethanol can be produced from a variety of fuels, in this publication, 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*

Gas includes natural gas, both associated and non-associated with petroleum deposits, but excludes natural gas liquids.

### *Gas-to-liquids*

Gas-to-liquids refers to a process featuring reaction of methane with oxygen or steam to produce syngas (a mixture of hydrogen and carbon monoxide) followed by synthesis of liquid products (such as diesel and naphtha) from the syngas using Fischer-Tropsch catalytic synthesis. The process is similar to those used in coal-to-liquids.

### *Hard coal*

Coal of gross calorific value greater than 5 700 kilocalories per kilogramme on an ash-free but moist basis. Hard coal can be further disaggregated into anthracite, coking coal and other bituminous coal.

### *Heat energy*

Heat is obtained from the combustion of fuels, nuclear reactors, geothermal reservoirs, capture of sunlight, exothermic chemical processes and heat pumps which can extract it from ambient air and liquids. It may be used for 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.

### *Heavy petroleum products*

Heavy petroleum products include heavy fuel oil.

### *Hydropower*

Hydropower refers to the energy content of the electricity produced in hydropower plants, assuming 100% efficiency. It excludes output from pumped storage and marine (tide and wave) plants.

### *Industry*

The industry sector includes fuel used within the manufacturing and construction industries. Key industry sectors include iron and steel, chemical and petrochemical, non-metallic minerals, and pulp and paper. Use by industries for the transformation of energy into another form or for the production of fuels is excluded and reported separately under other energy sector. Consumption of fuels for the transport of goods is reported as part of the transport sector.

### *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.

### *Light petroleum products*

Light petroleum products include liquefied petroleum gas (LPG), naphtha and gasoline.

### *Lignocellulosic feedstock*

Lignocellulosic crops refers to those crops cultivated to produce biofuels from their cellulosic or hemicellulosic components, which include switchgrass, poplar and miscanthus.

### *Lower heating value*

Lower heating value is the 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*

Middle distillates include jet fuel, diesel and heating oil.

### *Modern biomass*

Includes all biomass with the exception of traditional biomass.

### *Modern energy access*

Reliable and affordable access by a household to clean cooking facilities, a first connection to electricity and then an increasing level of electricity consumption over time.

### *Modern renewables*

Includes all types of renewables with the exception of traditional biomass.

### *Natural decline rate*

The base production decline rate that an oil or gas field would have in the absence of further investment.

### *Natural gas liquids*

Natural gas liquids (NGLs) are the 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*

Nuclear refers to the primary energy equivalent of the electricity produced by a nuclear plant, assuming an average conversion efficiency of 33%.

### *Observed decline rate*

The measured production decline rate of an oil or gas field; the operator of the field normally invests every year in measures that boost production or reduce its decline (for example infill drilling) so that the observed decline rate is not as large as the natural decline rate. For a group of fields, the observed decline rate is aggregated in a production-weighted average decline rate.

### *Oil*

Oil includes crude oil, condensates, natural gas liquids, refinery feedstocks and additives, other hydrocarbons (including emulsified oils, synthetic crude oil, mineral oils extracted from bituminous minerals such as oil shale, bituminous sand and oils from coal liquefaction) and petroleum products (refinery gas, ethane, LPG, aviation gasoline, motor gasoline, jet fuels, kerosene, gas/diesel oil, heavy fuel oil, naphtha, white spirit, lubricants, bitumen, paraffin waxes and petroleum coke).

### *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*

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.

### *Renewables*

Includes bioenergy, geothermal, hydropower, solar photovoltaics (PV), concentrating solar power (CSP), wind and marine (tide and wave) energy for electricity and heat generation.

### *R/P ratio*

Reserves-to-production (R/P) ratio is based on the sum of reported proven reserves and the last year of available data for production.

### *Self-sufficiency*

Self-sufficiency is indigenous production divided by total primary energy demand.

### *Total final consumption*

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*

Total primary energy demand (TPED) represents domestic demand only and is broken down into power generation, other energy sector and total final consumption.

### *Traditional biomass*

Traditional biomass refers to fuelwood, charcoal, animal dung and some agricultural residues.

### *Traditional use of biomass for cooking*

Refers to basic technologies used to cook with biomass, such as a three-stone fire, traditional mud stoves or metal, cement and pottery or brick stoves, often with no (or poorly operating) chimneys or hoods.

### *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, Democratic Republic of Congo, Côte d'Ivoire, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan[1], United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other African countries and territories[2].

### *Annex I Parties to the United Nations Framework Convention on Climate Change*

Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey, Ukraine, United Kingdom and United States.

### *APEC (Asia-Pacific Economic Co-operation)*

Australia, Brunei Darussalam, Canada, Chile, China, Chinese Taipei, Indonesia, Hong Kong (China), Japan, Korea, Malaysia, Mexico, New Zealand, Papua New Guinea, Peru, Philippines, Russia, Singapore, Thailand, United States and Vietnam.

### *ASEAN*

Brunei Darussalam, Cambodia, Indonesia, Lao PDR, Malaysia, Myanmar, Philippines, Singapore, Thailand and Vietnam.

### *Caspian*

Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyz Republic, Tajikistan, Turkmenistan and Uzbekistan.

1. Because only aggregated data were available until 2011, the data for Sudan also include South Sudan.

2. Individual data is not available for: Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Niger, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland, Uganda and Western Sahara. Data is estimated in aggregate for these regions.

### *China*

Refers to the People's Republic of China, including Hong Kong.

### *Developing Asia*

See Non-OECD Asia.

### *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[3,4], Gibraltar and Malta.

### *European Union*

Austria, Belgium, Bulgaria, Croatia, Cyprus[3,4], 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, the Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and other Latin American countries and territories[5].

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3. Footnote by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

4. Footnote by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

5. Individual data is not available for: Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, St. Kitts and Nevis, Saint Lucia, Saint Pierre et Miquelon, St. Vincent and the Grenadines, Suriname and Turks and Caicos Islands. Data is estimated in aggregate for these regions.

### *Middle East*

Bahrain, the Islamic Republic of Iran, Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, United Arab Emirates and Yemen. It includes the neutral zone between Saudi Arabia and Iraq.

### *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, Vietnam and other Asian countries and territories[6].

### *North Africa*

Algeria, Egypt, Libya, Morocco and Tunisia.

### *OECD*

Includes OECD Europe, OECD Americas and OECD Asia Oceania 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[7].

### *OPEC*

Algeria, Angola, Ecuador, the Islamic Republic of Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela.

### *Other Asia*

Non-OECD Asia regional grouping excluding China and India.

### *Southeast Asia*

See ASEAN.

### *Sub-Saharan Africa*

Africa regional grouping excluding the North African regional grouping.

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6. Individual data is not available for: Afghanistan, Bhutan, Cook Islands, East Timor, Fiji, French Polynesia, Kiribati, Lao PDR, Macau, Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Tonga and Vanuatu. Data is estimated in aggregate for these regions.

7. The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

# Abbreviations and Acronyms

| | |
|---|---|
| **ANP** | National Agency of Petroleum, Natural Gas and Biofuels (Brazil) |
| **APEC** | Asia-Pacific Economic Cooperation |
| **API** | American Petroleum Institute |
| **ASEAN** | Association of Southeast Asian Nations |
| **BTL** | biomass-to-liquids |
| **BGR** | German Federal Institute for Geosciences and Natural Resources |
| **BRICS** | Brazil, Russia, India, China and South Africa |
| **CAAGR** | compound average annual growth rate |
| **CAFE** | corporate average fuel economy (standards in the United States) |
| **CBM** | coalbed methane |
| **CER** | certified emissions reduction |
| **CCGT** | combined-cycle gas turbine |
| **CCS** | carbon capture and storage |
| **CDM** | Clean Development Mechanism (under the Kyoto Protocol) |
| **CFL** | compact fluorescent lamp |
| $CH_4$ | methane |
| **CHP** | combined heat and power; the term co-generation is sometimes used |
| **CMM** | coal mine methane |
| **CNG** | compressed natural gas |
| **CO** | carbon monoxide |
| $CO_2$ | carbon dioxide |
| $CO_2$**-eq** | carbon dioxide equivalent |
| **COP** | Conference of Parties (UNFCCC) |
| **CPS** | Current Policies Scenario |
| **CSP** | concentrating solar power |
| **CSS** | cyclic steam stimulation |
| **CTL** | coal-to-liquids |
| **CV** | calorific value |
| **E&P** | exploration and production |
| **EDI** | Energy Development Index |
| **EOR** | enhanced oil recovery |
| **EPA** | Environmental Protection Agency (United States) |
| **EPC** | engineering, procurement and construction |
| **EPE** | Empresa de Pesquisa Energética (Brazil) |
| **ESCO** | energy service company |
| **EU** | European Union |
| **EUA** | European Union allowances |
| **EU ETS** | European Union Emissions Trading System |
| **EV** | electric vehicle |
| **EWS** | Efficient World Scenario |

| | |
|---|---|
| **FAO** | Food and Agriculture Organization of the United Nations |
| **FDI** | foreign direct investment |
| **FFV** | flex-fuel vehicle |
| **FOB** | free on board |
| **FPSO** | floating production, storage and offloading unit |
| **GCV** | gross calorific value |
| **GDP** | gross domestic product |
| **GHG** | greenhouse gases |
| **GT** | gas turbine |
| **GTL** | gas-to-liquids |
| **HDI** | Human Development Index |
| **HDV** | heavy-duty vehicles |
| **HFO** | heavy fuel oil |
| **IAEA** | International Atomic Energy Agency |
| **ICE** | internal combustion engine |
| **ICT** | information and communication technologies |
| **IGCC** | integrated gasification combined-cycle |
| **IIASA** | International Institute for Applied Systems Analysis |
| **IMF** | International Monetary Fund |
| **IOC** | international oil company |
| **IPCC** | Intergovernmental Panel on Climate Change |
| **IPP** | independent power producer |
| **LCV** | light commercial vehicle |
| **LDV** | light-duty vehicle |
| **LED** | light-emitting diode |
| **LHV** | lower heating value |
| **LNG** | liquefied natural gas |
| **LPG** | liquefied petroleum gas |
| **LRMC** | long-run marginal cost |
| **LTO** | light tight oil |
| **LULUCF** | land use, land-use change and forestry |
| **MER** | market exchange rate |
| **MDGs** | Millennium Development Goals |
| **MEPS** | minimum energy performance standards |
| **NCV** | net calorific value |
| **NEA** | Nuclear Energy Agency (an agency within the OECD) |
| **NGL** | natural gas liquids |
| **NGV** | natural gas vehicle |
| **NOC** | national oil company |
| **$NO_x$** | nitrogen oxides |
| **NPS** | New Policies Scenario |

| | |
|---|---|
| **OCGT** | open-cycle gas turbine |
| **ODI** | outward foreign direct investment |
| **OECD** | Organisation for Economic Co-operation and Development |
| **OPEC** | Organization of the Petroleum Exporting Countries |
| **PHEV** | plug-in hybrid |
| **PLDV** | passenger light-duty vehicle |
| **PM** | particulate matter |
| **$PM_{2.5}$** | particulate matter with a diameter of 2.5 micrometres or less |
| **PPP** | purchasing power parity |
| **PSA** | production-sharing agreement |
| **PV** | photovoltaic |
| **RD&D** | research, development and demonstration |
| **RDD&D** | research, development, demonstration and deployment |
| **RRR** | remaining recoverable resource |
| **SAGD** | steam-assisted gravity drainage |
| **SCO** | synthetic crude oil |
| **$SO_2$** | sulphur dioxide |
| **SRMC** | short-run marginal cost |
| **T&D** | transmission and distribution |
| **TFC** | total final consumption |
| **TPED** | total primary energy demand |
| **UAE** | United Arab Emirates |
| **UCG** | underground coal gasification |
| **UN** | United Nations |
| **UNDP** | United Nations Development Programme |
| **UNEP** | United Nations Environment Programme |
| **UNFCCC** | United Nations Framework Convention on Climate Change |
| **UNIDO** | United Nations Industrial Development Organization |
| **UNPD** | United Nations Population Division |
| **URR** | ultimate recoverable resource |
| **US** | United States |
| **USC** | ultra-supercritical |
| **USGS** | United States Geological Survey |
| **WEO** | World Energy Outlook |
| **WEM** | World Energy Model |
| **WHO** | World Health Organization |
| **WTI** | West Texas Intermediate |
| **WTO** | World Trade Organization |
| **WTW** | well-to-wheel |

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