International Energy Agency

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Special Report

WORLD ENERGY **INVESTMENT** OUTLOOK

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Questions about the reliability, affordability and sustainability of our energy future often boil down to questions about investment. But are investors ready to commit capital in a fast-changing energy world? This special report in the *World Energy Outlook* series takes up this question in a full and comprehensive update of the energy investment picture to 2035 – a first full update since the 2003 *World Energy Investment Outlook*. With benchmark data on past investment trends and updated projections for investment at regional and global level, the report provides insights into:

- The structure of ownership and models for financing investment in different parts of the energy sector.
- The continued importance of oil investment in the Middle East to meet demand, and the consequences of delay in such investment.
- The dynamics and costs of LNG investment and how this can shape the future of global gas supply.
- Where investment in the power sector might fall short of what is required, with important findings on the reliability of electricity supply in Europe and in India.
- The outlook for investment in low-carbon technologies, including renewables, and energy efficiency and the barriers to their realisation.
- How global investment and financing requirements change if governments take stronger action to address climate change.

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INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 29 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

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

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International Energy Agency
9 rue de la Fédération
75739 Paris Cedex 15, France

www.iea.org

Investment is a topic close to the heart of the International Energy Agency. Without it, the core element of the Agency's mission, to promote a secure and reliable energy system, will not materialise. Yet data on today's investment flows have not been readily available and projections and costs for tomorrow's investment needs are often absent from the debate about the future of the energy sector. Filling these gaps, the comprehensive picture drawn together here by Dr. Fatih Birol and his team in the Agency's Directorate of Global Energy Economics is a good example of the service that the IEA seeks to provide to our member countries, to the wider energy community and to society at large.

The headline numbers revealed by this analysis are almost too large to register: $48 trillion of cumulative investment in energy supply and efficiency are required by 2035 in our main scenario; an even higher sum, $53 trillion, with a different composition and a greater accent on energy efficiency, is needed to move us onto an alternative path that gives us a chance of meeting the 2 °C climate change target.

These figures give us a sense of the magnitude of the task ahead. But, as always, the devil – and the interest – is in the detail. This report breaks down the investment challenge into its component parts, picking up a few of them for special analysis where there is a risk of investment or financing falling short and spelling out the potential consequences of these shortfalls for regional or energy security.

Among a rich choice of findings, the report highlights how governments are ever more active in shaping energy markets and investment decisions, motivated by a range of policy concerns and by increasing public awareness on a range of energy and environmental issues. But their interventions, if not carefully designed and consistently implemented, can also deter the private investors and private capital upon which governments depend to realise their objectives.

This report also shines a welcome light on the importance of the financial industry to the energy debate. Along with many other experts who generously gave advice and comments, I am pleased to acknowledge the contribution that we received from the world of finance. The availability of finance on suitable terms to meet energy investors' needs should not be taken for granted. There is room for much closer dialogue between governments, the energy community and the financial community on how to align future supply and demand for investment finance in the energy sector.

Bridging fields of expertise in this way is essential for future energy and economic security, and this is an area where the IEA will continue to do its utmost. In this spirit, I trust that the information and insights in this report will be of lasting use to a wide range of readers. Governments, businesses and households are all investors in energy; all of us have a stake in making productive, efficient and sustainable choices over the decades to come.

This report is published under my authority as Executive Director of the IEA.

Maria van der Hoeven
Executive Director
International Energy Agency

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Comments and questions are welcome and should be addressed to:

Dr. Fatih Birol
Chief Economist
Director, Directorate of Global Energy Economics
International Energy Agency
9, rue de la Fédération
75739 Paris Cedex 15
France

Telephone: (33-1) 4057 6670
Email: weo@iea.org

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

More than \$1 600 billion was invested in 2013 to provide the world's consumers with energy, a figure that has more than doubled in real terms since 2000; and a further \$130 billion to improve energy efficiency. A full picture of global energy investment trends – compiled for the first time in this special report – underlines the growing role played by renewable sources of energy, in which annual investment increased from \$60 billion in 2000 to a high point approaching \$300 billion in 2011, before falling back since to \$250 billion. The largest share of current investment, more than \$1 100 billion per year, is related to the extraction and transport of fossil fuels, oil refining and the construction of fossil fuel-fired power plants.

Over the period to 2035, the investment required each year to supply the world's energy needs rises steadily towards \$2 000 billion, while annual spending on energy efficiency increases to \$550 billion. This amounts to a cumulative global investment bill of more than \$48 trillion, consisting of around \$40 trillion in energy supply and the remainder in energy efficiency. The main components of energy supply investment are the \$23 trillion in fossil fuel extraction, transport and oil refining; almost \$10 trillion in power generation, of which low-carbon technologies – renewables (\$6 trillion) and nuclear (\$1 trillion)[1] – account for almost three-quarters, and a further \$7 trillion in transmission and distribution. Nearly two-thirds of this investment takes place in emerging economies, with the focus for investment moving beyond China to other parts of Asia, Africa and Latin America; but ageing infrastructure and climate policies create large requirements also across the OECD.

Less than half of the \$40 trillion investment in energy supply goes to meet growth in demand, the larger share is required to offset declining production from existing oil and gas fields and to replace power plants and other assets that reach the end of their productive life. Compensating for output declines absorbs more than 80% of upstream oil and gas spending. Replacing power plants that are retired triggers almost 60% of investment in electricity generation in OECD countries, although a much smaller share in emerging economies. These declines and retirements set a major re-investment challenge for policymakers and the industry, but they also represent a real opportunity to change the nature of the energy system by switching fuels or deploying more efficient technologies.

Of the \$8 trillion investment in energy efficiency to 2035, 90% is spent in the transport and buildings sectors, reflecting policy ambitions and remaining efficiency potentials. The European Union, North America and China together account for two-thirds of the total, reflecting the size of their car markets and the vehicle efficiency standards in place or planned; efforts in the European Union and in North America to improve the efficiency of electrical appliances and the buildings stock; and China's priority to upgrade the efficiency of its industry. In other emerging economies, the lack of targeted policies and access to finance, as well as the persistence in some countries of fossil-fuel subsidies, pose serious obstacles to investments in energy efficiency.

1. Nuclear power will be covered in detail in this year's *World Energy Outlook*, published in November 2014.

Decisions to commit capital to the energy sector are increasingly shaped by government policy measures and incentives, rather than by signals coming from competitive markets. In many countries, governments have direct influence over energy sector investment, for example, through retained ownership of more than 70% of global oil and gas reserves or control of nearly half of the world's power generation capacity, via state-owned companies. Some governments, notably in the OECD, stepped back from direct influence when opening energy markets to competition, but many have now stepped back in, typically to promote the deployment of low-carbon sources of electricity. In the oil sector, reliance on countries with more restrictive terms of access to their resources is set to grow, as output from North America plateaus and then falls back from the mid-2020s onwards. In the electricity sector, administrative signals or regulated rates of return have become, by far, the most important drivers for investment: the share of investment in competitive parts of electricity markets has fallen from about one-third of the global total ten years ago to around 10% today. With current market designs, of the $16 trillion required in the power sector to 2035, investment in competitive parts of electricity markets would account for less than $1 trillion.

Private sector participation is essential to meet energy investment needs in full, but mobilising private investors and capital will require a concerted effort to reduce political and regulatory uncertainties. Even where states and state-owned companies take direct responsibility for energy investment, pressures on public funds and the need for new technology and expertise create room for greater private involvement. Yet conditions are often not conducive: the requirement for energy supply investment grows most quickly outside the OECD and outside China, in some cases in countries that have a higher incidence of political instability, weaker institutions and less robust legal frameworks. Throughout the world, policymakers, though they may recognise investors' need for long-term policy consistency, are subject to various and sometimes conflicting pressures: demands for stronger action on climate change, but a backlash against the cost of subsidies to renewables; calls for lower energy prices, but public opposition of varying intensities to many new energy-supply projects. Against this backdrop, there is a risk that policymakers fail to provide clear and consistent signals to investors, with particular impacts on low-carbon technologies that depend, for the moment, on policy support.

New types of investors in the energy sector are emerging, but the supply of long-term finance on suitable terms is still far from guaranteed. Much of the dynamism in energy markets is coming from smaller market players or new entrants: the expansion of shale gas and tight oil production in North America has been driven by multiple, entrepreneurial companies; emerging state and private companies are taking an increasing share of investment in many non-OECD countries; and the expansion of distributed renewable energy capacities and of energy efficiency initiatives is turning more small businesses and households into energy investors. These players tend to share a reliance on external sources of financing. Even for efficiency projects, which we estimate are almost 60% self-financed today, the required scaling up of efforts is likely to depend on greater recourse to debt or equity. Outside North America (where external financing is more readily available), there is a need to unlock new sources of finance, via growth of bond, securitisation and equity markets and, potentially, by tapping into the large funds held by institutional investors, such as pension funds and insurers. This would help to diminish undue reliance on the relatively short maturity of loans available from the banking sector, which may themselves be further constrained by new capital adequacy requirements in the wake of the financial crisis.

Investment in natural gas supply rises almost everywhere, but meeting long-term growth in oil demand becomes steadily more reliant on investment in the Middle East. Upstream oil and gas spending rises by a quarter to more than $850 billion per year by 2035, with gas accounting for most of the increase. North America has been at the centre of the surge in global investment in recent years and this remains the region with the largest overall oil and gas investment requirement to 2035. But, in the case of oil, the focus for meeting incremental demand shifts towards the main conventional resource-holders in the Middle East as the rise in non-OPEC supply starts to run out of steam in the 2020s. The prospects for a timely increase in oil investment in the Middle East are uncertain: there are competing government priorities for spending, as well as political, security and logistical hurdles that could constrain production. If investment fails to pick up in time – a case considered in this report – the resulting shortfall in supply would create tighter and more volatile oil markets, with prices that are $15 per barrel higher on average in 2025. Importers of fossil fuels rely for secure supply on the adequacy of investment in resource-rich countries; the investment needed to supply India and China with imported oil and gas over the period to 2035 is more than $2 trillion, a level that helps to explain the push by their national oil companies to secure investment opportunities abroad.

Investment in liquefied natural gas (LNG) facilities creates new links between markets and improves the security of gas supply; but high costs of gas transportation may dampen the hopes of LNG buyers in Europe and Asia for much cheaper gas supplies. More than $700 billion invested in LNG over the period to 2035 accelerates the integration of regional gas markets, with exports from the United States playing a prominent role in stimulating some convergence between gas prices, which vary widely today. However, the expectation that a surge in new LNG supplies will totally transform gas markets needs to be tempered by recognition of the high capital cost of LNG infrastructure, with transportation typically accounting for at least half of the cost of gas delivered over long distances. Europe's near-term perspective for expanding LNG purchases is constrained by the need to outbid Asian consumers for available gas.

The investment required to maintain the reliability of Europe's electricity system is unlikely to materialise with the current design of power markets. Europe requires more than $2 trillion in power sector investment to 2035 and, alongside vigorous continued expansion in low-carbon generation, around 100 GW of new thermal capacity needs to be added already in the decade to 2025. Despite public and political concern about high prices to end-users, the wholesale price for electricity is too low at present, by more than 20%, to incentivise the investment required in new thermal plants. If this situation persists, the reliability of European electricity supply will be put at risk. Part of the solution involves higher revenues to thermal generators, but this potentially means higher prices to consumers, underlining the difficulties facing European policymakers as they seek to make simultaneous progress towards ensuring energy security, environment sustainability and economic competitiveness. Nonetheless, there is scope for a policy framework to combine a continued commitment to decarbonisation with lower import bills, while containing the impact on end-user prices.

For many emerging economies, keeping up with booming electricity demand is a huge investment challenge, and current investment trends provide some warning signs for the adequacy of power supply. We focus on India, where – despite achieving a doubling of power generation capacity since 2000 – current electricity output falls short of meeting demand. The incentives to invest in filling this gap are dimmed by high transmission and distribution losses and low end-user tariffs, which mean that many utilities are struggling to recover their costs. If network losses were 15%, rather than today's 27%, an increase of only 5% in average end-user tariffs would have allowed for full cost recovery. More than $1.5 trillion is required in power sector investment to 2035. New coal-fired power plants are projected to dominate future investment in generation capacity in India, as in many other parts of Asia: this is the main driver for the $1 trillion in global coal-supply investment over the period to 2035.

The investment path that we trace in this report falls well short of reaching climate stabilisation goals, as today's policies and market signals are not strong enough to switch investment to low-carbon sources and energy efficiency at the necessary scale and speed: a breakthrough at the Paris UN climate conference in 2015 is vital to open up a different investment landscape. We estimate that $53 trillion in cumulative investment in energy supply and in energy efficiency is required over the period to 2035 in order to get the world onto a 2 °C emissions path. Investment of $14 trillion in efficiency helps to lower energy consumption by almost 15% in 2035, compared with our main scenario. The $39.4 trillion of energy supply investment remains at a comparable level to our main scenario, but unit investment costs are higher as investment shifts away from fossil fuels (where investment is almost 20% lower on average and coal is hit hardest) and towards the power sector. Around $300 billion in fossil fuel investments is left stranded by stronger climate policies. A lack of clarity over policy would increase the risk of investments becoming stranded, although carbon capture and storage provides an increasingly important hedge for fossil-fuel assets against the possibility of under-utilisation or early retirement.

Consistent and credible policies and innovative financing vehicles can provide the bridge to a low-carbon energy system. By 2035, investment in low-carbon energy supply rises to almost $900 billion and spending on energy efficiency exceeds $1 trillion, double the respective amounts seen in 2035 in our main scenario. Dependable policy signals are essential to ensure that these investments offer a sufficiently attractive risk-adjusted return. Getting prices right is essential, both by phasing out existing distortions, in the form of fossil-fuel subsidies, and through carbon pricing. On the financing side, there is still much work to do to marry the available instruments with the specificities of low-carbon energy projects, notably their dispersed, diverse and small-scale nature. It will take time, realism and determination to harness the skills of the financial world to the ambition to reach climate change targets.

Questions about the affordability, sustainability and reliability of the global energy system often boil down to questions about investment. Will market conditions, much influenced by policy, create sufficient opportunities for investment in the regions and sectors where it is needed? Will sufficient financing be available, on suitable terms, for these opportunities to be realised? And will investment be channelled towards areas that ameliorate or degrade the contribution made by the energy sector to local pollution and climate change?

These questions are central to the analysis in the *World Energy Outlook* (*WEO*) series and were the particular focus of a *World Energy Investment Outlook* in 2003. We return to the issue in detail here, covering investment not only in energy supply but also in end-use efficiency (Box). A critically important initial task is one of quantification: to assess the scale of the investment challenge in all parts of the energy value chain and in all regions of the world, so as to meet projected energy needs over the two decades to 2035. Following on from this, a second set of tasks is more qualitative in nature: to consider the obstacles to this investment being realised in practice and examine in more detail specific sectors and countries where we see the risk of a shortfall in the coming years.

The investment outlook in this report has been based on extensive cost surveys covering each part of the energy value chain. The two scenarios that we consider are drawn from the *WEO* series, but have been updated since the *WEO-2013* to incorporate new energy and macroeconomic data:

- The ***New Policies Scenario*** is the main focus for our analysis. The energy demand and supply projections reflect energy policies and measures that have been adopted as of early 2014, as well as other commitments that have been announced, but not implemented, taking a cautious view of the extent to which these may be realised.
- We also present the investment associated with an updated ***450 Scenario***, which plots an emissions-reduction path for the energy sector consistent with the international goal to limit the rise in long-term average global temperatures to two degrees Celsius.[1]

The four chapters in this special report approach the investment question from different angles, but share a similar overall structure. They start with a review of newly-compiled historical investment trends, follow with a presentation of the investment and financing outlook in the New Policies Scenario and conclude with a review of how investment requirements and challenges alter in the 450 Scenario. In their respective areas, each chapter offers insights into the investment debate by exploring questions of ownership

1. As described in more detail in Box 1.4, this scenario has been modified to reflect the reality that no new international climate agreement is likely to enter into force prior to 2020: in the interim, we consider only the impact of specific national mitigation options, as defined in the *WEO Special Report: Redrawing the Energy-Climate Map*.

and models for financing. Each chapter identifies some critical regions or areas where new investment may fall short of what is required, with knock-on effects for regional or global energy security.

Box ▻ Energy investment covered in this report

The figures for new supply-side investment detailed in this report cover capital expenditure, i.e. the creation or refurbishment of assets that extract, transform or transport energy. They do not reflect operating expenditure, i.e. spending to ensure the day-to-day functioning of these assets. The main items covered by our estimates are the costs of engineering, procurement and construction, including all the equipment and other material required for a new supply facility, as well as the labour costs associated with installing a device, machine or plant, or drilling a development well. Our estimates also reflect other investment costs, such as planning, feasibility studies, external advisory services and all licensing and approvals (including environmental approvals), as well as acquiring the land for the project. They do not include research and development costs, or the costs of abandonment or decommissioning. The investments are booked in the year in which new energy supply appears; for a new power plant, this is the first year of operation. For oil and gas upstream projects, this can be over a period of a few years as production from a new source ramps up.

Energy efficiency investments are much more difficult to quantify (an issue covered in detail in Chapter 4). In this report, we analyse procurement capital, i.e. the money spent by end-users on energy-consuming products. We do not include all of this spending, only the amount that is spent to procure equipment that is more efficient than a baseline, established by the 2012 average efficiency of different products and sectors. In other words, this calculation reflects the additional amount that consumers have to pay for higher energy efficiency over the period to 2035.

Chapter 1 provides an overview of the investment trends and future needs in all sectors and regions over the period to 2035. It categorises the risks facing energy investment as well as the ways that projects are financed, and discusses how these might evolve over the coming decades. The last section of this chapter focuses on the prospect of scaling up low-carbon investment in order to be consistent with long-term climate objectives.

In Chapter 2, we examine the outlook for investment in the extraction, transformation and transportation of fossil fuels. Alongside a more detailed breakdown of investment needs and cost trends for the different fuels, we focus on potential constraints on upstream oil investment in the Middle East, a region that is central to meeting future oil supply growth, and the implications of high capital costs for new natural gas liquefaction capacity. The chapter concludes by considering the additional risks that could arise for fossil fuel investment as a result of stronger climate change policies.

Chapter 3 covers the power sector, including fossil-fuel, renewables and nuclear generation, as well as investment in the transmission and distribution networks. It looks in detail at Europe, India and Southeast Asia, in parts of which – for widely different reasons – the current framework is not conducive to recovering costs for some types of investment, and reviews the reasons and implications in each case. Meeting a 450 Scenario requires a faster low-carbon transformation of the power sector and we examine how investment can be mobilised to achieve this objective and how the cost of capital can affect decarbonisation.

Chapter 4 presents the outlook for investment in end-use energy efficiency, including defining the issues and current financing models. It explores future needs by end-use sector, as well as the specific risks and financing challenges that arise for different types of efficiency investment. The need for efficiency investment rises considerably in the 450 Scenario, and we examine the scale of the additional investment burden that needs to be borne before revenue gains fully offset the cost.

Chapter 1

Energy investment needs to 2035

Measuring the task ahead

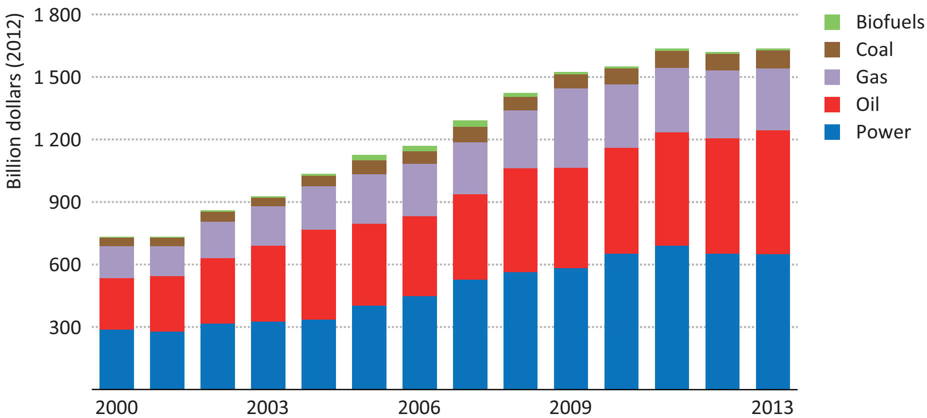
Highlights

- More than \$1 600 billion is being invested each year in order to provide the world's consumers with energy, a figure that has more than doubled in real terms since 2000, and an additional \$130 billion was spent in 2013 on improving end-use energy efficiency above 2012 levels.
- Almost \$1 000 billion of current energy supply investment is for primary fuel supply, mainly for oil and natural gas, and around \$650 billion is in the power sector. Spending on renewable energy sources has risen sharply since 2000 to reach \$250 billion today, 15% of the total.
- Over the period to 2035, the investment required each year to meet the world's energy needs in the New Policies Scenario rises steadily towards \$2 000 billion and annual spending on energy efficiency increases to \$550 billion. This means cumulative global investment of more than \$48 trillion, made up of around \$40 trillion in energy supply and the remainder in energy efficiency.
- Energy supply investment is dominated by the needs of the power sector (\$16.4 trillion), followed by oil (\$13.7 trillion) and gas (\$8.8 trillion). More than half of this is needed just to maintain energy supply at today's levels, e.g. to compensate for declining oil and gas fields and for power plants and other assets that reach the end of their operational life. The increase in energy supply investment comes mainly from countries outside the OECD and China.
- The largest share of the \$8 trillion in efficiency investment is in the transport sector, followed by efficiency investment in buildings, and is required in the European Union, North America and China, reflecting their shares in energy consumption, their policy ambitions and remaining efficiency potentials.
- Around \$53 trillion in investment in energy supply and efficiency is required to move the world onto a 2 °C path. Even though energy demand is lower, cumulative energy supply investment in a 450 Scenario is only marginally below that of the New Policies Scenario. The composition of this investment moves away from fossil fuels (\$4.3 trillion lower) and towards the power sector, particularly renewables, CCS and nuclear. Investments in energy efficiency are higher by \$5.5 trillion.
- Financing the transition to a low-carbon energy system is a major challenge, requiring strong policy and price signals to ensure that low-carbon and energy efficiency investments offer a sufficiently attractive risk-adjusted return. Our estimate of fossil fuel investments left stranded in the 450 Scenario is around \$300 billion, although lack of clarity over policy could increase this risk.

Historical and current trends

Investment in global energy supply amounted to more than $1 600 billion each year between 2011 and 2013 (Figure 1.1).[1] These projects ranged from the extraction of fossil fuels to the construction of power stations, wind farms, solar installations, oil refineries, storage and handling facilities, pipelines, tankers and other transportation facilities. The level of investment has more than doubled since 2000 in real terms, reflecting the rapid increase in global energy demand, higher prices in many countries, rising costs for the production of oil and gas, and investment in new and, for now, relatively expensive, renewable technologies in power generation.

Figure 1.1 ▷ Investment in global energy supply



On the demand side of the energy equation, households, companies and governments are continually procuring new energy-consuming equipment. To the extent that this new equipment is more efficient in using energy than the equipment it replaces, these purchases can be considered as investments in energy efficiency. Such expenditures are difficult to measure (see Introduction and Chapter 4), but the cumulative weight of these choices – and the speed at which more efficient products enter the market – strongly influences the extent of the rise in energy demand and therefore the need for new investment in supply.

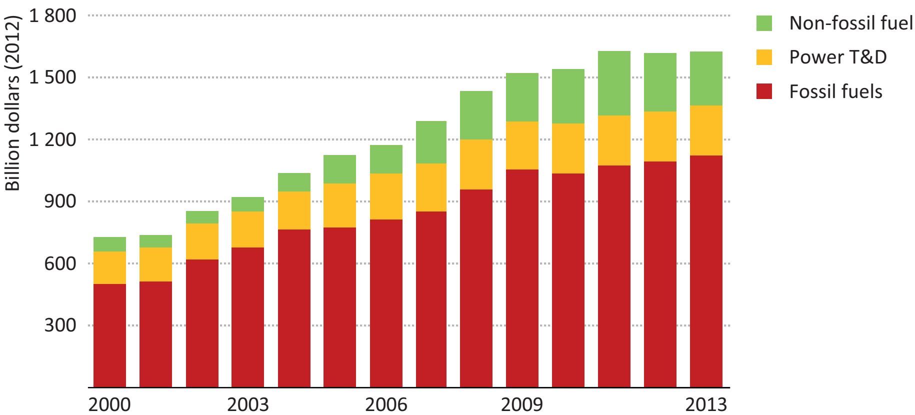
This myriad of investment decisions, from the individual purchase of an electrical appliance to a multi-billion dollar commitment to a new power plant or upstream hydrocarbon project, locks in patterns of consumption, fuel use and emissions, sometimes for long into

1. In the absence of historical global investment data in all sectors, all historical investment numbers are estimated based on IEA data for supply, demand and trade, as well as IEA and industry data for investment costs, checked against actual historical data, where available. For consistency with our projections of future trends, these numbers reflect "overnight investment", i.e. the capital spent is generally assigned to the year production (or trade) is started, rather than to the year when it was actually incurred. Investments for biofuels, coal, gas and oil include production, transformation and transportation; those for the power sector include all fuels and technologies for generation, as well as investments in transmission and distribution. Unless specified otherwise, all investment numbers in this report are in real terms in year-2012 US dollars.

the future. The extent of this influence naturally depends on the size of the investment and also on the operational lifetime of the asset in question. A domestic appliance might be replaced within a few years, but a coal-fired power plant typically operates for a half-century; the lifetime of the building stock is also measured in decades.

Around 70% of energy supply investment today is related to fossil fuels, whether in the extraction of oil, gas or coal, their transport to consumers, their transformation along the way (e.g. from crude oil to refined oil products), or the construction of fossil-fuel fired power plants (Figure 1.2). Our estimates do not show a clear diminishing trend in the share of investment going to fossil fuels since 2000, despite a quadrupling of the volume of investment going into non-fossil fuel energy supply – including all renewable technologies, nuclear and biofuels. Non-fossil fuel investment increased from around $65 billion in 2000 to a high point of $310 billion in 2011, before falling back to under $260 billion in 2013, by which time its share in total energy supply investment had increased from 9% to 16%. The remainder, some $250 billion in 2013, consists of investment in electricity transmission and distribution (T&D) grids; this figure has risen in absolute terms since 2000, but its share in the total fell from 22% to 15% over this period.

Figure 1.2 ▷ Investment in global energy supply by fossil fuel, non-fossil fuel and power T&D



Notes: Non-fossil fuel includes all renewable technologies, nuclear and biofuels. Power T&D is transmission and distribution for the power sector: this cannot be assigned to either fossil-fuel or non-fossil fuel use.

In this report we look at how investment trends might evolve over the next two decades, what scale and type of investments are needed in order to satisfy – or curtail – energy demand and what might prevent these investments from materialising. Our main focus throughout the report is on the adequacy and timeliness of investment in the conditions of the New Policies Scenario.[2] But enough investment to meet the projections of the New Policies Scenario may not be "adequate" in a broader sense. There are legitimate concerns that the policy framework in the New Policies Scenario results in energy investments being misdirected and misallocated in important ways. One example is the way in which, despite

2. See Introduction for a description of the scenarios considered.

a rising commitment in many countries to low- or zero-carbon sources, the energy sector continues to emit greenhouse gases and other pollutants at a rate that has profound consequences for the environment and human health. To what extent policymakers might intensify efforts to decarbonise the energy economy is a major source of uncertainty for those considering long-term investments. With this in mind, we also consider how investment and financing requirements – and the barriers to their realisation – might vary if climate change policies are strengthened.

Trends in the New Policies Scenario

The world's projected energy consumption in the New Policies Scenario will require more than $40 trillion in cumulative investment in energy supply over the period from 2014 to 2035, together with $8 trillion to improve end-use energy efficiency (Figure 1.3 and Figure 1.4). The size and success of the efficiency effort naturally has a direct impact on the magnitude of the challenge on the supply side. Investment in both supply and energy efficiency is essential to satisfy the anticipated increase in demand for energy-based services, pushed higher by a growing global population and an expanding economy, as well as to compensate for the steady decline in output from existing energy producing assets as they reach the end of their productive life.

The demand, supply and investment numbers presented in this report are derived from the latest runs of the New Policies Scenario (see Introduction), our main scenario in the *World Energy Outlook* (*WEO*) series. The assumptions underlying the updated projections are close to those presented in the *WEO-2013* (IEA, 2013a).[3] It is worth noting that:

- We regularly update our cost estimates as new information becomes available, and for this report we have conducted a systematic review of investment cost assumptions in all sectors via an extensive survey of energy companies, banks and other experts.
- The outlook for gross domestic product (GDP) growth has been updated in line with new estimates from the International Monetary Fund; the most significant change relates to the medium-term growth outlook for China (an annual average of 7% to 2020 compared with 8.1% in *WEO-2013*) and India (6.1% compared with 6.8% in *WEO-2013* for the same period). We have also incorporated new data on actual energy consumption and production, so the baseline for the modelling has shifted slightly.
- A major new energy policy proposal was issued by the European Commission in January 2014. This envisages that, by 2030, EU greenhouse-gas emissions should be reduced by 40% from 1990 levels, that the share of renewable energy in EU energy consumption should increase to 27% and that the EU emissions trading system should be reformed. Pending decisions by the European Council, we have not incorporated this package into the New Policies Scenario, but consider potential implications in Chapter 3 (see Box 3.2).

3. For details on the assumptions underlying the *WEO-2013* New Policies Scenario, see Chapter 1 of the *Outlook*, available online at *www.worldenergyoutlook.org.*

Figure 1.3 ▷ Cumulative global energy supply investment by type in the New Policies Scenario, 2014-2035

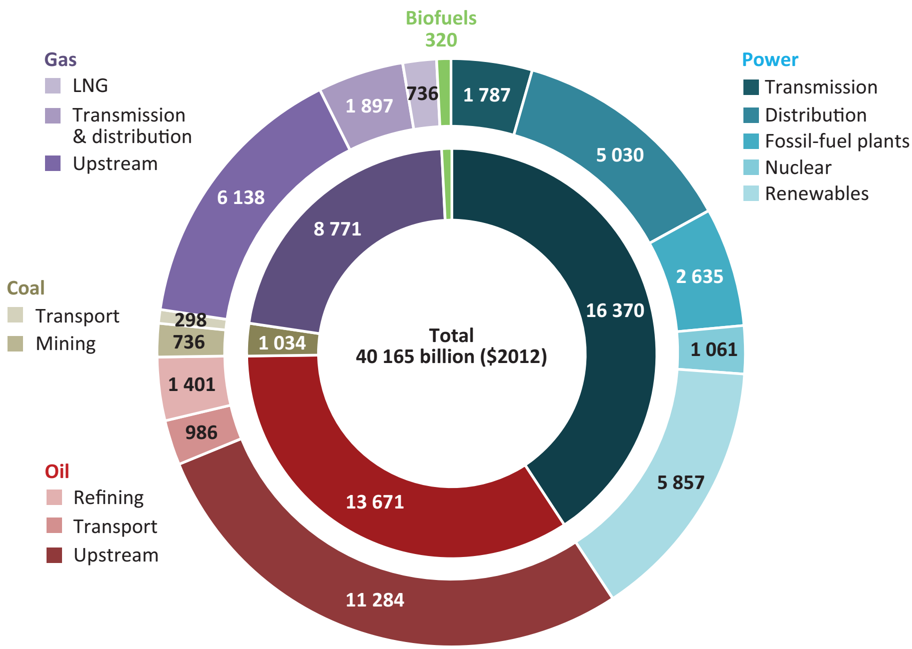
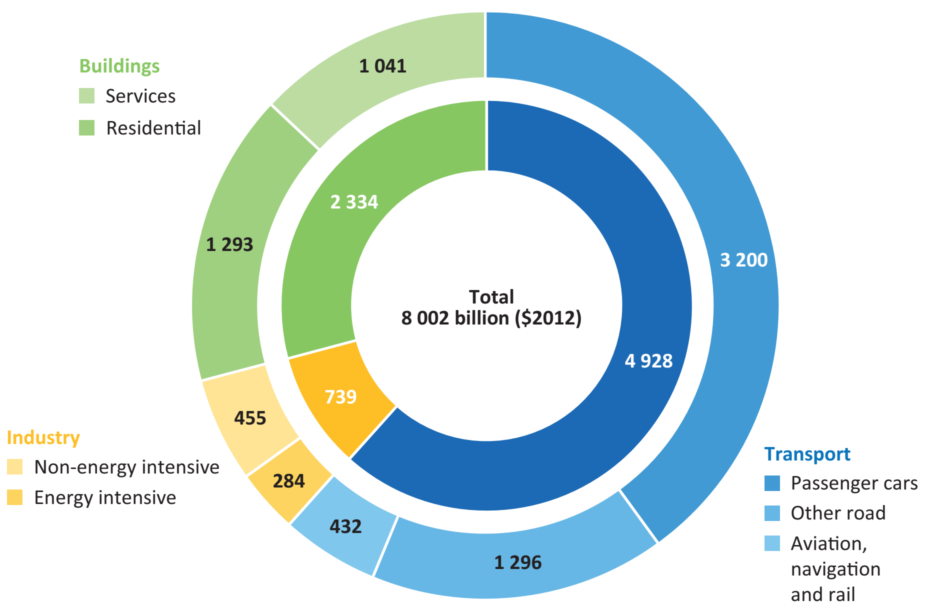


Figure 1.4 ▷ Cumulative global energy efficiency investment by end-use sector in the New Policies Scenario, 2014-2035



The outlook for energy demand and supply associated with the investment estimates differs only marginally from that in the *WEO-2013* New Policies Scenario. Global primary energy demand rises by around one-third in the period to 2035, driven higher mainly by China, India, Association of Southeast Asian Nations (ASEAN) countries and the Middle East. Oil and coal consumption grow more slowly than the overall rise in energy demand (12% and 16%), while natural gas, nuclear and modern renewables rise more quickly (44%, 74% and 134%) (Table 1.1). Despite low or zero-carbon energy sources meeting 45% of the growth in primary energy demand, the share of fossil fuels in primary energy demand falls only gradually, from its current 82% to a 76% share by 2035. Global carbon-dioxide (CO_2) emissions rise on average by 0.7% per year, slower than the 1.2% annual increase in energy demand, but well above the rate consistent with limiting the long-term rise in the average global temperature to two degrees Celsius, the internationally agreed target. This scenario also sees some progress towards broadening access to modern energy services, but similarly falls far short of the goals set by the international community (Box 1.1).

Table 1.1 ▷ World primary energy demand by fuel and energy-related CO_2 emissions in the New Policies Scenario

	1990	2000	2012*	2020	2025	2030	2035	2012-2035**
Oil	3 231	3 663	4 158	4 469	4 545	4 600	4 666	0.5%
Gas	1 668	2 072	2 869	3 234	3 537	3 824	4 127	1.6%
Coal	2 230	2 357	3 796	4 137	4 238	4 309	4 398	0.6%
Nuclear	526	676	642	869	969	1 051	1 118	2.4%
Hydro	184	225	313	391	430	466	501	2.1%
Bioenergy***	893	1 016	1 318	1 488	1 598	1 718	1 848	1.5%
Other renewables	36	60	142	311	432	566	717	7.3%
Total (Mtoe)	**8 769**	**10 070**	**13 240**	**14 899**	**15 749**	**16 534**	**17 376**	**1.2%**
Fossil fuel share	*81%*	*80%*	*82%*	*79%*	*78%*	*77%*	*76%*	*n.a.*
Non-OECD	4 047	4 506	7 606	9 019	9 859	10 623	11 406	1.8%
OECD	4 522	5 292	5 271	5 478	5 461	5 455	5 484	0.2%
CO_2 emissions (Gt)	**20.9**	**23.7**	**31.5**	**34.3**	**35.4**	**36.2**	**37.2**	**0.7%**

* 2012 data are preliminary estimates. ** Compound average annual growth rate. *** Includes traditional and modern biomass uses. Notes: Mtoe = million tonnes of oil equivalent; Gt = gigatonnes; Non-OECD and OECD totals exclude international bunkers.

Sectoral trends

In our projections, overall energy supply investment needs to rise steadily over the coming decades, from an estimated $1 630 billion in 2013 to an average of nearly $2 000 billion per year by the 2030s (Table 1.2). The elements that contribute most to this increase are investment in renewable energy and natural gas supply. Supply-side investment is required to fill two gaps in the global energy system: to meet rising demand and to compensate for declining output from existing assets as they reach the end of their operational life. It is striking that, in aggregate, the amount required to compensate for retirements and declines is larger than that required to meet the growth in consumption (Spotlight).

Table 1.2 ▷ Evolution of global average annual energy investment in the New Policies Scenario ($2012 billion)

	2007-2013	2014-2020	2021-2030	2031-2035	2014-2035
Oil	512	637	610	621	621
Gas	309	357	401	453	399
Coal	74	54	41	50	47
Power	616	713	729	818	744
Plants (all fuels)*	375	407	424	493	434
T&D	241	306	305	325	310
Biofuels	11	11	13	22	15
Total energy supply	**1 521**	**1 772**	**1 794**	**1 963**	**1 826**
Energy efficiency**	**130**	**212**	**385**	**533**	**364**

*Includes plants with CCS. **As described in the Introduction and Chapter 4, the methodology for measuring efficiency investment derives from a baseline of efficiency levels in different end-use sectors in 2012; the annual figure for energy efficiency in column "2007-2013" is therefore the figure only for 2013.

Box 1.1 ▷ Few signs of light for universal access to modern energy services

Access to modern energy services underpins many different aspects of development, from health and environmental sustainability to economic and social wellbeing. Some countries, notably China and Brazil, are closing in on the goal of providing electricity to their entire population. But it remains the case that today 1.3 billion people – almost one in five of the world's population – lack access to electricity and 2.6 billion people rely on the traditional use of biomass for cooking. The investment that would be required to close this failure in the global energy system does not materialise in the New Policies Scenario: our projections show a gradual decline in the number of people without electricity, bringing this below 1 billion in 2030, but a much smaller net fall in those without clean cooking facilities.

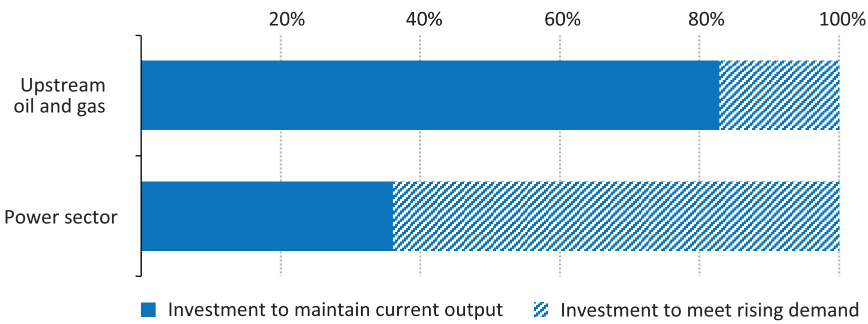
Two of the key objectives set by the United Nations Sustainable Energy for All initiative are to achieve universal access to electricity and to clean cooking facilities by 2030. We estimate that reaching these goals would require annual investment of around $50 billion (around 3% of global energy supply capital expenditure), whereas our most recent estimate of the annual amount being spent in these areas is $9 billion (IEA, 2011). No single policy or financing solution is expected to unlock the required increase. Additional financing would be needed from a combination of public and private banks, governments, state-owned utilities and the private sector, with public sources of finance likely to be particularly important in those cases where the commercial case is weak, such as in the provision of modern energy services to the poorest or most remote parts of the population. In many cases, a pre-condition to attracting new private sector investment to provide access to modern energy services will be more active policy prioritisation and intervention, aimed at securing investment not only in physical infrastructure but also in human capital and skills.

SPOTLIGHT

Running fast to stand still – how much investment is needed to keep energy supply at today's levels?

A critical determinant of future investment needs is the way that output from energy supply infrastructure falls away over time, as oil and gas fields become depleted, existing power plants are taken out of service and transmission lines and pipelines reach the end of their operational lifetime. We estimate that just maintaining energy supply at today's levels – assuming that today's energy mix is kept constant - would require $24 trillion in investment over the period to 2035. This means that less than half of the total investment in energy supply required in the New Policies Scenario goes to meet growth in energy consumption. In upstream oil and gas, more than 80% of investment is required to compensate for decline from existing fields (Figure 1.5).[4]

Figure 1.5 ▹ Share of investment required to keep global output at current levels versus total investment required in the New Policies Scenario, 2014-2035



These declines and retirements are a major investment challenge for policymakers and industry, but they also represent an opportunity to shift the energy system onto a new footing through the introduction of different technologies or fuels to the mix. This rate of change can be accelerated if existing assets are retired early, as with China's decision to close its least-efficient coal-fired power generating plants or Germany's move away from nuclear power, though such early retirements come with a cost – either an increase in the size of the overall investment bill or a claim for compensation for lost income. More fundamentally, the need for new supply investment related to closures could be removed entirely by improvements in energy efficiency.

The supply sector requiring the largest overall commitment of capital (more than 40% of energy supply investment needs) is the power sector. Of the $9.6 trillion required for power generation over the period to 2035, spending on renewables is by far the largest

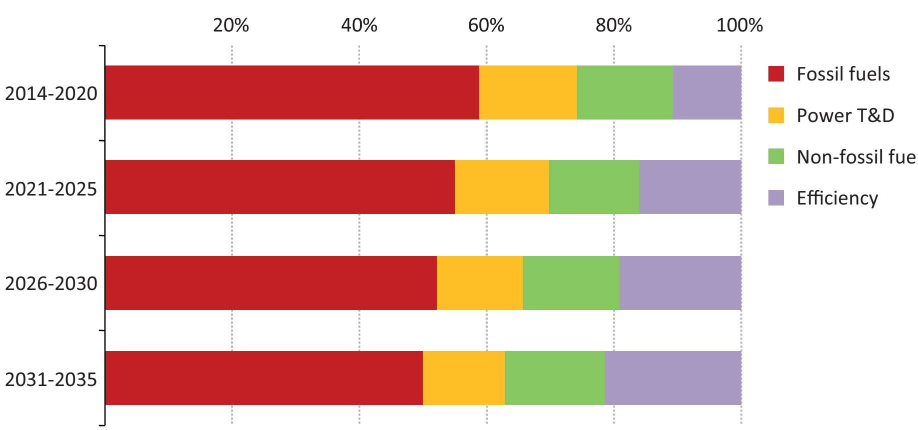
4. For information on the decline rates used to project output from existing oil and gas fields, please refer to *WEO-2013* (IEA, 2013a) and *WEO-2009* (IEA, 2009).

component (almost $6 trillion), more than double the amount foreseen for fossil fuel-fired plants and more than five times higher than anticipated spending on nuclear plants (around $1.1 trillion). Investment in the T&D network is a substantial part of the power total, with a cumulative $6.8 trillion. Among the fossil fuels, the largest investment requirements are in oil and gas (where categorisation can be difficult, for example where upstream gas investment produces natural gas liquids, an important source of oil supply). Between oil and gas, the larger share of investment is in the oil sector, a total of $13.7 trillion, more than 80% of which is in the upstream. However, the share of oil in total energy supply investment declines from 36% in the period to 2020 to 32% in the period after 2030. The share of investment in the gas supply chain rises from 20% to 23% over the same timeframe, reflecting faster growth in natural gas consumption. Investment in coal extraction is not capital intensive and accounts only for a small share of the total.

The policies assumed to be adopted by governments to promote more efficient vehicles, appliances and other energy-using equipment mean a rising level of investment in end-use energy efficiency. Of the cumulative $8 trillion in efficiency investment to 2035, over 60% goes into improving energy efficiency in the transport sector, close to 30% in buildings and the remainder into industry. Of the investment in transport, about two-thirds go to improving the fuel efficiency of passenger light-duty vehicles.

Viewing the total investment figures from a different angle, the share of all fossil fuel-related spending, including investment in extraction, transportation and refining as well as power plants, is on a declining trend, falling from around 60% to half of the total (Figure 1.6). This is primarily due to the increase in spending on energy efficiency: considering only energy supply spending, the share of fossil-fuel investment remains broadly stable in the New Policies Scenario, at just under two-thirds.

Figure 1.6 ▷ Shares of total global average annual investment in the New Policies Scenario

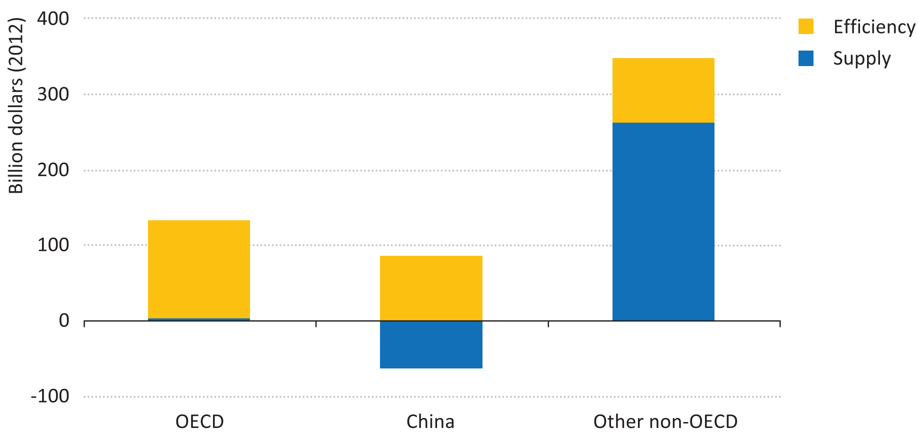


Notes: Non-fossil fuel includes all renewable technologies, nuclear and biofuels. Power T&D is transmission and distribution for the power sector: this cannot be assigned to either fossil-fuel or non-fossil fuel use.

Regional trends

In cumulative terms, 63% of energy supply investment, \$25.2 trillion, needs to be made in non-OECD countries, alongside some \$14.5 trillion in the OECD. Investment in energy efficiency is greater in the OECD countries, reflecting the existing size of OECD markets and the relative strength of policy interventions. The largest single-country markets for energy investment are in the United States and China, each of which accounts for around 15% of the global investment total. Cumulative investments in energy supply in Latin America, Africa, the European Union and the Middle East are all of the same order of magnitude (between \$3.2 trillion and \$3.7 trillion), but spending on energy efficiency is much higher in the European Union (Table 1.3).

Figure 1.7 ▷ Change in average annual investment between the periods 2014-2020 and 2031-2035 in the New Policies Scenario



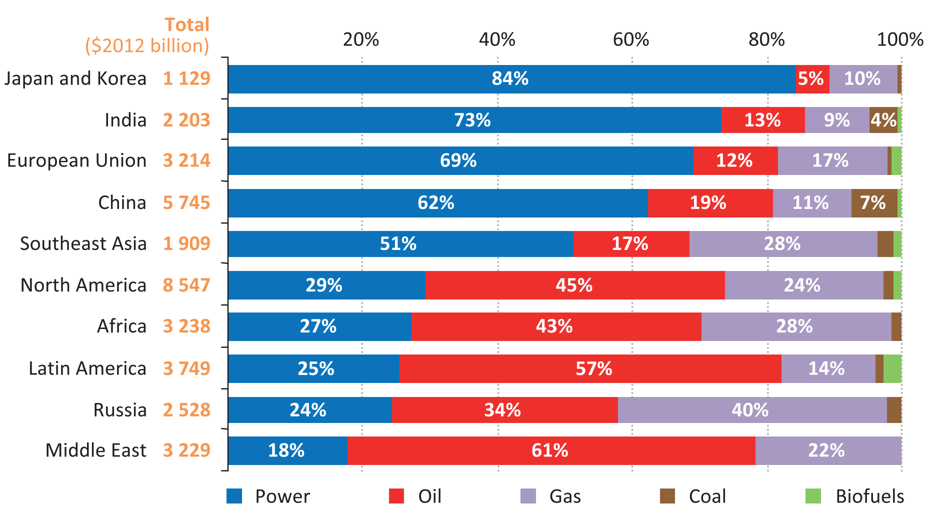
Considering regional trends in investment over the projection period, it is useful to distinguish three groupings (Figure 1.7):

- In most OECD countries, average annual energy supply investment remains relatively flat over the period, with large increases only in spending on end-user efficiency.
- China actually sees a decrease in its projected energy supply investments, as population and economic growth slows down, sharply reducing the pace at which the domestic power network needs to expand, compared with the frenetic pace of expansion seen over the last few years. Within China, investment in upstream gas grows, primarily because of the anticipated development of the country's large unconventional gas resources, but there is a fall in domestic upstream oil investment.
- Other non-OECD countries (excluding China) collectively have to generate a huge increase in energy investment in the coming decades. The largest rises occur in India and the Middle East, where average annual investment needs increase by around \$50 billion, followed by Africa, Latin America, Southeast Asia, Russia and the Caspian.

Table 1.3 ▷ Cumulative investment in energy supply and energy efficiency in the New Policies Scenario, 2014-2035 ($2012 billion)

	Oil	Gas	Coal	Power	Biofuels	Total supply	Efficiency
OECD	**4 645**	**3 296**	**250**	**6 157**	**146**	**14 494**	**4 630**
Americas	3 813	2 019	116	2 567	101	8 616	1 598
United States	2 260	1 500	102	2 052	98	6 012	1 331
Europe	666	815	22	2 434	42	3 978	2 303
Asia Oceania	167	463	111	1 157	3	1 901	729
Japan	32	43	3	664	0	741	445
Non-OECD	**8 735**	**5 381**	**715**	**10 212**	**171**	**25 215**	**3 140**
E. Europe/Eurasia	1 510	1 617	76	1 122	3	4 329	373
Russia	849	1 016	49	614	0	2 528	212
Asia	1 724	1 613	556	6 714	63	10 670	2 066
China	1 072	657	404	3 587	26	5 745	1 566
India	277	203	94	1 615	13	2 203	245
Southeast Asia	331	529	46	980	23	1 909	192
Middle East	1 956	699	1	573	0	3 229	169
Africa	1 395	915	46	882	0	3 238	217
Latin America	2 150	537	36	921	105	3 749	315
Brazil	1 393	157	2	565	88	2 206	183
Inter-regional transport	290	93	69	n.a.	2	455	232
World	**13 671**	**8 771**	**1 034**	**16 370**	**320**	**40 165**	**8 002**
European Union	394	531	19	2 227	44	3 214	2 170

Figure 1.8 ▷ Breakdown of cumulative energy supply investment by selected region in the New Policies Scenario, 2014-2035



The wide variation in energy supply spending for different countries and regions is a reflection of the range of resource endowments (Figure 1.8). Thus a large share of investment in the Middle East goes into the oil sector, while natural gas predominates in the case of Russia. Investment in countries and regions with few indigenous resources is heavily concentrated in the power sector. These countries also tend to be large net importers of oil and gas (and coal in the case of India), making them heavily dependent on sustained investment in the resource-rich countries (Box 1.2). While all consumers, even those shielded by subsidies, are liable to feel the price impacts of any shortfall in investment, high import dependency creates twin vulnerabilities – in the bill for imported energy and in the risk of physical interruption to supply.

Box 1.2 ▷ Reliance on distant oil and gas investments on the rise in Asia

A corollary of oil and natural gas import dependency is strong reliance on timely and adequate oil and gas investment in resource-rich countries. By 2035, oil imports to China and India amount to some 19.5 million barrels per day, 40% of inter-regional oil trade, and their combined gas imports of 270 billion cubic metres account for one-quarter of inter-regional trade in gas. The cumulative upstream investment required to generate these future imports is around $2 350 billion, $1 570 billion for Chinese oil and gas imports, and around $770 billion for India. This dependence creates a need, as well as an attractive opportunity, for investment in the resource-rich countries.

Reliance on investment taking place in third countries is growing in other parts of Asia, notably among the ASEAN countries. It has become an important element in their energy diplomacy and helps to explain the moves by Asian national oil companies (NOCs) to secure upstream opportunities outside their home countries (even if most of the resulting production, at least in the case of oil, is then sold on wholesale markets, rather than transported to home markets). Chinese and Southeast Asian companies, notably CNPC, CNOOC and Sinopec from China, ONGC and IOC from India, Malaysia's Petronas, Indonesia's Pertamina and Thailand's PTT have become increasingly active in licensing rounds abroad, as well as seeking international partnerships and acquisitions. We estimate that upstream capital expenditure by Chinese NOCs outside China was more than $18 billion in 2013, the largest share of this being spent in North America and the Middle East. This is well ahead of the comparable 2013 figure for Indian companies, at $1.4 billion.

Where large-scale upstream opportunities are difficult to obtain, China, in particular, is pursuing other avenues. A conspicuous example is the financing, through bank loans and advance payments, that Chinese companies and banks have provided to Russia's Rosneft in recent years. In 2013 alone, Rosneft received a $2 billion loan from the State Bank of China and the Chinese Development Bank and signed two long-term oil export contracts, one with CNPC, for 360 million tonnes (around 2.6 billion barrels) over 25 years, and the second with Sinopec, for 100 million tonnes (around 730 billion barrels) over ten years. The combined value of the contracts at today's oil price is about $350 billion; both include a substantial element of pre-payment for future deliveries.

Risks facing energy investment

Each investment project has its own distinctive risk profile, in which different factors – market, environmental, technical, regulatory or political – have different degrees of prominence. From a financing perspective, there is one overarching concern: that the cash flows (or savings, in the case of an energy efficiency project) during the project's lifetime may, for whatever reason, be insufficient to pay back the amounts invested in real terms and earn a reasonable return. Table 1.4 summarises reasons why this might be the case.

Investors and financiers have become increasingly adept at managing economic and project-specific risks (the second and third categories in Table 1.4), or at least mitigating them. Examples include the use of financial instruments, such as hedging, to address currency and price risks, or the use of fixed-price contracts and performance guarantees to reduce the risk of delays or cost overruns. Long-term fuel supply or power purchase agreements in the electricity generation sector are likewise well-known mechanisms to address market risk, as are take-or-pay contracts in the gas sector. In some instances, governments choose to accelerate investment by addressing market risks directly, for example, by policies that provide a degree of long-term price certainty for investors in low-carbon projects.

Political risks, by contrast, are usually outside the ability of companies to control (even if, particularly in the case of oil and gas companies, these are risks with which they are very familiar). There are instruments, such as upstream production-sharing agreements, that attempt to safeguard specific operating conditions for the duration of an investment, as well as bilateral and multilateral instruments that attempt to address the risk of expropriation.[5] But, in general, governments retain the ability to change legal, regulatory or tax provisions at any time in ways that may substantially affect a project's financial viability, in some cases re-visiting issues that appeared to have been guaranteed at the time an investment was made. Policy interventions, sometimes in the form of regulation, may also greatly influence the way that markets and relative prices evolve (the impact of CO_2 prices on coal-to-gas competition being a good example). The coherence and predictability of the regulatory framework is, therefore, a fundamental element of the risk assessment for any energy investment project.

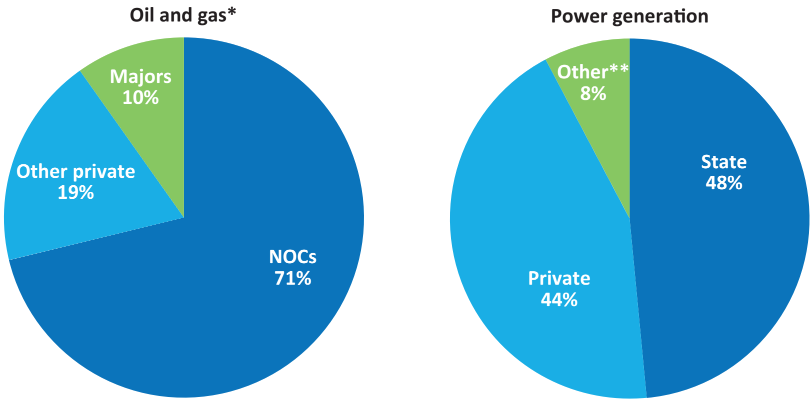
How political factors affect investment decision-making varies from country to country, but it also varies according to company ownership. State-owned companies (by which we mean any company in which the state has a greater than 50% share) own nearly half of the world's power generation assets and – together with their host governments – more than 70% of global oil and gas reserves (Figure 1.9). State-owned companies also have prominent positions in the coal sector and in many pipeline networks and transmission grids.

5. The Energy Charter Treaty is the main multilateral investment treaty covering the energy sector, offering some protection to investors against the risk of discriminatory treatment, direct or indirect expropriation, or breach of individual investment contracts. The Treaty has 47 state contracting parties across Europe and Eurasia and has also been signed collectively by the European Community and Euratom.

Table 1.4 ▷ Categories of risk facing an energy investment project

Category	Description
Political	*Risks related to:*
– **Country**	▪ Quality and resilience of political institutions and the legal system. ▪ Conflict or civil unrest affecting the safety and security of assets or personnel. ▪ Possibility of expropriation or nationalisation. ▪ Cross-border issues, especially where ultimate marketing of the output involves transit through a third country.
– **Policy and regulatory**	▪ Credibility and durability of energy policy frameworks or support schemes. ▪ Misalignment with eventual climate or environmental policies, e.g. carbon pricing or new emissions standards. ▪ Consistency and stability of the legal or tax basis for investment. ▪ Complexity of the business environment (e.g. for permitting, licensing, local content) and transparency of business dealings. ▪ Restrictions on currency convertibility or transfer of funds.
Economic	*Risks related to:*
– **Market**	▪ End-user prices held below costs of production (subsidies). ▪ Shifts in absolute or relative prices that undermine revenues. ▪ Declines in demand for the fuel or technology in question. ▪ Competition from alternative providers or technologies.
– **Macro-economic**	▪ Unstable or inflationary economic environment. ▪ Abrupt fluctuations in exchange rates, especially where costs/ repayments and revenues are in different currencies.
– **Financial**	▪ Rise in interest rates, where debt is based on floating rates or needs to be re-financed.
Project-specific	*Risks related to:*
– **Construction and costs**	▪ Project completion delays, low build quality, cost inflation or overruns.
– **Partners**	▪ Reliability and performance of consortia members or suppliers. ▪ Ability of off-takers to meet their obligation to pay for the produced energy. ▪ Mismatch of incentives and time horizons, e.g. between tenants and property owners for a building efficiency investment.
– **Human resources**	▪ Availability of necessary expertise and qualified labour.
– **Environmental and social**	▪ Possible climate impacts, e.g. water scarcity. ▪ Local pollution or other environmental degradation. ▪ Public opposition and relations with local communities.
– **Operation**	▪ Geological risk, e.g. smaller or more challenging resources than anticipated (for upstream projects). ▪ Uncertain future decommissioning or abandonment costs.
– **Technological**	▪ Lower-than-expected performance (e.g. in terms of efficiency, reliability) of chosen technologies.
– **Measurement** (for efficiency projects)	▪ Identification and quantification of the savings attributable to the efficiency investment.

Figure 1.9 ▷ **Ownership of existing power plants (all fuels and technologies) and oil and gas reserves worldwide**



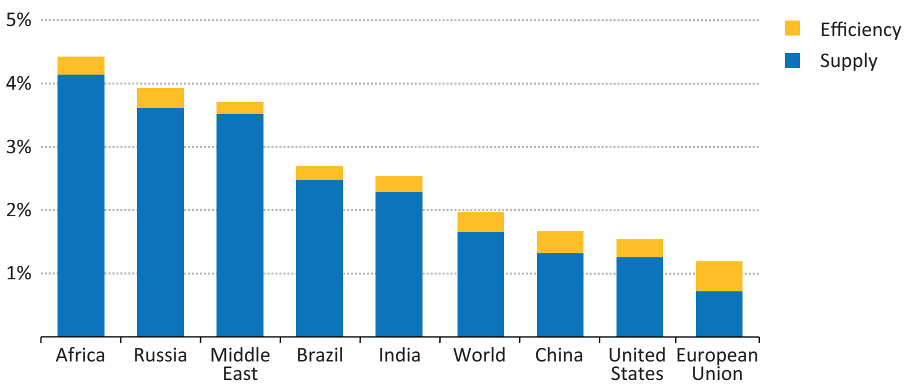
* Oil and gas reserves are proven-plus-probable reserves (2P); the seven Majors are BP, Chevron, ExxonMobil, Shell, Total, ConocoPhillips and Eni. ** Other includes auto-producers, e.g. an industrial plant owning its own generating capacity, as well as assets owned by households and communities.

In theory, ownership should not matter, since all owners might be expected to pursue the same goal of maximising returns. This can be the case in liberalised markets where all participants, regardless of ownership, are expected to compete on an equal basis. But in practice, and particularly in markets that are regulated or liberalised only in part, many states pursue secondary goals via companies in which they have a controlling stake. Governments may wish to develop oil and gas supply while maintaining internal price subsidies for the resulting product, or support a specific technology or pipeline project, or bring electricity supply to a specific area: project returns can take a back seat to these goals. The objectives, corporate culture and sources of financing for this large public or quasi-public sector are critically important for the direction and adequacy of energy investment.

For companies operating in a commercial environment, the perceived level of risk associated with an investment project is a major determinant of the level of return that investors and financiers require on the investment: the higher the perceived risk, the potentially more profitable the investment will need to be in order to secure a positive decision, possibly making it difficult to find financing on suitable terms. The energy sector contains a wide range of different businesses with different risk profiles, from small companies exploring for oil and gas (where risks are very high, but possible returns likewise) to companies operating in regulated parts of the power sector, where the upside is often capped but the return on equity is ordinarily very predictable.

How might the risks facing energy investments evolve over the coming decades? There is no simple answer to this question, but there are reasons to think that certain categories of risk are on the rise. As examined in subsequent chapters, decisions to commit capital to the energy sector are increasingly shaped by government policy measures and incentives, rather than by signals coming from competitive markets. In oil markets, increases in capital expenditure in the latter part of our projection period are concentrated in countries with more restrictive approaches to private participation in the upstream sector. In the power sector, investments in most low-carbon energy sources are heavily dependent, for the moment, on policy support, introducing a significant element of regulatory risk into investment decisions on those sources while, at the same time, introducing a threat – at least in Europe – to the traditional business case for investment in conventional generation. Carbon pricing gives rise to a set of commodity risks that are dependent on political decisions. Any new fossil fuel investment has a 20 to 30-year horizon during which energy use and energy policy are likely to change considerably, with implications for different fuels and various parts of the value chain that are difficult to foresee. Geological and technical risks to oil and gas production are similarly likely to increase as some of the most accessible reserves are depleted, obliging companies to go after more challenging resources, often in remote parts of the world. In addition, investment needs are set to rise most quickly outside the OECD (and outside China), in some cases in jurisdictions that have weaker institutions and regulatory frameworks, and where capital needs are high relative to the size of the economy (Figure 1.10).

Figure 1.10 ▷ Cumulative energy investment as a share of GDP in the New Policies Scenario, 2014-2035



Investments made now also occur at a time of increasingly strong public awareness and pressure on energy and environmental issues. This is by no means confined to the OECD region. The political imperative to limit high levels of pollution from coal use and from road transport is strong and influences investment decisions in many non-OECD economies, most notably China. Energy investments in general are subject to lengthy approvals processes; delays are particularly likely where projects involve areas which are socially and environmentally sensitive.[6] But the messages received by policymakers from the public are many and conflicting: a demand for stronger action on climate change but

6. In Peru, the Ministry of Mines and Energy has established a social conflict unit to seek to prevent and resolve conflict with local communities over extractive industry projects.

a backlash against the cost of subsidies to renewables; opposition to fracking; protests against nuclear or coal-fired plants; suspicion about CCS. Against this backdrop, the risk of policy incoherence and even policy reversals is high.

Financing energy investments

Capital comes to the energy sector from a variety of sources, from the energy investor itself as self-financing, through (in some cases) an allocation from the state budget, or through external financing via bank lending and the capital markets (Table 1.5). How a particular investment is financed depends on the actors and sector, the risks and returns, the structure and maturity of the local financial sector and the overall institutional, regulatory and market environment. As a general rule, external financing is available only if a certain minimum share of self-financing is provided. At company level, there are some distinctive regional and country variations in the respective importance of different sources of investment financing. In the main developed markets, around two-thirds of capital expenditure made by companies (in all sectors) is self-financed through retained earnings. By contrast, retained earnings are generally insufficient to keep pace with the investment needs in fast-growing emerging markets where, on average, around three-quarters of company investment depends on external financing (G30, 2013). The banking sector is the predominant source of external finance in most countries, except in the United States (in particular), where the deep and well-developed capital markets provide extensive alternative sources, in the form of debt or equity.

Governments, whether by direct payments, by reducing tax liabilities or by providing loans or loan guarantees, remain a critically important source of financing, although this role has been subject to two countervailing trends in recent years. On the one hand, many governments have opened up their energy sectors in full or in part to private investors and private capital, lessening state ownership or the involvement of state-owned entities. On the other hand, particularly in the power sector, government intervention has increased in order to support the growth of investment in low-carbon energy sources.

Governments also play a role in funding via multilateral development banks which, backed by groups of countries, are able in some cases to lend at concessional rates or offer more favourable terms than the commercial banking sector. The major multilateral banks provided around $28.5 billion in loans to projects in the energy sector in 2012, with the largest contributions coming from the European Investment Bank ($9.3 billion), the World Bank ($5.6 billion) and the Asian Development Bank ($4.9 billion). National development banks also play a very important role. In 2012, the China Development Bank increased net lending to the domestic power and oil and gas sectors by around $22 billion; Brazil's National Development Bank (BNDES) lent almost $17 billion to energy projects; Germany's KfW financed more than $12 billion in renewable energy projects alone. Multilateral and national development banks also provide a major source of funding for energy efficiency improvements (financing energy efficiency investment has specific characteristics that are discussed in detail in Chapter 4).

Table 1.5 ▷ Main sources of financing for an energy investment[7]

Category	Notes
Self-financing	Governments and companies (and households, in some cases) can finance energy investments directly from their income.
– Retained earnings	▪ In the case of a company, self-financing is via retained earnings: income that is not distributed to the owners of a company is available for re-investment.
– State budget allocation	▪ Governments are often direct investors in the energy sector, notably in infrastructure. In addition, the earnings of some state-owned energy companies, though transferred initially to the state, may be returned (at least in part) to finance capital expenditure.
Banks	Banks and some other financial institutions lend money on a short- or long-term basis to support company operations and capital expenditure, earning interest on the transaction. The importance of loans as a source of investment financing varies widely by region. In priority areas, governments may provide loan guarantees and national or multilateral development banks lend funds, often with the aim of reducing risk and facilitating the involvement of private capital, and export credit agencies finance or underwrite purchases of goods or services from their host countries.
Capital markets	The depth and sophistication of capital markets varies widely by region. They may offer a variety of long-term financing options, in the form of both debt and equity.
– Debt	▪ Bonds are the main debt instrument available on capital markets, issued primarily by governments but also by companies for large-scale borrowing. Corporate bonds typically have longer maturities than bank loans.
– Equity	▪ Companies can also raise money by selling a share of ownership in the company, or equity. There are many different types of equity investor (including individuals, companies, funds and institutional investors), but a common denominator is that they are generally willing to bear somewhat greater risk, provided it is adequately rewarded.

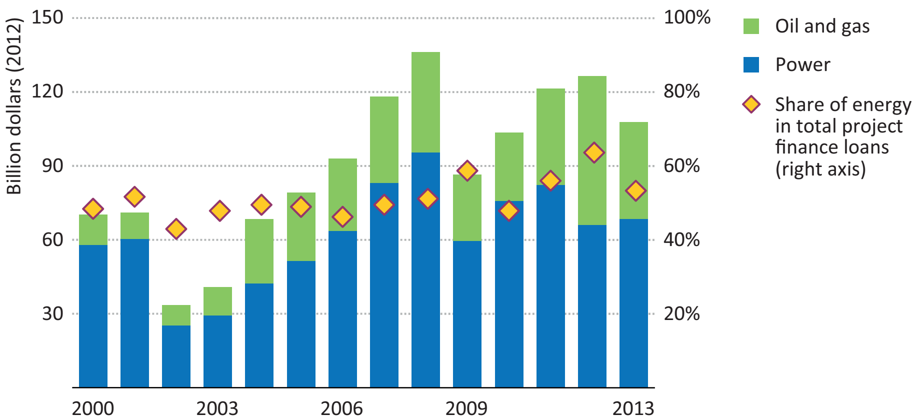
Note: References to debt financing in the text can refer to either bank lending or debt raised on capital markets, or a combination of the two.

Companies do not finance all projects on their own balance sheets. A common technique for raising money for large capital-intensive infrastructure projects (including public-private partnerships) is project finance, whereby the project sponsors set up a separate company specifically for the purpose of constructing, owning and operating the project facility (e.g. a power plant, pipeline or transmission line, refinery, liquefied natural gas [LNG] plant). This project company is financed with a mixture of equity and debt (and is

7. Other sources of finance, such as institutional investors (pension funds, insurers, sovereign wealth funds and so on) are starting to play a role in financing energy projects directly, but their exposure to this sector remains small in practice (Box 1.7).

often highly leveraged, i.e. with a high share of debt financing) and the returns on equity or debt service are derived solely from the revenue stream of the project itself. By limiting or eliminating any recourse to the other assets and revenues of the project sponsors, a contrast to most traditional corporate financing, project finance gives energy companies access to additional capital and the opportunity to pursue multiple projects without limiting their creditworthiness or burdening their balance sheets. Project finance is used in many sectors, but the oil, gas and power sectors are by far the most significant (Figure 1.11).

Figure 1.11 ▷ Value of global project finance loans in oil, gas and power



Source: Project Finance International "League Tables" 2000-2013.

One means by which the energy sector might diversify its sources of finance would be to tap the large funds held by institutional investors (pension funds, insurers, sovereign wealth funds and so on) which, in many cases have long-term liabilities offering a good match with investments that have predictable long-term revenue streams. Thus far, these investors have very little exposure to the energy sector (Box 1.7) and any greater involvement is very likely to be limited, for some time, to developed markets.

Potential constraints on energy financing

Capital expenditure on energy supply rises by around one-fifth in the New Policies Scenario. Even if expenditure on investment in energy efficiency is included as well, the rise in total energy investment is around half the rate of growth in the global economy. Despite the possibility that the risks facing investment in the energy sector are on the rise, this provides a degree of reassurance about the prospects for financing energy investment in the New Policies Scenario, but there are also some general concerns about the supply of finance to support capital-intensive long-term investments in the energy sector, as well as wide variations across sectors and regions (discussed in subsequent chapters). Where demand for long-term finance exceeds its supply, the cost of capital will rise, increasing the possibility that some energy projects will not satisfy normal commercial tests.

Most state energy investment comes from the cash flow generated by existing state energy assets, but general taxation and the central budget remain important sources of financing for energy projects, particularly outside the OECD countries. However, the availability of public funds to support large investment projects (in the energy sector as in other sectors) cannot be taken for granted in the face of increasing competition from other areas of public spending. As emerging economies grow, so they come under pressure to expand the provision of pensions and healthcare, with demographic trends – including an ageing population in some cases – meaning that these systems require an increasing share of public expenditure. There are similar signs of strain on public finances in OECD countries. The tightening of fiscal belts to reduce the share of government debt in GDP has been accompanied in some countries by pressure to cut subsidies to low-carbon technologies.[8]

Against this backdrop of fiscal consolidation in the OECD and longer-term pressures on public spending in many non-OECD countries, meeting future energy sector financing needs will require the mobilisation of increasing amounts of private capital. Yet the basis on which this capital will enter the market is, in many instances, unclear. In the countries that see the largest increase in energy investment needs in our projections (those outside both the OECD and China), present conditions are often not conducive to a large increase in long-term private investment, either on its own or in partnership with state entities, nor do companies have easy access to external sources of financing. This is less of an issue for export-oriented projects, such as upstream oil or gas projects, but it could be a much more serious constraint on projects to supply electricity or natural gas to domestic markets.

Outside of the United States, where capital markets play a much larger role, the banking sector is the dominant source of external financing. But many of the international commercial banks have reined in lending in the aftermath of the financial crisis, particularly in countries perceived as high-risk, and become much more selective about the projects that they support. This has exacerbated an existing mismatch between the relatively short term of most bank loans (especially, but not only, in developing markets) and the needs of energy companies in financing projects that have long payback periods. The crisis has also left a more permanent mark on the outlook for long-term financing in the form of the new regulatory regimes and higher capital requirements that are being introduced in an attempt to increase the resilience and stability of the global financial system (Box 1.3). Lending by multilateral development banks may, in some countries, be able to fill a part of the gap (and facilitate lending by private commercial banks), but rising investment needs in many emerging countries may outpace the amounts available.

Corporate or project bonds raised on capital markets tend to have longer maturities and therefore offer a potential match with companies' long-term investment plans; but this route is rarely followed at present outside the United States. Corporate bonds tend to be

8. These subsidies reached $85 billion in OECD countries in 2012 ($100 billion worldwide). They do not, in most cases, involve direct financing for energy investments but, by providing guarantees of future cash flow, they are instrumental in ensuring that these investments take place. Although such subsidies are not exclusively provided from state budgets (in many countries, they are included in full or in part in consumer bills), there is a strong political feedback if the impact on end-user prices is perceived to be too high.

issued by large companies and the relative under-development of local capital markets in many emerging economies limits access to this source of funding. The US financial system has played a critical role in supporting the many medium-sized and small companies that have led the surge in shale gas and tight oil activity. Similarly dynamic change in other regions and other parts of the energy sector, notably in the areas of low-carbon investment and energy efficiency, will depend on the ability of new investors to access finance on suitable terms from a range of sources, not only from the banking sector.

But if developing more robust debt and equity capital markets is an important condition for the energy sector to meet its financing needs in full, governments will also need to be vigilant, as financial markets develop, about the scale and composition of capital inflows and outflows. Most capital inflows to developing countries have traditionally been in the form of foreign direct investment. But as the share of short-term bank lending in total capital flows increased in recent years, so did the risk of volatility – as demonstrated by successive crises in Russia, Brazil and Asia. China, with a large surplus of domestic savings over investment, is not expected to rely on net imports of capital. Other markets – including other fast-growing emerging economies – will need stable inflows of foreign capital to finance large-scale investment in energy and other sectors.

Box 1.3 ▷ Regulation of financial markets and the incentives for long-term energy investment

The financial sector is facing a tighter regulatory framework, both at national and international levels, designed to discourage the sort of excessive risk-taking that led to the recent financial crisis. In terms of financial stability, the most prominent of these initiatives is the Third Basel Accord, known as Basel III. It is a global, voluntary regulatory agreement to strengthen the regulation, supervision and risk management of the banking sector. To date, all major financial centres have agreed to adopt its rules (although some regional variations remain), which are to be phased in over the period to 2018. Basel III covers bank regulation and more stringent capital adequacy requirements, but it is also influencing regulation in other areas, for example Europe's new regulation for the insurance sector, known as Solvency II.

One unintended consequence of Basel III's focus on short-term liquidity and solvency is likely to be an increase in the cost of long-term energy financing, accompanied by a reduced readiness among banks to issue long-term corporate and project finance loans.[9] This is emerging as an important concern for the energy sector and other sectors requiring long-term capital. If banks do pull back from this area, policymakers and the financial industry will need to devise other sustainable and secure sources of long-term finance for investment.

9. One example is the net stable funding ratio, which requires banks to have stable funding related to the maturity of their loans. In addition, the amount of capital a bank has to hold in reserve to protect against default ("capital reserve requirements") is higher where it has a larger proportion of loans with long payback periods (Thomä, et al., 2013).

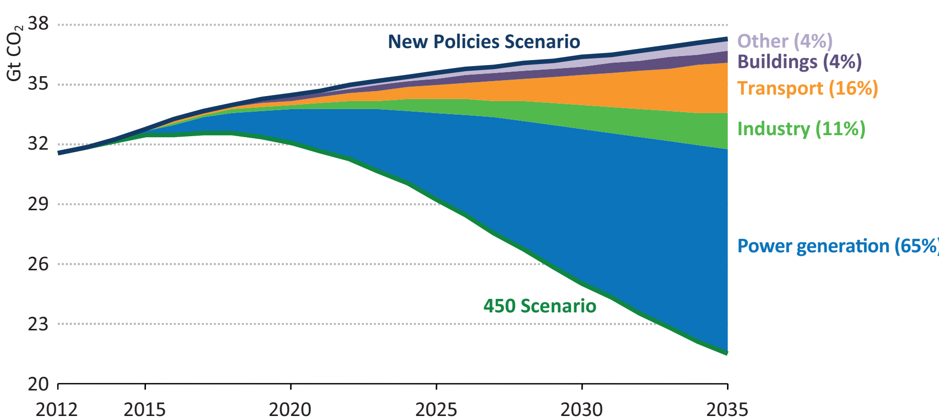
Trends in the 450 Scenario

Achieving a transition to a low-carbon energy system requires profound long-term changes to the way we produce and consume energy. Despite progress in recent years, for example the increasing focus on energy efficiency policy and wider deployment of low-carbon technologies, the switch to low-carbon technologies (which are capital-intensive) has not materialised at the scale required to achieve this transformation (IEA, 2014a). In short, the trends of the New Policies Scenario are not in line with reaching the 2 °C objective that governments have agreed to. They point, instead, to a long-term temperature increase of 3.6 °C. In an updated 450 Scenario, we plot an alternative course for the global energy sector that gets it on track for 2 °C (Box 1.4).

From an investment perspective, the energy sector transition in the 450 Scenario requires not only more capital investment in energy, but also a different allocation of capital. National policies have not been sufficient, in the absence of a global climate agreement, for this shift in investment flows to take place at the necessary rate and speed. A critical indicator of the prospects for this switch will come from the 21st United Nations Framework Convention on Climate Change (UNFCCC) Conference of the Parties (COP-21), to take place in Paris in 2015, which will seek to agree on "a protocol, another legal instrument or an agreed outcome with legal force under the Convention applicable to all Parties" to reduce CO_2 emissions to meet the 2 °C target, for entry into force in 2020. Clarity of intent and, to the extent possible, stability of implementing measures are essential to build the confidence of investors to realise the energy transition.

In the 450 Scenario, cumulative emissions to 2035 are reduced by some 145 Gt compared with the New Policies Scenario, with the overwhelming majority of emissions savings achieved after 2020 (Figure 1.12). By 2035, emissions are lower by almost 16 Gt. The largest abatement at the point of emission occurs in power generation, partly because of reduced electricity demand, followed by the transport and industry sectors.

Figure 1.12 ▷ World energy-related CO_2 emissions by scenario



Note: Share of savings by sector in 2035 denoted in brackets.

Box 1.4 ▷ Agreement at COP-21: an updated 450 Scenario

The 450 Scenario in this report differs in important ways from preceding versions. Recognising that truly concerted global action before 2020 is unlikely, as this is the earliest date by which any agreement reached at COP-21 is expected to come into effect, for the period to 2020 we draw upon the analysis done in the *WEO Special Report: Redrawing the Energy-Climate Map* (IEA, 2013b). Emissions reductions to 2020 come from four measures, at no net economic cost:[10]

- Targeted specific energy efficiency improvements in the industry, buildings and transport sectors.
- Limiting the use and construction of inefficient coal-fired power plants.
- Minimising methane emissions in upstream oil and gas production.
- Partial phase out of fossil-fuels subsidies to end-users.

Taken together, these measures help reduce global greenhouse-gas emissions by some 3 gigatonnes (Gt) (in CO_2-equivalent terms) in 2020, compared with the New Policies Scenario, an outcome which keeps open the possibility of reaching the 2 °C target.

As the latest report from the Intergovernmental Panel on Climate Change suggests, the 2 °C objective – which underlies the 450 Scenario – is not yet out of reach (IPCC, 2014). But the measures described above are not sufficient to get us there and, to put the world on a track consistent with a 50% chance of reaching the 2 °C target, further reductions are required. In the 450 Scenario, we therefore assume that, after 2020, one of the main deficiencies of current climate policy is remedied: a CO_2 price is adopted globally in the power generation and industry sectors at a level sufficiently high to make investment in low-carbon technologies attractive. It is implemented in OECD countries first and then progressively extended to other major economies. We assume a complete phase-out of inefficient fossil-fuel subsidies by 2035 (except for the Middle East, where the average subsidisation rate declines to 8% in 2035) and an element of carbon pricing also in transport; both of these measures have the effect of accelerating energy efficiency improvements. There is also a further extension and strengthening of minimum energy performance standards in the transport and buildings sectors.

Cumulative investment in energy supply and energy efficiency in the 450 Scenario is around $53 trillion, $4.8 trillion more than the $48 trillion needed in the New Policies Scenario (Table 1.6). Energy supply requires investment of $39.4 trillion, only marginally less than the $40 trillion required in the New Policies Scenario, even though primary energy consumption is 13% lower in the 450 Scenario by 2035. Much of the reduction in energy use is achieved by higher investment in energy efficiency, a cumulative $13.5 trillion compared with $8 trillion in the New Policies Scenario (Figure 1.13). There is still a significant need for investment in fossil fuel supply, at $19 trillion, but this is $4.3 trillion less than in the New

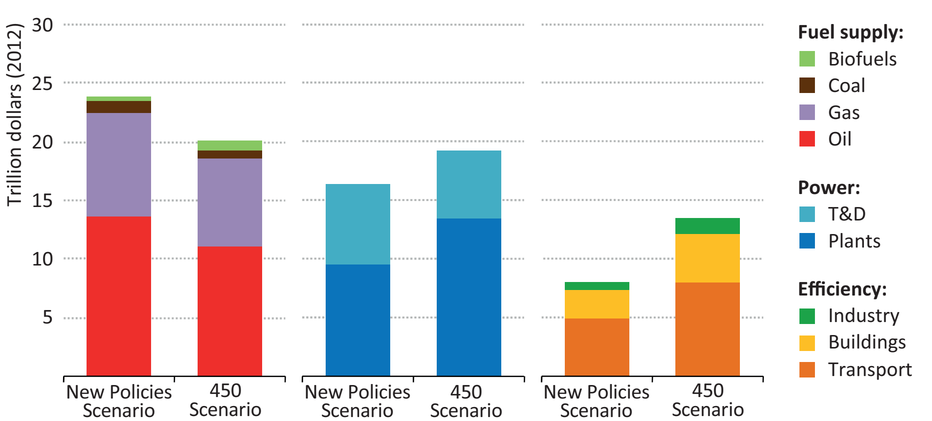
10. These measures were welcomed by IEA ministers at their Ministerial meeting in November 2013; see www.*iea.org/newsroomandevents/ieaministerialmeeting2013/ministerialclimatestatement.pdf.*

Policies Scenario, because of the lower demand for fossil fuels. The power sector requires additional investment, as low-carbon technologies tend to be more capital intensive than conventional technologies. To date, even though the operating and (where applicable) fuel costs of low-carbon systems are usually lower than for conventional technologies, the accrued savings over the long-term have not been sufficient to persuade investors to finance the associated higher capital costs to the required extent.

Table 1.6 ▷ Cumulative investment in energy supply and energy efficiency in the 450 Scenario, 2014-2035 ($2012 billion)

	Oil	Gas	Coal	Power	Biofuels	Total supply	Efficiency
OECD	**3 840**	**2 801**	**167**	**7 608**	**467**	**14 883**	**6 807**
Americas	3 113	1 703	76	3 467	304	8 664	2 377
United States	1 903	1 261	65	2 968	270	6 468	1 930
Europe	581	716	18	2 838	137	4 291	3 325
Asia Oceania	146	382	72	1 303	26	1 928	1 105
Japan	29	39	2	749	7	827	692
Non-OECD	**6 962**	**4 578**	**475**	**11 649**	**345**	**24 010**	**6 214**
E. Europe/Eurasia	1 185	1 276	55	1 156	7	3 678	694
Russia	676	737	34	665	0	2 112	373
Asia	1 394	1 557	363	7 994	151	11 459	3 837
China	828	654	283	4 361	93	6 218	2 526
India	244	209	52	2 003	13	2 521	660
Southeast Asia	282	496	22	1 010	45	1 855	490
Middle East	1 523	548	1	690	0	2 762	365
Africa	1 151	763	33	901	5	2 853	481
Latin America	1 709	435	23	909	182	3 258	837
Brazil	1 108	128	1	521	161	1 919	457
Inter-regional transport	260	78	48	n.a.	109	495	510
World	**11 062**	**7 457**	**690**	**19 258**	**920**	**39 387**	**13 531**
European Union	358	453	16	2 566	136	3 528	2 998

Figure 1.13 ▷ World cumulative investment in energy supply and energy efficiency by scenario, 2014-2035



Box 1.5 ▷ How large is the risk of stranding energy sector investment?

Stronger climate change policies will have an impact not only on future investment decisions, but may also affect the economics of existing energy sector assets (IEA, 2013b). Some investment in fossil fuel-based energy assets, as a result of changes brought about by climate policy, may not be able to earn an economic return prior to the end of their economic life and risk becoming stranded assets – not recovering all or part of their investment during the time that they are operational.

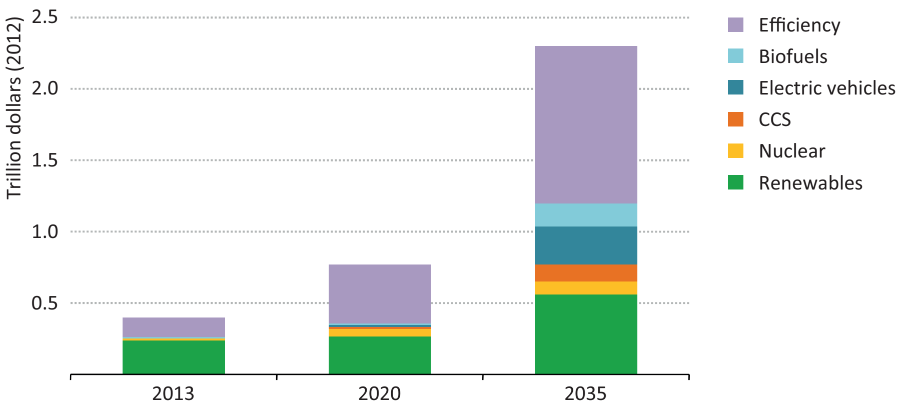
- In the power sector, 165 gigawatts (GW) of new fossil-fuel capacity is idled before repaying its investment costs in the 450 Scenario, resulting in an unrecovered sunk cost of around $120 billion, or about 40% of the initial investment (see Chapter 3). Another 90 GW of new power plants are idled over the projection period, but after recovering their investment costs.
- In upstream oil and gas, stranded investment is largely confined to the exploration costs of fields that, because of variations in demand, are developed before 2035 in the New Policies Scenario, but not in the 450 Scenario (see Chapter 2). As a result, the fields in question do not start to recover their exploration costs in this timeframe. This affects the equivalent of some 5% of proven oil and gas reserves. We estimate the value of these stranded exploration costs to be about $130 billion in the case of oil and about $50 billion for gas.
- In coal mining, capital costs for exploration and development make up a relatively low share of total production costs (see Chapter 2). Reduced demand and lower prices in the 450 Scenario lead to the closure of the highest-cost mines, which are usually old mines that typically have already recovered their investment. The danger of stranded assets is, accordingly, limited for the industry as a whole, but individual players could, still, incur substantial losses. We estimate the additional risk of stranding investments in coal mining in the 450 Scenario to be $4 billion.

The values for stranded investment assets given here assume a high degree of clarity for investors over the evolution of climate policies and their impact on demand and prices. In practice, however, investors can misread signals from policymakers, receive misleading signals from them and/or misjudge the way that markets will evolve. This is an ever-present hazard, but it is arguable that the scale of the transformation implied by climate change for the energy sector increases the potential for financial losses if investors err, for example, by investing on the basis of future demand and prices in the New Policies Scenario, but ending up in a 450 Scenario world. This implies a higher potential for fossil-fuel investments to end up stranded than we give here, although it also follows that clarity on future policy frameworks minimises the additional risk.

Low-carbon technologies and energy efficiency

We estimate that more than $260 billion was invested in low-carbon energy technologies in 2013 (Figure 1.14), divided between the power generation sector (more than $255 billion), biofuels ($4 billion) and electric vehicles ($2 billion).[11] The level of investment in energy efficiency was $130 billion in 2013.[12] To achieve the climate target as reflected in our 450 Scenario, annual investments in low-carbon technologies and energy efficiency need to double to reach almost $790 billion by 2020, and to increase by nearly six times to reach $2.3 trillion by 2035. Over the period to 2035, cumulative investments in low-carbon technologies and efficiency in our scenario reach $28.5 trillion, split between energy efficiency (48%) and energy supply in the form of renewables, nuclear and biofuels (40%), with the remainder going to other technologies, CCS and electric vehicles.

Figure 1.14 ▷ Global investment in low-carbon technologies and energy efficiency in the 450 Scenario



Low-carbon investment to 2020 is dominated by the need to improve energy efficiency and to scale-up low-carbon technologies in the power sector, using technologies that are commercially available today. These categories of investment continue to rise quickly after 2020, helped by increasing and more widely-adopted carbon prices, but there is also large-scale investment in electric vehicles, CCS and concentrated solar power (CSP). Over the projection period, cumulative investment in these technologies reaches $2.1 trillion for electric vehicles, $1.4 trillion for CCS (of which two-thirds is required in the power

11. For the purpose of investment in low-carbon technologies here, we include CCS in industry and a part of investment in electric vehicles, which are otherwise not included in the energy investment figures elsewhere in this report. For electric vehicles, only the additional costs of an electric car, relative to a conventional car, are included. In 2013, some 156 000 electric cars and plug-in hybrids were sold.

12. As described in the Introduction and discussed in Chapter 4, the methodology for measuring end-use efficiency investments starts from a baseline of efficiency levels in different end-use sectors in 2012. The resulting numbers can therefore differ from those presented by other research bodies, but they are consistent with the projected numbers elsewhere in this report.

generation sector) and $0.8 trillion for CSP. Those technologies are at early stages of commercialisation today, and can succeed on the scale required after 2020 if sufficient research, development and demonstration investment (a category not covered in this report) materialises during the present decade (IEA, 2014b).

China, the European Union, the United States, India, Japan and the Middle East are the six largest markets for investment in low-carbon technologies and energy efficiency, absorbing 70% of global investment in these areas. Transformation is required across the energy system, but the largest shares of investment go to power generation and transport (Box 1.6). The success or failure of climate policy therefore depends to a large extent on whether the investment conditions in these markets are sufficient to attract enough capital in power generation and transport.

Box 1.6 ▹ Impact of climate policy on transport refuelling infrastructure

Natural gas and electricity are currently the most widely discussed alternative fuels in the road transport sector. In contrast to biofuels, which can be used within the existing retail infrastructure, the use of natural gas and electricity requires the build-up of dedicated refuelling infrastructure. In the New Policies Scenario, cumulative investment in refuelling infrastructure for natural gas use in road transport is close to $55 billion over the projection period, of which more than 10% are dedicated to the use of LNG in road freight, while the bulk goes to expanding use of compressed natural gas (CNG) in passenger cars. The electricity recharging infrastructure for use in household and public transport recharging together requires some $55 billion.

The pursuit of the climate targets in the 450 Scenario, however, entails different investment needs. Investment in LNG infrastructure increases by 40%, to almost $10 billion, reflecting the need to further expand the use of LNG in trucks, the options to substitute oil in road freight transport being largely confined to biodiesel and LNG. The extent of the need for strong decarbonisation of road passenger car transport actually cuts investment needs in CNG infrastructure by 20%, as natural gas vehicles are partially pushed out of the market by electric vehicles, which produce fewer emissions on a well-to-wheel basis. At more than $400 billion, the investment requirements for the electricity recharging infrastructure are about eight times higher than in the New Policies Scenario in order to support very substantial growth in the use of electric cars.

Financing the transition[13]

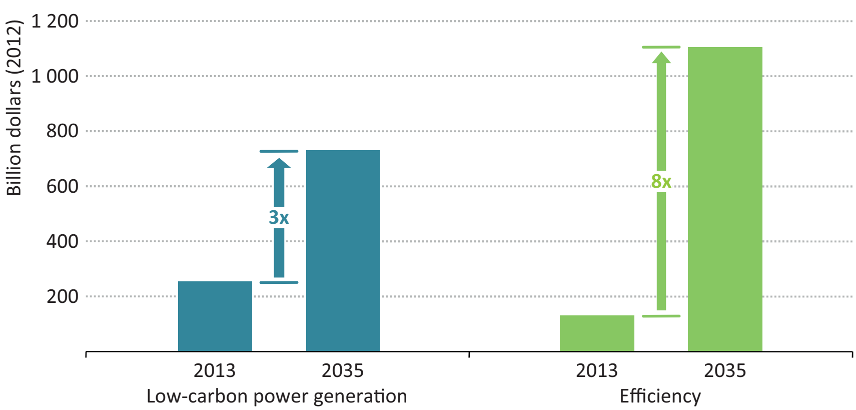
Attracting sufficient capital to the energy sector to achieve climate targets is a major challenge. Compared with the New Policies Scenario, an additional $12 trillion needs to be directed to low-carbon technologies and energy efficiency, a rise of 75%. Of this increase,

13. Investment and financing of nuclear power plants will be covered in detail in the special focus on the outlook for nuclear power, in this year's *World Energy Outlook*, to be published in November 2014.

45%, or $5.6 trillion, is required for additional investment in energy efficiency; $4.2 trillion for more rapid deployment on the supply side in renewables, nuclear and biofuels; and $2.4 trillion for investment in new technologies such as electric vehicles and CCS.

Investments in these areas encompass a wide variety of projects, each with its own risk profile and potential sources of finance (an issue taken up in more detail in subsequent chapters). But a common factor is that the transition to the 450 Scenario will require a step-change in the volume of external financing from banks and from capital markets. As detailed in Chapter 4, we estimate that today's energy efficiency investments are self-financed to the extent of about 60% from the budgets of governments, industry or households. But maintaining this scale of self-financing will be difficult when investment in energy efficiency is eight times larger than it is today, as it needs to be in 2035 in the 450 Scenario (Figure 1.15), while GDP rises only by a factor of two. Household expenditures will need to shift from current expenditure on operating costs towards a higher degree of capital expenditures to finance more efficient equipment. In cases where upfront investments are particularly high, as they are, for example, in buildings renovation, additional sources of external finance will be needed and imaginative new financing initiatives will be required even for less costly investments. Likewise, to increase investment in low-carbon power generation by a factor of three will require the mobilisation of additional sources of external finance, a particular challenge given that, in the wake of the economic and financial crisis, some of the traditional sources of low-carbon finance and investment – governments, commercial banks and utilities – face significant constraints.

Figure 1.15 ▷ Growth in investment needs in low-carbon power generation technologies and energy efficiency in the 450 Scenario



Successful financing of the transition to the 450 Scenario requires the financial community to be convinced that low-carbon and energy efficiency investments offer a sufficiently attractive risk-adjusted return. This has not yet been achieved. The reasons include doubt about technology readiness and a mismatch between desired investment size and the size of the projects, particularly in the case of institutional investors (Box 1.7). In the end, much of the issue comes back to deficiencies – or a lack of confidence – in the policy frameworks. Many low-carbon investments depend today on monetary or policy support to stabilise or lift revenues and make returns sufficiently commercially attractive. Until technology costs come down sufficiently for low-carbon technologies to compete without regulatory intervention or financial subsidies, many potential financiers will remain very cautious of allocating capital on the basis of measures or incentives that might be changed or withdrawn. Abrupt changes in support policies for renewable energy generation in several countries have reinforced this caution.

Getting energy pricing right is necessary to shift the balance of risks and rewards in favour of low-carbon technologies and energy efficiency. This means phasing out existing price distortions in the form of fossil-fuel subsidies. It also means including in the price of fossil fuels a suitable element to reflect the cost of the environmental damage they cause – a carbon price. There needs to be a clear and sustained signal to investors from this price, in particular to investors in the power sector (see Chapter 3). Investors and financiers are used to dealing with commodity price risks, and a carbon price can, in principle, readily be incorporated into their decision-making.[14] But in practice, the carbon price has so far often been volatile, and acting on this price signal requires confidence in the stability of the regulatory framework behind it, raising again the question of policy and regulatory risk. Ensuring that policy acts as a reliable guide to investment decisions (as it does in our modelling of the 450 Scenario) is, in practice, the most important contribution governments can make to achieve a 450 trajectory.

There are additional potential barriers to overcome:

- Low-carbon projects tend to have high up-front capital expenditures as a share of project cost, placing an extra burden particularly on those governments which are involved directly or indirectly in financing energy sector investments (as in some non-OECD countries).
- Higher unit capital costs and risk premiums mean that low-carbon projects may suffer disproportionately in the event that banks and other institutions retreat from providing long-term finance due to Basel III capital adequacy requirements (Box 1.3).
- The dispersed, diverse and small-scale nature of many low-carbon and energy efficiency projects makes it difficult to package them (to pool risk diversification and project size to better meet investment criteria) and "securitise" credit to investors, a key instrument to reduce risk.

14. Some multinational companies already use internal carbon pricing in their investment decisions.

Box 1.7 ▷ What is the role of institutional investors in low-carbon finance?

With low-carbon energy projects looking for additional sources of financing, the possibility of tapping into the huge resources held by institutional investors is generating considerable interest. These investors include insurance companies, investment funds, pension funds and sovereign wealth funds. They held over $83 trillion in assets in OECD countries in 2012. In emerging and developing countries, sovereign wealth funds are key sources of capital, with $6 trillion in assets in 2012. In many cases, these institutional investors have to invest for the long term to match long-term liabilities, so energy projects that can, in the right circumstances, deliver steady, inflation-linked, income streams could meet their needs. But institutional investment in the energy sector is rarely project-related, being largely confined to indirect investments in the listed shares and bonds of companies that build infrastructure. There has been some direct investment in wind power and solar photovoltaic projects, as well as projects in other parts of the energy sector, but overall the direct exposure of institutional investors to the energy sector has been very limited. Direct investment in infrastructure of all types accounted for only 1% of pension funds asset allocation in 2012, of which low-carbon energy was only a fraction.

What could help unlock this source of finance for low-carbon projects? OECD research, undertaken as part of its focus on green growth, recommends a number of steps that governments can take to facilitate institutional investment in low-carbon energy projects (Kaminker, et al., 2013):

- Ensure, as far as possible, a stable and integrated policy environment which provides investors with clear and long-term incentives and predictability.
- Address market failures (including a lack of carbon pricing) which result in investment profiles that favour polluting or environmentally damaging infrastructure projects over low-carbon infrastructure investments.
- Provide a national infrastructure road map which would give investors confidence in government commitments and demonstrate that a pipeline of investable projects will be forthcoming.
- Issue financing vehicles (e.g. green bonds), or support the development of markets for instruments or funds with appropriate risk-return profiles.
- Reduce the transaction costs of low-carbon investment by fostering collaborative investment vehicles between investors, so helping to build scale and in-house expertise.
- Support existing platforms for dialogue between institutional investors, the financial industry and the public sector, or create new ones where necessary.
- Promote market transparency and improve data on infrastructure investment by strengthening formal requirements to provide information on investments by institutional investors in infrastructure and green projects.

There is demand for low-carbon investment finance for many types of projects with different needs and risk profiles. Similarly, investors have various time horizons and tolerance for risk. A learning process is needed between policymakers and the finance industry to bridge the gaps. Policymakers need to understand the sectors of finance that they expect to be engaged and the conditions necessary to attract that investment. The financial community needs to appreciate the distinctive nature of such investment and to develop suitable vehicles to finance low-carbon projects in a way that aligns with their varying sizes, operational models and investment objectives. Aggregators, such as multilateral banks and corporate banks, can offer effective channels for better communication (Table 1.7).

Table 1.7 ▷ Selected finance vehicles for pooling investments in low-carbon energy projects and typical applications

Category	Description	Actors	Advantage	Typical application
Green bonds	Fixed-income debt securities.	Principally issued by governments, multinational banks or corporations.	High degree of security where backed by government or multilateral guarantees.	All mature low-carbon technologies, currently predominantly wind and solar power.
Pooled vehicles	Green infrastructure funds, private equity funds, and other listed vehicles.	Issued by asset managers, investment banks or specialist private equity funds.	Exposure to companies or assets for small investors.	All mature low-carbon technologies, currently predominantly wind and solar power.
Special purpose vehicles	Leasing scheme using debt facilities.	Provided from corporate or investment banks to equipment providers or utilities.	Equipment can be leased to end-user to reduce the impact on cash-flow, while giving access to large-scale debt finance.	Energy efficiency or micro-generation.

Sources: Della Croce, et al. (2011); Accenture and Barclays (2011); and IEA analysis.

The potential upside from this learning process for low-carbon and energy efficiency investment is huge, as it could open up new sources of finance. There are signs of progress in other areas with an expanding market for vehicles to pool "green" finance, as well as infrastructure funds supporting climate change policy. The United Nations Green Climate Fund is a prominent example.[15] But further innovation will be essential if the ambition to reach climate targets is to be aligned with the means of the financial world.

15. The Green Climate Fund is accountable to the UNFCCC and aims to raise $100 billion/year by 2020 to support projects, programmes, policies and other mitigation and adaptation activities in developing countries. Therefore it is broader than low-carbon technologies.

Investment in fossil fuels

Continuing to extract value?

Highlights

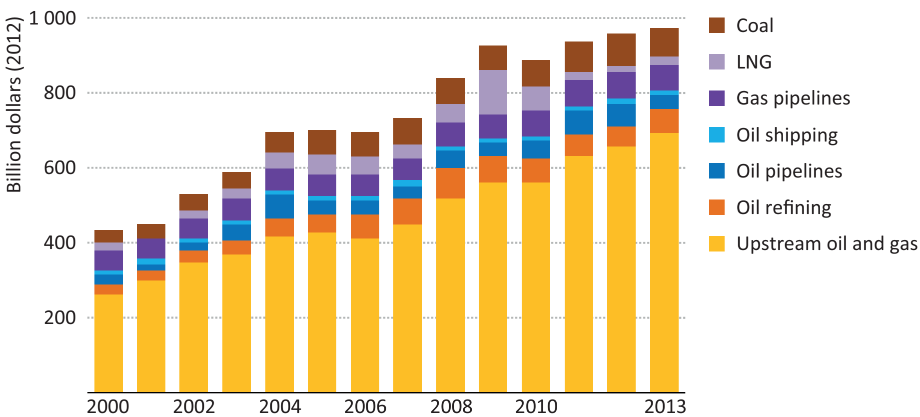
- Annual capital expenditure on oil, gas and coal has more than doubled in real terms since 2000 and surpassed $950 billion in 2013. The epicentre of increased oil and gas investment activity has been North America, with the rapid expansion of shale gas and tight oil output, but investment in other parts of the world has also been on an upward trend.
- Annual investment in upstream oil and gas rises in the New Policies Scenario by one-quarter to more than $850 billion by 2035, with gas accounting for most of the increase. More than 80% of the cumulative $17.5 trillion in upstream oil and gas spending is required to compensate for decline at existing oil and gas fields. A further $5 trillion is required for oil and gas transportation and oil refining.
- Gradual depletion of the most accessible reserves forces companies to move to develop more challenging fields; although offset in part by technology learning, this puts pressure on upstream costs and underpins an oil price that rises to reach $128/barrel in real terms by 2035.
- Investment in coal supply is much less expensive per equivalent unit of output than oil or gas; cumulative requirements in mining amount to $735 billion, with a further $300 billion in transportation. China accounts for around 40% of the total.
- Meeting long-term oil demand growth depends increasingly on the Middle East, once the current rise in non-OPEC supply starts to run out of steam in the 2020s. Yet there is a risk that Middle East investment fails to pick up in time to avert a shortfall in supply, because of an uncertain investment climate in some countries and the priority often given to spending in other areas. The result would be tighter and more volatile oil markets, with an average price $15/barrel higher in 2025.
- High transportation costs for gas, compared with other fuels, are a constraint on the prospect of more globalised gas markets. Investment in LNG capacity has the potential to create new links between markets and reduce current price differentials. However, the high cost of many liquefaction projects and cost inflation could dampen the hopes of LNG buyers for more affordable supply.
- Even with widespread deployment of CCS technology, the 450 Scenario sees a significant fall in the share of fossil fuels in the global energy mix, from the current 82% to 65% in 2035, compared with 75% in 2035 in the New Policies Scenario. Of the fossil fuels, only natural gas consumption is higher in 2035 than today. At $19.2 trillion, total investment in gas, oil and coal is more than $4 trillion lower than the $23.5 required in the New Policies Scenario, but still accounts for around half of total supply-side investment.

Historical and current trends

Fossil fuel investment

Fossil fuels remain at the heart of global energy use. Despite heightened efforts made around the world to shift energy consumption towards low-carbon sources of energy, today's share of fossil fuels in the global primary energy mix – 82%, according to IEA data – is exactly as it was 25 years ago. The share of oil has fallen steadily over the years to 31% in 2012, but it remains the largest single fuel in the global mix. Coal, with 29%, has met the biggest share of energy consumption growth since 2000, playing a pivotal role in fuelling the economic rise of Asia. The share of natural gas, the least carbon-intensive of the fossil fuels, has risen less dramatically than coal, but nonetheless accounts for 22% of the world's primary energy consumption.

Figure 2.1 ▹ Global investment in fossil fuel supply



Capital expenditure in the oil, gas and coal supply chains has more than doubled in real terms since 2000 (Figure 2.1).[1] In recent years, prices for oil and natural gas have been high (except in the case of natural gas in North America) and have incentivised investment across a broad front. Despite the resultant constraint on natural gas prices, the epicentre of this surge in investment has been in North America, the United States in particular, with a rapid expansion of unconventional oil and gas output since 2005. This has also made North America a focus for global spending on mergers and acquisitions, as companies seek to acquire not only acreage but also expertise on unconventional developments and technologies. Elsewhere in the world, the volume of investment has also been on a rising trend, including in conventional plays in the Middle East and Africa.

1. In the absence of historical global investment data in all sectors, all historical investment numbers are estimated based on IEA data for supply, demand and trade as well as IEA and industry data for investment costs, checked against actual historical investment data, where available. For consistency with our projections of future trends, these numbers reflect "overnight investment", i.e. the capital spent is generally assigned to the year production (or trade) is started rather than to the year when it was actually incurred; for example, the high LNG investment in 2009 in Figure 2.1 reflects the start of the large Qatari LNG plants.

National oil companies (NOCs), fully or majority-owned by national governments, account for just over 40% of global upstream investment and the largest share in the Middle East and South America. They range from companies entirely focused on their domestic resource base to those that are increasingly indistinguishable in operation and corporate culture from large privately owned companies.[2] What distinguishes them as a group is a degree of expectation (whether tacit or explicit) that they will act in the national interest, normally as defined by the government in office. They also hold most of the cards when it comes to oil and gas resources: we estimate that around 80% of proven-plus-probable oil reserves and 60% of natural gas reserves are held by NOCs or their host governments.

As with the upstream, investment in the oil and gas transportation sector has been particularly dynamic in North America, as pipeline flows are reversed and new ones are planned or built in an attempt to keep pace with the new regional geography of production. Outside North America, there has been a major expansion in liquefied natural gas (LNG) infrastructure since 2000, with liquefaction capacity rising 130% to reach 285 million tonnes (Mt) in 2013 and regasification capacity rising even more quickly. The focus for long-distance pipeline investment has been in Eurasia, as Eurasian resources are drawn eastwards by the rapid rise of demand for oil and gas in Asia-Pacific markets – as with Russia's East Siberia-Pacific Ocean (ESPO) oil pipeline (that includes a spur to China) and the Asia Gas Pipeline linking Turkmenistan to China. Investment has also been heavy in domestic oil and gas transportation networks in fast-growing Asian markets, notably China.

Compared with oil and gas, capital expenditure is only a modest component in the supply costs of coal. The bulk of the expenditure needed to bring coal to the market is made up of the variable costs of production, e.g. the fuel and power for the mining machinery and the labour costs (despite increasing mechanisation, coal mining remains a labour-intensive business). Capital investments are, nonetheless, indispensable in developing coal reserves and the related infrastructure development cost – railway lines, roads and ports – can be large especially when a new and remote coal field is being tapped.

Capital expenditure in the coal industry has more than doubled from $30 billion in 2000 to $75 billion in 2013. Most of this has taken place in developing Asian countries, with China and Indonesia at the forefront. Chinese coal production grew on average by more than 8% per year between 2000 and 2012, adding each week average production capacity of 3 million tonnes per annum (Mtpa) – an amount roughly corresponding to a typical mine in Australia. But the global surge in coal investment and production has now led supply to run ahead of demand, which has been held back in the United States (because of shale gas displacing coal in power generation) and in China (because of flattening demand growth for electricity). This has led to a fall in the price for internationally traded coal and, as a result, many of the coal supply investment and expansion plans announced by major exporters, such as Australia, Indonesia, Russia, United States, Colombia and South Africa, have been put on hold until the market outlook improves.

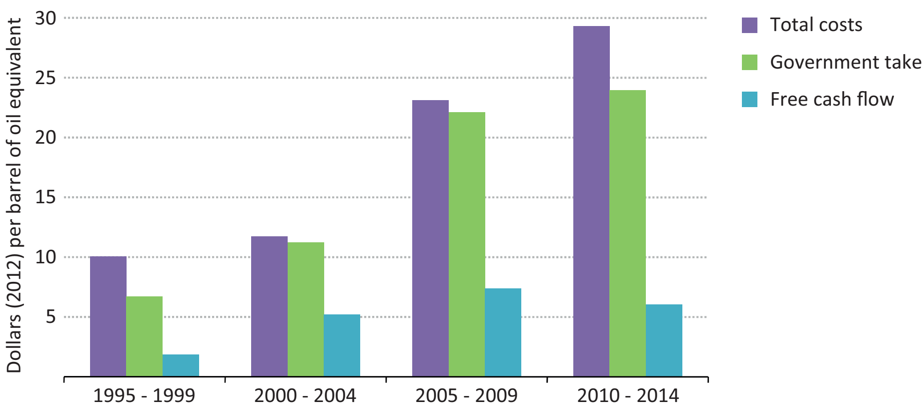
2. References to private or privately owned companies in this chapter distinguish this group of companies from majority state-owned companies. Private companies may be listed or unlisted on stock exchanges.

Structure of ownership and sources of financing

Oil and gas

The estimated market value of the oil and gas produced globally in 2012 was around $4.2 trillion, almost double the estimated $2.3 trillion that these sectors generated in 2005 (in year-2012 dollars) and more than four times the figure for 2012 oil and gas capital expenditure. This has provided a welcome windfall to resource-owning governments; in the case of the Organization of Petroleum Exporting Countries (OPEC), we estimate that oil export revenue rose from $600 billion to almost $1.2 trillion over the same period. It has been less of a financial bonanza for some of the major oil and gas companies, as costs and government take have more than kept pace with the increase in revenues (Figure 2.2). The prominence of government take, i.e. the total revenue that governments receive from production, including taxes, royalties and government participation, is a reminder of the leeway that policymakers have to influence investment decisions by adjusting fiscal conditions in the upstream.

Figure 2.2 ▹ Aggregate split of oil revenue for private upstream companies between total costs, government take and free cash flow

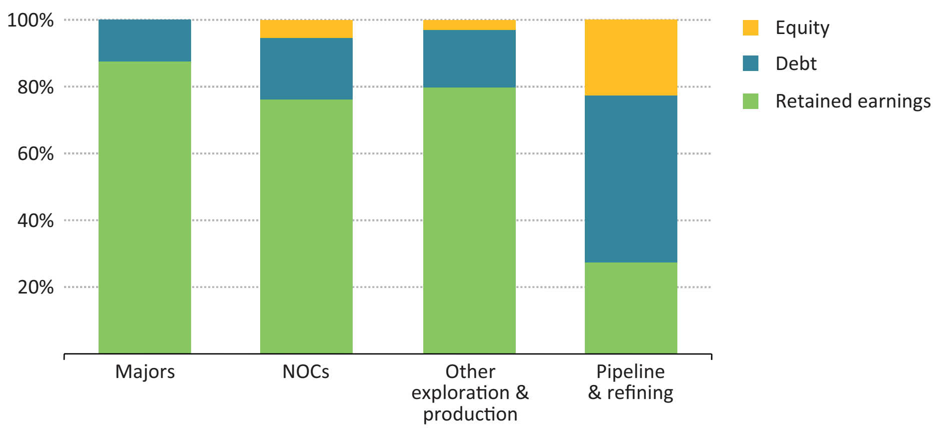


Sources: IEA analysis; Rystad Energy AS.

In many cases, the largest private oil and gas companies are not seeing returns commensurate with their massive increase in capital expenditure over the last few years and are under pressure to reduce costs, an atypical situation for a high-price environment (strong pressure for cost containment is more often a hallmark of periods when prices are low). Many large private upstream players have indicated that they will be reining in their capital expenditures in 2014. Among the NOCs, there are likewise indications in some countries of a disconnection between higher price levels and the availability to them of sufficient sums for investment. Rising costs play a role in this picture, notably in Brazil, although in general the natural resources at the disposal of NOCs are among the cheapest to develop. More pressing constraints, notably in the Middle East and in Russia, come from the fiscal needs of the host governments, which have quickly adapted to $100/barrel oil by increasing public spending. If the oil price stabilises around current levels and increases only moderately to 2035, as anticipated in the New Policies Scenario, governments that have become accustomed to burgeoning hydrocarbon revenues could be in for a difficult process of adjustment. This is one of the elements that underpin our analysis of a possible shortfall in Middle East upstream investment.

The way that upstream oil and gas investment is financed depends on the type of company or companies involved and the type of project. For the Majors, the income generated by their portfolio of upstream assets has traditionally been the main source of funding for capital expenditure, supplemented as necessary by corporate borrowing either from banks or from the capital markets (Figure 2.3). Where NOCs operate under strong commercial disciplines and are subject to the same taxation regime as other upstream players, their reliance on self-financing tends to be at similar levels to that of the Majors. This is the case for those NOCs that have listed at least some of their shares, such as PetroChina (part of CNPC), Statoil, Ecopetrol and Rosneft. A partial exception among the NOCs is Petrobras, which – because of the speed at which it hopes to increase production in the coming years – relies more on debt financing for its huge capital spending programme. In cases where NOCs need to raise capital to finance investment, for example in the case of some Asian NOCs looking to expand their presence abroad, they can often rely on borrowing, on favourable terms, from state banks.

Figure 2.3 ▹ Indicative sources of financing for capital expenditure for different types of listed oil and gas companies, 2002-2012



Notes: This is calculated looking at total change in debt and equity financing for the top 50 listed oil and gas companies as a percentage of capital expenditure, used to proxy the share of external financing. The seven Majors are BP, Chevron, ExxonMobil, Shell, Total, ConocoPhillips and Eni.

Sources: IEA analysis and 2° Investing Initiative, based on data from Bloomberg Professional service.

Among unlisted NOCs, Saudi Aramco allocates funds for capital expenditure and operating expenses directly from earnings, on the basis of a budget presented to the authorities, before transferring its income to the government. For some other NOCs, subject to stronger elements of political supervision, the degree of financial autonomy tends to be more constrained, operating surpluses being surrendered to the government, which then allocates funds for capital expenditure. A similar effect can be obtained when the NOC is subject to additional taxes and dividends. In the case of the Southern Oil Company in Iraq, for example, no revenue is received directly from the oil that it produces, all of its oil being sold via the State Oil Marketing Organisation.

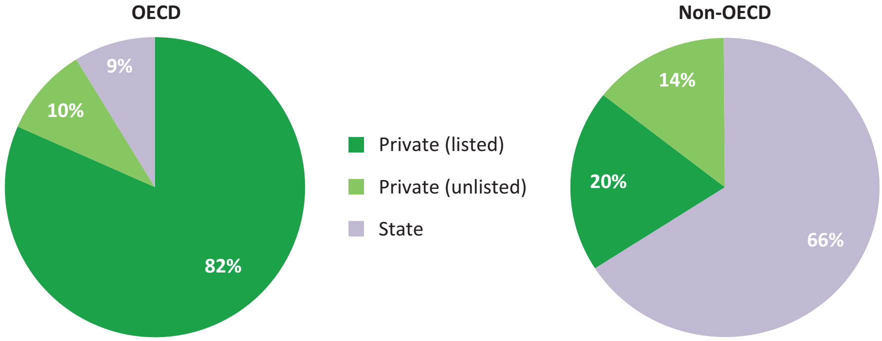
In some cases (particularly for smaller players) cash flow from existing operations may not be sufficient to fund new developments. The financing options then depend on the sort of investment that is being undertaken and vary widely by jurisdiction, depending on the maturity of the local banking and capital markets, the overall fiscal system and the applicable contractual regime upstream. But there are some common threads. Borrowers planning to develop (or acquire, in some cases) specific proven reserves can typically raise funds based on the value of these assets. Operating fields with established production can borrow against future revenue, through pre-payment arrangements or pre-export finance. Where risks are higher and/or where future revenues are more uncertain, as for companies involved in exploration, banks are apt to be reluctant lenders and the most promising way of raising funds is likely to be through an equity offering. As companies grow in size, they develop a portfolio of activities that allows them better to manage risks and financing needs.

A higher proportion of debt or equity financing is common for projects in the midstream and downstream, on the basis of an expectation of long-term and relatively predictable revenues. In the case of pipelines, LNG plants and refineries, high capital intensity and the expectation of stable long-term cash flows make these projects good candidates for project finance. The top three global project finance deals in 2013 were all in the oil and gas sector: the Sabine Pass LNG facility in the United States ($5.9 billion), the Nghi Son refinery in Vietnam ($5 billion) and the Kazakhstan section of the Asia Gas Pipeline ($4.7 billion).

Coal

Given that coal projects do not need high margins to recover their investment cost, financing coal mining projects has typically not been a major problem, funds coming either from operations (typically the case in India and China over the last ten years) or debt financing from banks and capital markets. Ownership has a strong influence on the pattern of financing, influencing company strategy and behaviour, and there are important differences in the ownership pattern in different parts of the world. Within the OECD, state ownership of hard coal production capacity is less than 10% and is confined to parts of Europe and, to a lesser degree, to Australia. By contrast, the share of state ownership is very high in India, China and Vietnam; it is significantly lower in export-oriented producers, like Indonesia, Colombia and South Africa (Figure 2.4).

Figure 2.4 ▷ Ownership structure of hard coal production capacity, 2012



Sources: Wood Mackenzie databases; IEA analysis.

Trends in the New Policies Scenario

The world remains heavily dependent on fossil fuels in the New Policies Scenario. Their share in the global energy mix falls to around 75% in 2035 (from 82%), but this nonetheless involves an increase in the world's annual consumption of fossil fuels, by around 2 300 million tonnes of oil equivalent (Mtoe), over today's levels (Figure 2.5). Natural gas accounts for more than half of this growth. Fossil fuel use falls in the countries of the OECD, with a slight increase in the use of gas more than outweighed by a larger decline in coal and oil. All of the growth in fossil fuel use comes from non-OECD countries, mainly for mobility (in the case of oil) and for power generation (in the case of coal and gas). Per capita fossil fuel consumption in non-OECD countries is only half that of the OECD by 2035, but by then China has overtaken the United States to become the largest oil-consuming country and its gas demand is comparable to that of the European Union today.

Figure 2.5 ▷ Growth in world fossil fuel demand in the New Policies Scenario

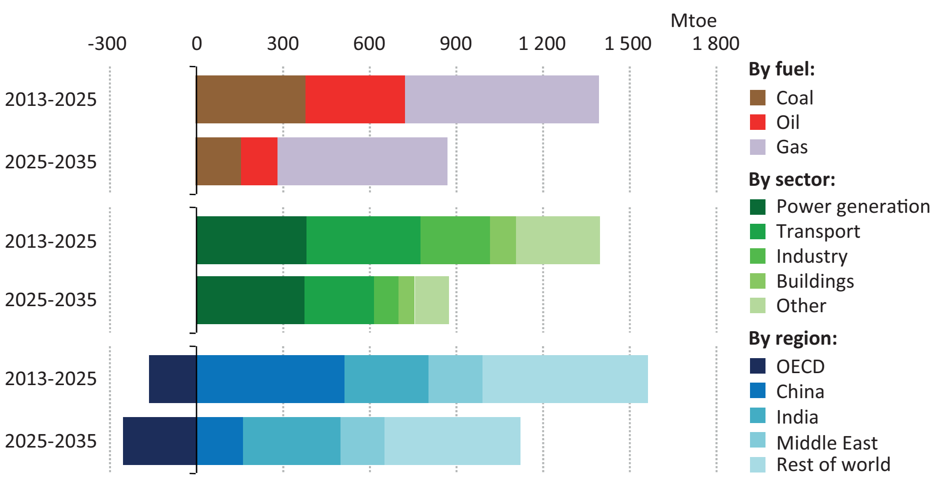


Table 2.1 ▷ Cumulative fossil fuel investment by region in the New Policies Scenario, 2014-2035 ($2012 billion)

	Oil				Gas			Coal			Fossil fuel total
	Upstream	Transport	Refining	Total	Upstream	Transport	Total	Mining	Transport	Total	
OECD	**4 087**	**124**	**434**	**4 645**	**2 177**	**1 119**	**3 296**	**202**	**47**	**250**	**8 191**
Americas	3 488	98	226	3 813	1 433	586	2 019	100	16	116	5 948
United States	2 021	46	193	2 260	1 057	443	1 500	89	14	102	3 862
Europe	500	18	147	666	512	303	815	13	9	22	1 503
Asia Oceania	98	7	61	167	233	231	463	89	22	111	741
Japan	2	1	30	32	1	43	43	0	3	3	78
Non-OECD	**7 197**	**572**	**966**	**8 735**	**3 961**	**1 421**	**5 381**	**534**	**181**	**715**	**14 831**
E. Europe/Eurasia	1 345	71	95	1 510	1 199	417	1 617	50	26	76	3 203
Russia	750	28	70	849	715	301	1 016	32	17	49	1 914
Asia	1 079	161	484	1 724	1 186	427	1 613	416	140	556	3 893
China	715	83	274	1 072	448	209	657	335	69	404	2 133
India	78	53	146	277	133	70	203	53	42	94	575
Southeast Asia	261	18	52	331	446	83	529	23	23	46	906
Middle East	1 578	186	193	1 956	458	241	699	0	1	1	2 656
Africa	1 291	50	54	1 395	674	241	915	39	6	46	2 356
Latin America	1 905	104	141	2 150	443	93	537	28	9	36	2 723
Brazil	1 205	89	100	1 393	127	30	157	0	2	2	1 552
Inter-regional transport	n.a.	290	n.a.	290	n.a.	93	93	n.a.	69	69	452
World	**11 284**	**986**	**1 401**	**13 671**	**6 138**	**2 633**	**8 771**	**736**	**298**	**1 034**	**23 475**
European Union	242	15	136	394	254	276	531	12	7	19	944

Asia increasingly becomes the destination for traded fossil fuels. Rising oil and gas import dependence among the region's main emerging economies coincides with a decline in North American oil imports and the start of North American gas exports. The net effect is a major re-orientation of global trade, away from the Atlantic basin and towards the Asia-Pacific. China is already in the process of becoming the world's largest importer of oil, while India overtakes China in the 2020s as the largest global importer of coal. The Asia-Pacific import market becomes the main global arena for trade in gas, based primarily on LNG.

To meet these demand projections, investment of $23.5 trillion is required in fossil fuels (Table 2.1): a cumulative $13.7 trillion in the oil sector, $8.8 trillion in natural gas and $1 trillion in coal.[3] In our modelling, the price trajectories for the various fuels provide for these investments to yield reasonable rates of return, so it is also reasonable to expect that the required investment will be forthcoming.[4] In practice, good foresight will be required as to future regulatory and market conditions. Investor and company investment decisions are determined by their judgements as to the nature of regulatory and other risks, and their perceptions of future market opportunities. There is always a risk that investment will turn out to have been insufficient, driving energy prices higher or even creating energy shortages and thereby stimulating a new cycle of investment.

Given the dominance of fossil fuels in the global mix, these investment flows are clearly critical to the reliable functioning of the energy system. In some cases, they can also contribute to environmental objectives, as when gas substitutes for coal in power generation. But, overall, the continued high reliance on fossil fuels in this scenario has damaging consequences, as the high levels of combustion of oil, gas and coal adversely affect, to different degrees, the local environment and the global climate. Alongside the myriad other challenges and risks facing oil, gas and coal investment over the coming decades, we examine in the concluding part of this chapter the effects that stronger policies on decarbonisation might have on investment in the different fossil fuels and their respective value chains.

Upstream oil and gas

From an estimated $700 billion in 2013, global upstream oil and gas expenditure rises steadily throughout the projection period, reaching an average of more than $850 billion annually by the 2030s. More than 80% of this spending is required just to keep production at today's levels, that is, to compensate for the effects of decline at existing fields. The figure

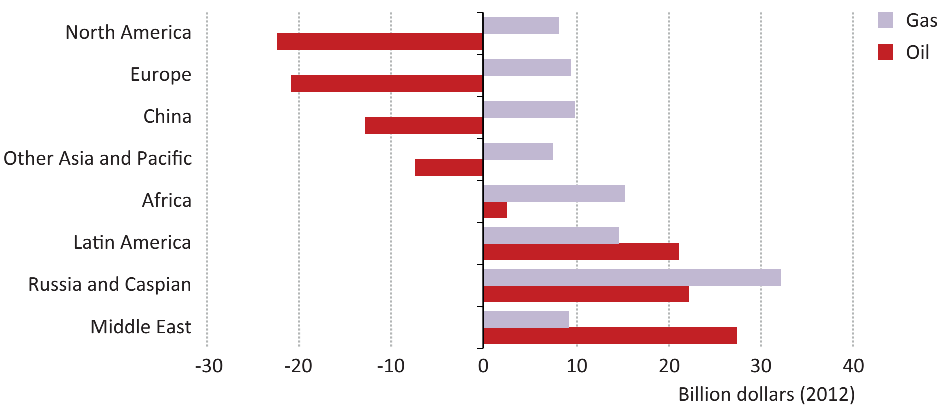
3. There is no authoritative way to divide upstream investment between oil and gas (as fields drilled for oil can produce associated gas that is marketed, and fields drilled for gas can produce natural gas liquids that meet part of the oil demand. The split given here should be considered as indicative.

4. As a result of our comprehensive review of recent cost trends for this report, the upstream investment numbers for oil and gas in the New Policies Scenario are revised upwards compared with *WEO-2013*, such that the average F&D costs over 2014-2035 for a barrel of oil rise to $17.6 from $14.5 in *WEO-2013*, and for an MBtu of gas, from $1.4 to $1.6. Although these differences imply upward pressure on prices, they could be accommodated within the *WEO-2013* oil and gas price trajectories used in this analysis. (See Chapter 13 of *WEO-2013* for a detailed discussion of the relationship between oil supply costs and prices).

is higher in the case of oil (at close to 90% of total capital expenditure) and slightly lower for gas (at around 70%), not because of any major structural difference in decline rates, which are similar, but because overall gas demand – and hence investment in additional production – grows more rapidly than that for oil. Investment in gas projects accounts for almost all of the increase in total upstream expenditure, the share of natural gas in total upstream investment therefore rises steadily over the period to 2035.

Although total spending on upstream oil projects remains fairly constant, at an average of just over $500 billion/year, there is a noticeable shift in the location of this investment over the coming decades. Average annual investment levels start to tail off in North America, largely in the United States, where investment and then production start to fall from the mid-2020s onwards. Investment levels also fall in China and in some other mature basins, but they rise considerably in three regions: the Middle East (see focus on investment in the Middle East, below), Brazil and the Caspian region (Figure 2.6). Of the $11.3 trillion in cumulative investment required over the period to 2035, $2.9 trillion (26%) is required in the countries of OPEC; this is sufficient to give OPEC a 46% share in total output by 2035.

Figure 2.6 ▷ Change in average annual upstream oil and gas investment by region in the New Policies Scenario

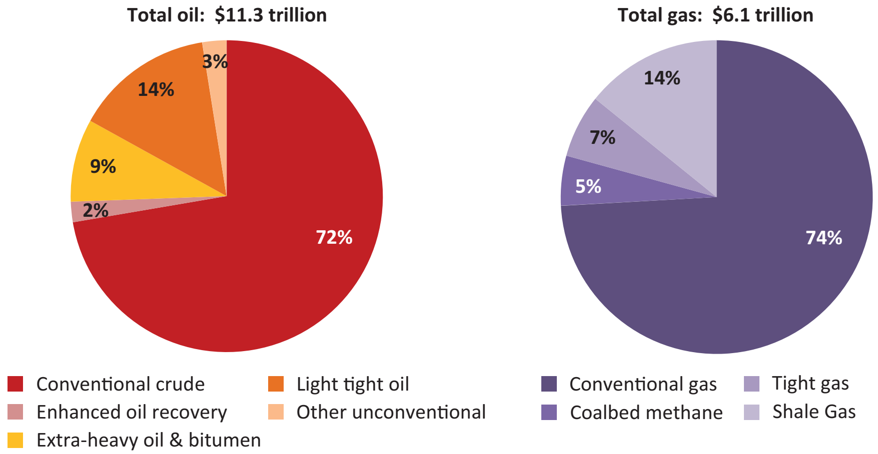


Note: The figure shows the change in spending between the annual averages for 2014-2020 and 2031-2035.

Upstream natural gas expenditure rises from an annual average of $230 billion in the period to 2020 to more than $330 billion by the 2030s, with spending on upstream gas rising in all the major regions. One-third of the total takes place within the OECD countries, mostly in the United States, Canada and Australia. A large increase is required over coming decades in investment in Russia in natural gas exploitation (accompanied by large expenditure on the new pipelines and LNG plants that will be needed in association with the development of East Siberian and Arctic resources). The same is true in the Caspian region. Upstream gas investment also rises sharply in China, reflecting efforts to develop the country's unconventional gas potential, and in parts of Africa, notably because of the investment associated with developing the offshore gas discoveries in East Africa.

One-quarter of the cumulative investment upstream in oil and gas is required to develop unconventional resources (Figure 2.7). Most of this occurs in North America, which accounts for around three-quarters of total investment in unconventional oil (including oil sands in Canada and tight oil in the United States). Unconventional oil production is slow to take off elsewhere in the world in our projections, with the partial exception of Venezuela (where extra-heavy oil substitutes for declining conventional output), some development of tight oil production in Russia, China and Argentina, and expansion of coal-to-liquids and gas-to-liquids projects in several parts of the world.

Figure 2.7 ▷ Breakdown of cumulative world upstream investment by resource type in the New Policies Scenario, 2014-2035



The share of North America in unconventional gas investment is lower, at just over 60%. This indicates how production of shale gas (notably in China, but also Argentina, India and elsewhere) and coalbed methane (in Australia, China and India) gains more momentum, although – with the exception of Australia, where coalbed methane production is well underway – it takes some time to achieve significant levels of commercial production.

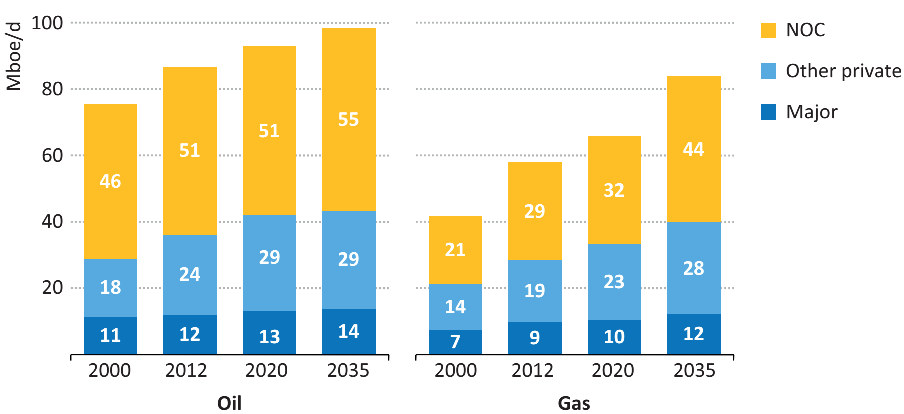
Investment actors and opportunities

The projected pattern of investment by region and resource type offer some insights also into the part expected to be played by different types of company, whether Majors, other private companies or the wide spectrum of NOCs. Recent years have seen a greater range of upstream opportunities open up for private companies and internationally-minded NOCs, as robust demand and high prices brought new resource types into play. Our projections suggest that this ebb in the bargaining power of the main conventional resource-holders is set to remain for oil, at least into the medium term, and to become a longer-lasting feature of gas markets, even as demand for gas rises more rapidly.

In the case of oil, non-OPEC supply continues to expand into the 2020s, on the back of rising output of tight oil in the United States, growing supply from the oil sands of Canada, deepwater of Brazil and natural gas liquids (NGLs) from a variety of sources. However, from the mid-2020s onwards, as non-OPEC supply levels out and then tails off, the pendulum swings back towards the main conventional resource-holders – primarily in the Middle East – where NOCs hold sway.

In the gas sector, the concern that the world might become increasingly dependent on a small number of conventional resource-holders has receded. Not only are unconventional resources large and widely distributed, but new contributions to conventional supply are also anticipated from Iraq, Brazil, East Africa, the Eastern Mediterranean and elsewhere, providing greater diversity in global gas supply and so a sound foundation for well-functioning markets. A major uncertainty is how rapidly the role of gas will expand in fast-growing non-OECD markets, primarily in Asia, which provide more than 80% of global demand growth in our projections. The need to tackle air pollution in the major cities and a desire among governments to diversify the energy mix provide a strong opportunity for gas, but the region is currently characterised by rigid contracting structures for imported supplies that lead to market inefficiencies and a high price level, compared with other markets. Buyers are seeking a new commercial model for gas purchases – and competitively priced North American LNG exports may speed this process – but the uncertain transition increases the risk for upstream projects looking to target this region.

Figure 2.8 ▹ Indicative split of global oil and gas production by company type in the New Policies Scenario



Note: This analysis assumes no change in the ownership of reserves at country level; it reflects only the change in geographical location of supply. Mboe/d = million barrels of oil equivalent per day.

Source: IEA analysis based on Rystad Energy AS.

The net result is a changing upstream landscape. The medium-term outlook for oil is for robust spending in countries that offer open investment frameworks and a relatively attractive balance of risk and reward. This is the case in North America and, to a large degree, in Brazil, even though a more restrictive licensing regime has been put in place for development of the most prolific deepwater pre-salt deposits. There are signs that other countries may improve their upstream terms in order to attract investment. For example, Mexico is reforming laws limiting participation by foreign companies in the hydrocarbon sector. But, in the latter part of the projection period, increases in capital expenditure are concentrated in countries with a more restrictive approach to international participation in the upstream, notably in the Middle East. As a consequence, after 2020, the volume of oil produced by private companies is projected to level off, with almost all the increase in output coming from NOCs (Figure 2.8).

Among the private companies, the challenges ahead appear particularly acute for the Majors, which have traditionally dominated the global industry, but which face short-term pressure from financial markets to curb capital expenditure (with consequent impacts on medium-term production levels) and long-term pressures from international NOCs looking for investment and acquisition opportunities outside their home countries (see Box 1.2 in Chapter 1). One strategic response from the Majors has been to switch their focus more to natural gas, where the scope for growth is that much greater and the access to resources less constrained.[5] Another has been to pursue partnerships with NOCs, as for example, the agreement between ExxonMobil and Rosneft to develop tight oil, Arctic resources and LNG projects in Russia. Even though many NOCs are becoming increasingly confident about taking on large and complex projects alone, or with the assistance of service companies, co-operation with the Majors on capital-intensive or "frontier" plays looks to be a good way to harness the Majors' project management skills, technical expertise and access to finance.

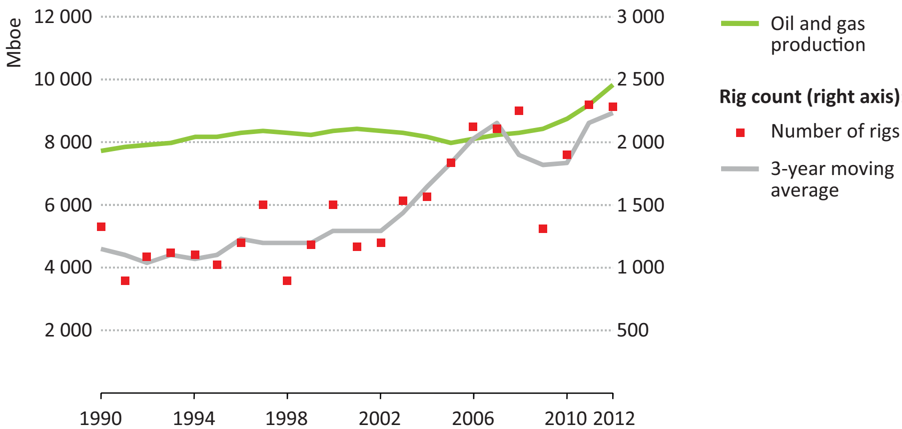
Trends in costs and complexity

The rise in oil prices over the last ten years has been accompanied, arguably underpinned, by growth in the costs of finding and developing (F&D) new resources.[6] This reflects increases in the prices for cement, steel and other production materials and equipment, and in the cost of hiring skilled personnel and contracting for oilfield services and drilling rigs. It also reflects, in part, the complexity of the upstream projects being undertaken. One indicator of this trend is the number of active oil and gas rigs in North America, where the rise in output since 2005 has required almost a doubling of the rig count (Figure 2.9). The intensity of drilling required for unconventional production has been the main reason for this increase, but this sign of greater complexity is also apparent elsewhere in the world. For the ten years prior to 2000, production growth outside North America was being maintained with a rig count that was broadly stable; a similar rate of production growth since 2000 has required a 50% increase in the number of active rigs.

5. Although here too the competition from NOCs is intense, as for example in Mozambique where all four stakes offered in two offshore gas discoveries were bought by NOCs for a combined $11 billion (China's CNPC, India's ONGC and IOC and Thailand's PTT).

6. The main components of finding and development costs are the geophysical and geological analysis, drilling of exploration wells (the exploration phase), drilling of production wells and the installation of processing facilities at the surface once a discovery is confirmed (the development phase). Finding and development costs, do not alone establish a breakeven oil price, which also needs to take into account operating costs, such as lifting costs, and government take.

Figure 2.9 ▷ North American oil and gas production versus active rig count



Source: Baker Hughes Rig Count.

There is no shortage of resources to meet the projected demand in the New Policies Scenario, but geological and technical risks are nonetheless set to increase as "easy" oil and gas is gradually depleted and companies move to develop more challenging deposits. A trend towards smaller discoveries is set to continue and, where large fields remain to be discovered, they are likely to be in increasingly remote locations, such as deepwater offshore and the Arctic. These types of developments are not only expensive but, in many cases, push at the frontiers of what the industry can undertake.

This transition to more challenging and complex reservoirs is a key element in our modelling of future F&D costs. But it is only one of the factors at work. For each basin and resource type, the way that costs evolve depends on the interplay between three variables, not all of which push in the same direction:

- The first is the depletion effect. As a higher percentage of the ultimately recoverable resource base is produced, so finding and development costs per barrel tend to rise. The North Sea, a mature producing area, provides a good example: not only are the fields to be developed in the traditional production areas smaller and more challenging, but there is also a move away to deeper waters, west of the Shetlands, on the UK side and a move further north on the Norwegian side.
- Technology learning and infrastructure build-up can counter-act this effect. Technology learning has clearly been at work over the last few years in the shale plays in North America: as operators learn about a play, they are able to optimise the rig and well designs to reduce costs. Technologies developed for difficult fields, such as horizontal drilling or production monitoring with 3D seismic, are spread to other fields. New infrastructure needs diminish: if, for example, the first offshore fields in a basin require construction of expensive infrastructure (which can be justified only for large fields), subsequent developments can piggy-back on this infrastructure and so reduce costs.

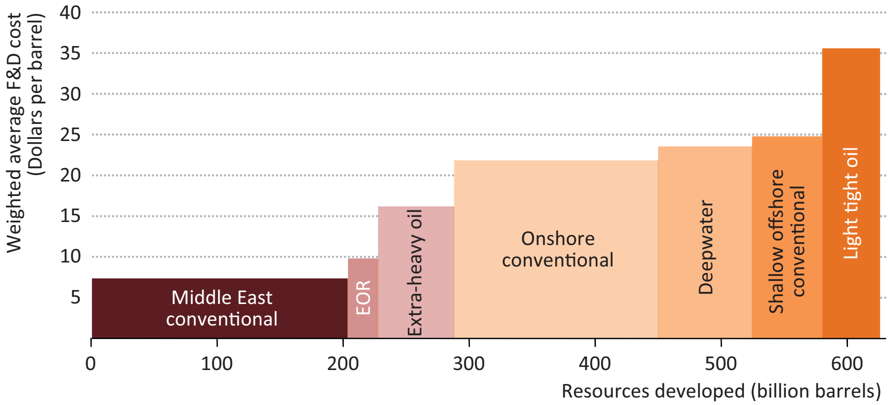
- The costs of services and supplies often go through cycles, following cycles of drilling activity in specific basins. The price of other commodities and the tightness of the market for skilled specialists also play a significant role. In our model, we make the simplifying assumption that these costs are correlated with oil prices, a supposition that appears to be borne out by the experience of the last ten years. This effect is muted in our projections, as the oil price rises only very gradually in real terms to reach $128/barrel in 2035.

As a result of the interplay of these different factors, the evolution of F&D costs to 2035 varies by region and by type of resource. For the major producers in low-cost regions such as the Middle East, costs are in the range of $5-12/barrel; although the complexity of development increases, the largest producers do not experience major increases in costs because they still have a choice of resources to exploit to meet the expected production demands on them over the projection period, and there are significant opportunities to benefit from learning effects. The two countervailing pressures, of depletion versus beneficial learning and infrastructure effects, keep F&D costs in most regions in the $20-30/barrel range, only a moderate cost increase in real terms. There are, though, a few countries and basins that see a larger rise, as rapid production rates move them from a very low rate of depletion to a more significant rate, even though the resulting cost increases are partly offset by technological progress. This is the case of Brazil, for example, as it moves towards developing smaller deepwater fields.

Within the category of unconventional resources, F&D costs for extra-heavy oil and bitumen (including oil sands) do not change significantly: depletion is and remains small and technology learning more or less offsets the increasing price of oil (an important input in the extraction process). In the case of tight oil, the way that costs are projected to evolve differs inside and outside the United States. In the United States, on the basis of the current estimates of total recoverable resources, high production rates mean resources are rapidly depleted, with a corresponding rise in costs per barrel as operators move out of the sweet-spots to areas where the recovery per well is lower. This explains the peak and then the subsequent decline in US tight oil production after 2025 in our projections. In the rest of the world, only a low level of tight oil production is expected (compared to the resources), so learning effects outweigh the small impact of depletion, gradually bringing average costs down to levels below those anticipated in the United States.

Looking at the cost profile of the oil resources that are developed in the New Policies Scenario, there is a wide range from the conventional resources of Middle East producers, through to tight oil production in and outside North America (Figure 2.10). There are many more low-cost resources available than are developed in this scenario, but – as discussed above – access is limited by resource-owning governments: the way that resources are developed in this scenario demonstrates how, for oil, it is access to resources, rather than their cost, that determines where investment goes. In OPEC countries of the Middle East, 13% of the total upstream oil investment accounts for almost one-third of the new resources developed to 2035. Tight oil in North America similarly accounts for 13% of upstream investment, but only 6% of new resources.

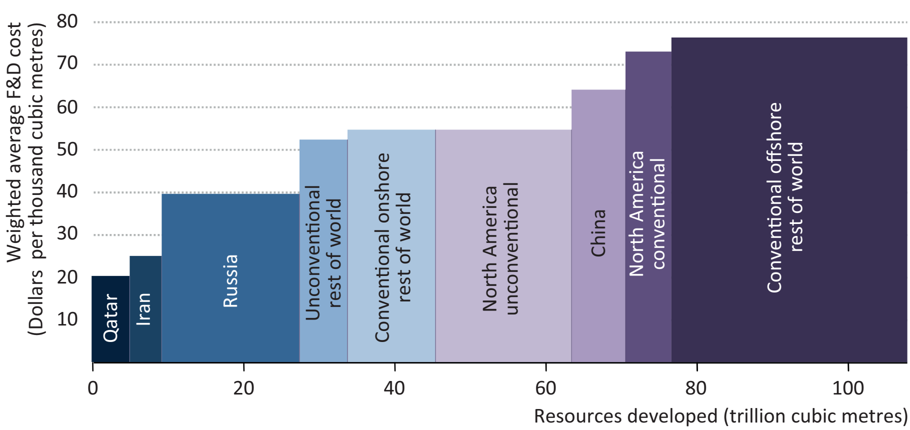
Figure 2.10 ▷ **Oil resources developed to 2035 in the New Policies Scenario**



Notes: Each basin and resource type has its own estimate of F&D costs; the levels shown here are averages, weighted by production over the period to 2035. Average values for shallow offshore production are pulled up by the exclusion of Middle East shallow water production and by relatively expensive developments in Kazakhstan and Norway; deepwater is pulled down by relatively low cost per barrel developments in Brazil. EOR = enhanced oil recovery.

The overall picture is quite similar for gas, though there is more of a continuum of finding and development costs, ranging from those of Qatar (around $20 per thousand cubic metres, or well below $1 per million British thermal units [MBtu]) to more than $3/MBtu in the North Sea (Figure 2.11). Countries that are currently producing (or planning to produce) at significant rates, compared to our current estimate of their conventional recoverable resources, experience rapid increases in costs as a result, due to depletion effects: examples include Trinidad and Tobago, Angola, China and Egypt. Others see more modest changes. Norway sees an increase in costs as developments move further north, while the rest of the North Sea has relatively steady costs (but a decreasing level of production). Costs for shale gas in the United States rise, under the same pressures as tight oil, while the rest of the world generally sees decreasing shale gas costs, due to learning effects.

Figure 2.11 ▷ **Gas resources developed to 2035 in the New Policies Scenario**



Focus on upstream oil in the Middle East

Rising output of tight oil from the United States, the oil sands of Canada and the prospect of new deepwater conventional supplies from Brazil, have put oil developments in the Middle East somewhat in the shade in recent years. But, as we have seen, meeting long-term growth in oil demand relies much more heavily on the holders of the large remaining conventional resources, which are concentrated in the Middle East. From the early 2020s through to the end of the projection period in our New Policies Scenario, Middle East output rises from 28 million barrels per day (mb/d) to more than 34 mb/d in 2035, an annual average rise of around 400 thousand barrels per day (Table 2.2).

Table 2.2 ▻ Indicators for the Middle East in the New Policies Scenario

Indicators	Unit	2013*	2020	2030	2035
Oil production	mb/d	28	28	32	34
Oil demand	mb/d	7	8	9	10
Oil net exports	mb/d	21	20	23	25
Gas demand	bcm	430	502	653	713
Electricity demand	TWh	760	956	1 303	1 474
GDP	$2012 billion	2 550	3 399	4 995	5 973
Population	million	217	246	282	297
Annual averages ($2012 billion)		**2007-2013**	**2014-2020**	**2021-2030**	**2031-2035**
Upstream oil and gas investment		73	74	97	110
Power sector investment		20	21	27	32
Oil export revenue		682	803	915	1 083

*Preliminary estimates. Note: bcm = billion cubic metres; TWh = terawatt-hours.

Picking up the unmet demand in oil markets will require major investment upstream. After a slight lull, caused by the continued rise in tight oil and other non-OPEC supplies, the oil investment requirement in the Middle East in our projections picks up again in the latter part of the current decade and then rises substantially through the 2020s, as output increases and costs creep higher.[7] Yet the required upturn in investment is by no means guaranteed, even though the oil resources of the Middle East remain ample and are among the cheapest in the world to develop. This section explores the reasons why a shortfall in upstream investment might occur and examines the consequent effects of tighter oil markets on prices and demand.

This analysis is not influenced directly by the current disruptions to output in the Middle East and North Africa due to the turmoil in Syria and in Libya, although these do contribute to a more general climate of uncertainty and to heightened perceptions of risk. The main considerations that could inhibit funding for investment in the oil sector include:

7. In our projections, future investments are booked in the year in which new supply comes on stream; given the lead times for projects, in practice the pick-up in investment would need to come much earlier.

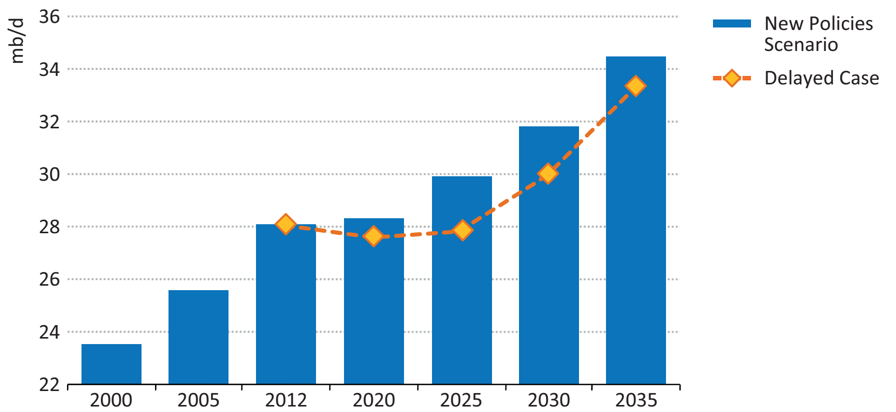
- The prospect that aggregate revenues from oil export will level off. The projected rise in non-OPEC supply and our relatively flat price trajectory for oil mean that projected revenues from oil export across the Middle East, estimated at more than $800 billion in 2013, remain around or slightly below that level in real terms for much of this decade, after having more than tripled in real terms over the period since 2000. For many of the countries in the region, revenue from oil export is the most important source of national income: for the Middle East as a whole, oil export revenue in 2013 was the equivalent of one-third of GDP and it was higher for Kuwait, Saudi Arabia, Iraq and the United Arab Emirates.[8]
- The possibility that public programmes outside the energy sector will be given priority, due to demographic and fiscal pressures. Political turmoil has come in some countries at the same time as a demographic bulge of young people entering the job market: as of 2010, more than half of the population of the region was under 25 years old (more than 20% between the ages of 15 and 24). The political response to this situation has, in many cases, included a large increase in social spending, mainly in the form of benefits and salaries rather than capital expenditure. There is an expectation in some countries that the state will create opportunities in the public sector to absorb the new arrivals on the job market.
- High oil consumption growth, driven by continued fossil-fuel subsidy regimes. The need to maintain social stability may discourage governments from attempting to reform these subsidy regimes, despite the wasteful consumption to which they give rise and the consequential lost volumes of oil for export. We estimate that the value of the subsidies provided in the Middle East for oil products in 2012 was $112 billion (or around $500 per person). Adding in the subsidies given to consumption of natural gas and electricity, the total rises to $203 billion, equivalent to around one-quarter of total oil export revenues. Low prices for gas and electricity, and consequent problems with financing and feedstock for new power projects could see continued high use of oil in the power sector (currently 2 mb/d for the region as a whole).
- The uncertain outlook for production in Iran. Though there are some signs of progress, early resolution of the tension between Iran and the international community is far from assured. Even if accord is reached, it will take considerable time to rebuild production capacity lost through a lack of investment, as well as through constrained access to technical expertise and equipment.
- Major hurdles to growth of production in Iraq. There has been steady improvement in some areas, but persistent security concerns, weak institutions and logistical difficulties, as well as continued differences between Baghdad and Erbil on the governance of the hydrocarbons sector, could hold back output.

8. Two ways to increase export revenue would be to restrict production (and increase oil prices) or, on the contrary, to try to recapture market share by pushing oil prices down. However, in our estimation, the projections for the New Policies Scenario are already close to a revenue-maximising strategy for the region and there is not much scope for significant gains in revenue (a misjudgement of evolving demand elasticity and non-OPEC supply elasticity could lead to loss of revenue).

These potential constraints on capital flows to the upstream are compounded by commercial uncertainty over the right moment for Middle East producers to boost investment in anticipation of a plateau and eventual fall in non-OPEC supply. This is related in large part to uncertainty over the prospects for tight oil production in the United States – whether and when the current growth will start to run out of steam. Investment decisions in the Middle East will need to be taken well in advance of this becoming evident, because of the long lead times in conventional production between initial investment and full production. A misjudgement in timing is quite conceivable.

If investment were to fall short of the levels required in the New Policies Scenario, any spare production capacity could initially be drawn upon, though prices would still rise as a result of the heightened risk premium associated with reduced spare capacity. But the effects would become much more apparent in the 2020s, the start of a second phase in our oil outlook, when steady increases in Middle East supply are required to meet rising demand (Figure 2.12). In a Middle East Delayed Case[9], the shortfall in investment leads to an extended period of flat Middle East production, at a time when the projected call on such production in the New Policies Scenario picks up considerably. This shortfall in output, relative to the New Policies Scenario, peaks at just above 2 mb/d in the mid-2020s. From this point on, production in our Delayed Case starts to grow again, as investment and eventually output respond to higher prices, gradually closing in on (but not reaching) the levels seen in the New Policies Scenario by the 2030s.

Figure 2.12 ▷ Middle East oil production in the New Policies Scenario and in the Delayed Case



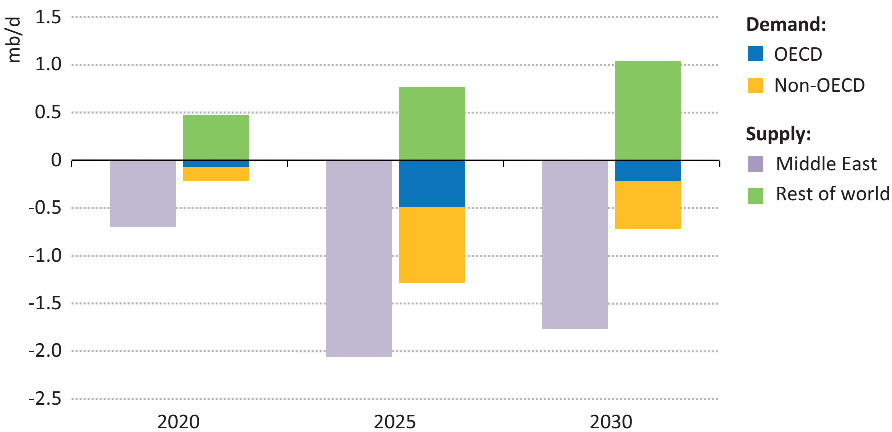
The oil price in the Delayed Case is pushed higher as the implications of the investment shortfall are felt in the market, with the price peaking at $130/barrel in real terms in 2025 – some $15/barrel higher than in the New Policies Scenario. Our oil prices assume a smooth

9. The Delayed Case takes the framework of the New Policies Scenario as its starting point and then imposes a constraint on Middle East oil production, such that it does not exceed current output levels until 2025.

trajectory, for want of any basis for anticipating supply difficulties. In practice, the tightness in the market associated with the Delayed Case would in all probability be accompanied by a significant increase in price volatility.

The "missing barrels" in the Delayed Case are replaced in part by higher production from other parts of the world and compensated in part by lower demand for oil (Figure 2.13). Lower demand is felt primarily in the transport sector (the largest source of oil demand): in the short term, higher prices encourage more economical driving habits, while, in the longer term, they encourage both drivers and manufacturers to invest more in efficient vehicles or, in some cases, to switch fuels. These reactions leave long-term oil demand slightly lower in the Delayed Case than in the New Policies Scenario. Higher output outside the Middle East comes from a number of regions, notably North America and Africa, and the long lifetime of the capacity that is brought online contributes to lower long-term production in the Middle East, compared with the New Policies Scenario.

Figure 2.13 ▷ Changes in global oil production and demand in the Delayed Case versus the New Policies Scenario

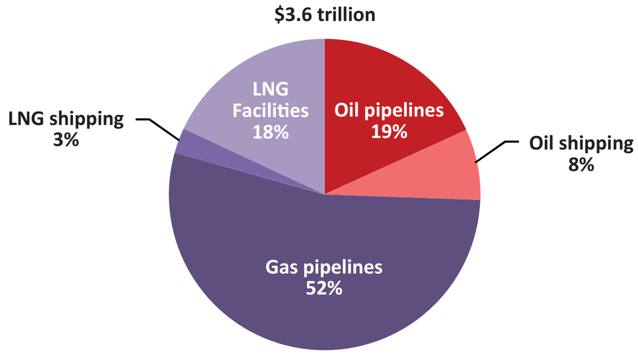


Oil and gas transportation

Over the period to 2035, investment of $3.6 trillion is required in oil and gas transportation, some 15% of total oil and gas investment (Figure 2.14). Three-quarters of this, $2.6 trillion, is needed to bring gas to consumers. This figure includes transmission lines (domestic and cross-border) and distribution systems, as well as LNG facilities (including liquefaction and regasification plants) and LNG tankers. Just under $1 trillion is for oil transportation, which includes the infrastructure necessary to bring crude oil to refineries or export terminals, to transport oil products, to fractionate and transport NGLs and to build tankers for the international shipment of crude oil and products.[10]

10. The investment calculation for oil transportation has been expanded in this report to include domestic and intra-regional transport of oil and oil products, and NGLs fractionation and transport; hence the numbers for oil pipelines are higher than previously reported.

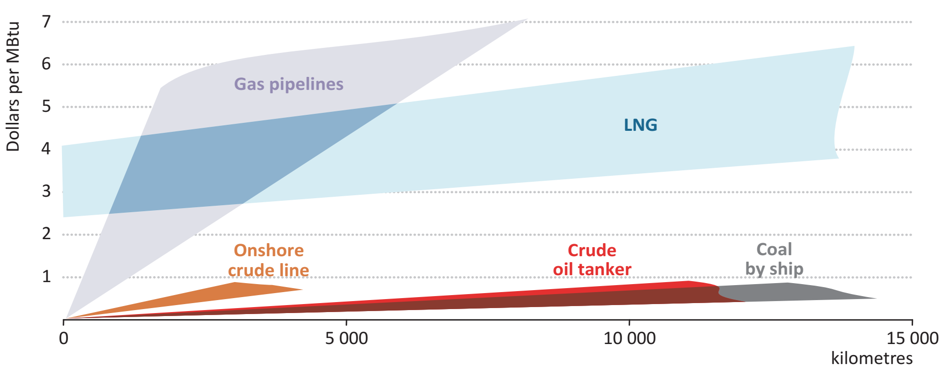
Figure 2.14 ▷ Cumulative investment in global oil and gas transportation in the New Policies Scenario, 2014-2035



Almost two-thirds of the total pipeline spending (oil and gas combined) is required in non-OECD countries. Most of the investment in OECD countries is spending on maintenance for existing infrastructure that is ageing or requires replacement. The bulk of the spending on oil shipping is likewise primarily for maintenance or replacement, as the total volume of oil trade (including both crude and products) does not increase significantly in our projections.

Gas producers face the main transport-related dilemmas. The lower energy density of natural gas means that the cost of transportation is a much higher share of the cost of the delivered product, which is why most gas is consumed within its region of origin. Bottlenecks in the North American network show how transportation can also be a constraint for oil, but there is a greater variety of cost-effective ways of bringing oil to market and constraints usually prove to be temporary. In the case of gas, there is a higher chance that remote resources can be stranded (or flared). For the same energy content, gas is between seven and ten times more expensive to transport than oil or coal (Figure 2.15).

Figure 2.15 ▷ Indicative comparison of fossil fuel transportation costs



Note: The main determinants of gas transportation costs within the ranges indicated are: for pipelines, the diameter of the pipe and the terrain to be crossed; and for LNG, the initial costs of liquefaction capacity.

Source: Adapted from Jensen (2012).

Focus on LNG investment

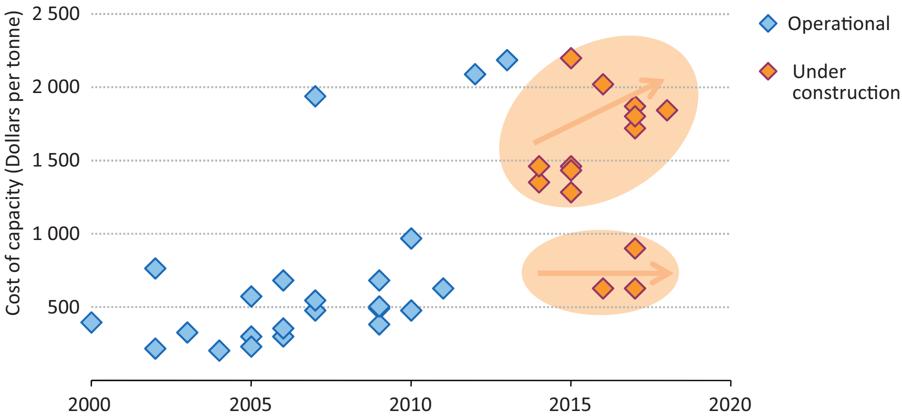
The longer the distance over which natural gas has to be moved, the more favourable are the economics of LNG over pipelines (Figure 2.15). Where producers have a choice between the two, the tendency to favour LNG has, in practice, been even stronger than a straight economic calculation might suggest. Price levels and regional market dynamics have been shifting rapidly over the past decade, so the option to switch destination that comes with LNG is increasingly seen as a critical advantage. Meanwhile, the interruptions to Russian supply to Europe since 2006, because of disputes with Ukraine and Belarus, have increased the perception of the risks associated with cross-border pipeline supply, particularly when transit through third countries is involved.

Cumulative spending on LNG amounts to $735 billion in the New Policies Scenario, $640 billion in liquefaction and regasification facilities and around $90 billion in LNG tankers. This makes provision for a steady increase in inter-regional LNG trade, from 330 billion cubic metres (bcm) in 2013 to 560 bcm in 2035. This increase is fundamental to our outlook for gas markets. With new suppliers (including North America and East Africa) extending into new markets and some existing suppliers expanding their presence (notably Australia and Russia), we anticipate that contract structures gradually become more flexible and a greater share of LNG supply is available without commitment to a specific destination. LNG trade thus provides the spur for greater integration of regional gas markets. Exports from the United States, in particular, have the potential to encourage movement towards a global gas market and to stimulate some diminution of today's wide regional variations in gas prices (although the high costs of transportation would prevent the emergence of anything approaching a single global gas price).

Whether LNG will be able to deliver all that is expected of it remains uncertain. At the root of this uncertainty is the high capital cost of LNG infrastructure, which creates a strong preference among project developers and financiers for mechanisms that lock in, as much as possible, a stable long-term cash flow. The traditional way in which this has been done is via long-term oil-indexed gas supply contracts. But this traditional model is coming under stress. Faced with current prices for imported gas that are among the highest in the world, buyers in the Asia-Pacific region (the market that is expected to absorb most of the new LNG supply) have made it clear that they seek more advantageous terms for future purchases, as the current situation is leaving their economies with heavy import bills and serious concerns about industrial competitiveness.

There are conflicting indications of how far LNG suppliers can go to meet their buyer's concerns. On the one hand, the evidence from some current LNG projects under construction is that capital costs are rising rapidly, a trend that reinforces sentiment among some suppliers that dependable high prices for LNG are necessary and unavoidable (Figure 2.16). On the other hand, the current wave of liquefaction projects and proposals in the United States (only one of which has thus far started construction) suggests there is scope for much greater flexibility, as envisaged capital costs are significantly lower (for reasons discussed below) and their financing is based on a different model for risk reduction.[11] Which direction costs for new liquefaction capacity takes is an important question for the future of LNG, as without competitive and affordable supplies of LNG, the growing position that we anticipate for gas in the global mix could be threatened, especially in the Asia-Pacific markets that are expected to develop quickly.

Figure 2.16 ▷ Diverging trends in the evolution of capacity costs for global LNG liquefaction projects



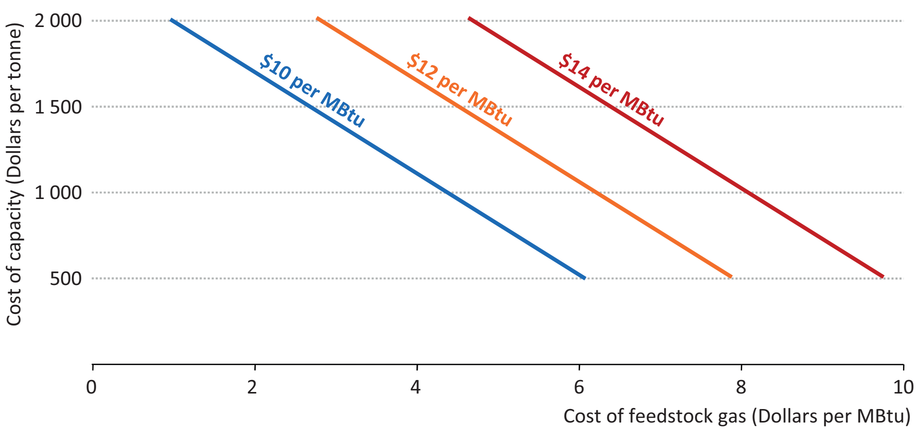
Sources: IEA analysis based on Wood MacKenzie data; Songhurst (2014).

The increase in costs for recent projects shown in Figure 2.16 is largely attributable to developments in Australia, the site of two-thirds of current global investment in LNG, and to two other higher-cost projects in Norway and in Papua New Guinea. In Australia, seven projects are under construction, to join the three facilities already in operation. In part because these projects are being built simultaneously, there has been strong upward pressure on costs: the appreciation of the Australian dollar (and of the Papua New Guinea kina) has also been a major contributing factor. Other features some or all of these projects share are technical complexity and very remote locations. The major projects that are most advanced in the United States (Sabine Pass, which has already been approved, plus six other projects that have received the requisite export approvals from the US Department of Energy) appear to be free from these exceptional pressures. They are being built in industrialised areas, with established infrastructure and access to a large market for engineering and construction services; moreover, most are conversions from regasification terminals, so can make use of existing pipelines, storage, ports and jetties.

11. Instead of contracts to supply different gas purchasers, the project company concludes long-term take-or-pay contracts with potential users of the plant's liquefaction capacity (this is often referred to as a tolling arrangement). Gas is sourced not from a specific upstream project, as with most integrated LNG projects, but bought on the US gas market for processing in the LNG facility. Thus, in this model, the financing of the liquefaction project is not tied to the destination or marketing arrangements for the LNG. This disaggregation of the value chain lowers the cost of capital for US projects (below the levels assumed for a generic project in Figure 2.17) and is a major component of the competitiveness of US LNG.

The cost of constructing capacity is a major determinant of a project's ability to combine an adequate return on investment with the prospect of delivering competitively priced LNG – two conditions which need to be satisfied before a decision to invest takes place. If, for example, the price of feedstock gas is $4/MBtu and the intention is to deliver gas at a price of $10/MBtu (at an indicative distance of 10 000 kilometres), then the cost of new LNG capacity should not exceed $1 000/tonne (Figure 2.17). For the same delivered price, if the cost of new capacity is $1 500/tonne, then feedstock gas should be available more cheaply – at well under $3/MBtu.

Figure 2.17 ▷ Indicative trade-off between the costs of new LNG capacity and of gas feedstock for a range of delivered prices



Notes: The calculations here are for a 2-train, 10 million tonnes per year liquefaction facility, operating at 90% capacity, and include costs for a shipping distance of 10 000 kilometres (around $0.1/MBtu per 1 000 km, depending on the cost of feed gas) as well as regasification ($0.45/MBtu). The assumed asset life is 30 years and the return on capital is 15%.

Beyond those in the first wave of US liquefaction projects (which are unusual, in global terms, because they involve the conversion of existing regasification facilities), the projects that are currently in the planning stage vary widely in scope, unit cost and potential cost. The simplest are those that involve only the addition of an extra train at an existing plant. For a complete greenfield LNG facility, other key variables include the proximity of existing infrastructure (accommodation, port facilities, airports), and whether or not the project requires major new gas pipelines from the upstream source(s) of the gas (Songhurst, 2014). Another critical consideration is the availability of local engineering and construction services. Wariness about these risks is one factor that explains the attraction of floating LNG facilities (the first of which is Shell's Prelude project in Australia) which can be built in lower-cost locations, and scalable, modular options that can be prefabricated and transported, rather than be built entirely at the site.

The large gas price differentials which exist now between regional markets appear to offer a clear and viable opportunity for new LNG investment, but, alongside the important constraints imposed by the demand side of the equation, the cost of liquefaction facilities also gives reason for caution when estimating the pace at which LNG capacity will expand in the years ahead and the speed at which these differentials might be reduced (the European example is considered in Box 2.1). Current Australian projects may well be exceptional on the upside in terms of costs, but the first US projects are also likely to be closer to the bottom end of the range, especially compared with greenfield projects in remote locations, such as Yamal or Vladivostok LNG in Russia or the East African projects. High cost for liquefaction and cost inflation can easily move projects out of the zone where they deliver returns to investors as well as LNG that meets their buyers' needs. This is a reason why, in our projections, the expansion of LNG promises gradual, rather than radical, changes to gas markets over the period to 2035.

2

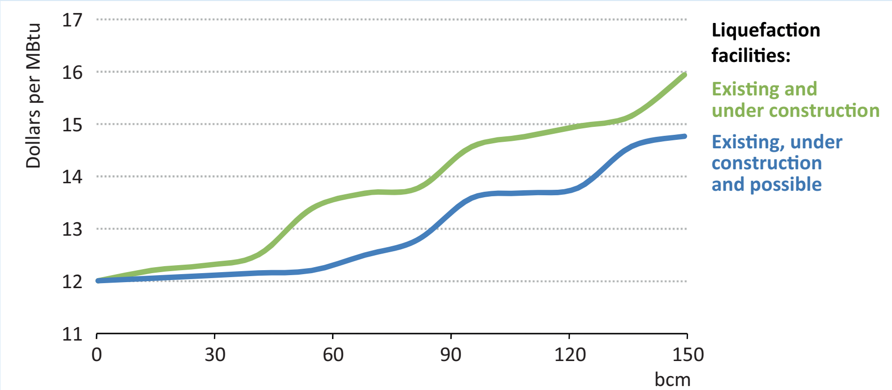
Box 2.1 ▻ Is LNG the solution to Europe's gas dilemma?

The gas industry in Europe has experienced a dismal few years since 2010. Demand has declined to levels last seen in the early 2000s, pulled down by a weak economic environment, efficiency improvements, strong competition from coal (abetted by low carbon prices) and a large expansion in renewables-based capacity. Recently, the 2014 Ukraine crisis has reignited fears about the security of Europe's pipeline supplies. Against this gloomy backdrop, there are expectations that LNG could offer the European gas market a lifeline. The continent has ample regasification facilities available (it used only around one-quarter of almost 200 bcm of LNG import capacity in 2013), making it possible to tap into sources of LNG available or coming on to the market. From this perspective, LNG from the United States appears to be well placed – and well-priced – to meet Europe's needs once it starts to come on to the market.

To explore this question, we have looked at the potential availability of additional LNG to Europe in 2020 from existing liquefaction facilities, those currently under construction and also those that we assess as having a reasonable prospect of making progress by 2020 (given sufficient demand) (Figure 2.18). We have estimated only volumes not committed to a firm destination, i.e. either not yet covered by any sales contract or likely to be available within the portfolios of major global LNG marketers. To secure these volumes, a key consideration is the netback price available to a seller from a particular liquefaction plant, taking into account the prevailing import prices in different markets, minus the costs of transportation.

In a 2020 time horizon, the biggest potential source of additional supply to Europe is, indeed, US LNG exports, both because of their potential size and because Europe's relative proximity to the US Gulf Coast (compared with the much longer route to Asian markets) offsets, in part, the more attractive price available in Asia-Pacific markets. Nonetheless, we estimate that Europe would need to pay around $12/MBtu to bring this gas to its shores (a price level that is higher than the current average price of pipeline imports to Europe, at $10-11/MBtu).

Figure 2.18 ▷ Indicative potential for additional LNG available to Europe in the New Policies Scenario, 2020



Notes: The main competition for deliveries to Europe comes from the higher-priced import markets in the Asia-Pacific region, where the price of imported gas in the New Policies Scenario in 2020 is $14.2/MBtu. The supply curve is indicative as it does not model the feedback between the volume of European purchases and producer behaviour, gas purchases and prices in other markets.

If Europe were to seek by 2020 to re-balance gas imports away from pipelines and towards LNG, then importers would need to look for an additional 70-80 bcm (at a minimum) in 2020, part of which would be required to replace existing LNG contracts as they expire (around 20 bcm by 2020) and to offset the expected decline in Europe's indigenous production. For this sort of volume, the price would be in the range $13-14/MBtu, a level at which gas would clearly struggle to compete.

In the longer-term, the LNG supply cost curve could flatten out considerably. Clear indications that European countries are ready to commit to new LNG supplies could help to secure positive decisions on investment in new export facilities, both in North America and other areas, such as East Africa. But the price for gas to Europe would still remain contingent, in large part, on developments in the "premium" Asian market. In this sense, Europe has a big stake in the evolution of more flexible and responsive gas markets in the Asia-Pacific region.

Refining

A stark difference between the outlook for the upstream sector and that for refining is that investments into greenfield refinery capacity are not required on a global basis in the New Policies Scenario. In aggregate, there is already sufficient refining capacity to meet demand through to 2035 and, by way of contrast to the power sector, it is economically feasible to transport refined products long distances and in large quantities. Current installed refining capacity is around 93 mb/d and refineries have been running at just above 77 mb/d. As highlighted in *WEO-2013*, a growing share of oil supply bypasses the refining system altogether, including most NGLs as well as oil products produced directly from gas or coal. As a result, global demand for refined products grows by only 10 mb/d to 2035.

Just over half of the $1.4 trillion in refinery investment over the period to 2035 is required to maintain existing refinery infrastructure, but over one-third – around $500 billion – goes to new refinery projects. There are many such projects underway or planned around the world, as oil-importing countries build refinery capacity to match their internal product demand and some producers look not only to cover growing demand but also to capture added value from the export of refined products. In the New Policies Scenario, most of the envisaged capacity expansion (which is modest, compared with the number and capacity of projects that have been announced around the world) takes place in the Middle East and Asian countries, with the former diversifying into product exports and the latter preferring crude imports over long-distance product imports (Table 2.3). This means that most of the investment in the new refining complexes is managed by the NOCs of these countries, occasionally in partnership with private companies.

Table 2.3 ▷ Cumulative refining investment in the New Policies Scenario, 2014-2035

	Investment ($2012 billion)				New capacity (mb/d)
	Greenfield	Secondary units	Maintenance	Total	
China	150	0	124	274	4.0
North America	14	38	172	224	0.4
Middle East	106	2	85	193	2.9
Europe	7	26	128	160	0.2
India	98	2	46	146	2.3
Brazil	72	0	27	100	1.4
Rest of world	58	24	223	304	1.5
Total	**504**	**92**	**804**	**1 401**	**12.7**

In regions with rapidly expanding refining capacity, the share of investment in secondary units at existing refineries is low, as the greenfield capacity complexes include a range of new secondary units as well. In regions with excess distillation capacity, such as Europe[12], North America and former Soviet Union countries, investments in secondary units prevail. Even in the absence of demand growth, refiners still need to invest in secondary units to improve the quality of the fuels they produce, in line with changes in regulations or consumer preferences. Together with changes in feedstocks, towards both heavier and lighter ends, this is driving a trend towards more complex and expensive technologies. The need for such expensive upgrades adds to the economic pressures on some refiners in markets showing a structural decline in demand, as in Europe (Box 2.2).

12. The one greenfield refinery investment in Europe is being built by SOCAR, the Azerbaijan NOC, in Turkey. This new refinery (probably the last new-build refinery that Europe will see) has little to do with the downstream outlook in the region and more with SOCAR's diversification strategy at a convenient location in its crude oil export infrastructure.

Box 2.2 ▷ Divesting, not investing in, European refining

In the last few years, the downstream sector has rarely featured as a positive contributor to the corporate bottom-line of the Majors. Their refining capacity is concentrated in Europe and North America and, while the US energy industry in general is going through a revival as the downstream sector profits from rising supplies of cheaper local supply, European refineries are in a far more difficult position. They face falling demand for oil products, declining local crude oil production, competition from imports and disappearing export markets for gasoline. This has prompted the Majors to reduce their refining capacity in Europe, either by selling it or by shutting it down.

Since 2005, about 2.9 mb/d of capacity has changed hands in Europe (about 18% of total) and about 2 mb/d has been closed (Table 2.4). Of capacity that was sold, some 0.5 mb/d was subsequently resold. The Majors accounted for just under 2 mb/d of the sold capacity and directly shut down 0.8 mb/d. Of the refineries that they sold, the subsequent owners shut down one-third. The fate of one particular refiner has been very telling: the company Petroplus was formed in 1990-2000s, by buying refineries, mostly from BP and Shell, at the peak of refining margins. A few years later, with a serious deterioration in margins in Europe, the company could no longer function. It closed the four largest of its eight refineries, and sold the remainder, mostly small refineries, to Vitol and Gunvor, two major commodity trading houses.

Table 2.4 ▷ Refinery capacity sold in Europe since 2005 (mb/d)

	Shut by owner	Sold	*of which sold again*	Shut by subsequent owner
BP	-	0.6	*0.2*	0.2
Shell	0.1	0.9	*0.1*	0.4
Total	0.3	-	-	-
Other Majors	0.4	0.4	*0.1*	0.1
Other	0.5	1.0	*0.1*	-
Total	**1.3**	**2.9**	***0.5***	**0.7**

The new owners of European refining capacity include not only commodity traders, which have acquired 0.3 mb/d of capacity so far, but also Russian and Asian oil companies. Promising areas for refining continue to exist in Europe as, for example, where assets are strategically placed in trading hubs that allow commodity houses to enhance their logistics portfolio, or are located in prosperous inland regions with large retail markets. But, overall, the appetite for the continent's refineries is waning. Whereas upstream fields, as they decline, provide companies with some natural insulation against the risk of falling oil or gas demand, assets in the midstream and downstream have long operational lives and count on being run consistently at high utilisation rates and at positive margins in order to turn a profit.

Implications for financing

Over the period to 2035, total annual revenues from oil and gas rises in our projections to almost $6 trillion, a faster rate of increase than that envisaged for capital expenditure. On this basis, upstream projects should continue to offer a sufficiently high risk-adjusted return to attract capital, especially those undertaken by large oil and gas players with strong balance sheets and creditworthiness. There are, though, numerous caveats to attach to this conclusion. Many relate to the broad financing environment discussed in Chapter 1, in particular the impact of more restrictive capital adequacy requirements on the availability and cost of long-term funding. Many international commercial banks have simply withdrawn from parts of Africa, Central Asia and the Middle East in the aftermath of the financial crisis, or – if still present – are much more selective and demanding in their choice of projects. As local banks and capital markets are not yet large or mature enough to step in and provide all the necessary funding, large projects in these countries, including those in the energy sector, are at risk. Where NOCs face difficulties with borrowing, this may oblige them to place greater reliance on financing brought in by international project partners or development banks, in order to avoid project delays and cancellations.

The financing situation for some NOCs is prejudiced by the obligation on many of them to supply oil products and/or gas to the domestic market at prices that do not reflect their international market value. This is generally the case across the Middle East, as well as in other major consuming countries. In some cases the revenue foregone is made good from the state budget, but in others the NOC has to absorb the loss. Even where the difference from international prices is slight, the implications can be significant. In Brazil, for example, domestic prices for gasoline have lagged behind international prices since the end of 2010, boosting gasoline demand above the levels that can be supplied from the domestic refineries. This has come at a significant cost to Petrobras, which has had to import fuel at a loss to cover the gasoline balance, diminishing the availability of internal funding for its very large capital expenditure programme.

Financing a refinery in countries with little or no local oil production and subsidised product prices to consumers is especially challenging. Numerous refinery projects which are planned in less well-off Asian countries and in Africa fail to materialise in our projections, as the returns are too uncertain, despite the unsatisfied demand. Export-oriented refinery projects, backed by financially strong companies, have a much greater chance of going ahead, even if they have to import crude oil from international markets, as in the case of India's Reliance refinery.

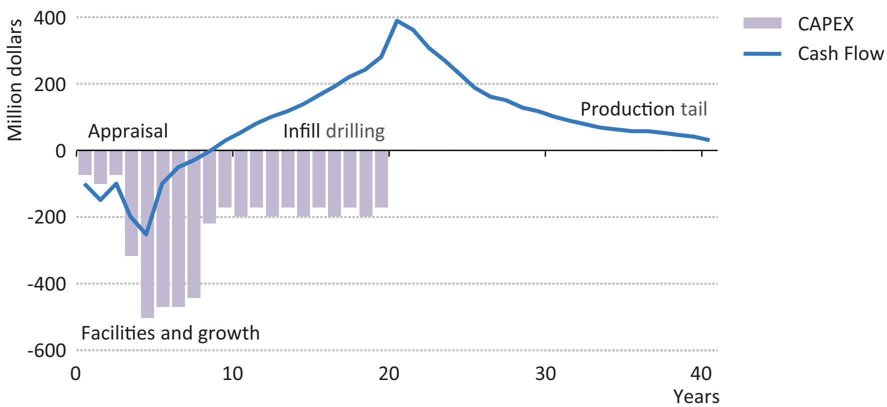
The speed at which shale gas and tight oil production might become worldwide phenomena, replicating the example of the United States, is an open question. One element, sometimes neglected in this debate, is the critical role that the US financial system has played in supporting the surge in shale gas and tight oil activity, by channelling large amounts of capital to a new, rapidly evolving area of the economy (Spotlight). The fact that multiple, small exploration and production companies were able to finance their activities greatly facilitated the "trial and error" process of finding the most productive areas and the right mix of technologies in the various shale plays. These conditions rarely exist elsewhere.

SPOTLIGHT

Financing shale gas and light tight oil

In North America, the rapid expansion in capital expenditure to fund shale gas and tight oil development has been financed by a mixture of equity (often for smaller players or those holding promising acreage), debt (where bigger players already have conventional or unconventional assets producing cash flow, the debt is often secured against future production, hedged at firm prices in the futures market) and farm-in arrangements or acquisitions that have brought into the sector many larger companies. The last group includes not only the international Majors but also some NOCs which are seeking not only commercial gains – which have proved elusive, particularly in shale gas, as gas prices fell – but also technical know-how and expertise.

Figure 2.19 ▷ Illustrative capital expenditure and cash flow for a large shale gas / tight oil investment



Distinctive elements of shale gas and tight oil investment include very low exploration risk and, because of high initial decline rates, the fact that most of the output from an individual well is produced in the first few years – a feature that gives operators greater possibilities to hedge price risk. But a multi-year investment programme across a large licensing area still retains some of the features of a more typical upstream project (Figure 2.19): an initial period of appraisal, followed by a capital-intensive development phase and in-fill drilling, after which – despite high initial decline rates – there is still a substantial inflow of revenue from the cumulative production (albeit at low rates per well) of a large number of wells. For now, success stories are concentrated in a handful of basins and the tight oil and shale gas industry in the United States continues to invest, in aggregate, more than it earns, although this gap is narrowing. There is financial vulnerability to any increase in financing costs or loss of productivity, as companies move to areas with lower recovery per well. While it is likely that further consolidation in the industry will come as it moves beyond a highly leveraged expansion phase, an excess of investment over the value of output is not at all surprising at this phase in the industry's development.

The reliable cushion of oil and gas revenue over expenditure is a product of the steady upward trajectory of the oil price in the New Policies Scenario. In practice, companies have to manage substantial fluctuations in prices and revenues, which can swiftly result in volatility in spending. Price volatility is an especially complicated matter for the refiners, who depend upon the difference between crude oil and product prices, both of which may be volatile. Refiners also tend to have fewer possibilities for hedging, financial instruments based on oil products are traded over a shorter forward period than crude oil and are less liquid. Investors also need to consider the possibility (as we do in the concluding section of this chapter) that governments will act in a more concerted way to decarbonise the energy economy, bringing down fossil fuel demand and prices in the process.

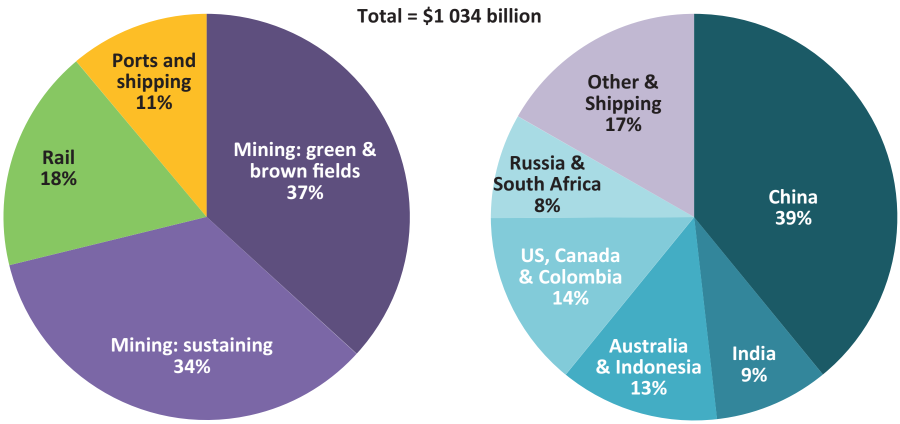
Project economics, particularly for large and capital-intensive developments in the offshore and deepwater, are very sensitive to delays and cost overruns and, as discussed in the previous section, there is a gradual but inexorable tendency towards greater complexity in upstream activity as companies develop more difficult resources. Moreover, regulatory frameworks increasingly include local content requirements that can cause bottlenecks in the supply chain, as well as much stricter prohibitions on practices like gas flaring. Reaching understandings with multiple partners and with host governments can be a painstaking process. The huge Kashagan project in Kazakhstan is a classic example of these kinds of project risks. The original production-sharing contract for this field was signed in 1997, with the expectation of first oil in 2005. This moment eventually came in late 2013, but production was immediately suspended because of leaks from processing pipelines. Resumption of production is likely, at the earliest, in late 2015. Kashagan may be an extreme case, but the perception of rising project risk can feed through more generally into a higher cost of capital.

A related consideration is the greatly heightened regulatory oversight and public scrutiny of environmental and safety risks. Projects have to clear high hurdles in order to receive the necessary approvals and authorisations, and exemplary performance is required in order to keep projects on track, not only from a regulatory perspective but also because public tolerance for any lapse in standards is thin. Opposition from local communities, often allied with litigation from environmental pressure groups, can be one of the major reasons for project delay or, in some cases, abandonment.

Coal

Over the period to 2035, cumulative investments of $1 034 billion are needed in the global coal supply chain in the New Policies Scenario. Mining, with $736 billion, is the largest component, followed by investments in railways ($183 billion) and ports and shipping ($115 billion) (Figure 2.20). A little more than half of the capital expenditure in mining is spent on development of new mining capacity; the average annual investment in such new development falls over the next ten years as the market absorbs the current overcapacity. From the mid-2020s, investment in new mining capacity needs to pick-up again (even as global demand flattens out) as the mines developed since 2000 start to need replacement.

Figure 2.20 ▷ Cumulative coal supply investment by type and region in the New Policies Scenario, 2014-2035

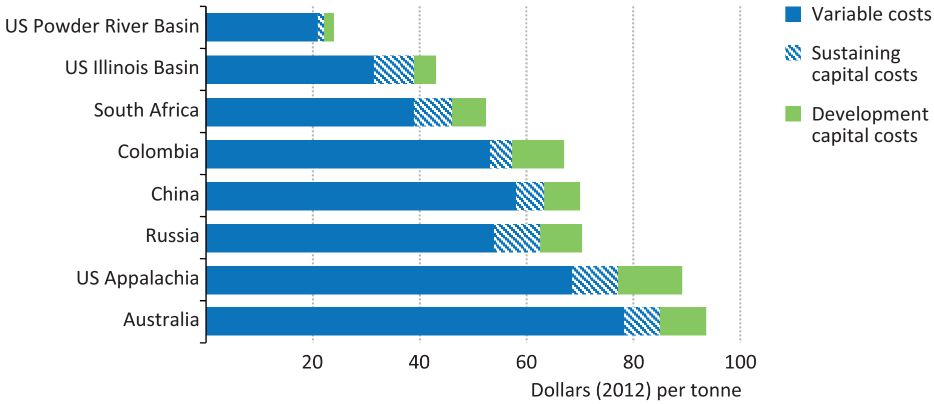


Development costs for new mines are defined as those incurred before the mine starts producing. They comprise, for example, driving the shaft of a deep mine, the acquisition of mining machinery and heavy equipment, the construction of a coal-washing plant and the exploration and assessment cost. However, to keep an existing mine operational, substantial capital also needs to be spent over the course of its lifetime. This spending, called "sustaining capital expenditure", amounts to more than $350 billion over the period to 2035 and includes the replacement of machinery and equipment.

There are marked regional differences in the investment trends, driven partly by variations in anticipated regional demand growth, particularly in developing Asian countries, as well as by the differing economics of supply from the various producing regions. The competitiveness of a coal mine is determined predominantly by its variable cost, but regional differences in fixed investment costs play a role, too (Figure 2.21). The average capital intensity of development, i.e. the average amount required to install one tonne of annual production capacity, was $70/tonne per annum (tpa) over the last five years. Over the same period, the figure for Australia was $130/tpa, while that for Indonesia was around $40/tpa. Some of the regional differences can be explained by short-term or cyclical factors, notably a rise in costs in Australia associated with the mining boom over recent years, but there are also underlying factors, such as geological conditions and coal quality.

In the OECD, cumulative investment to 2035 in coal mining capacity is more than $200 billion, corresponding to 27% of global capital expenditure on coal. Australia has a share of around 40%, as significant amounts of capital are required to bring a few large-scale greenfield projects online in the Galilee and Surat basins. Moreover, Australia is a key country for the expansion of coking coal supply. As coking coal typically commands higher prices than steam coal, mining under less favourable geological conditions (deeper and/or higher strip ratios) is often still economically viable. In combination with washing requirements, this also results in higher development capital needs. The United States invests \$90 billion into coal mining over the period to 2035 – as much as Australia, despite declining coal production. The majority of the capital spent in the United States is devoted to sustaining existing operations. Most of the greenfield investment takes place in the Illinois Basin; complemented by substantial brownfield investments in the Powder River Basin. Only a small amount of new steam coal mining capacity is projected to come online in the Appalachian basins, alongside a few coking coal mines.

Figure 2.21 ▷ Average total cost of steam coal production for greenfield projects by region, 2014-2024



Notes: Based on a sample of more than 400 possible coal mining projects that could become operational by 2024. Cash costs include mining, processing and transport to the main point of sale (not consumption).

Source: IEA analysis based on Wood MacKenzie databases.

Most of the coal production growth and the majority of mining investment (\$534 billion) occur outside the OECD. Unsurprisingly, China accounts for the lion's share of this total, with capital expenditure of around \$335 billion. The Chinese authorities' recent push to re-organise the coal mining industry has resulted in thousands of small coal mines being shut or integrated into large mining complexes. This has increased productivity and capacity at relatively low cost, but future investment costs are set to rise as Chinese coal companies will have to dig deeper (especially for coking coal) or move further to the west of the country for new projects. In addition, sustaining capital expenditure for thousands of mines, amounting to \$165 billon over the period to 2035, adds substantial weight to China's investment burden.

Indonesia sees rapid expansion of output over the period (growth of 175 million tonnes of coal equivalent) and benefits from low development capital intensity, resulting in relatively low cumulative capital expenditure of around \$20 billion. Geological conditions are favourable, with virtually all production coming from surface mines, which are generally less capital-intensive than underground mines. A large part of the output increase is expected to come from capacity expansion of existing mines; these brownfield projects also tend to have lower development capital intensity than new mines.

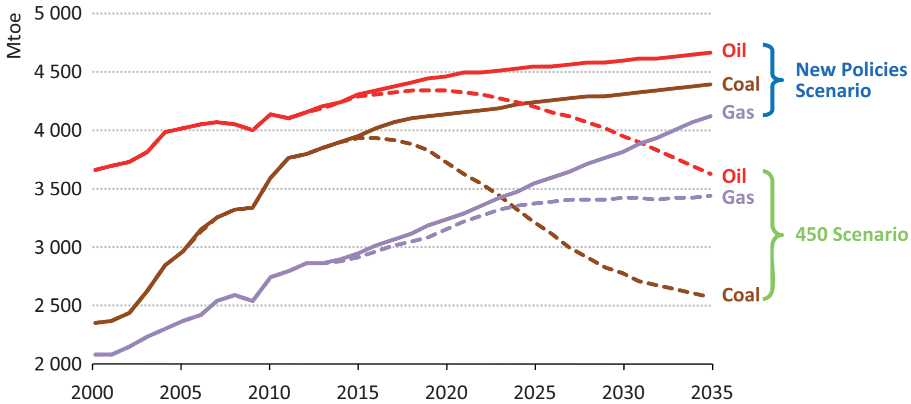
While some coal is consumed close to the mines, most is hauled some distance to reach the centres of coal demand. This requires substantial infrastructure for inland transport, maritime shipping and handling. Global coal-related investment in these areas reaches a cumulative $300 billion over the projection period. More than 60% of this total, $185 billion, goes to the railways for tracks, engines and rolling stock: railways provide the backbone of overland coal haulage in most countries. This figure includes only dedicated coal links and an allocated share of investment in lines that carry large volumes of coal traffic alongside other traffic. China (with $65 billion) and India ($35 billion) together make up more than half of global coal-related railway investments. The two countries face similar challenges: China's mines move further west, far away from the demand hubs along the east coast. While conversion into electricity near the mines and subsequent energy transport via the power transmission grid ("coal by wire") gains in share, large physical quantities of coal still need to be transported by railway across the country in the New Policies Scenario. India also needs to expand the strained railway network to link up new coal fields and cater for increasing imports that need to be distributed. Russia has the third-largest coal-related railway investment requirement ($15 billion), mainly driven by expansion of rail lines to export ports in the Russian Far East, as well as upgrades of the ageing rail network.

With investments of $70 billion, ocean-going vessels are the second-largest component of future coal supply infrastructure needs. Seaborne shipping capacity is projected to be sufficient over the medium term, as a result of expansion in the last few years but, with international trade growing, new vessels and replacements are needed in the longer term. Cumulative investment for ports, essential to both export and import growth, at $45 billion, represents a minor component in total infrastructure capital expenditure. Unsurprisingly, two-thirds of the capital expenditure for ports is concentrated in developing Asia and Australia – the growth engines of international coal trade.

Trends in the 450 Scenario

In the 450 Scenario, the share of fossil fuels in the global energy mix falls to 65% by 2035 from 82% today, a much more rapid decline than in the New Policies Scenario. The impact is far from uniform across the three fuels (Figure 2.22). Coal is by far the hardest hit: demand in 2035 is more than 40% below the amount anticipated in the New Policies Scenario (and one-third below today's level). In practice, the 450 Scenario means eliminating almost all of the increase in coal consumption seen since 2000. Oil demand in 2035 is lower by more than 20%, compared with the New Policies Scenario, and is some 13% below today's consumption. As with coal, 2035 demand for oil of some 80 mb/d would represent a fall in demand to the levels last seen in the early 2000s. Natural gas demand in 2035 is some 17% lower than in the New Policies Scenario, but nonetheless 20% higher than today's levels. Gas is the only fossil fuel that sees an increase in this scenario. The compatibility of these figures with achievement of the 2 °C trajectory for emissions is contingent on the widespread deployment of carbon capture and storage (CCS).

Figure 2.22 ▻ **Fossil fuel demand in the 450 Scenario relative to the New Policies Scenario**

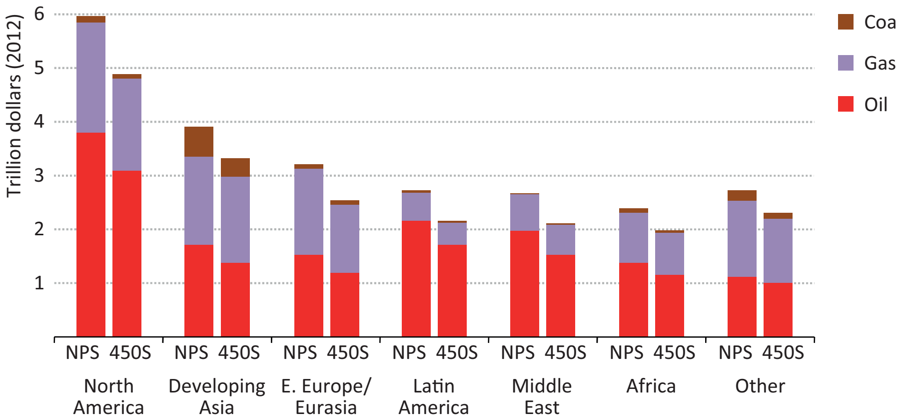


Fossil fuel supply investment is $19.2 trillion in aggregate in the 450 Scenario. This is almost 20% lower than in the New Policies Scenario, but still amounts to almost half of total energy supply investment. It follows that mobilising and financing this level of fossil fuel investment in the 450 Scenario remains essential for reliable and secure energy supply, even though the energy system is increasingly different from that of today. The composition of this investment changes: the requirement for capital expenditure on natural gas is affected least, with cumulative investment decreasing by 15% between the scenarios; oil investment is lower by close to 20%; and investment in coal is down by one-third (Table 2.5). All regions see lower fossil fuel investment in the 450 Scenario and one-quarter of this decline takes place in North America, the region that requires most of the investment in the New Policies Scenario (Figure 2.23).

Table 2.5 ▻ **Global fossil fuel cumulative investment by scenario, 2014-2035** ($2012 trillion)

	New Policies Scenario	450 Scenario	Difference (%)
Oil	**13.7**	**11.1**	**-19**
Upstream	11.3	9.0	-20
Transport	1.0	0.9	-8
Refining	1.4	1.1	-18
Gas	**8.8**	**7.5**	**-15**
Upstream	6.1	5.1	-16
Pipeline	1.9	1.7	-9
LNG	0.7	0.6	-19
Coal	**1.0**	**0.7**	**-33**
Mining	0.7	0.5	-31
Transport	0.3	0.2	-39
Total	**23.5**	**19.2**	**-18**

Figure 2.23 ▷ **Cumulative investment in fossil fuel supply by region and by scenario, 2014-2035**



Note: NPS = New Policies Scenario; 450S = 450 Scenario.

In the case of oil and gas, revenue in the 450 Scenario is still more than sufficient to cover anticipated capital expenditure: we estimate that total revenue from sales of oil and gas in 2035 amounts to around $3.9 trillion. This represents a slight fall, compared with estimated revenue in 2012 of $4.2 trillion, and is a decline of around one-third, compared with 2035 revenue of $6 trillion in the New Policies Scenario. However, since the required oil and gas capital expenditure in 2035 in the 450 Scenario is slightly more than one-third below the levels of the New Policies Scenario, the cushion between revenue and capital spending is similar. But this should not be interpreted as a guarantee of the adequacy or security of investment in a 450 Scenario as the market and price risks affecting long-term investment remain substantial.

In Chapter 1 (Box 1.5), we estimated the value of investments at risk of becoming stranded in a 450 Scenario. As mentioned, investment in upstream projects is insulated, to a degree, against the risk of becoming stranded by climate policies, because output decline is a natural phenomenon for all oil and gas fields and these declines are steeper than any conceivable rate of policy-induced declines in demand. Nonetheless, once a credible path towards decarbonisation is in place, projects at the higher end of the supply cost curve, particularly those that feature both long lead times and relatively high carbon-intensity, face significantly higher commercial and regulatory hazards. Midstream and downstream investments, including refineries, could experience declining utilisation rates over their long operational lifetimes because of declining consumption of fossil fuels in certain regions, undermining the revenue streams upon which their profitability depends. In addition, coal-fired and some gas-fired power plants likewise face a substantial risk of under-utilisation and early retirement in the 450 Scenario, although CCS retrofits offer a viable asset-protection strategy if the technology is commercialised in time (see Chapter 3).

Table 2.6 ▻ Cumulative global production of oil and gas by scenario, 2014-2035

	Oil (billion barrels)	Gas (trillion cubic metres)
New Policies Scenario	**756**	**93**
Production from existing fields*	299	29
Additional production	457	64
450 Scenario	**692**	**87**
Production from existing fields*	299	29
Additional production	393	57

* This shows production from existing fields in the absence of any further investment, i.e. subject to natural rates of decline.

Despite the uncertainties, the oil and gas industry would still need to develop a large volume of new resources in a 450 Scenario. Cumulative production figures for oil and gas are actually relatively close in the two scenarios, with a difference of only 8% for oil and 7% for gas (Table 2.6). All the output from currently producing fields (volumes that are produced without any additional investment) is required to meet demand. Additional investment is then required to produce between 393-457 billion additional barrels of oil and 57-64 trillion cubic metres of gas over the period to 2035, depending on the scenario.[13] The difference in this requirement between scenarios means that there are fields that are developed in the New Policies Scenario that are not developed in the 450 Scenario; the fields in question consequently fail, in the 450 Scenario, to recover their exploration costs over the timeframe to 2035. Nonetheless, despite the uncertain outlook, there are still good reasons for companies to explore for new resources, even in a 450 Scenario (Box 2.3).

Box 2.3 ▻ Why continue to explore for oil?

The amount of oil production required in the period to 2035 in the New Policies Scenario amounts to around 760 billion barrels. The amount required in the 450 Scenario is around 690 billion barrels. Yet the estimated level of proven oil reserves is already close to 1 700 billion barrels. So why do companies still engage in exploration for and appraisal of new resources? The main reason is that many of the OPEC countries which hold the largest, lowest-cost reserves are deliberately limiting their production rates so as to keep reserves for production in the longer term, creating a market opportunity for other countries and companies to produce and sell a substantial amount of oil. The aggregate figures for reserves are not a good indication of the oil that is likely to be developed by 2035.

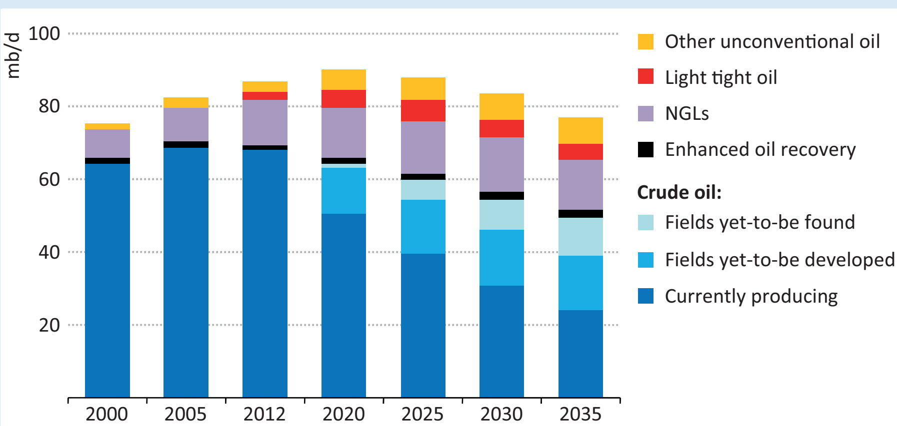
A more telling number is the volume of reserves held by non-OPEC countries. This stands at 469 billion barrels, much more in line with projected cumulative non-OPEC production

13. Since today's fields continue to produce, in declining volumes, to 2035 without investment, and additional investment made to 2035 continues to result in production post-2035, there is no direct equivalence between the cumulative investment numbers and the cumulative production numbers in our scenarios.

in the New Policies Scenario, at 437 billion barrels, and the 403 billion barrels produced in the 450 Scenario.[14] Even for these more accessible reserves, logistical constraints can preclude early development, so it still makes sense for the industry to explore elsewhere. A case in point is the Canadian oil sands, where large proven (or rather established) reserves are reported (IEA, 2013), but attempts at rapid development in the past have led to sharp cost inflation, pricing the projects out of the market.

Many countries with small or no reserves are keen to explore for potential domestic resources in order to reduce their import bills or to provide much-needed export revenues; they therefore organise exploration bidding rounds at conditions that they hope will attract investors. The industry, in turn, is made up of a variety of players adept at operating in various niches (regional, geological or type of resources). Specialised players always have an incentive to explore for more hydrocarbons in their own niche, so as to increase their share of future production. Even a company with all the resources it needs for planned production might want to explore for resources that can be developed at lower cost or on more advantageous contractual conditions. Taking all these considerations into account, we project that at least a small part of the production projected in our scenarios will come from fields that are yet-to-be-developed or to-be-found, even in the 450 scenario (Figure 2.24). This is why exploration and appraisal continue to be a part of the future investment picture.

Figure 2.24 ▻ World oil production by type in the 450 Scenario



Although coal is the hardest hit among the fossil fuels in the 450 Scenario, cumulative investment into coal supply, at $690 billion, is still two-thirds of the amount required in the New Policies Scenario. Of the $510 billion in mining investment in the 450 Scenario, a

14. For conventional oil, the projected cumulative non-OPEC production, at 355 billion barrels in the New Policies Scenario and 330 billion barrels in the 450 scenario, exceeds the proven non-OPEC reserves of 292 billion barrels.

little more than half is needed to sustain the production levels of existing operations, while the remainder flows into the development of new mines. Although the in-situ reserves of operating mines exceed coal demand in the 450 Scenario up to 2035, investment in new mines still takes place for economic and commercial reasons. Existing mines may not be located where the coal is needed, transport be costly or infrastructure lacking. New mines are being developed closer to the markets in developing countries in Asia, where coal demand remains comparatively strong; China ($105 billion), Australia ($30 billion) and India ($20 billion) are at the forefront of mine development expenditure.

New mines may be also able to supply coal at a lower variable cost than some existing operations. Since the capital cost of development is rather low in the coal industry, a new mining project may still be economically viable even where the margin between its variable costs and the coal price amounts to no more than a few dollars (Figure 2.21). In a low growth environment, competition is fierce and coal companies who manage to keep costs down and develop the most promising coal projects can maintain their market share. This process inevitably leads to industry consolidation, but developing new mines can be a prudent business strategy and one of the few ways to out-compete rivals in the 450 Scenario.

While development capital is inevitably sunk and hence fully at risk if a mining operation has to shut-down prematurely, half of mining capital expenditure goes into sustaining existing mining operations. The case for spending this money can be re-evaluated over the course of a mine's lifetime and the expenditure be avoided if the case is weak. Capital committed to sustaining production is mostly associated with the acquisition of mining machinery and equipment, which may have substantial salvage value.

Power sector investment

Keeping the lights on?

Highlights

- Global investment in power generation capacity more than tripled from the level in 2000 to $415 billion in 2012, 5% lower than 2011 largely due to lower solar PV costs, and with a further 3% reduction in 2013 mainly due to lower wind additions. Over 2014-2035, cumulative investment of $16.4 trillion is needed across the power sector. OECD countries account for $6.2 trillion, mainly to replace ageing infrastructure and meet decarbonisation targets. In non-OECD countries, governments need to facilitate a larger role for private capital to raise the $10 trillion needed to expand networks and generation capacity to meet rapid demand growth.
- Ownership of global installed capacity is divided equally between governments and the private sector (often large utilities). The increase of small and distributed renewables reduces the share of utilities and government, and will rely more on debt financing. The share of investment in competitive parts of electricity markets fell from about one-third of the global total in the early 2000s to about 10% today. With current market designs, competitive parts of markets require less than $1 trillion of cumulative investment to 2035 out of the total power sector needs of $16.4 trillion.
- In Europe, cumulative investment of $2.2 trillion (second only to China) is needed to replace ageing infrastructure and meet decarbonisation goals. Renewables account for three-quarters of the investment in new power plants to 2035. Despite excess capacity today, 100 GW of new thermal capacity are needed in the decade to 2025 to maintain the reliability of power systems. Reform of the wholesale market will be critical to make this a reality, as we estimate that wholesale prices in 2013 are $20/MWh (or 23%) below the level that would incentivise needed investments.
- In India, despite a doubling of generation since 2000, 9% of electricity demand was unmet in 2013, hindering economic growth. The state owns most installed capacity and networks, but private capital will play a larger role in the $1.6 trillion of power sector investment to 2035. With high T&D losses (27%) and low regulated end-user tariffs, utilities incurred losses of $14 billion in 2011-2012. If T&D losses were reduced to the target level of 15%, average tariffs would need to increase by some 5% for utilities to be financially solvent.
- Decarbonising the power sector to meet global climate targets requires cumulative investment of $19.3 trillion, 18% more than in the New Policies Scenario. Investment in low-carbon technologies needs to triple from $255 billion today to $730 billion in 2035, three-quarters for renewables. Well-designed policies and new financing vehicles could help lower the cost of capital, a reduction of three percentage points after 2020 would make renewables more competitive, cutting subsidies by over 20% to 2035.

Historical and current trends

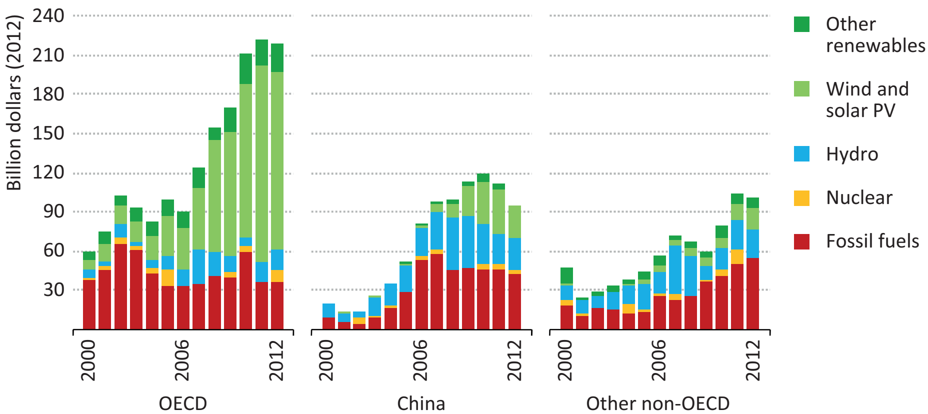
Power sector investment

Power sector investment – which includes spending on new power plants, new transmission and distribution (T&D) grids, and refurbishment or replacement of old infrastructure and power plants – totalled $6.1 trillion (in year-2012 dollars) over 2000-2012, an annual average of some $470 billion.[1] During that time, more than one out of every three dollars invested into energy supply worldwide was in power systems, highlighting their importance in supporting and sustaining the energy supply which underpins economic growth and prosperity, as well as their potential role in decarbonising the energy mix. On an annual basis, power sector investment increased almost two-and-a-half times, from around $290 billion in 2000 to almost $650 billion in 2012, with most of the growth coming from increased investment in new power plants, while T&D investments increased by about 50%, from $160 billion to around $240 billion in 2012. Investment in new power plants surged from almost $130 billion in 2000 to $415 billion in 2012, an average rate in excess of 10% per year. Investment in new generation technologies peaked in 2011 and then decreased for the first time in a decade in 2012 (-5%) as solar photovoltaics (PV) expenditure fell due to significant unit cost reductions and constant levels of deployment in 2011 and 2012. Preliminary estimates for investment in new power plants in 2013 point to a further decrease to about $400 billion (-3%), due to a further decline in renewables investment – as capacity additions of wind decreased by over 20%, while those of solar PV increased by over 20% – that was partially outweighed by an increase of investment in fossil-fuelled power plants. Investment in wind and solar PV grew robustly from 2000 to 2011, both in magnitude – seventeen-fold – and as a share of total investment in power plants – from less than 10% to 45% – to account for 60% of the global increase in investment over the period. The evolution of power sector investment over 2000-2012 varied considerably by region, reflecting differences in electricity demand growth, resource endowments, policies and competition among technologies.

In non-OECD countries, power sector investment has been driven chiefly by the need to meet fast-rising electricity demand, which grew at an average annual rate of 6.5% in the last decade. Compared with some $135 billion in 2000, power sector investment in non-OECD countries reached $360 billion in 2011, and then slightly declined in 2012. While 35% of the growth in investment went to T&D grids, the majority of the increase was to build new power plants. The expenditures are weighted heavily towards China, which accounted for around 60% of the growth of investment in non-OECD countries (Figure 3.1). In recent years, trends in China and other non-OECD countries have diverged, reflecting differences in electricity demand growth. In China, investment in new power plants increased rapidly before 2008, peaked in 2010 and has since been declining. In the other non-OECD countries, investment has consistently increased, more than doubling from 2000 to 2012.

1. Historical investments for power generation and T&D capacity are allocated to the year in which the capacity is first ready for operation, i.e. they reflect "overnight investment costs". In reality, investment in new capacity will be spread over the years preceding the installation of capacity.

Figure 3.1 ▷ Investment in power plants by type and region, 2000-2012



Sources: IEA analysis and IEA (2014a).

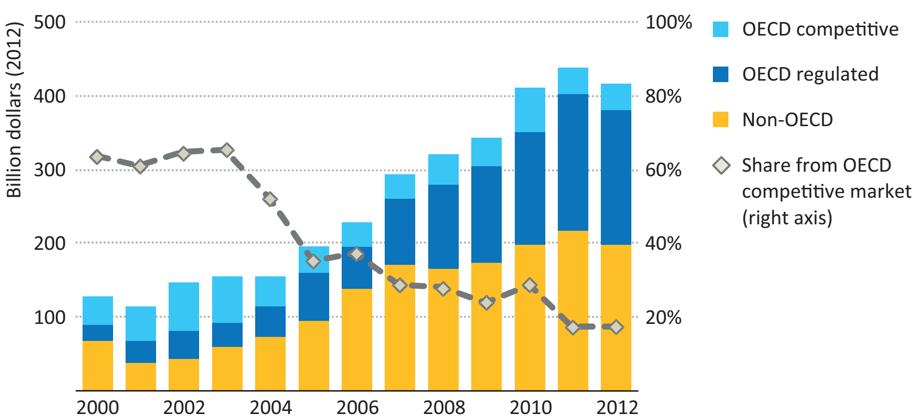
The relatively even spread of investment across power generation technologies in non-OECD countries reflects their use of most – if not all – available options to satisfy surging electricity demand. Over 2000-2012, traditional baseload power plants (i.e. coal-fired, hydropower and nuclear) accounted for 68% of power plant investment and 66% of new capacity; gas-fired power plants accounted for 12% of expenditure and 20% of new capacity; and non-hydro renewables garnered 18% of the total for 10% of new capacity (a share lower than in recent years).

Investment trends have followed a very different trajectory in OECD countries, where the last decade has seen the widespread enactment of policies to support the deployment of non-hydro renewables, notably wind and solar PV. These measures ensured attractive returns and reduced risks associated with this relatively new sector. Consequently, these technologies attracted a range of investors wider than those in conventional power plants and extending far beyond publicly listed utilities. The result has been a surge in investment in non-hydro renewables, with wind and solar PV accounting for the majority of the increase in overall investments in new power generation capacity (which have quadrupled since 2000). Investments in wind and solar PV increased rapidly in the period to 2011, even as unit costs fell dramatically for solar PV, before declining in 2012, due to lower deployment (and capital costs) for solar PV. As a share of total investment in power plants, wind and solar PV grew from 14% in 2000 to over 60% in 2012. Over 2000-2012, OECD countries added over 500 gigawatts (GW) of new gas-fired capacity, nearly doubling the installed gas-fired capacity. This required investment of $400 billion, one-quarter of total investment in new power plants over the period. Investment in T&D grids remained fairly stable at around $100 billion year over the same period.

But unanticipated events have shifted the landscape significantly in the electricity markets of some OECD countries. Electricity demand growth has been sluggish – averaging 1.0% per year in OECD countries in the last decade, especially so following the height of the financial crisis in 2008. With the boom in the construction of non-hydro renewables (and to some extent gas), this has exacerbated excess power generation capacity in many OECD countries and caused wholesale electricity prices to fall. In North America, the shale gas revolution has lowered prices for natural gas, making it more competitive relative to coal in power generation and reducing wholesale electricity prices. By contrast, in Europe, prices for natural gas have increased more than those for coal in recent years. Compounded by very low carbon prices, this has favoured the use of coal in power generation and put further downward pressure on electricity prices. These events have reduced revenues and put a major strain on power generators in competitive parts of electricity markets, hindering their ability to invest and creating concern that such markets, as currently structured, may be unable to deliver sufficient investment in new capacity in the future (a later focus in this chapter).

Reflecting these conditions, investment has increasingly been concentrated in the regulated parts of electricity markets and stagnated in the competitive parts (Figure 3.2).[2] Investment in the competitive portions of OECD markets reached $66 billion in 2002, but has not surpassed that level since. With investments in the regulated parts of OECD markets increasing dramatically and the surge of investments in non-OECD countries – mainly China, India and the Middle East – the share of global investment in the competitive parts has plummeted from about one-third in the early 2000s to about 10% today.

Figure 3.2 ▷ Worldwide investment in power plants by region and market type, 2000-2012



2. The regulated parts of electricity markets are defined as those where generators receive revenues at a predetermined rate, often established by governments. This applies, to varying degrees, to electricity markets in all non-OECD countries and to those in some OECD countries. Those parts of electricity markets in which revenues are received at a market-determined rate are categorised as competitive. All markets, both competitive and policy-driven, are of course regulated (in a general sense) in various ways.

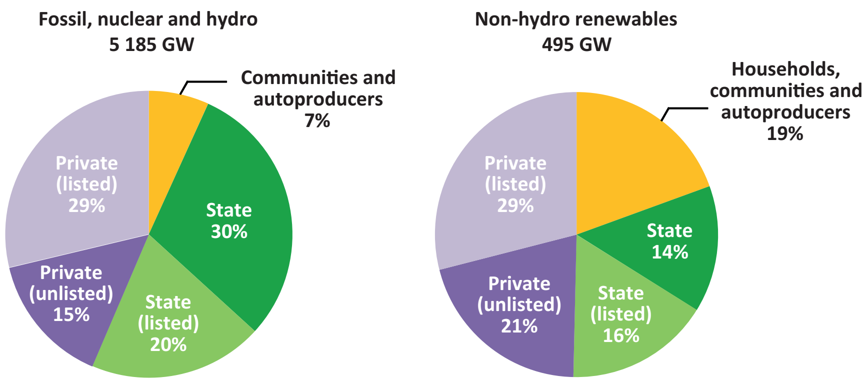
Structure of ownership and sources of financing

Power sector projects are diverse and subject to a large variety of risks, such as regulatory risk, technology risk and market risk (see Table 1.4 in Chapter 1). Projects are carried out by a large number of heterogeneous investors that pursue different business strategies, have diverse management styles and expectations, operate in distinct legislative and tax systems and have various asset portfolios. Projects themselves vary in scale and are subject to a number of location-specific factors, such as access to fuel-supply infrastructure and water for cooling, environmental impacts and public acceptance. Power projects accordingly require a diversity of financial products and services. How a particular investment is financed depends on a project's ownership, risk/return profile, and the overall institutional, regulatory and market environment.

Ownership of power plants

The ownership structure of power generation assets determines, to a large extent, potential sources of finance. Governments, through state-owned entities, own almost half of current global installed capacity (Figure 3.3). Another 44% of power generation assets are owned by private companies. The share of state ownership is typically higher in non-OECD countries (that account for almost half of global power capacity). Electricity markets and infrastructure in non-OECD countries are generally less mature and governments may assume a major part of the responsibility for security and managing system growth. Around 60% of the conventional capacity in China and almost two-thirds in India are controlled by the state (through direct control or a majority ownership stake). This compares with 45% in the European Union, 25% in Japan and less than 20% in the United States.

Figure 3.3 ▷ Ownership of global power generation assets in 2012



Note: Plants with mixed ownership were fully attributed to the majority owner.

Sources: IEA analysis and 2° Investing Initiative, based on Platts, Bloomberg Professional service, Bloomberg New Energy Finance and national sources.

Two-thirds of privately owned power generation companies and almost 40% of companies that have majority state-ownership are publicly listed on stock markets and therefore in principle, available to investors globally. Public listing of companies may reduce the transaction cost of capital flows, allowing companies to tap capital markets more easily to raise money. Moreover, stock market listing requires certain transparency and corporate governance standards that may stimulate increased efficiency of management.

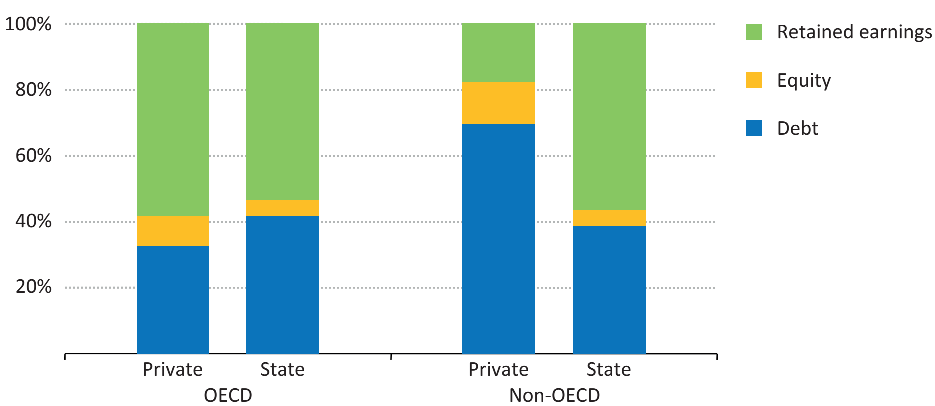
The ownership of non-hydro renewables assets, which currently make up nearly 10% of global power capacity, differs considerably from that of fossil-fuelled, nuclear and hydropower plants. Utilities and other well-established power companies usually have long-standing experience and are well-positioned to attract financing. Often they can issue shares or make use of specific financial products, such as bonds. They are well-placed to invest in larger scale renewables projects, such as hydropower projects, offshore wind farms or large-scale solar parks, with the opportunity to raise capital for the portfolio of their operations and investments, rather than for an individual project.

Expansion of distributed renewable energy capacity, such as rooftop PV, small hydro, smaller onshore wind farms or biogas in agriculture, provides opportunities for new investors, such as project developers, households, small businesses and specialised power companies. But such small-scale projects tend to have higher transaction costs. Moreover, the investment conditions are country specific (as they are for other technologies), demanding knowledge of local/regional policies and regulations, such as issues of local development and grid connection considerations. Specialisation and business models tailored to such investments can – if the regulatory conditions are right – support economic viability and boost renewables expansion. In Europe, in particular, ownership of non-hydro renewables by municipalities, small businesses and households is high (mainly for onshore wind and solar PV), while in the United States and China, expansion of renewables has been driven mainly by established utilities. Growth of non-hydro renewables has been especially rapid in markets where households and smaller companies have underpinned deployment. However, such investors do not usually have substantial assets that can generate income to finance new capital expenditures. The expansion of renewables assets by household and small company investors, therefore, relies more on external sources of finance than is typical for conventional power plants. On the basis of the global financial information disclosed to Bloomberg New Energy Finance by investors responsible for more than 60% of investment in non-hydro renewables in 2013, our analysis shows that financing of capital expenditures through retained earnings and equity represented almost 45%, a share well below that seen in the financing of conventional power plants in OECD countries. Most of the remainder was financed by long-term loans and about 10% by shorter-term loans, such as bridge finance (BNEF, 2014). Often renewable energy projects allow for substantial leveraging *(*increasing the share of debt financing), where regulated remuneration reduces the risk of cash-flow shortfalls, providing additional security for the lender.

Financing structure of publicly listed companies

Over the past decade, around 60% of investment in new capacity by publicly listed companies in OECD countries was financed from retained earnings, i.e. self-financed. Companies with the state as the majority stakeholder have chosen a similar financing pattern over the past decade, suggesting that the choice of financing is primarily driven by commercial considerations and largely independent of other policy targets (Figure 3.4). In the early 2000s, many utilities in OECD countries were still vertically integrated monopolies, making only modest use of external capital. Liberalisation and unbundling pushed utilities to lower their weighted average cost of capital and increase their return on equity (debt has financed 30-40% of overall capital investment in the past decade). Equity issuance played a smaller role, as it typically involves higher transaction costs than debt and is often not favoured by existing shareholders since it risks a dilution of their influence. Equity issuance is therefore predominately done to finance large-scale transactions.

Figure 3.4 ▷ Financing of projects by publicly listed power companies, by majority stakeholder and region, 2002-2012



Sources: IEA analysis and 2° Investing Initiative, based on data from Bloomberg Professional service.

In non-OECD countries majority ownership by the state has a more pronounced influence on the financing structure. The first priority of companies with governments as the main shareholder may be to invest to extend the provision of electricity services, while private investors would tend to focus on dividend payments. Consequently state-owned utilities may be able to re-invest a larger part of their cash flow than some of their counterparts in OECD countries. In countries where pricing allows for full cost recovery, stable and potentially large cash flows may be available for re-investment. But where the tariff structures do not allow for full cost recovery, the reverse is true and utilities may have to rely heavily on debt – often in the form of loans from a state-owned bank. Indeed, a series of important initial public offerings (IPOs) in non-OECD countries has had as its main objective a reform process to make the companies more subject to commercial pressures, rather than to raise capital. Private ownership has been burgeoning in developing countries over the last decade. Since many private companies are newcomers in the power sector, they lack an asset base to generate cash flow for re-investment, obliging them to rely to a larger degree on external sources to finance their investments. These utilities tend to sell their power to the government through long-term power purchase agreements as a means of guaranteeing stable cash flows for the future. Such arrangements provide an alternative basis for companies to issue debt, giving them leverage, which is high compared with companies under similar ownership in OECD countries. Investors in the power sector in non-OECD countries sometimes form part of large conglomerates that can make use of other assets for cross-hedging to facilitate access to loans.

Trends in the New Policies Scenario

Electricity demand, generation capacity and T&D infrastructure

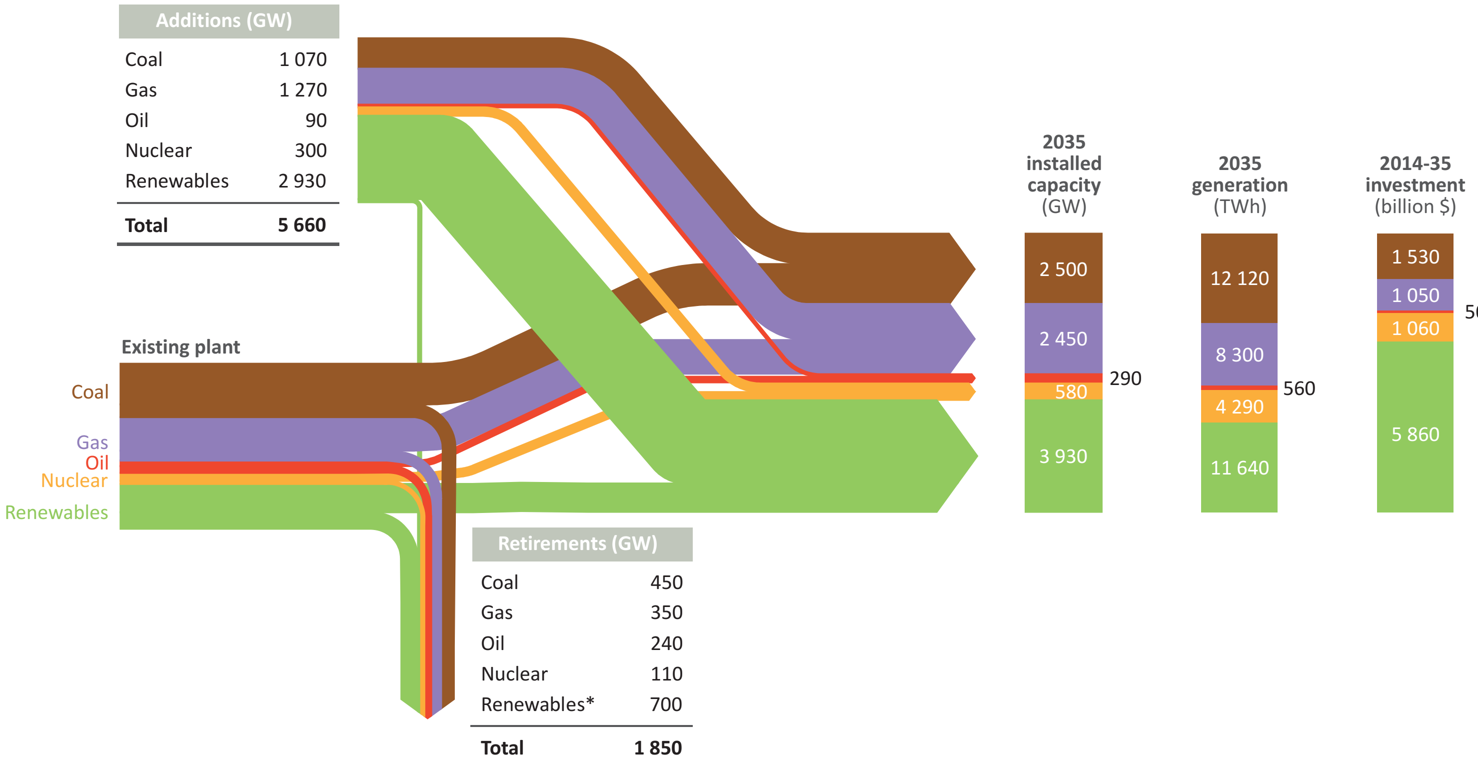
Expectations about future electricity use underpin changes in the installed capacity of power generation technologies and in transmission and distribution networks. In the New Policies Scenario, global electricity demand increases by around two-thirds in the period 2012-2035, at 2.2% per year on average (Table 3.1). Over 90% of this incremental growth comes from the buildings and industry sectors. Non-OECD countries – which experience strong economic and population growth, rising living standards and a shift from rural to urban living – account for the vast majority of new electricity demand. Electricity demand growth in OECD countries is tempered by efficiency gains and saturation effects.

Retirements are another key determinant of power sector investment, as old units may need to be replaced when they reach the end of their technical lifetime.[3] About 30% of current installed capacity is retired worldwide over 2014-2035 in the New Policies Scenario. This capacity is concentrated mainly in OECD countries, where coal, oil and nuclear power plants are much older, on average, than in non-OECD countries.

Gross capacity additions worldwide total 5 660 GW over 2014-2035, with about 1 850 GW replacing retired plants and the rest meeting new electricity demand (Figure 3.5). Most new plants are powered by natural gas (1 270 GW), wind (1 190 GW) and coal (1 070 GW). About 2 930 GW of renewables are added; of which 64% are wind and solar PV. Because wind and solar PV have short lifetimes (20-25 years), significantly more capacity additions are required late in the projection period to replace installations that are retired. Two-thirds of global capacity additions are in non-OECD countries, most to meet new demand. China installs 1 400 GW over 2014-2035, of which 37% is wind and solar PV, and 28% is coal-fired (Figure 3.6). India's capacity additions are just over 680 GW, of which 40% is coal-fired. OECD countries add capacity primarily to replace units that are retired and to decarbonise the power mix. The European Union sees the world's second-largest capacity

3. Power plant lifetimes are expressed in both technical and economic terms. Technical lifetime corresponds to the design life of a plant. It is assumed to be 70 years for hydropower, 50 years for coal, 40-60 years for nuclear, 40 years for gas and 20-25 years for wind and solar PV. Economic lifetime is the time to recover investment in a plant and is usually shorter than its technical lifetime. The economic lifetime can also vary between regulated and unregulated markets (see footnote 2). Typically, companies operating in unregulated markets need to recover their cost of capital in a shorter period of time because their risks are higher.

Figure 3.5 ▷ Power generation global capacity flows and investment, 2014-2035



Note: Over the projection period, a small portion of the renewables additions is retired following the lifetime assumption for wind and solar PV of 20-25 years additions (740 GW) due to significant retirements, large-scale deployment of renewables and fossil-fuelled capacity additions to ensure system reliability. The United States also installs significant capacity to replace retired plants (60% of additions). Gas-fired capacity makes up more than one-third of additions, followed by wind (28%) and solar PV (15%).

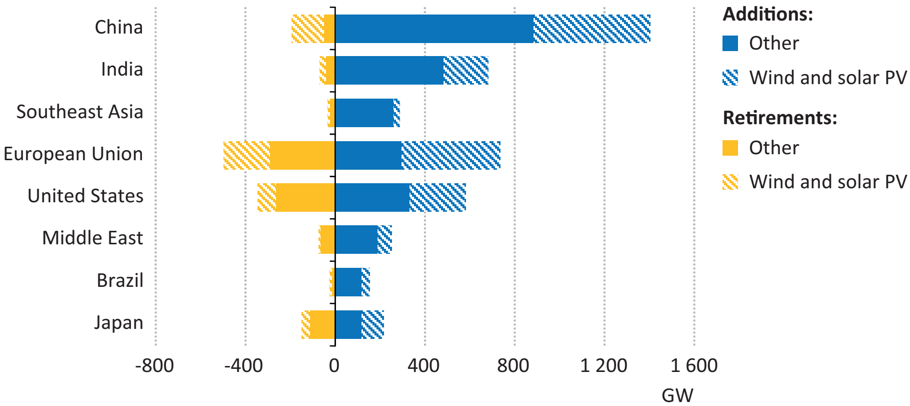
Table 3.1 ▷ Electricity demand, generation capacity and T&D line lengths in the New Policies Scenario

	Electricity demand CAAGR	Capacity Additions (GW)	Transmission lines (thousand km)		Distribution lines (thousand km)	
	2012-35	2014-35*	Additions 2014-35*	Refurb. 2014-35*	Additions 2014-35*	Refurb. 2014-35*
OECD	**0.9%**	**1 908**	**541**	**1 356**	**3 845**	**14 219**
Americas	1.1%	757	342	760	1 754	5 780
United States	1.0%	579	260	611	1 326	4 873
Europe	0.7%	799	144	421	1 208	5 492
Asia Oceania	0.8%	352	54	175	884	2 947
Japan	0.5%	218	20	110	358	1 960
Non-OECD	**3.2%**	**3 749**	**2 639**	**1 650**	**20 389**	**17 481**
E. Europe/Eurasia	1.6%	373	145	406	1 054	2 963
Russia	1.7%	221	89	262	484	1 004
Asia	3.6%	2 559	1 650	802	13 516	11 117
China	3.2%	1 400	1 035	499	5 395	5 597
India	5.0%	681	277	167	3 097	3 796
Southeast Asia	4.1%	291	240	85	3 735	1 140
Middle East	3.1%	249	148	103	1 314	682
Africa	3.4%	290	377	133	2 360	903
Latin America	2.7%	277	319	205	2 145	1 816
Brazil	3.0%	158	228	135	1 363	948
World	**2.2%**	**5 657**	**3 180**	**3 007**	**24 234**	**31 700**
European Union	0.6%	738	119	388	857	5 201

*Cumulative over the period. Notes: CAAGR = compound average annual growth rate; refurb. = refurbishments.

Expansion and reinforcement of T&D infrastructure will be necessary to extend service to new customers, to connect new sources of generation and to maintain or improve the quality of service to existing customers. In the period 2014-2035, net additions of 3.2 million kilometres (km) are made to transmission lines, which transport power over long distances from generators to local substations (Table 3.1). Distribution lines, which deliver power over shorter distances from substations to end-users (and therefore are much denser than transmission lines), have net additions of 24.2 million km. Around 5% of T&D investment serves to integrate new renewables capacity. The share can be significantly higher in regions that add more renewables, such as the European Union (9%). In non-OECD countries, the bulk of T&D line additions are needed as part of growing electricity systems; in OECD countries, most of the T&D investment is needed to replace old infrastructure. By 2035, about half of current T&D assets – more in Europe and the United States – will have reached the end of their technical lifetimes of 40 years. This leads to over 34.7 million km of T&D lines being refurbished and/or replaced worldwide during the projection period. The total length of the T&D lines which need to be added or refurbished is 62 million km, more than 1 500 times the circumference of the earth.

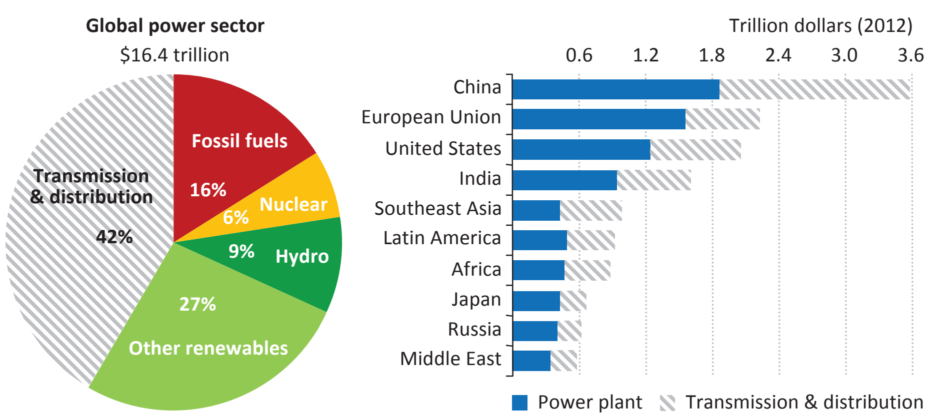
Figure 3.6 ▷ Power generation capacity retirements and additions by selected region in the New Policies Scenario, 2014-2035



Investment requirements

Global investment in the power sector amounts to $16.4 trillion over 2014-2035 in the New Policies Scenario, an annual average of about $740 billion per year. This represents some 40% of investment in energy supply infrastructure during that period. About 58% of power sector investment is allocated to the construction of new power plants and refurbishment of existing ones; the remainder is used to build and refurbish T&D networks. At the regional level, cumulative investment needs are largest in China ($3.6 trillion), followed by the European Union ($2.2 trillion), United States ($2.1 trillion), India ($1.6 trillion) and Southeast Asia ($1.0 trillion) (Figure 3.7).

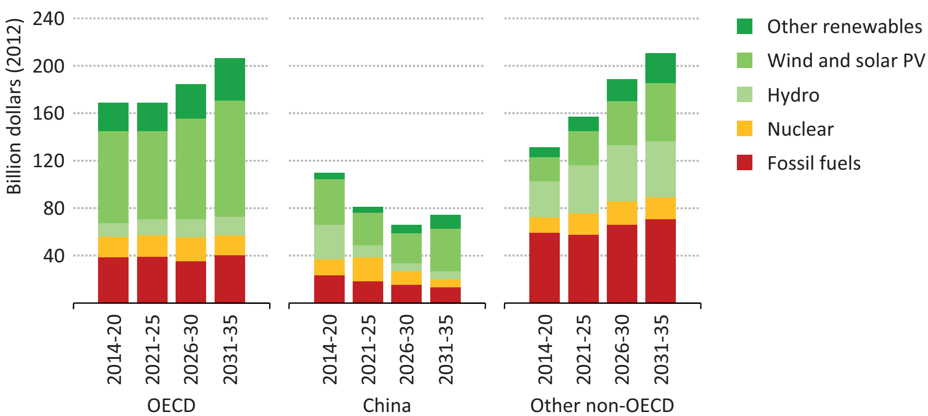
Figure 3.7 ▷ Cumulative global power sector investment by type and selected region in the New Policies Scenario, 2014-2035



Power generation

Cumulative investment in power plants is projected to be $9.6 trillion in the period to 2035 (Table 3.2). Investment in conventional capacity (fossil-fuelled, nuclear and hydropower) amounts to 54% of the total, while the rest goes to non-hydro renewables (mostly wind and solar PV). In many regions, average annual investment in conventional capacity is flat or declining over time, while that in non-hydro renewables is increasing. Worldwide, investment in non-hydro renewables rises from over $200 billion in 2012 (half of the total investment in power plants) to $290 billion (55%) at the end of the projection period, including replacements. This is due partly to a surge in capacity additions, starting around 2030, to replace a large amount of wind and solar PV capacity that is retired.

Figure 3.8 ▷ Average annual investment in power plants by type in the New Policies Scenario



Non-OECD countries account for more than 60% of investment in power plants, though the evolution of spending is notably different for China relative to other non-OECD countries. Average annual spending on power plants in China falls by around one-third as installed capacity catches up with electricity demand (Figure 3.8). In other non-OECD countries, the need for additional capacity to satisfy continued strong electricity demand growth drives up average annual investment by more than three-quarters over 2014-2035. During that period, other non-OECD countries also invest in absolute terms much more heavily than China in conventional capacity. OECD countries invest mainly in non-hydro renewables, simultaneously to make up for retirements and to decarbonise their power systems. From the beginning to the end of the projection period, the average annual investment in these technologies grows by over one-third, including replacements. Gas-fired capacity, which is important for system flexibility as variable sources of generation increasingly enter the mix, accounts for the majority of OECD countries' spending on fossil-fuelled plants over the projection period.

Table 3.2 ▷ Investment in power plants by region and plant type in the New Policies Scenario, 2014-2035 ($2012 billion)

	Coal	Gas	Oil	Nuclear	Bioenergy	Hydro	Wind onshore	Wind offshore	Solar PV	Other*	Total
OECD	**367**	**471**	**14**	**389**	**371**	**303**	**739**	**373**	**720**	**229**	**3 976**
Americas	195	234	6	111	164	122	299	94	234	88	1 547
United States	185	183	4	90	143	57	219	72	212	67	1 234
Europe	103	139	4	176	167	144	371	228	258	95	1 686
Asia Oceania	68	98	5	102	40	37	69	51	227	46	743
Japan	21	79	4	12	24	25	32	29	189	16	431
Non-OECD	**1 162**	**583**	**38**	**672**	**268**	**1 204**	**690**	**187**	**556**	**218**	**5 577**
E. Europe/Eurasia	168	155	1	200	33	87	25	8	13	6	695
Russia	84	103	0	125	25	55	6	5	3	5	411
Asia	867	200	7	405	167	715	565	161	402	100	3 587
China	332	70	2	293	87	311	368	140	207	60	1 870
India	302	54	1	72	34	174	138	14	139	17	945
Southeast Asia	175	52	2	18	21	97	16	2	34	18	435
Middle East	2	120	20	26	8	24	34	5	58	51	347
Africa	114	55	6	22	21	120	23	4	51	45	462
Latin America	11	54	4	20	39	258	43	9	32	16	485
Brazil	5	23	2	11	27	158	35	5	17	6	290
World	**1 528**	**1 054**	**52**	**1 061**	**639**	**1 507**	**1 429**	**560**	**1 276**	**447**	**9 553**
European Union	103	117	4	166	160	100	354	220	254	93	1 572

*Includes geothermal, concentrating solar power and marine.

Box 3.1 ▷ *World Energy Outlook* survey to update investment costs

In preparation for this report, and as part of our continuous efforts to update and improve the World Energy Model, a survey was conducted with 40 external experts from utilities, equipment vendors, government agencies, universities, international organisations and non-governmental organisations across the world to review data on investment costs. In general, the comments confirmed large regional variations in investment costs for power generation assets, an increase in the cost of new greenfield nuclear plants and a reduction in capital expenditures in renewables technologies due to learning effects. While our data were mostly in line with peer reviewer's expectations, their feedback prompted us to revise our assumptions for technologies whose costs have varied most in recent years. The most significant changes were:

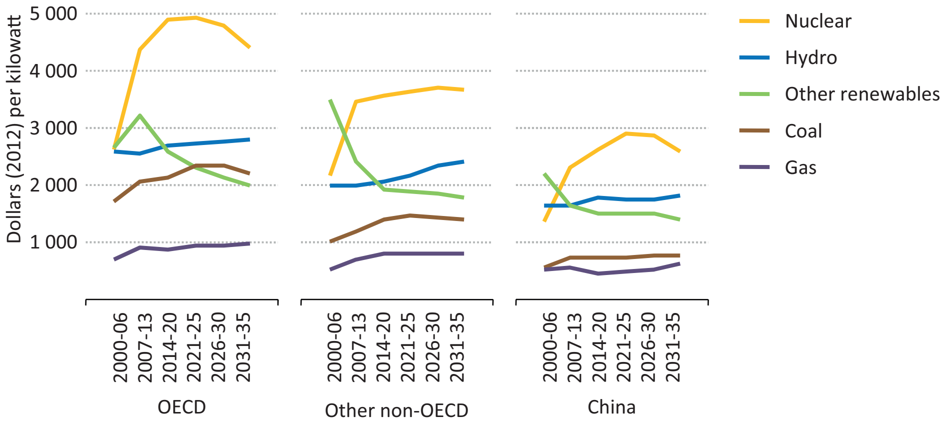
- Nuclear – unit costs in the United States, the European Union and China were increased (by 10-40%).
- Wind offshore – unit costs in all regions were increased (by 30-50%), reflecting projects more distant from shore, with higher costs and higher capacity factors.
- Wind onshore – unit costs in China were decreased (by 15%).
- Combined-cycle gas turbines – increased unit costs in OECD countries (by 10-20%).

The full set of investment cost assumptions used in the World Energy Model, detailed by power generation technology and region, can be found on our website at *www.worldenergyoutlook.org/weomodel/investmentcosts/*.

Non-hydro renewables account for 46% of investment in power plants globally, even though they represent only 40% of capacity additions. This reflects their higher capital intensity today relative to fossil-fuel plants. However, unit investment costs for non-hydro renewables are anticipated to fall in all regions over time, as learning is enhanced by increased rates of deployment (Figure 3.9). Thus, faster deployment of non-hydro renewables in the early part of the projection period can help to temper investment requirements in the long term. Investment costs for coal-fired power plants, and to a lesser degree, gas-fired power plants, rise towards the end of the projection period due to the deployment of more efficient technologies and carbon capture and storage (CCS).

Comparisons of investment costs should also take into account the utilisation rate and lifetimes of different options (Box 3.1). Nuclear plants, for example, involve substantially higher investment costs than other sources, but typically provide baseload power for 40-60 years. By contrast, variable renewables, such as wind and solar PV, have lower investment costs but generate power only when the wind is blowing or the sun shining and are retired after 20-25 years. Differences in regional investment costs reflect the state of economic development characterised by variations in labour, material and land costs. Differences also arise due to the costs associated with project planning, licensing, feasibility studies and environmental assessment.

Figure 3.9 ▷ **Average annual unit investment cost in power plants by type in the New Policies Scenario**



Note: Unit costs do not include investments in carbon capture and storage.

Transmission and distribution

Investment in T&D infrastructure over 2014-2035 totals $6.8 trillion. Non-OECD countries account for almost two-thirds ($4.6 trillion) of this investment; OECD countries spend the remainder ($2.2 trillion). T&D investment can be divided into several components: additional capacity to meet higher electricity demand; refurbishment and replacement of ageing assets; and additional capacity to integrate expanding renewables generation (Figure 3.10). Higher electricity demand accounts for 56% of total global T&D investment, refurbishment and replacement of existing assets for 40% and grid integration of renewables for 4%. Almost three-quarters of global T&D investment is in distribution lines, which represent over 90% of the total length of current networks.

Figure 3.10 ▷ **Average annual investment in T&D infrastructure in the New Policies Scenario**

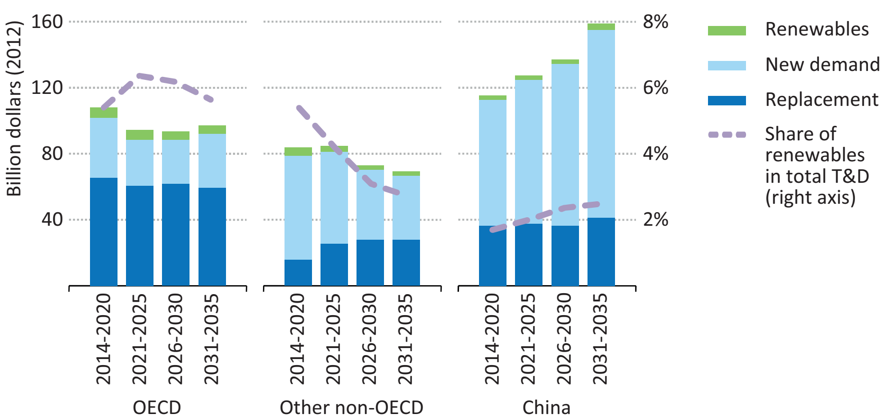


Table 3.3 ▷ Investment in T&D infrastructure by region in the New Policies Scenario, 2014-2035 ($2012 billion)

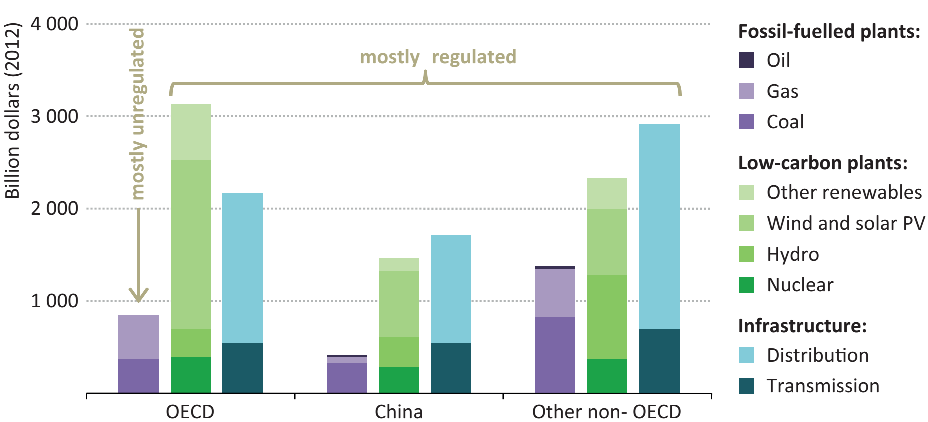
	Transmission				Distribution				Total T&D
	Total	Additions		Refurbishment	Total	Additions		Refurbishment	
		New demand	Renewables			New demand	Renewables		
OECD	**546**	**169**	**73**	**304**	**1 635**	**521**	**53**	**1 062**	**2 181**
Americas	324	127	26	171	696	245	18	433	1 020
United States	254	98	19	138	564	183	16	365	819
Europe	158	26	37	94	590	157	23	409	748
Asia Oceania	64	15	9	40	350	119	11	219	414
Japan	33	4	5	25	199	44	10	146	233
Non-OECD	**1 241**	**854**	**91**	**296**	**3 395**	**2 307**	**39**	**1 049**	**4 635**
E. Europe/Eurasia	126	50	3	73	301	124	1	176	427
Russia	81	32	1	48	121	59	0	62	202
Asia	793	567	69	156	2 335	1 602	32	701	3 127
China	548	392	49	107	1 169	746	20	403	1 717
India	119	78	14	28	551	333	9	208	670
Southeast Asia	88	73	2	13	456	394	1	61	544
Middle East	60	38	7	16	165	129	2	34	225
Africa	135	110	5	20	286	238	2	46	420
Latin America	128	89	7	31	308	214	2	92	436
Brazil	90	63	6	20	186	136	2	48	275
World	**1 787**	**1 023**	**163**	**601**	**5 030**	**2 828**	**91**	**2 111**	**6 817**
European Union	139	17	35	87	516	105	23	388	655

In non-OECD countries, more than two-thirds of investment in T&D grids reflects strong growth in electricity demand and the need to connect many new customers and power plants; around 30% is for refurbishment and replacement (Table 3.3). Russia and other countries in Eastern Europe/Eurasia are an exception, as about 60% of investment in T&D lines is needed for refurbishment and replacement. The share of T&D investment in non-OECD countries allocated to the integration of renewables is around 3% over 2014-2035. In OECD countries, due to the age of existing T&D infrastructure and stable electricity demand, 63% of investment during the projection period is needed for refurbishment and replacement. Renewables integration costs rise to nearly 6% of T&D investment in 2020, due to increased renewables deployment, but fall slightly towards the end of the projection period, as a significant share of additions of renewables capacity replace retired (and already-connected) units.

Implications for current financing models

Going forward, government policymakers will play a critical role in attracting financing for new investment in the power sector, as our projections indicate that by far the greater part of investment will be needed in markets that are mostly regulated. Over 2014-2035, with current market designs, less than $1 trillion will be required in the competitive parts of electricity markets out of the cumulative $9.6 trillion invested in power plants, with an additional $6.8 trillion needed in T&D grids, for cumulative power sector investment of $16.4 trillion (Figure 3.11). Two major challenges have to be overcome if the power sector infrastructure required through to 2035 is to be financed: first, capital increasingly has to flow to developing countries, where the majority of the new power generation capacity and T&D grids will be built; second, capital increasingly has to flow to renewable energy technologies which expand their share substantially, backed by government support.

Figure 3.11 ▷ Power sector investment by market type and region, 2014-2035



Notes: Low carbon in this figure does not include CCS. See footnote 2 for definitions of regulated and competitive markets.

In many developing countries, the rate of installation of power generation capacity is largely controlled by governments. State ownership requires the state to carry out the bulk of the future investment. However, governments in developing countries, especially the poorest, suffer from high public debt and often do not have the resources to finance large power projects. The optimal economic and financial expansion of the power sector in those countries will require a larger share of private capital and an increasing focus by governments on creating the necessary conditions to attract domestic and foreign capital.

External financing to the state sector is currently provided mostly through bank loans, as state-owned utilities have similar credit worthiness to their underlying government owner and therefore access to debt. Moreover, many banks are state-owned in developing countries. Access to equity (even where diluted state ownership is politically acceptable) is currently under-developed: most stock exchanges have lower levels of market capitalisation and liquidity than OECD stock markets. Access to OECD capital markets is often difficult or even undesired, owing to the stricter transparency and corporate governance rules that apply.

Foreign direct investment will be important in financing the new infrastructure, especially in markets where privatisation is already progressing. Multilateral development banks, regional development banks and import/export agencies have a variety of mechanisms and instruments available to facilitate the activity of foreign investors in developing countries. Yet, governments will continue to have a key role to play in mitigating risk for investors by creating a legal system capable of giving assured legal protection, planning for the establishment of financial sectors and providing multilateral agreements on investments. The long lifetime of power infrastructure and long amortisation periods inflate the risks of political change over the lifetime of a project.

The rapid increase in non-hydro renewables, such as wind and solar, will also require careful design of market and intervention policies by governments in both OECD and non-OECD countries. The expansion in investment in those technologies has so far been driven by state intervention and their continued deployment will require ongoing support for most of the projection period to ensure a reasonable rate of return. Globally, there is now more than a decade of experience with support policies for renewables (at different stages of market development), including emissions trading schemes, carbon taxes, feed-in tariffs, tax credits, renewable portfolio standards and market premiums.

Since the cash flow of a renewable energy project is often heavily dependent on government policies, regulatory risk plays a key role. From a financing perspective, the maximum return is typically capped by the terms of the support scheme. Regulatory risks, including the danger of retroactive measures concerning the remuneration scheme, are ever present, in OECD countries but also (even more so) in developing countries. Going forward, if the right conditions are in place, renewable energy assets will start generating stable and predictable cash flows (after accounting for interest and dividend payments) that could be re-invested, increasing the share of self-finance, compared with today. Stable and reliable cash flows offer good security and will influence the structure of the external sources of finance, raising the part of debt over equity and lowering the weighted average cost of capital. This will in turn increase the competitiveness of renewables and spur their further deployment (see later section on the 450 Scenario).

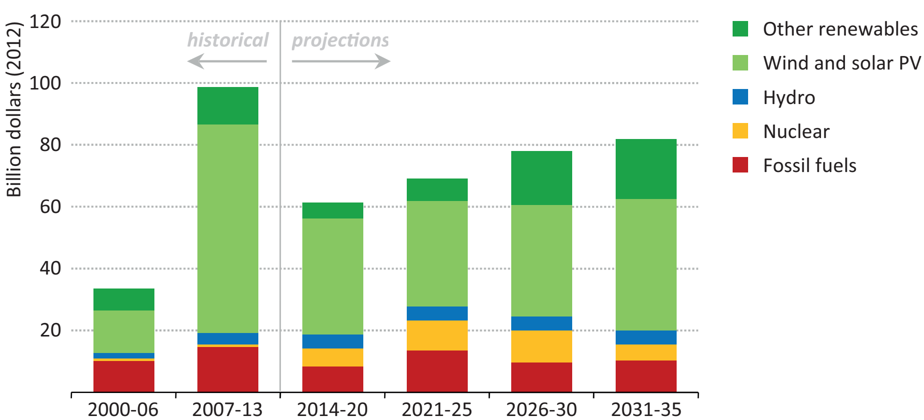
These trends offer large opportunities for the finance sector. What is required is an imaginative package of services and products that can help mitigate the risks of power sector investment. The role of the state, in turn, will have to evolve from direct investor to an investment enabler through the provision of financial support, guarantees or other forms of risk mitigation, while creating credible, reliable and sustainable policy frameworks for the expansion of low-carbon technologies that offer a reasonable return on investment. This must be sufficient to attract the capital from households, companies and institutional investors that states may not be able to provide due to budget constraints.

Focus on the European power sector

Past investment and future needs

Investment in the European Union (EU) power sector amounted to a cumulative \$1.2 trillion from 2000 to 2012. Of this, about 30% was directed to T&D, with fairly stable annual investment over the period. About 70% of the cumulative expenditure was for power plants, annual investment in which increased more than five-fold, to reach a peak of almost \$145 billion in 2011. This surge was driven by support policies to deploy renewable energy technologies – mainly wind and solar PV - that together accounted for 60% of the overall investment in new power plants (Figure 3.12). Bioenergy power plants received a significant share of investment, in most cases owing to support measures. Natural gas was the preferred fuel among conventional power plants investment. Only three nuclear power plants came online during this period, accounting for a very small share of overall investment. Investments in new power plants dropped to some \$110 billion in 2012 (down 25% from 2011), mainly because of less expenditure for solar PV due to lower unit costs and slower deployment, particularly in Italy.

Figure 3.12 ▷ European Union investment in power plants by type, historical and in the New Policies Scenario



3

Publicly listed utilities dominate the EU power sector, holding almost 60% of the installed generation capacity. Governments own a little under half of the listed utilities, with the remaining shares in private ownership. Around 15% of the installed capacity is controlled by state-owned utilities that are not listed on a stock exchange, for instance Vattenfall and Statkraft. With the rapid growth of distributed variable renewables in the past decade, the ownership structure is changing. While listed utilities are strongly present in the conventional power generation sector, less traditional investors have led the expansion of variable renewables and now own more than half of the non-hydro renewables capacity. Of this share, households, communities and auto-producers own two-thirds and private companies, such as smaller power producers and project developers, own one-third. Large and often publicly listed utilities have been active in expanding renewables too, with an emphasis on larger-scale projects.

In the New Policies Scenario, the need to replace ageing infrastructure and the will to further decarbonise the power mix together mean that the European Union sees the second-largest (after China) gross capacity additions in the period to 2035 (almost 740 GW). This is despite electricity demand growth of only 11% (electricity demand returns to the pre-crisis level of 2008 only by 2020). Almost three-quarters of these additions are renewable energy technologies, 60% alone are wind and solar PV. As these technologies have shorter technical lifetimes than conventional power plants, some recent additions and new plants will need to be replaced over the period to 2035.

These large capacity additions, with their relatively high unit investment costs (particularly when compared with non-OECD countries), bring total investment in the EU power sector to $2.2 trillion over 2014-2035. Almost 30% of the investment is needed to replace and reinforce T&D grids as well as to meet growing demand and provide new connections. Replacements make up almost three-quarters of the T&D total ($655 billion) while about one-third of the remaining $180 billion is needed to integrate the growing shares of renewables (9% of total T&D investments if replacements are included). Investing in interconnections will be important, both for completion of the EU energy market, and for integrating renewable energy technologies, helping to smooth their variability and reduce the need for additional conventional generation capacity. The application of electricity storage technologies and demand-side management could avoid the need for new lines. This may render a challenging environment for investors in new T&D capacity, which is usually in place for 40 or more years. Moreover, tariff structures might need to evolve to reflect the rapid deployment of decentralised power generation, especially solar PV. Today many rate structures recover part of the T&D cost through the tariff for each unit of consumption. With strong deployment of decentralised generation more power may be consumed on-site, particularly for residential solar PV. This reduces the amount of electricity purchased from the grid, while the size and cost of the T&D grid remains largely unchanged (or increases), therefore raising a challenge about how to recover its cost.

Of the $1.6 trillion needed for new generation capacity in the European Union, three-quarters is invested in renewables, mostly wind and solar PV, even though the investment requirements for these technologies are tempered by the continuing decline of their unit costs. Renewables see their share of total generation almost double, from 24% in 2012 to 44% in 2035, with wind and solar PV together accounting for three-quarters of this growth, increasing the need for both their grid and market integration. Over time, an increasing share of investment in wind is for offshore installations. Investment levels also increase for bioenergy, concentrating solar power (CSP) and marine technologies.

Fossil-fuelled and nuclear power plants account for almost $400 billion of investment in new capacity, with gas-fired capacity accounting for 30% and coal-fired power plants for more than one-quarter. Four nuclear plants are under construction in the European Union and each is taking longer to complete and is costing more than initially expected. Uncertainties about the economics and regulatory environment limit the installation of new nuclear plants in the New Policies Scenario and only two-thirds of the plants retired are replaced by new nuclear capacity. However, nuclear plants still account for most of the remainder of the investment in conventional power plants due to their high capital costs.

The past decade: unprofitable conventional investment in the European power market

Low prices in several wholesale electricity markets in the European Union in recent years have raised questions about the ability of existing and new power plants to recover their capital investment under current market conditions. Low wholesale electricity prices stem from two factors: overcapacity in these markets and the growing share of renewables, which enjoy a protected place in the market.

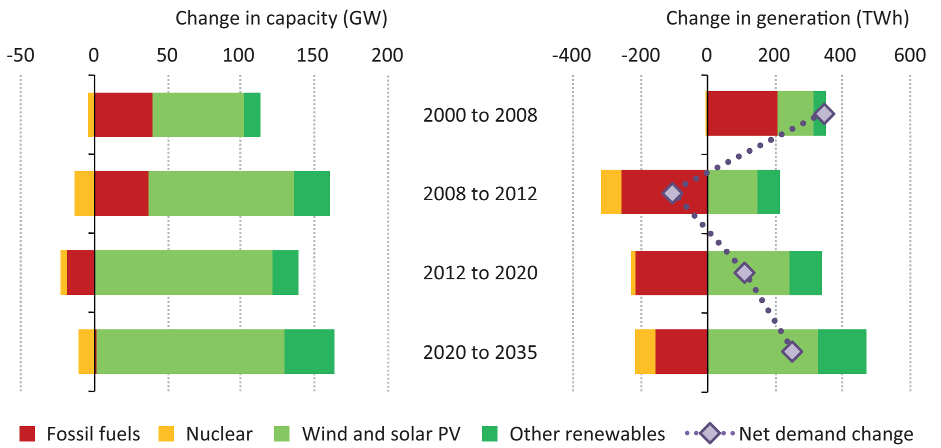
The overcapacity stems largely from the economic crisis of 2008 and the accompanying decrease in electricity demand. Prior to the global economic downturn, new power generation capacity was built in expectation that electricity demand in Europe would continue to increase steadily, having grown by 11% from 2000 to 2008. Over that period, installed capacity expanded by some 110 GW, or 15% (Figure 3.13). About two-thirds of this new capacity was renewables-based and the remainder was gas-fired. However, the global financial crisis and the debt crisis in Europe depressed economic activity, causing electricity demand in Europe to decline by several percent from 2008 to 2013.

Taken in isolation, the situation of excess capacity that is the result of lower-than-expected demand will resolve itself in a properly functioning competitive market: it puts downward pressure on electricity prices that encourage additional consumption, while providing a clear signal to investors to stop building new capacity and consider early retirements.

In the European Union, however, additional capacity has continued to be added while wholesale prices have decreased, as renewables were remunerated outside the competitive part of the market. These additions often outpaced planned retirements, exacerbating the fall in prices and turning the overcapacity situation into a more persistent problem. From 2008 to 2012, electricity demand fell by 3% while renewables capacity increased by more than 120 GW, 50% more than the level in 2008 and equivalent to 13%

of today's total installed capacity. At the same time, fossil-fuelled and nuclear capacity grew by about 25 GW, as completion of gas-fired plants that were planned before the crisis largely compensated for retirements of nuclear and oil-fired capacity.

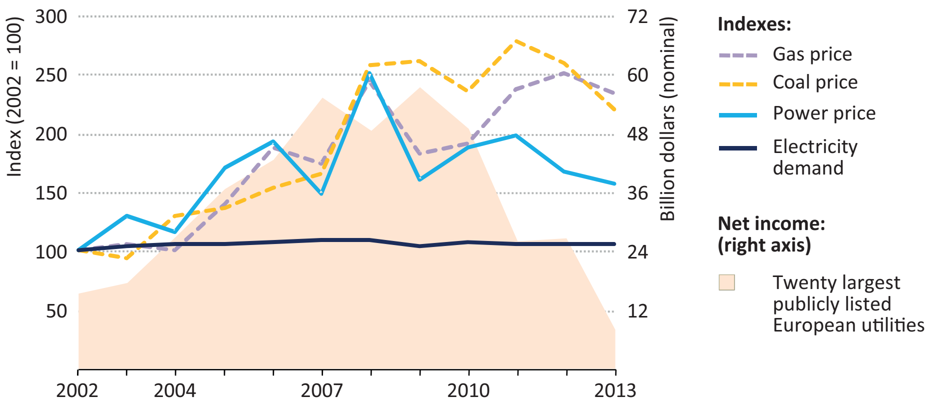
Figure 3.13 ▷ Net capacity additions and net incremental demand and generation by type in the European Union, 2000-2035



As additional renewables capacity came on line between 2008 and 2012, electricity output from renewables increased by 210 terawatt-hours (TWh), while electricity demand fell by some 100 TWh. As a result, generation by fossil-fuelled power plants was reduced by 260 TWh (14% of fossil-fuelled generation in 2008), with the remaining reduction accommodated by the shut-down of nuclear plants in Germany in the aftermath of the Fukushima accident. The sizeable reduction in generation lowered revenues for conventional power plants operating in competitive markets, because it had not been accompanied by a similar reduction in installed capacity. Therefore, the fleet of conventional power plants was forced to generate power for fewer hours, while at the same time the electricity price received also dropped. This was mainly a consequence of the overcapacity: the most expensive peaking power plants were needed less often, leaving the power plants with lower marginal costs – often combined-cycle gas turbines (CGGT) plants and even coal-fired power plants – to set the price (the "merit-order" effect). Peak electricity prices during the day were further reduced by strong deployment of solar PV.

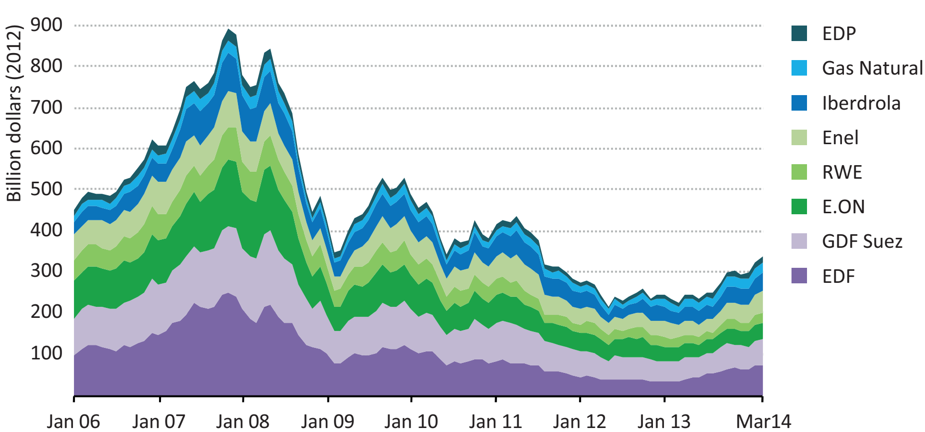
In addition to lower revenues, conventional power plants have had to cope with higher operating costs: the strong deployment of renewables with variable production profiles leads to greater variations in the level of production required from conventional sources, involving more frequent start-ups and shut-downs. These give rise to additional fuel costs (to pre-heat the steam cycle) and maintenance costs, due to wear and tear. The burden of these additional costs has been carried by both gas- and coal-fired power plants. In addition, gas prices have been rising in recent years, increasing fuel costs, while coal prices have declined, easing the situation somewhat.

Figure 3.14 ▷ Evolution of energy prices, electricity demand and net income for Europe's top 20 publicly listed utilities, 2000-2013



As a result of these factors, the combined net income of the 20 largest publicly listed EU utilities fell by some 85% between 2009 and 2013 (Figure 3.14). The market capitalisation of eight of the major listed continental European utilities halved in value owing to the financial crisis and then worsened further over 2011-2012 (Figure 3.15). In 2012 and 2013, European power plants as a whole were not able to recover their fixed costs (including capital investments) in competitive wholesale electricity markets. We estimate the gap between the revenues received and the revenues needed to be about $20/MWh of electricity sold on wholesale markets in 2013, where the average price was $70/MWh, about 23% below the level needed to recover the costs of supply.

Figure 3.15 ▷ Market capitalisation of selected European utilities



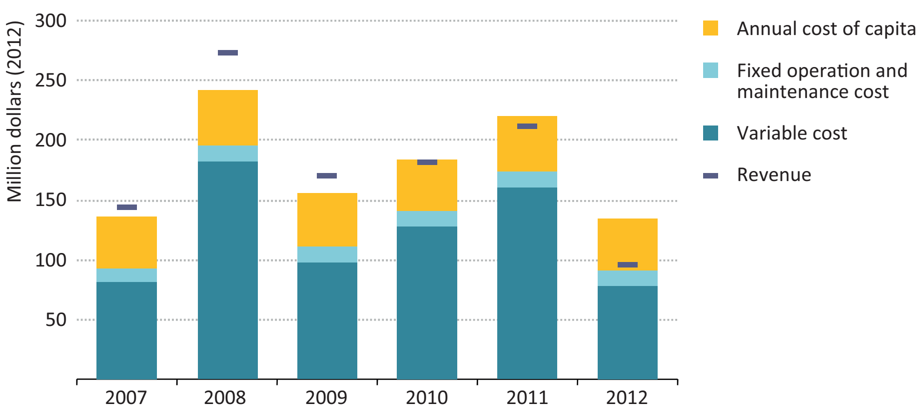
Note: GDF and Suez were distinct companies until June 2008.

Sources: IEA analysis and 2° Investing Initiative, based on Bloomberg Professional service.

The revenue gap in 2013 was also the result (though to a lesser extent) of the long-standing "missing money" problem (Green, 2005). This refers to the difficulty of plants with the highest operating costs to recover their fixed costs, since they operate for a small number of hours per year. More recently, in the European Union, because of the circumstances described, this problem has extended to mid-merit power plants. Most importantly, this includes high-efficiency CCGTs that are needed to maintain system adequacy, provide flexibility to accommodate an increasing share of variable renewables and contribute to other policy goals, such as reducing carbon-dioxide (CO_2) emissions from the power sector by displacing coal-fired generation.

Some utilities, citing poor economics, have announced plans to mothball recently installed high-efficiency CCGTs. Among the plants affected are the Irsching plant in Germany and the Claus C plant in the Netherlands. We estimate that the combination of fewer operating hours, widening gas-coal price spreads, low carbon prices (that further weaken the competitiveness of gas-fired plants, relative to coal) and lower wholesale electricity prices has meant that high-efficiency CCGTs in Europe have been unable to fully recover their capital costs since 2011 (Figure 3.16). In 2012, the annual income of a representative plant (400 MW, 59% efficiency) may have fallen some $40 million (€30 million) below the level needed. In this situation, the high-efficiency CCGTs recover all their variable costs (fuel and carbon) and their fixed operating costs, but only a part of their capital costs. So long as revenues are sufficient to cover all variable costs and some portion of fixed costs, mothballing facilities may be premature (although the situation worsened in 2013). If the situation persists, the incentive for utilities to invest in CCGTs will be lost.

Figure 3.16 ▷ Allocation of revenues for a high-efficiency CCGT in a competitive European electricity market, 2007-2012



Ensuring sufficient investment in the future

The European Union's long-term policy goal to decarbonise its power sector by 2050 will continue to drive the deployment of large amounts of renewables-based capacity. In the New Policies Scenario, installed capacity of renewables in the European Union increases by

140 GW by 2020, and another 160 GW from 2020 to 2035. Electricity demand recovers to the level of 2008 by 2020 and then grows by a further 7% by 2035. In the period to 2020, the retirement of fossil-fuelled and nuclear capacity outpaces additions.

In the regulated parts of electricity markets in Europe relevant to renewables, the main risks to securing future investment stem from regulatory uncertainty. Frequent (and sometimes retroactive) changes in regulation and complicated frameworks weaken the confidence of investors, causing them to act more cautiously. Feed-in tariffs for renewables, of which there are some 3 000 in place across Europe, are at the heart of this uncertainty. Investors are apprehensive about whether such schemes will be sustained, especially given economic pressures to cut payments or shorten their duration, and whether these policies will continue to be the main instrument to push renewables deployment. In the longer term, it will be important for renewable energy technologies to be further integrated into competitive wholesale markets. Having them face similar risks and receive similar price signals as conventional technologies will help to increase the coherence of their deployment with system needs. Since, in most cases, the full costs of renewables still exceed average wholesale electricity prices, their expansion hinges on financial support mechanisms to offset the difference between their costs and the revenues received from power sales on wholesale markets.

Of cumulative renewables capacity additions in the European Union through to 2035, 80% is wind and solar PV, which have three important impacts on conventional capacity. First, wind and solar PV have low capacity credits,[4] with less than 15 GW out of the 250-GW increase in installed capacity by 2035 in the New Policies Scenario counting towards system adequacy. This means that about 200 GW of fossil-fuelled capacity additions are necessary to ensure the reliable supply of electricity through to 2035. Second, variable renewables generate more power on average than their capacity credit, reducing the number of hours in which conventional power plants operate. There is a 5% decrease in thermal (fossil-fuelled and nuclear) capacity between 2012 and 2035, while their generation decreases by 18%, potentially reducing revenue flows. Third, the variability of wind and solar power requires other capacity to be flexible to adjust output to accommodate the level of renewables output, influencing the type of capacity needed in the system.

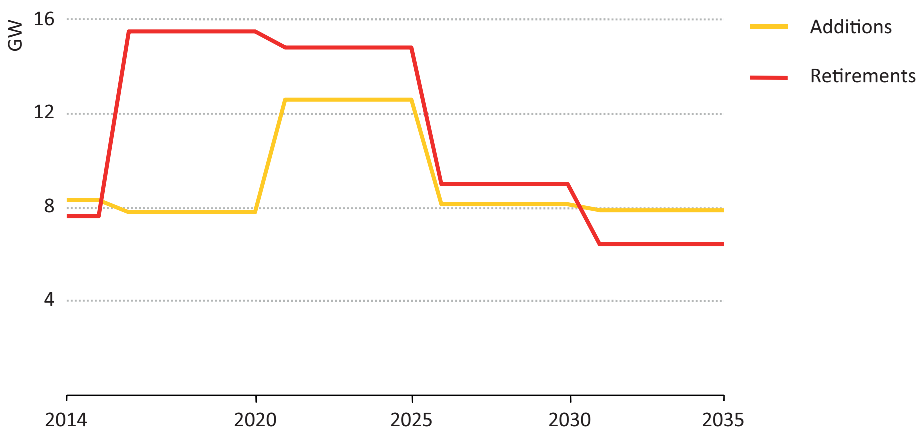
In the period 2016-2025, thermal installed capacity of some 150 GW, equivalent to 25% of the current EU capacity of these technologies, is expected to come to the end of its lifetime. To maintain system adequacy, about 100 GW of new thermal capacity will be needed – less than 10% of that is under construction. By 2035, the total installed capacity of these technologies decreases by less than 10%.

Today's excess capacity does provide some breathing space to resolve the issues in the investment environment in the EU power sector, in particular in the period to 2020, as retirements far exceed required additions (Figure 3.17). Over the period to 2035 as

4. The capacity credit is the share of installed capacity that can be confidently relied upon at times of high demand. It is usually quite small for variable sources such as wind and solar PV.

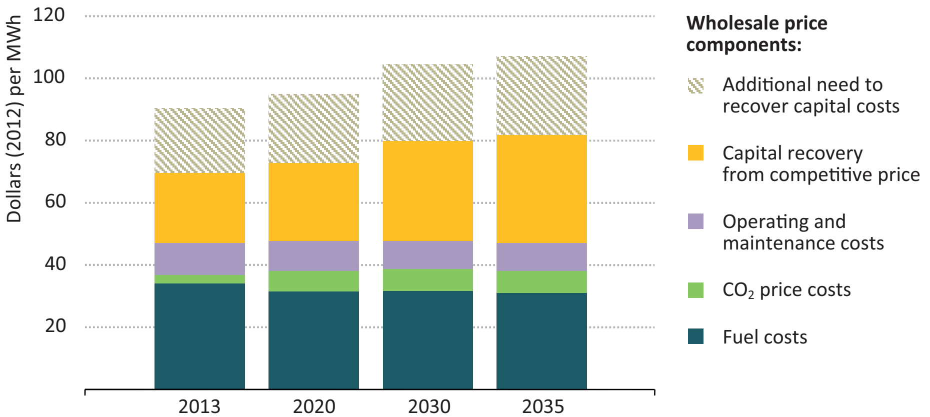
a whole, less than one-third of the 6 GW of coal plants retired on average each year is replaced. Of these replacements, only a small share are based on power market-driven investment decisions in the future, with around 20% currently under construction, one-third combined heat and power (CHP) and another 20% equipped with carbon capture and storage. Additions of new gas-fired power plants, favoured for their flexibility (that can more readily accommodate increasing shares of renewables), amount to almost 6 GW per year, almost four times as much as the 1.5 GW retired on average. More capital-intensive plants, such as coal-fired and nuclear, can also provide flexibility, but their profitability is hard hit when their operating hours decrease significantly. Gas-fired capacity is better-suited to this need, because its relatively low capital costs and typically high fuel costs mean that it is generally profitable when operating at medium capacity factors.

Figure 3.17 ▷ Average retirements and capacity additions of thermal plants in the European Union in the New Policies Scenario



In the New Policies Scenario, it is assumed that competitive wholesale electricity markets will continue to expand throughout Europe and that greater integration of markets will be achieved, in line with announced EU policies. The projections in the New Policies Scenario are also based on the assumption that means will be found by 2020 to sustain the necessary investment, with wholesale electricity prices sufficient for all power plants to recover their variable costs and for newly built plants to recover their fixed costs. To fully cover these fixed costs, wholesale electricity prices exceed $100/MWh by 2030 (Figure 3.18). Such an increase contributes to higher end-user prices in Europe, relative to some other countries. Energy efficiency offers a means to prevent these costs becoming too onerous for end-users and national economies (IEA, 2013a). To address competitiveness concerns for certain sectors, other measures could be envisaged such as making use of auctioning revenues under the EU ETS.

Figure 3.18 ▷ **Gap between wholesale prices expected with current EU market structure and price for full cost recovery**



Note: Prices are generation-weighted averages.

While the excess of retirements over new build up to 2025 will alleviate – or solve – the current overcapacity situation in Europe, questions remain about future levels of investment in fossil-fuelled and nuclear capacity. Will investors have sufficient assurance of adequate financial returns in the future to be able and willing to raise the necessary capital? To answer this question positively requires power sector market reforms.

Market reforms

There is a range of market reforms that could alleviate the situation for new capacity in Europe in the coming years. First, measures that enable the deployment of technologies that improve the efficiency of the power system could avoid the need for some new conventional capacity, thereby reducing investment requirements. Some examples are improving demand response through smart grids, real-time pricing and metering, and optimising the use of existing capacity by increasing the use of energy storage or by expanding network connections across Europe (building more interconnectors and intra-country transmission lines). Such measures are currently limited by regulatory hurdles and challenging economics. Ensuring clear and stable market signals through the EU ETS can improve the ability of electricity markets to provide higher revenues to the most efficient technologies, while helping to achieve decarbonisation goals.

One way to provide for the recovery of investment costs for new power plants is to restructure the market to allow adequate price spikes during times of scarcity (which would only take place once the excess capacity in the market has been eliminated). While this could provide adequate revenues for generators, it may prove challenging for public acceptance as it could increase bills for end-users significantly. Moreover, the uncertainty associated with price spikes may make it less attractive for financing (increasing risk premiums) and could lead to insufficient investment in needed capacity.

Another option is to introduce "capacity mechanisms" that remunerate power plants for being able to provide electricity at any time, thereby rewarding reliability and providing a signal about system needs over a medium- to long-term horizon. Variable renewables typically do not qualify for remuneration under such schemes. A well-designed capacity mechanism would determine the need for firm capacity in a system and provide a payment to electricity generators that is high enough to either retain that level of capacity in the market or spur investment in new capacity. As the need for flexible capacity increases due to growing shares of variable renewables through to 2035, balancing and services markets should favour the exploitation of all resources, including demand response mechanisms.

In practice, capacity mechanisms can take many different forms – the main ones being a strategic reserve, reliability options, a focused capacity market and a decentralised capacity market. In European markets, careful consideration should be given to the following elements of the design: technology neutrality; co-ordination of national mechanisms at the EU level; maximising the use of market forces; the unbundling of capacity and energy markets; and avoiding discrimination between existing and new capacity. While several European countries are considering some form of capacity mechanisms, they are often being developed independently and risk posing additional hurdles to the realisation of a single European market. The consistency of country-level measures with EU-wide approaches, including instruments to ensure market participation of all technologies (including renewables and nuclear) and providing appropriate long-term signals for investment, will be critical to achieving decarbonisation goals for the EU power sector.

Box 3.2 ▷ EU 2030 Climate and Energy Goals

In January 2014, the European Commission proposed the "2030 climate and energy goals for a competitive, secure and low-carbon EU economy".[5] Several more steps, including a final decision by the European Council, are required before it is officially adopted. There are two main goals put forth by the communication:

- A target to reduce EU domestic greenhouse-gas emissions by 40% below the 1990 level by 2030;
- An EU-wide binding target for renewable energy to make up at least 27% of the EU's energy consumption by 2030, without specific national targets.

There is also the requirement to establish a market stability reserve for the EU Emissions Trading System (ETS) to enhance its functioning and compliance flexibility. The New Policies Scenario in this special report does not include this proposal, though policies that are included reduce emissions to 34% below 1990 levels by 2030, while renewables reach a share of 25.5% in 2030, with generation of 1 460 TWh. The final EU policy design and compliance approaches will affect not only overall investment needs,

5. For further details, see *http://ec.europa.eu/clima/policies/2030/index_en.htm.*

but also the extent to which other goals are achieved, such as energy security (for example, a reduction of natural gas and oil imports). Two illustrative cases consistent with the new proposal were analysed to gain insights into how different policy designs could play out.

In the first case, the emissions target for 2030 is achieved by assuming carbon prices at \$55/tonne of CO_2 in 2030 (\$22/tonne CO_2 higher than in the New Policies Scenario). In this case, similar amounts of renewables are deployed as in the New Policies Scenario, but their share increases to the required minimum level of 27% as total electricity demand is lowered through end-use energy efficiency measures. These measures, assumed to be enforced as part of the expected contribution from non-ETS sectors to the overall emissions target, are facilitated by an additional investment of \$240 billion in energy efficiency through 2030, relative to the New Policies Scenario. As a result, imports of natural gas are 28 billion cubic metres (bcm) (7%) lower in 2030 due to less gas demand in the buildings sector and a relative shift from coal to gas in power generation. Oil imports are 0.5 million barrels per day (mb/d) (7%) lower, three-quarters of which is due to a higher share of alternative fuels in road transport and most of the remainder is the result of lower use in buildings. At \$10.7 trillion, cumulative oil and gas import bills to 2035 are \$450 billion lower than in the New Policies Scenario.

To illustrate the effect of additional renewables deployment, in a second case, the share of renewables reaches 28% in 2030, achieved with an increase in the power sector. With energy efficiency investments equal to the previous case, the CO_2 price required to reduce emissions to 40% below the level in 1990 is \$40/t CO_2 in 2030 (\$7/tonne CO_2 higher than in the New Policies Scenario), as more emissions are abated through renewables. Electricity generation from renewables is 9% higher in this case than in the New Policies Scenario, requiring additional cumulative investment of some \$150 billion. Consumption of gas in the power sector is reduced more than in the previous case (by 33 bcm in 2030) directly due to additional renewables generation displacing some gas-fired generation, plus an additional reduction as there is less need for fuel switching from coal to gas to meet the emissions targets. As a result, in 2030 net gas imports are reduced by 60 bcm to 355 bcm, only 5% above the levels of 2010. Cumulative oil and gas import bills are \$620 billion lower than in the New Policies Scenario.

Overall, it is clear that increased energy efficiency investments in end-use sectors are key not only to achieving the emission reduction targets, but also to reducing fuel imports. The outlook for natural gas will be determined by the interplay between targets for renewables and the ETS, as the price difference between gas and coal and the power sector market design may facilitate a different power mix, with implications for energy security, but also for the functioning of power markets.

Focus on the Indian and Southeast Asian power sectors

Past investment and future needs

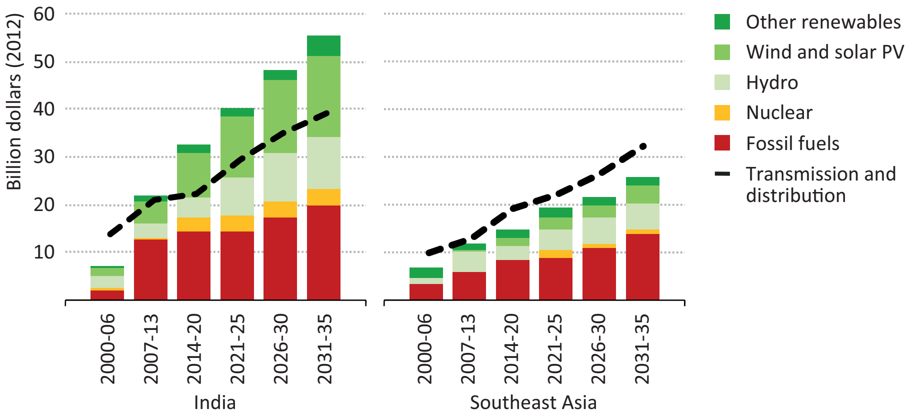
India and Southeast Asian countries have had considerable success in the past decade in developing their power sectors to keep pace with booming electricity demand. Since 2000, India's installed capacity and electricity generation have nearly doubled and annual investment in new power plants has increased four-fold, from $7 billion in 2000 to $32 billion in 2012. In Southeast Asia, the expansion of the power sector has been similarly impressive, with total installed capacity increasing from 140 GW in 2000 to 237 GW in 2012, requiring investment of $118 billion over the period. In both regions, expanding the electricity supply has been critical to achieving strong economic growth and lifting hundreds of millions of people out of energy poverty.

Even with these important achievements, substantial additional development of the power sector is needed to improve the poor reliability of these electricity systems to help overcome fundamental economic and social issues. Coupled with certain market features, such as cross-subsidies from industry and commercial segments to residential and agricultural end-users in India, some consumers are incentivised to generate their own electricity (mostly fuelled by diesel). In India, this reduces the competitiveness of its manufacturing sector, which is small for a country of its size and stage of economic development. In addition, with 300 million people in India and around 110 million in Southeast Asia still lacking access to electricity, under-development of the power sector also has a high human cost.

Meeting future investment needs will require calling upon the financial resources of both the government and private investors, domestic and foreign. In Southeast Asia, the ownership structure of power generation assets is varied: around half are state-owned. In India, the government undertakes most power sector investment and owns around two-thirds of the generation capacity. However, private capital has increasingly flowed into the sector, feeding the recent growth in non-hydro renewables, which is the only type of generation that has exceeded the targets set out in the past several five-year plans. Foreign direct investment (FDI) to India's power sector had previously been capped, but reform in 2013 removed the limit, paving the way for more FDI to flow into the sector.

In the New Policies Scenario, India's power sector investment requirements total $1.6 trillion (fourth-largest in the world) over 2014-2035, with 60% needed for new power plants and 40% for expanding T&D networks (Figure 3.7). Coal and renewables account for about 85% of the cumulative investment in power plants, indicating where it is most critical to attract future capital flows (Figure 3.19). In Southeast Asia, investment needs amount to $1 trillion (fifth-largest in the world), split almost evenly between new power plants and T&D infrastructure. Continuous investment over 2014-2035 in coal-fired power plants increases coal's share of generation from 32% to 48%. In addition, investment in renewables raises their share by 5 percentage points over the period.

Figure 3.19 ▷ India and Southeast Asia average annual investment in the power sector by type, historical and in the New Policies Scenario

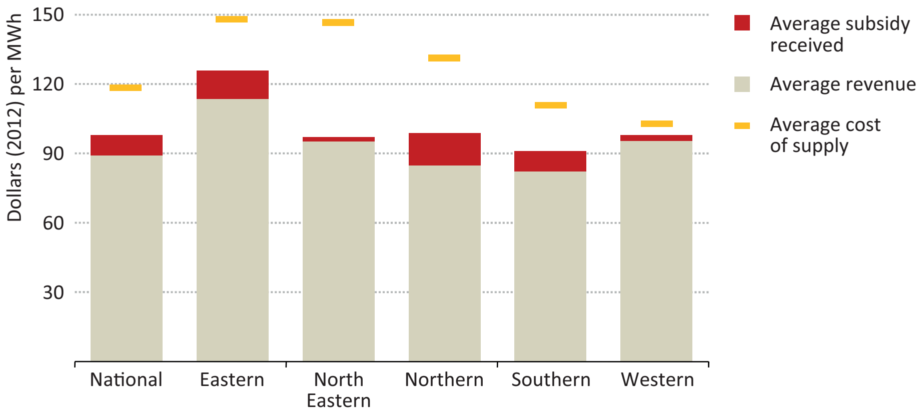


Financial health of the power sectors

The power sector in India has experienced financial difficulties in recent years. During the fiscal year (FY) 2011-2012, all utilities taken together booked losses of close to $14 billion (year-2011 dollars). Utilities directly exposed to the risks of low regulated end-user prices and selling directly to consumers took the bulk of these losses, accounting for nearly $13 billion, compared with total revenues from sales of power and other activities of $56 billion and subsidies received to compensate for under-pricing of $5 billion (Power Finance Corporation, 2013). These utilities include state-energy boards, distribution companies and private utilities and cover all electricity sales to end-users in FY 2011-2012. Across the country, this equates to nearly $30/MWh of power sold (before subsidies), or about one-quarter of the average cost of supply for these utilities in FY 2011-2012. This revenue gap has been increasing in recent years, as it was closer to $25/MWh sold in FY 2008-2009. Generation, transmission and trading utilities incurred the remaining losses of $1 billion to utilities.

The revenue gap is the result of a disparity between the average costs of supply and average revenues (Figure 3.20). In FY 2011-2012, power purchases accounted for more than 60% of the costs of supply for State Electricity Boards, distribution companies and private utilities. Electricity was purchased largely from power plants owned by central power sector utilities, namely the NTPC (formerly known as National Thermal Power Corporation) and National Hydroelectric Power Corporation, whose prices cover both the fixed and variable costs of generation. The balance of the costs of supply was related to the fixed and variable costs of generation from their own generation capacity and overhead costs.

Figure 3.20 ▷ **Supply costs, revenues and subsidies per unit for utility sales direct to consumers by region in India, FY 2011-2012**



Note: Regions are defined as: Eastern includes Bihar, Jharkhand, Orissa, Sikkim and West Bengal; North Eastern includes Arunachal Pradesh, Assam, Manipur, Meghalaya, Mizoram, Nagaland and Tripura; Northern includes Delhi, Haryana, Himachal Pradesh, Jammu and Kashmir, Punjab, Rajasthan, Uttar Pradesh and Uttarakhand; Southern includes Andhra Pradesh, Karnataka, Kerala, Puducherry and Tamil Nadu; Western includes Chhattisgarh, Goa, Gujarat, Madhya Pradesh and Maharashtra.

Source: Power Finance Corporation Ltd.

The revenues of utilities selling directly to consumers in India depend on cross-state tariffs that are regulated by the Central Electricity Regulatory Commission, and end-user tariffs that are regulated by state electricity regulatory commissions. In recent years, regulators have been reluctant to raise tariffs high enough to cover costs, instead approving the creation of "regulatory assets" for utilities – a means of shifting the losses from utilities to the state.[6] As end-user tariffs are regulated at the state-level, and some utilities are more efficient than others, average revenues per MWh sold vary widely by state and so, therefore, does the size of the revenue gap. In FY 2011-2012, utilities in six states were profitable (Delhi, Andhra Pradesh, West Bengal, Gujarat, Kerala and Karnataka) while the three states with the highest losses (Rajasthan and Uttar Pradesh in the Northern region and Tamil Nadu in the Southern region) accounted for over half of the total losses of all utilities. Subsidies to electricity consumers do not contribute to the revenue gap, as they are repaid to utilities with government funds or compensated in other ways. Aggregate technical and commercial (AT&C) losses (the difference between power supplied to the grid and the power for which payment is collected), which were 27% in FY 2011-2012, are a major contributing factor to the revenue gap, meaning that utilities purchase significantly more power than they are able sell to consumers. Technical losses in India are high due to insufficient investment and maintenance, and commercial losses are high as a result of insufficient metering and theft.

6. Regulatory assets are created on utility balance sheets to make up for foregone revenues as regulated prices fail to recover costs, which are eventually to be paid from state funds.

The revenue gap reduces the profitability of utilities and cash available for operations and investment. The past provision of regulatory assets only partially addressed this gap, providing an asset but failing to increase the cash available in the short term. These utilities are less able to raise capital than if they were properly remunerated in cash. The Central Electricity Authority within the Ministry of Power has also been affected by the revenue gap for utilities, as State Electricity Boards have not been able to make full payment for power and coal purchases in recent years. This has, in turn, led to large debts accumulating. On two occasions since 2001, reduced payments have been accepted by the Central Electricity Authority from State Electricity Boards to help settle their debts.

It will take strong government action to bridge the revenue gap so as to provide for future investment. This can be done either by decreasing costs or increasing revenues, or a combination of the two. Progress in reducing the AT&C losses means less power has to be generated or purchased, thereby reducing the average cost of supply per MWh sold. If AT&C losses had been 15% in FY 2011-2012, the target level set by the Restructured Accelerated Power Development and Reforms Programme, instead of the actual 27% in that year, utility expenditures on power purchases would have been reduced by over $10 billion, equivalent to more than 80% of the losses for all utilities.

Increasing revenues will also depend on the end-user tariffs set by the central and state governments. While the authorities recognise that these need to keep pace with the cost of supply, additional efforts to increase average tariffs are needed. Recent court rulings require the liquidation of regulatory assets, a mechanism through which tariff increases could be delayed. This indicates that tariffs will need to be more in line with the costs of supply in the future, requiring a significant increase in coming years. At the current level of AT&C losses, average tariffs needed to be over 20% higher to cover the costs of supply in FY 2011-2012. Had AT&C losses been 15%, average tariffs to all consumers across India would have needed to be only 5% higher to cover the costs of supply. The challenge for end-user tariffs to fully cover the costs of supply may be made more difficult by rising natural gas and steam coal prices over time, and requirements for utilities to purchase increasing amounts of power generated by renewables at a premium over thermal power plants.

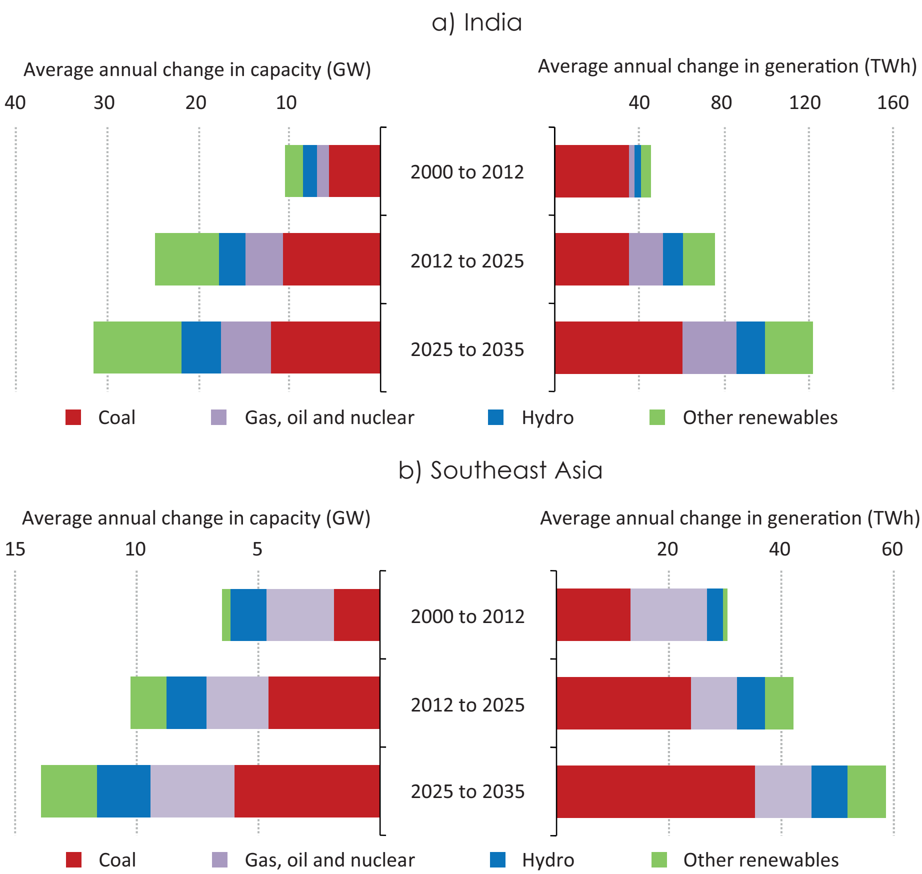
The situation is much the same for the power sector in Indonesia, where electricity tariffs are regulated by the government, and, at least in 2013, revenues were insufficient to cover the costs of supply. The state-owned electric utility, Perusahaan Listrik Negara (PLN), which owns and operates the vast majority of generation capacity, incurred losses of $3 billion in 2013, or about $17/MWh sold, after taking into account more than $10 billion in subsidies received from the government. Tariffs were actively adjusted upwards over the course of 2013, but failed to keep pace with higher costs.

Utilities in some countries in Southeast Asia are in better financial shape. After many years when regulated prices caused losses for state-owned utilities, the situation has improved in Malaysia, as Tenaga Nasional Berhad (TNB), its largest utility, has been profitable in each of the last ten years. Electricity rate increases continue to be implemented in Malaysia to match supply costs. The power sector in Thailand has also performed well in recent years, as a more liberalised market in which independent power producers provide for more than one-third of installed capacity and tariffs are more closely tied to costs. Also, the state-owned Electricity Generation Authority of Thailand had a return on assets of 7% in 2011 and 8% in 2012 (EGAT, 2013).

Investment in coal-fired generation capacity

Coal is fundamental to the outlook for the power sectors for India and Southeast Asia in the period 2014-2035. In the New Policies Scenario, the lion's share of new power plants in both regions will burn coal, representing about 40% of total capacity additions over the period in both regions. Coal is the largest source of generation in both regions in 2035, though the share of generation in India falls from 72% to 56%, while Southeast Asia is one of the few regions in the world in which coal accounts for a higher share of generation in 2035 (48%) than in 2013 (32%) (Figure 3.21).

Figure 3.21 ▷ India and Southeast Asia average annual change in capacity and electricity generation in the New Policies Scenario



Note: GW = gigawatt; TWh = terawatt-hour.

Future investments in coal-fired power plants in both regions face three critical challenges. First, the tariff and market structures must allow power generators to make a sufficient return on capital, both for state-owned utilities and those needing to attract private capital. Second, the development of new coal-fired power plants depends on there being sufficient supporting infrastructure, such as railways. Third, the average cost of capital in India and Southeast Asia is high, making it difficult to obtain financing on acceptable terms and pushing investment decisions toward cheaper low-efficiency technologies.

Box 3.3 ▷ Developments in financing coal-fired power plants

In 2013, several international financial institutions – including the World Bank Group (WBG), European Investment Bank (EIB), European Bank for Reconstruction and Development (EBRD), US Export-Import Bank and UK Exports Credits Guarantee Department – set new rules that will reduce lending for new coal-fired power plants. This change was motivated by the climate change implications of locking in over the long term CO_2 emissions from new coal-fired capacity.

While the World Bank's new policy does not preclude financing coal-fired plants, its updated energy sector policy states "WBG will provide financial support for greenfield coal power generation projects in rare circumstances". Coal projects will be financed only after full consideration of viable alternatives to the least-cost options and when additional financing from donors for the incremental cost of preferred alternatives is not available. Previously, in June 2013, the EIB published a revised energy review, in which it set an emission performance standard of 550 grammes of CO_2 per kilowatt-hour (g CO_2/kWh), a de facto requirement for carbon capture and storage, allowing exceptions for new builds on small islands and for substantial contributions to poverty alleviation. Similarly, EBRD's energy policy, amended in December 2013 is that it will not finance investment in coal except in rare and exceptional circumstances, where there are no feasible alternative energy sources.

Forgoing capital from these international financial institutions should not have a major impact on the ability to finance coal-fired power plants. Over the past two decades, they have contributed \$37 billion, or around one-third, of coal power financing by international public financiers, but this is only a small share of overall investment over the period (WRI, 2012). However, financing could be more significantly affected if other banks move in the same direction. Other development banks, e.g. Korea Development Bank, the Asian Development Bank or the Japan Bank for International Cooperation, do not have restrictions on funding coal-related investments provided they are equipped with the best technology, but a growing number of commercial banks and sovereign wealth funds are reconsidering their policies in this respect.

While increased investor awareness of climate-related issues is a positive development, policies deliberately adverse to coal may have unintended consequences. In the 450 Scenario, which limits the global average temperature increase to 2 °C, world investment in coal-fired capacity totals \$1.9 trillion (25% higher than in the New

Policies Scenario), of which $800 billion is for plants fitted for carbon capture and storage (CCS). Coal-fired power plants become more expensive on average because, in most regions, more efficient technologies are deployed, as well as greater emphasis on CCS technologies. If development banks withhold financing for coal-fired power plants, countries that build new capacity will be less inclined to select the most efficient designs because they are more expensive, consequently raising CO_2 emissions and reducing the scope for the installation of CCS. In addition, many of the countries that build coal-fired capacity in the 450 Scenario need to provide electricity supply to those who are still without it, a problem that may be resolved less quickly if investment in coal-fired power plants cannot be financed.

Inadequate infrastructure to produce and deliver input fuel poses a threat to investment in new coal-fired generation capacity in both regions. In India, constraints on the availability of coal due to limited transport infrastructure and inadequate production have meant some power plants have had insufficient supplies to run at the level needed to meet electricity demand. In Southeast Asia, maintaining or expanding domestic coal production will necessitate investment in transport infrastructure to tap resources further inland.

The movement of coal to power plants in India depends heavily on the rail network, which delivers around 70% of total coal consumed. Booming demand in recent years has seen coal transport by rail increase by 7-8% annually. However, because the railways operate today at full capacity, additional future coal consumption (by power plants or otherwise) must be matched by an increase in rail capacity. Estimated investment needs to deliver coal are some $35 billion over 2014-2035, about 10% of the amount that is needed to build new coal-fired generation capacity. Around one-quarter of the investment must be made before 2020, a period in which Coal India, the key state-owned mining company, already has plans to build three rail lines that together will cost between $1.4-1.8 billion.[7]

Additional port infrastructure to enable India to receive increasing coal imports will eventually be needed, though existing capacity provides some room for growth. Nonetheless, existing ports will need to be upgraded or modernised in the short and medium term to improve rail connectivity (to distribute coal inland), to accommodate larger vessels (such as Capesize or Panamax type), to improve productivity and to expand onsite storage capacity. In the longer term, with India set to become the world's largest importer of coal, investment will be needed in more capital-intensive and longer lead-time port projects, costing an estimated $7 billion over 2014-2035.

7. These rail projects include the 92 kilometre (km) Tori-Shivpur line (connecting to the North Karanpura coal fields) with a capacity of 80 million tonnes per annum (Mtpa), the 52 km Juharsuguda-Barpalli line with a capacity of 30 Mtpa (Ib Valley) and the 180 km Chhattisgarh line with a capacity of 40 Mtpa (Mand-Raigarh and Korba). The areas to be connected have much larger production potential than the rail infrastructure that is currently planned. If production were to be ramped-up further, it would have to be done in phases and require further expansion of the rail network.

In Indonesia, investment in additional transport infrastructure will be essential to bring inland coal resources to market. To date, most of Indonesia's coal production has taken place in coastal areas where it can be barged cheaply to ports and loaded onto bulk carriers. The need for expensive inland transport infrastructure such as rail and roads has been minimal, keeping investment costs low and allowing a fast increase in Indonesia's coal output. However, with the depletion of resources along the coast, companies will have to move inland to tap coal resources for both the fast-growing domestic market and export. This will require more substantial and long-term investments than in the past, highlighting the importance of creating and maintaining a stable policy framework. Infrastructure challenges in other Southeast Asian countries that are coal importers more closely resemble those of India. As coal imports rise, they may need to invest in infrastructure to deliver the coal to power plants.

There are ways to minimise coal transport infrastructure needs in both regions by locating new coal-fired plants more strategically. For example, plants designed to run on imported (or domestically shipped) coal could be located near the coast – this is already happening with several large projects in India. Alternatively, new plants could be located at the mine mouth and deliver electricity to consumers over an expanded transmission network. Coal washing, which improves the energy density of coal, could also reduce the scale of transport infrastructure needs, though the right price incentives will be needed and water must be available.

The cost of capital has been rising in emerging economies in Asia, including India and Southeast Asia. In India's power sector, for example, the average cost of capital – the weighted average of the cost of equity and the cost of debt – is around 15% (Ernst & Young, 2013). This is contrary to recent trends in many OECD countries, where expansive monetary policies have helped drive down interest rates. Relatively high levels of inflation and perceived risk in the power sector are the two main factors pushing up the cost of capital in India and Southeast Asia. Higher perceived risks lead domestic and international investors to demand higher returns than for comparable investments elsewhere.

An elevated cost of capital tends to shift investment decisions to less capital-intensive technologies. In the case of coal-fired generation, this pushes investment decisions towards low-efficiency technologies. Subcritical coal-fired power plants in India and Southeast Asian countries operate with a low average efficiency of around 30%. Relative to high-efficiency ultra-supercritical coal-fired generation, subcritical plants have higher operating costs, but their capital costs are about 30% less. Based on these characteristics, investment in subcritical plants becomes more attractive than ultra-supercritical plants when the cost of capital is higher, exaggerating the difference in up-front investment costs. This one factor helps to explain why more than 80% of coal-fired capacity built in India during the last decade has been based on subcritical technologies, and why the same applies to 65% of coal-fired capacity under construction in Southeast Asian countries. Reducing the cost of capital by cutting inflation or improving power sector finances would help shift technology choices towards higher-efficiency plants.

Investment in non-hydro renewables

The installed capacity of renewable energy technologies, excluding hydropower, has been increasing rapidly in India, while in Southeast Asia onshore wind and solar PV have only just begun to be deployed, supplementing several gigawatts of installed geothermal capacity. In India, non-hydro renewables have been an important component of recent capacity expansion, diversifying the power mix and reducing pressure on domestic primary energy resources. During the periods covered by the 10th and 11th Five-Year Plans in India, non-hydro renewables (including onshore wind power, solar PV and bioenergy) have been the only technology group to exceed installed capacity goals. The private sector has made the greater part of these investments and own 85% of installed non-hydro renewables capacity, with a significant contribution coming from FDI, in part through the Kyoto Protocol's Clean Development Mechanism.

Investment from the private sector has been incentivised by a variety of policy measures, the most important being long-term power purchase agreements between utilities and private project developers. These provide project developers with greater certainty about revenue flows, providing a basis for obtaining finance. Utilities are motivated to engage in these agreements by renewable purchase obligations, as established by the state electricity regulatory commissions. Some renewable energy projects are also being developed based on the additional value prospect of renewable energy certificates (RECs). Power generated by these projects will be sold to utilities at rates comparable to rates for conventional sources, with additional revenues earned by selling RECs on power exchanges.

Looking to the future, India plans to build on the momentum of its recent successes of deploying large amounts of non-hydro renewables, while Southeast Asia steps up the deployment of these technologies. In the New Policies Scenario, cumulative investment needed in non-hydro renewables in Southeast Asia is $92 billion from 2014-2035, out of $435 billion invested in power plants. Of the $92 billion invested, around 40% goes to new solar PV capacity and nearly all the remainder is divided equally between onshore wind and geothermal. In India, non-hydro renewables require investment of $340 billion from 2014-2035, more than one-third of total power plant investment. This is based on average annual capacity additions of nearly 8 GW through 2025 and closer to 13 GW/year from 2026-2035 (Figure 3.21). Wind and solar are the most important non-hydro renewable energy technologies in this case, with generation from these two technologies combined increasing from 2.6% today to 11% in 2035.

Investment from the private sector will continue to flow as long as the prices paid for renewables-based power generation remain favourable. In 2013, India's restrictions on the amount of FDI to the power sector were lifted, expanding potential access to the market of private sector funds. The main threat to the continued expansion of non-hydro renewables in India is the financial stability of the utilities selling directly to consumers, particularly the state-owned utilities. If the revenue gap persists, these utilities will eventually not have the funds to meet purchase obligations for renewable energy. This underscores the critical importance of improving the financial situation of these utilities.

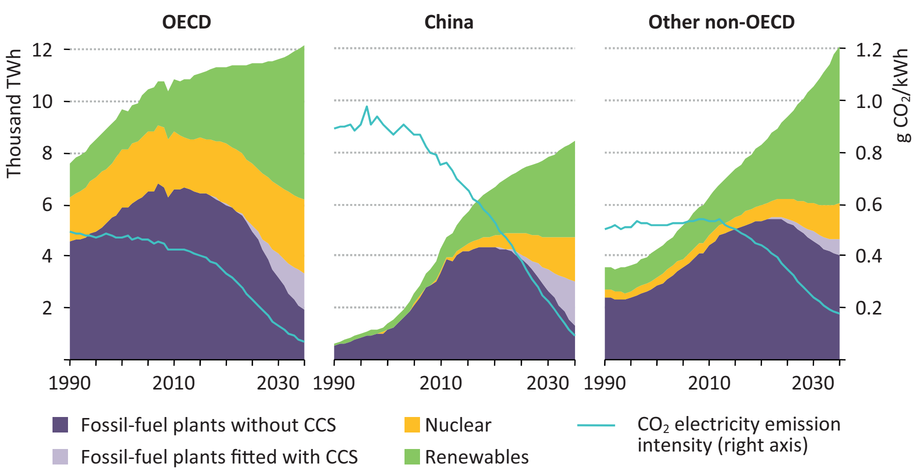
Trends in the 450 Scenario

Clear government policies and measures reflect the strong and stable commitment in the 450 Scenario to ensure that emissions are consistent with limiting the long-term rise in the average global temperature to two degrees Celsius (see Box 1.4 in Chapter 1). The most relevant steps towards reducing the climate impact of the power sector include:

- Efficiency measures in end-use sectors that temper electricity demand growth and new generation needs.
- Worldwide limits on the use and construction of the least-efficient power generation technologies from 2015, in particular coal-fired capacity.
- In all OECD countries and other major economies, carbon pricing in the power sector, introduced by 2020 or strengthened where it is already in place and reaching up to \$125/tonne CO_2 in 2035.
- Measures that support the development and deployment of less mature low-carbon technologies, such as some types of renewables and carbon capture and storage.

In the 450 Scenario, global electricity generation in 2035 reaches 32 800 TWh, an increase of 45% over today's levels. Efficiency measures in buildings and industry temper demand growth, but the increased electrification of transport pushes demand upward: in OECD countries, transport accounts for two-thirds of electricity demand growth. In 2035, more than three-quarters of electricity is generated by low-carbon technologies (including renewables, nuclear and CCS), two-and-a-half times the current share (Figure 3.22).

Figure 3.22 ▷ Electricity generation by technology and CO_2 intensity in the 450 Scenario



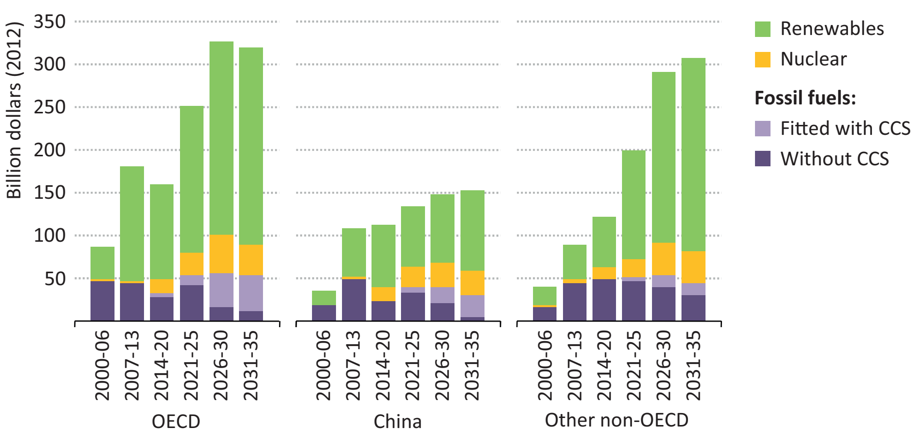
Through to 2035, cumulative capacity additions exceed 6 900 GW, almost one-quarter higher than in the New Policies Scenario, despite lower electricity demand. A higher level of additions are partly the result of the early retirement of old, inefficient coal plants and partly from such a high share (about 50%) of incremental additions being variable renewables (wind and solar PV) with low capacity credits. Average annual additions of low-carbon technologies triple, from about 120 GW today to around 360 GW/year towards 2035. They account for more than 95% of annual capacity additions by that time.

Investment requirements

Power sector investment totals $19.3 trillion from 2014-2035, almost one-fifth more than in the New Policies Scenario. Annual investment in power plants grows steadily over time, doubling from $420 billion today to $780 billion late in the period. Investment needs increase at a faster rate than capacity additions due the deployment of more capital-intensive technologies. Additional up-front costs are more than offset by lower fuel costs.

Globally, annual investment in renewables more than doubles, from $270 billion to $555 billion (70% of total investment in 2035), representing almost two-thirds of the overall investment needs (Figure 3.23). Stable government commitments to support the deployment of renewables are needed until they become mature and can compete with other technologies in the market. This situation is reached earlier in the 450 Scenario, as the increased deployment of renewables drives more cost reductions and the widespread implementation of CO_2 prices raises costs for fossil-fuelled power plants. The scale-up of renewables investment depends also on the development of technologies that are less mature, such as CSP, geothermal and marine energy. Investment in these technologies grows from $11 billion today to $120 billion in 2035. Investments in offshore wind also increase dramatically, from $7 billion today to around $70 billion. Those levels of deployment can materialise only if strong research, development and demonstration (RD&D) occurs through 2020 (IEA, 2014b).

Figure 3.23 ▷ Average annual investment in power plants by type in the 450 Scenario



Over the period to 2035, investment in fossil-fuelled power plants remains at levels similar to today, around $130 billion/year, but with a different distribution across technologies.

In 2035, almost 90% of investment in fossil-fuelled plants goes into either those equipped with CCS (60%) or highly-efficient coal- and gas-fired power plants (almost 30%); together these account for less than 70% of investment today, with very little going to CCS projects. Investment in coal-fired power plants averages $85 billion/year over the projection period. This is 25% higher than in the New Policies Scenario because, though capacity additions are similar, there is a shift towards more expensive coal-fired technologies, those incorporating CCS technology and those with the highest efficiencies and lowest carbon emission rates, including ultra-supercritical and integrated gasification combined-cycle designs.

Policies to limit carbon emissions in the 450 Scenario lead to the early retirement of a substantial amount of old, inefficient capacity; almost 60% of current installed coal-fired capacity is retired before it reaches the end of its technical lifetime. In 2035, 63% of fossil-fuelled plants fitted with CCS (365 GW) are plants that have been retrofitted. Retrofitting fossil-fuelled plants – in particular coal-fired power plants – is essential to limit the failure of assets to recover their investments costs. Globally, some 165 GW do not repay their investment cost, or 8% of the total capacity that is either retired early, idled or retrofitted with CCS (IEA, 2013b). As in the case of less mature renewables, only a strong effort on RD&D through 2020 will generate investment to support this level of deployment.

Nuclear capacity doubles over the projection period, reaching almost 800 GW, thanks to government measures, including the introduction in several regions of CO_2 pricing that improves nuclear economics, and government support, including long-term power purchase agreements. Annual investments increase eight-fold during the projection period, reaching about $100 billion in 2035. While high upfront investment costs and the relatively high cost of capital remain crucial hurdles to the deployment of nuclear power, the additional problem of reduced revenues arises in the 450 Scenario due to the high share of variable renewables in some regions. These high shares mean that, at times, the amount of renewables generation will be very high compared with electricity demand, requiring nuclear power plants to adjust their output. When these adjustments decrease the number of hours of operation at maximum capacity, revenues may be reduced. In the 450 Scenario, the regions with high shares of nuclear and variable renewables in the electricity mix are Europe and Japan, followed by China, India and South Africa.

Worldwide transmission and distribution investment amounts to $5.9 trillion over 2014-2035. Average annual spending is relatively flat, at $250 billion, during the first 15 years, increasing towards the end. Slower electricity demand growth requires less network growth and leads to lower cumulative investment requirements ($1 trillion) than in the New Policies Scenario. This reduction outweighs higher renewables integration costs, which amount to $450 billion, or 8% of total investment in T&D infrastructure in the period (compared with 4% in the New Policies Scenario). Investment for renewables integration rises quickly over the period 2020-2030, when most of incremental generation comes from renewables, in particular wind and solar PV. T&D networks play a crucial role in smoothing the variability of some renewables and accommodating increased distributed generation.

Implications for financing

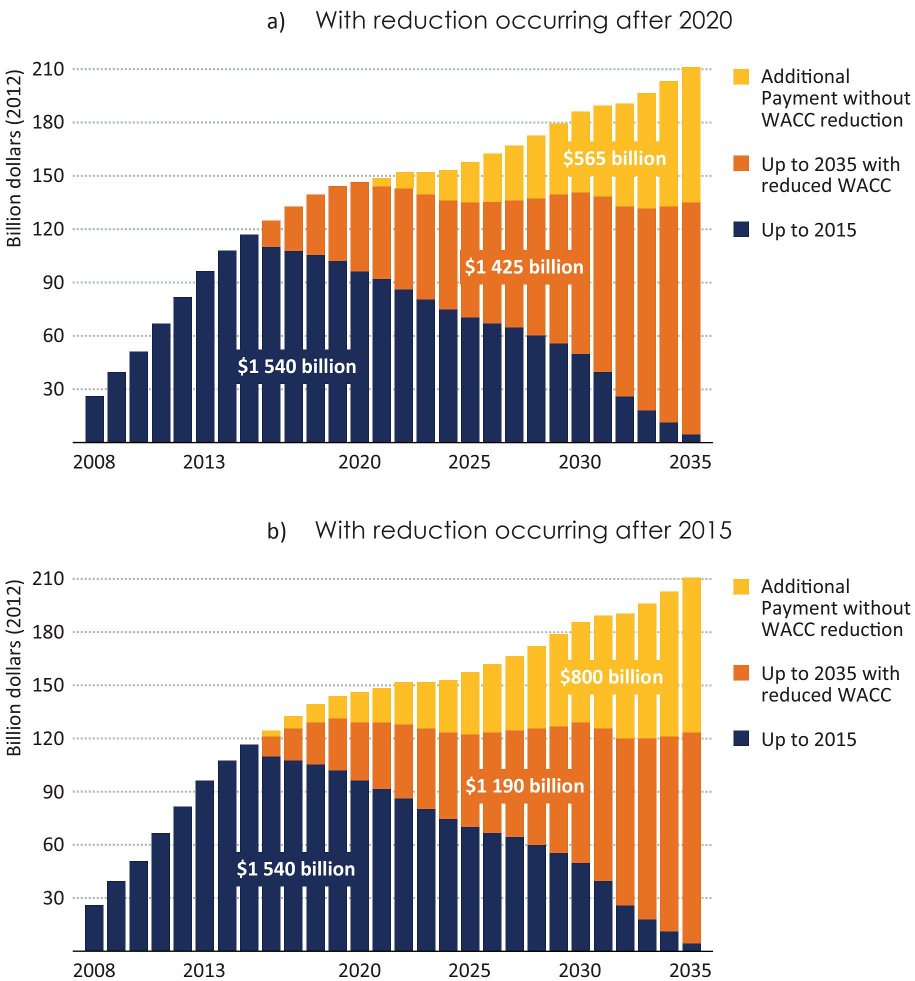
To attract the level of investment needed to transform the global power sector in the 450 Scenario, stable government commitments are needed to support the deployment of low-carbon technologies, including variable renewables, together with market designs or reforms that also provide adequate returns on investment in conventional power plants. Reforms currently under consideration need to ensure that new measures are consistent with a low-carbon future, thereby avoiding the lock-in of undesirable capacity. Banning the construction of new inefficient and polluting power plants, such as subcritical coal (one of the key measures in place to the 2020 horizon), and phasing out existing ones are important first steps, though, to make them fully effective, a simultaneous effort should be made to push efficient electricity use. Market designs need to provide the signals necessary to attract sufficient investment in conventional power plants in order to ensure system stability (see earlier Focus on the European power sector).

Financing will not be a constraint if the power sector appears to offer both sufficient returns and stability. Revenues from the power sector provide adequate returns in the 450 Scenario on the assumption that markets undergo the necessary reforms. The increase in revenues is less than the required increase in investment, which indicates a need for expanded access to capital markets. Compared with traditional financing, an increase in the use of public capital (through debt or equity) can reduce the weighted average cost of capital (WACC) for renewable energy technologies (NREL, 2013). Other changes can also help reduce the cost of capital, lower the cost of producing electricity from a given technology and reduce the need for subsidies (especially in the case of some renewable technologies and CCS). In high-risk investment environments, such as in some non-OECD countries, these include greater political stability, improved regulatory systems and greater market transparency. In lower risk markets, including those in OECD countries, there are opportunities in the marketplace to lower both the cost of debt and equity. More participation from bond markets in project refinance and the expansion of securitisation offer pathways to lower the long-term cost of debt, while additional interest of institutional investors in project equity would increase competition and drive down the cost of equity.

Reducing the cost of capital could have major implications for low-carbon technologies, given that many are capital intensive and require significant upfront investment. For example, measures that cut the cost of capital by three percentage points could lead to a 25% reduction in the levelised cost of electricity generation for nuclear and 15% for coal CCS, depending on the particular technology and region. The impact on renewables varies widely, depending on the technology and region, though the reductions in the levelised cost for wind and solar PV are generally of the order of 20%. While other objectives, such as minimising system costs and providing efficient incentives need also to be considered by policymakers, reductions of this order would make such technologies attractive to investors (see earlier section on implications for current financing models), thereby reducing costs and fostering deployment. Lower capital costs would also help less mature and (presently) costlier technologies close the gap with other generating technologies, making them competitive earlier and reducing the need for additional subsidies.

In the 450 Scenario, subsidies to renewables amount to \$3.5 trillion cumulatively over 2014-35, a level similar to the New Policies Scenario, despite 60% higher electricity generation from non-hydro renewables. This is because higher CO_2 prices in the 450 Scenario lead to an increase in wholesale prices, which improves the economics of low-carbon technologies. However, higher electricity prices have a negative impact on industrial competitiveness in several regions, such as Europe (where CO_2 prices are the highest), as well as on the affordability of electricity consumed by households. In some regions, subsidies to renewables create additional upward pressure on prices.

Figure 3.24 ▷ Implications of a reduced weighted average cost of capital on subsidies to renewables in the 450 Scenario



If the average WACC for renewables were reduced by three percentage points after 2020,[8] the subsidies needed to support the deployment of capacity built thereafter would be reduced by $565 billion over 2020-2035 (Figure 3.24). If the reduction of the WACC was introduced five years earlier, it would result in savings of some $800 billion, or 40% of the additional subsidies for new capacity built after 2015. Where they are applied to end-user prices, subsidies for renewables account for only a fraction of electricity prices, but reducing them would nonetheless help lower electricity tariffs, boosting the competitiveness of industry and improving the affordability of electricity for households.

8. For the purpose of this analysis the deployment of renewable technologies is kept equal to the level reached in the 450 Scenario.

Investment in energy efficiency

Are current investments efficient enough?

Highlights

- Current investment in improving energy efficiency above the average level in 2012 is estimated to be around $130 billion/year, which is equivalent to one-fifth of power sector investment or 13% of fossil fuel investment. Multiple hurdles complicate an expansion of energy efficiency investment: small project size, high transaction costs and fossil-fuel subsidies.
- Global energy efficiency investment in the New Policies Scenario more than quadruples, to $550 billion in 2035; it totals $8 trillion cumulatively over the period. The European Union (27%), North America and China (each 20%) account for the bulk, reflecting their share in global final energy consumption, policies in place and remaining efficiency potential. Developing Asia (excluding China) accounts for just 6% of efficiency investment, highlighting the need for a well-functioning local banking sector and targeted efficiency policies, plus phasing-out fossil-fuel subsidies.
- In the New Policies Scenario, households need to make about half of total investment, businesses about 40% and governments 11%. While governments can borrow capital at the lowest cost, the world's 2.1 billion households tend to finance efficiency improvements via savings or bank loans. Mobilising necessary financing is a huge task given the low priority afforded to energy efficiency and prevailing economic preoccupations in many regions. We estimate that, in the period to 2020, almost 60% of the investment could be self-financed, mainly by households and businesses. Capital markets, either in the form of debt (bonds) or equity, today play a small role. However, aggregating loans for efficiency assets offers an opportunity to increase the role of capital markets in energy efficiency financing.
- More than 60% of total investment is in the transport sector, as a result of increased efficiency standards for new vehicles, and the sheer volume of vehicles — three billion — affected over the period to 2035. About 30% of efficiency investment is destined for the buildings sector and the remainder for industry. Almost two-thirds of transport investment aims to increase the fuel efficiency of cars, while most of the measures in industry aim to boost efficiency in furnaces, steam systems and motors. Efforts in the buildings sector largely aim to reduce the need for space heating and cooling by insulating new buildings and retrofitting existing ones.
- Energy sector decarbonisation requires an increase of more than eight times from the current level of annual efficiency investment, reaching $1.1 trillion in 2035. Financing from capital markets needs to increase significantly. In the 450 Scenario, spending per household on efficiency in 2035 is four times the level of today; while average household income grows by only 50%, fuel savings outweigh additional investment.

Introduction

Energy efficiency is an essential part of a sustainable energy future. It helps reduce energy consumption. It also drives economic growth, creating jobs and investment opportunities, reduces greenhouse-gas emissions and air pollutants, lowers fuel expenditures and enhances energy security (IEA, 2012). Unlike, for instance, the market for oil and gas, the market for energy efficiency is not well-defined. Opportunities for energy efficiency are widely dispersed, covering a range of end-use sectors and technologies and involving a great number and variety of often relatively small projects. The market is not simple to quantify, since it requires establishing a baseline from which effectiveness can be measured. Nonetheless, stakeholders across the energy sector are increasingly realising the extent of untapped opportunities for energy efficiency improvements.

Current trends

Energy efficiency investment is notoriously difficult to track because it is carried out by a multitude of agents, households and firms, often without external financing. It often constitutes only a portion of broader investment and is not accounted for explicitly. Assessing efficiency investment is further complicated by the definitional and data quality issues related to energy consumption in various end-uses. While there is steadily increasing interest in energy efficiency by decisionmakers, financial institutions and energy consumers, there is no systematic, standardised tracking of energy efficiency investment.

With that reservation, and on the basis of the definition in Box 4.1, this report estimates current annual investment to be on the order of $130 billion. Several other sources have estimated the size of the global energy efficiency market to be between $124 billion and $712 billion annually (Table 4.1). These estimates compare to investments in 2013 of roughly $900 billion in the oil and gas industry and about $650 billion in the power sector, of which $240 billion were made in renewable energy sources (see Chapters 2 and 3). On the basis of our estimate, efficiency investments are 15% the size of the investments in oil and gas and about half of renewable investments.

The large range in estimates of efficiency investment derives principally from differences in estimation methods and definitions. The IEA used a top-down approach for both the *World Energy Outlook 2012* (*WEO-2012*) and the *Energy Efficiency Market Report 2013* (IEA, 2013a), while this report uses a bottom-up approach as explained in Box 4.1. To estimate private investment, various regional leverage ratios[1] were applied to public funds, as such funds typically mitigate risks and build trust, thus encouraging private investment. However, leverage ratios are based on generic investment data and therefore the specific levels cannot be determined precisely. Relatively small changes in the assumptions on leverage ratios have significant effects on the estimate of the scale of investment in energy efficiency. In addition, bank reporting on energy efficiency is not standardised: sometimes it includes total investment in end-use equipment, rather than the additional investment in efficiency.

1. In this context, the leverage ratio describes how much private finance is generated by public funds.

Box 4.1 ▷ Defining energy efficiency investment

No standardised definition of energy efficiency investment exists for uniform application by governments, academia and financial institutions. For the purposes of this report, energy efficiency investment is defined as the additional expenditure made by households, firms and governments to improve the performance of their energy-using equipment above the average efficiency level of that equipment in 2012. To illustrate, in the case of a refrigerator, the baseline in 2012 is assumed to be an A++ refrigerator (annual electricity consumption: 230 kilowatt-hours [kWh]) costing $800. A family replacing this refrigerator in 2020 buys an A+++ refrigerator (annual energy consumption: 150 kWh) costing $950, so the investment cost related to improving energy efficiency is $150 (all prices in constant dollars) per refrigerator.

To calculate energy efficiency investment on this basis, we have made use of the extensive technology detail in the World Energy Model (IEA, 2013b). Analysis of investment cost, stock turnover and the economic return required across sub-sectors in industry, across modes in transport and across end-uses in buildings, has enabled us to estimate current levels of investment and to project future investment needs. Efficiency levels and their associated investment costs vary by region and technology. These factors have been updated for this report and verified via a survey sent to key stakeholders in industry, academia and research bodies.

Energy efficiency investment covered here includes improvements achieved through more efficient technologies (such as more efficient vehicle engines), better insulation of buildings or implementation of improved energy management systems, for example in industrial processes. They are categorised in three end-use sectors: buildings, covering residential and non-residential buildings (also known as the services sector); transport; and industry.[2] Investment in fuel supply or the transformation sector are not included here but are covered in Chapters 2 and 3. Energy savings resulting from fuel switching (for example, replacing individual gas-fired boilers with district heating or using an electric vehicle instead of a gasoline one), with a modal shift in transport or through behavioural change are also not counted here as energy efficiency investment, even if, in practise, they increase the energy efficiency of the system. Nor do we include capital expenditure for research and development of energy-efficient technologies.

Investment costs include the additional cost for the more efficient product or measure (including taxes and freight costs) and the labour costs that are directly related to an installation. Additional costs related to administrative procedures, legal protection and border clearance are also included in the cost estimate.

2. While there is potential for energy efficiency improvement in agriculture, the sector, which accounts for only 2% of global final energy consumption today, is not included in this analysis.

On the other hand, Grubler, et al. (2012) used a bottom-up method to estimate the efficiency market by analysing the most common end-use technologies and determining how much investment was going into the energy-using component. HSBC (2014) used a similar approach, but separated out the value of the component that delivers improved energy efficiency. Difficulties associated with this approach concern the adequacy of the selection of technologies considered and the reliability of the quantification of the investment cost of the diverse set of end-use devices. BNEF (2014) and CPI (2013) estimate current efficiency investments at $35 billion and $32 billion, respectively. However, both sources report only part of the efficiency market: BNEF cites only publicly reported efficiency investment, while CPI reports only public investment as part of wider climate finance.

Table 4.1 ▷ Estimates of current size of the global energy efficiency market

Estimate	Source	Comment
$130 billion	this report	Estimate refers to energy efficiency investments by end-users in 2013 to increase the efficiency of devices above the 2012 stock efficiency level.
$147-300 billion	IEA (2013a)	Estimate refers to 2011. It is based on surveys and interviews with public and private banks, using a leverage ratio for private capital where data were not available. The *World Energy Outlook 2012* (IEA, 2012) used $180 billion as a best estimate.
$365 billion* ($330-410 billion)	HSBC (2014)	Estimate refers to 2012 and includes capital expenditures in the purchase of equipment in transport, buildings and industry that were categorised as efficient. The estimate is based on significantly higher building retrofit rates than those used in this report.
$298 billion* ($124-712 billion)	Grubler, et al. (2012)	Estimate refers to 2012 and includes investment for "selected energy-using components" across a set of end-use technologies in transport, buildings and industry by contrast with investment for "efficiency improvements of such components" (a narrower definition) used in this report.
$200 billion	BCC Research (2011)	Estimate refers to 2010 and includes efficiency investments and combined heat and power (CHP), waste-to-energy and smart meters.

* This is the central estimate of the range provided in the brackets.

Another issue concerns where to draw the line when accounting for energy efficiency. For example, in the case of vehicle efficiency, does one consider the whole car, the engine only or the part of the car that makes it more efficient only? For this report, energy efficiency investment is defined as that which is needed to increase the efficiency of a device above a baseline level. For a vehicle this includes, among others, low-resistance tyres, light-weight materials and direct fuel injection. It is not easy to make this distinction. Reporting from public banks and other sources sometimes gives total investment in end-use technologies, which results in larger values being attributed to efficiency-related investment. It is also difficult to include all sectors in making an estimate of efficiency investment. For instance, banks may report efficiency investment in industry and buildings, but few estimates exist that include financing in transport. A factor that can contribute to under-reporting is that efficiency improvements are often carried out as part of normal business activity, and not accounted for separately.

Trends in the New Policies Scenario

Quantifying investment requirements

In the New Policies Scenario – our central scenario that includes policies in place and those announced – global final energy consumption increases on average by 1.2% per year in the period 2012-2035, resulting in energy demand being one-third higher in 2035 compared with 2012 (Table 4.2). This compares to an average annual growth rate of 1.7% since 1990. This slower rate of energy demand growth reflects economic restructuring, energy efficiency gains, less energy-intensive production methods in industry and saturation effects, particularly in the transport and residential sectors in OECD countries.

Table 4.2 ▷ World final energy consumption by sector in the New Policies Scenario (Mtoe)

	1990	2012*	2020	2025	2030	2035	2012-2035**
Buildings	2 228	2 929	3 171	3 337	3 513	3 691	1.0%
Industry	1 813	2 607	3 063	3 254	3 391	3 541	1.3%
Transport	1 581	2 478	2 840	2 999	3 157	3 322	1.3%
Non-energy use	479	818	991	1 069	1 131	1 183	1.6%
Agriculture	181	196	221	233	244	253	1.1%
Total	**6 281**	**9 028**	**10 285**	**10 892**	**11 436**	**11 990**	**1.2%**

* 2012 data are preliminary estimates. ** Compound average annual growth rate.

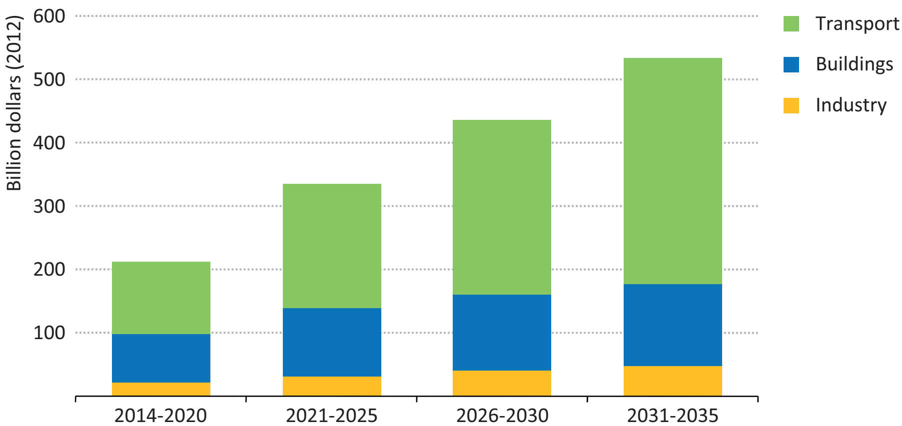
Note: Mtoe = million tonnes of oil equivalent.

The buildings sector is the largest energy-consuming sector today, accounting for more than 30% of total final energy consumption, about three-quarters of which is consumed in households. Industry makes up just less than 30% of total final energy consumption. The transport sector represents 27%, followed by non-energy use (9%) and agriculture (2%). Non-energy use covers petrochemical feedstock, as well as asphalt and lubricants, where energy efficiency opportunities are very limited.

Over the past three years, average oil prices have been at the highest level in history, and natural gas prices have been high in Europe and Asia. This has renewed interest in energy efficiency in many countries, while energy security concerns and pressing local air pollution problems have sparked related action in others. A range of new policies have been put in place to limit future energy demand growth in passenger and freight vehicles, industrial processes, as well as tighter building codes and stricter standards for appliances (IEA, 2013c).

In the New Policies Scenario, average annual energy efficiency investments grow to $530 billion in 2031-2035 across the transport, buildings and industry sectors, an amount higher than Sweden's GDP today. Cumulative investment over the projection period – $8 trillion – is distributed unevenly across sectors: 62% goes to improve the performance of vehicles, trains, aircraft and ships; 29% to improve energy efficiency in buildings; and 9% for industrial energy efficiency projects (Figure 4.1).[3]

Figure 4.1 ▷ Average annual investment in energy efficiency by sector in the New Policies Scenario



The transport sector dominates energy efficiency investment in the period to 2035 for two reasons: the sheer volume of new, more-efficient cars and trucks sold over time and high unit investment costs compared with other end-use sectors. Industrial energy efficiency investment is low relative to buildings and transport as unit investment costs are less expensive and most of the efficiency improvement occurs during stock turn-over, which is comparably slow.

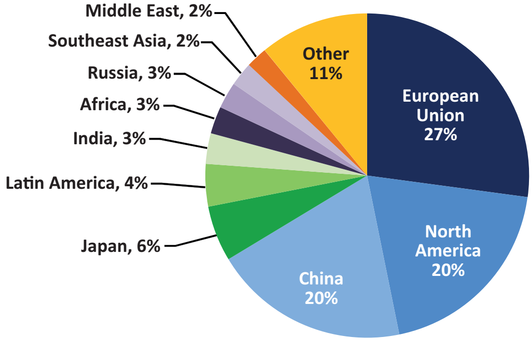
The growth in total energy efficiency investment from around $210 billion/year in the period to 2020 to around $530 billion/year after 2030 reflects two factors: more energy-consuming cars, furnaces and washing machines are sold; and, targeted policies and market forces

3. Taking 2012 as the baseline against which we measure progress in energy efficiency means the sums attributable to energy efficiency investment increase each year as technological progress occurs. This could be corrected for by using a moving baseline incorporating what is called "autonomous energy efficiency improvements". Using the technological progress built into the *WEO* Current Policies Scenario, which incorporates only policies in place, as a proxy for such autonomous efficiency improvements results in efficiency investment of $3.3 trillion from 2014-2035 in the New Policies Scenario. This indicates that up to 60% of the investment measured against 2012 is techno-economically driven; the rest is driven by energy efficiency policy. The Current Policies Scenario is, however, an imperfect baseline as it already incorporates existing policies. Taking this scenario as a baseline underestimates the policy-driven component of the investment.

make end-use devices more efficient, i.e. they consume less energy while providing the same energy service, but at increasing marginal cost.

In this analysis, three regions dominate global energy efficiency investment in the period to 2035: the European Union (27%), North America[4] (20%) and China (20%) (Figure 4.2). This partly reflects the magnitude of their current energy consumption: the European Union accounts for 13% of today's global final energy consumption, North America for 20% and China for 19%. It is also partly a consequence of their current and planned energy efficiency policies. These three regions represent the world's largest car markets and all have adopted stringent fuel-economy standards or emissions targets for personal light-duty vehicles (PLDVs) and, in some cases, for light-commercial vehicles and trucks. The European Union and United States introduced energy labelling for household appliances in 1992; moreover, the European Union requires new buildings to be "nearly zero-energy" from 2020. In industry, China includes numerous efficiency policies to limit the sector's energy demand growth in its 12th Five-Year Plan.

Figure 4.2 ▷ Regional share in cumulative global energy efficiency investment in the New Policies Scenario, 2014-2035



These three regions account for two-thirds of cumulative global efficiency investment, while many other regions account for far less investment than their share in final energy consumption. India and Africa constitute only 3% each and the Middle East and Association of Southeast Asian Nations (ASEAN) countries 2% each. Underlying the comparatively low level of investment is the reduced amount of current capital stock, relative to OECD countries, and climatic conditions, which require less space heating. Additional factors are the lack of stringent and targeted efficiency policies, the absence of functional local banking in some countries and the persistence of fossil-fuel subsidies (which make investments in energy efficiency less attractive).

4. In this context, North America includes Canada, the United States and Mexico.

Box 4.2 ▷ **Energy efficiency financing in Southeast Asia**

Energy efficiency can make a key contribution to meeting energy, environmental and economic challenges in Southeast Asia. Yet it remains an untapped resource due to poor institutional frameworks, price distortions from fossil-fuel subsidies, high capital costs and insufficient information about energy efficiency (ADB, 2013). Given an environment of high economic growth, attention is often directed towards expanding energy supply and industrial production in order to increase revenue, rather than to cutting costs through energy efficiency. Investments in energy efficiency, however, would provide access to energy for more people with the same amount of energy supply and would reduce the need for energy imports, thus freeing up resources for alternative investment in education, health care and public transport. The *WEO Special Report: Southeast Asia Energy Outlook* found that overcoming barriers to energy efficiency investment could reduce oil imports by roughly $30 billion in 2035 (IEA, 2013d).

In the New Policies Scenario only 9% of total energy investment in ASEAN countries is dedicated to energy efficiency, compared with 16% at the global level. Nonetheless, annual efficiency investment in ASEAN countries increases by about three-and-a-half times from today's level, to about $14 billion by 2035. In order to mobilise the necessary funds, clear and consistent policy frameworks need to be devised, evaluated, implemented and enforced. Development banks have an important role to play in financing energy efficiency efforts through appropriate mechanisms.

Sectoral trends

Transport

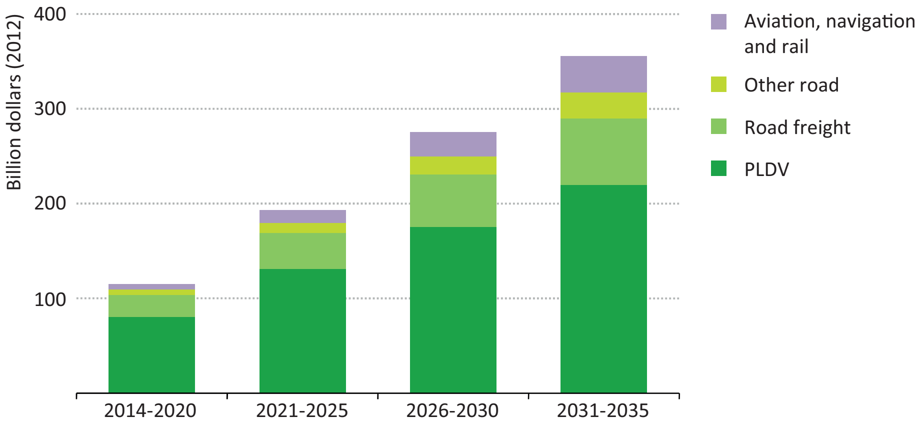
When discussing energy efficiency investment, the transport sector is often overlooked. Yet cumulative investments in transport account for more than 60% of all efficiency investment ($5 trillion in total) in the period 2014-2035 in the New Policies Scenario. Investment more than triples, from $115 billion/year in the period to 2020 to almost $360 billion/year from over 2031-2035 (Figure 4.3). This is a consequence both of growing sales of vehicles over time and of continuing and increasingly costly fuel-efficiency improvements, driven by ever stricter fuel-economy standards.

Each year some 80 million PLDVs are sold globally; by 2035, this figure rises to above 130 million. In the New Policies Scenario, increasing the average on-road efficiency of a new PLDV from 8 litres per 100 kilometres (l/100 km) in 2012 to around 6 l/100 km in 2035 results, on average, in an increase of $1 400 in the cost of the vehicle, leading to annual investment volumes above $100 billion. The efficiency improvements are achieved through a variety of measures, ranging from low rolling resistance tyres and aerodynamic improvements to the use of direct fuel injection and weight reduction, at costs from a few dollars to $700 per vehicle. Vehicle manufacturers make the initial investment, but ultimately consumers pay for the improvement.

Compared with other sectors, energy efficiency investment in the transport sector is significant not only because sales volumes are large but also because the cost per avoided-unit-of-fuel in road transport is much higher than in industry and, to some extent, in buildings. Diesel and gasoline prices, on an energy-equivalent basis, are significantly above what industry pays for coal or natural gas, incentivising the uptake of more costly energy efficiency measures in the transport sector.

Paying the cost of efficiency gains in PLDVs represents almost two-thirds of all transport-related investment. About four out of five vehicles on the road today are PLDVs, accounting for more than half of all road vehicle fuel consumption. In contrast to most other transport segments, PLDVs have been a focus of government regulation for many years, leading to stringent fuel economy and emissions standards via the Corporate Average Fuel Economy (CAFE) standards in the United States, the Top-Runner programme in Japan, fuel consumption limits in China and carbon-dioxide (CO_2) emissions standards in the European Union (IEA, 2013). The share of efficiency investment in non-road transport, mainly aviation, more than doubles over the projection period to 2035, both because of the substantial increase in air travel and the realisation of large parts of the efficiency potential.

Figure 4.3 ▷ Average annual investment in energy efficiency in transport in the New Policies Scenario



Notes: PLDV = passenger light-duty vehicles. Road freight includes light-commercial vehicles (<3.5 tonnes) and trucks (>3.5 tonnes).

In the period to 2020, markets in which car ownership is already high (including North America, Europe and Japan) account for around two-thirds of total energy efficiency investment in transport due to large volumes of vehicle sales and tight PLDVs standards. The United States, in addition, has recently introduced fuel-economy standards for trucks. After 2020, the share of efficiency investment in emerging markets increases due to fast-rising vehicle sales. China's share in global efficiency-related transport investment increases from 18% in the period to 2020 to 23% thereafter, with Latin America's share rising from

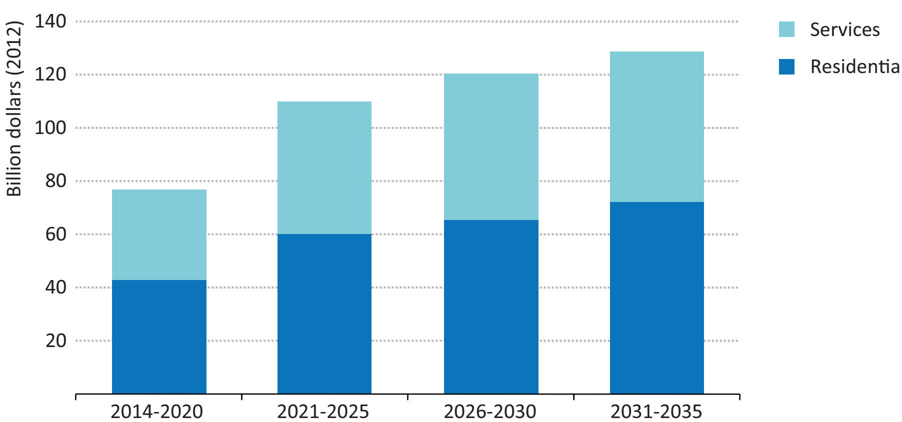
3% to 4% and India's from 2% to 3%. Since the market for PLDVs is global, with spill-over effects from one region to another, the costs per vehicle for efficiency improvements are comparable across regions. Their share in the average cost of a car, however, can vary significantly. Markets with small, less expensive cars, such as India, see a proportionally higher increase in total vehicle cost.

Sources of financing for more efficient vehicles are linked directly to how purchases are made. Today, vehicles are either self-financed from cash flow for businesses or from savings for households, or paid for by loans from the automotive industry or banks. Globally, about 60-70% of private vehicles and company cars are purchased from savings or cash flow, with the rest financed from loans. Sources of vehicle financing vary significantly from region to region, with company cars in Russia and China being almost completely self-financed, while in Western Europe loans make up 55% of company car purchases (KPMG, 2012). A strong uptake of electric cars (not counted here as energy efficiency, but as fuel switching) is expected to affect current financing models.

Buildings

The buildings sector (including the residential and services sectors[5]) accounts for around one-third of current global final energy consumption. Almost 30% of total cumulative energy efficiency investment in the New Policies Scenario is spent on buildings, with $1.3 trillion in the residential sector and $1 trillion in the services sector (Figure 4.4). While households account for three-quarters of the energy consumption in buildings, their share in efficiency investment is only 55%, with the services sector accounting for the rest. This imbalance reflects that the services sector uses more energy than households for lighting and cooling and these end-uses entail relatively more expensive efficiency improvements.

Figure 4.4 ▷ Average annual investment in energy efficiency in buildings in the New Policies Scenario

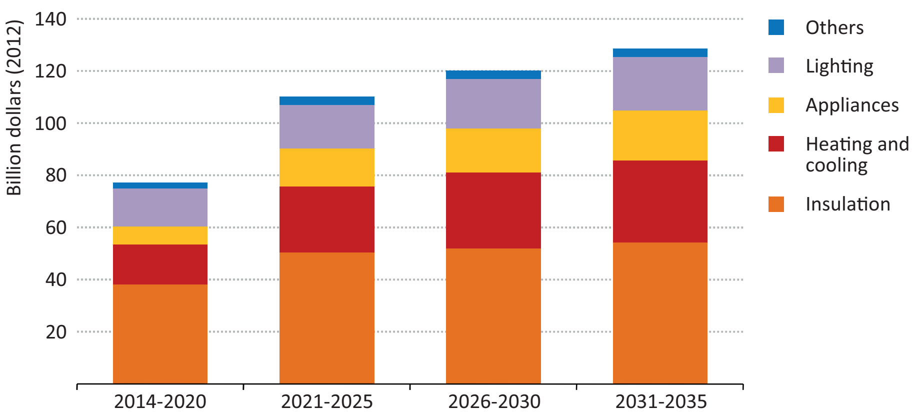


5. The services sector includes commercial activities and public services, such as hospitals, universities, schools and public administration.

The European Union (39%) and North America (23%) account for the bulk of cumulative efficiency investment in buildings in the period to 2035. This reflects their large share in global energy consumption in buildings and their relatively stringent standards. The European Union and, to a lesser extent, the United States and Japan have strict efficiency-related codes for new buildings and all three have a range of energy performance standards in place for appliances, complemented by financial and informational measures. Broadly speaking, households in OECD countries have greater need for space heating because they are located in colder climates, thus building insulation and retrofits play a bigger role there than in non-OECD countries. The level of ownership of energy-consuming appliances, e.g. televisions, clothes washers and air conditioners, is also higher in OECD countries. China accounts for 8% of cumulative efficiency investments in buildings over the outlook period, with the uptake of more efficient appliances and building insulation representing almost two-thirds of the total.

Heating and cooling account for about two-thirds of current global energy demand in buildings and represent almost 70% of total investment (including insulation) in energy efficiency improvements in this sector (Figure 4.5). Given the importance of space heating in OECD countries, their relatively old building stock, and their existing building codes and financial incentives, about 90% of investment in renovating existing buildings and insulating new ones takes place in OECD countries. Expenditures for appliances and lighting account for almost 30% of cumulative investment in the global buildings sector and increase over time, particularly for electric appliances, as more and more are used and because of their relatively short lifetime.

Figure 4.5 ▷ Average annual investment in energy efficiency in buildings by end-use in the New Policies Scenario



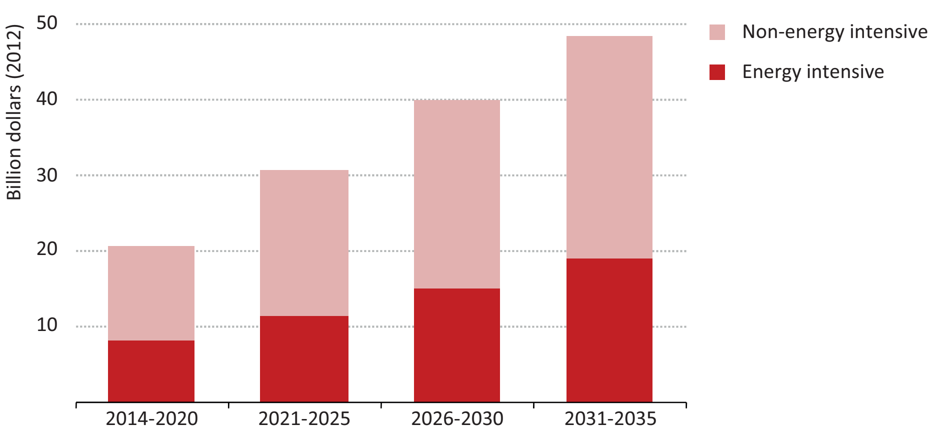
Notes: Heating and cooling includes water heating. Insulation includes retrofits.

In the period to 2035, more than three-quarters of efficiency investment in buildings needs to be realised in OECD countries, where existing financing barriers, particularly misaligned incentives and measurement and verification issues, often must be overcome in order to mobilise the necessary capital.[6] Banks will play a pivotal role. They already hold significant capital in buildings through the management of real estate funds, and efficiency represents an opportunity to improve their asset value (EEFIG, 2014). Moreover, banks are involved in the property market through mortgage loans, where mortgage-backed energy efficiency financing can raise more capital in the future. Development banks play a crucial role in incentivising the uptake of energy efficiency, through grants and low-interest loans with long terms, particularly in residential buildings.

Industry

The industry sector is responsible for 30% of today's global final energy consumption. Yet in the New Policies Scenario it accounts for only 9% ($0.7 trillion) of cumulative investment in energy efficiency in the period to 2035 (Figure 4.6). This share is relatively low because the lifetimes of industrial equipment, in general, are much longer than for appliances (in buildings) or vehicles (in transport). This matters because efficiency improvements occur mostly when new equipment is purchased rather than through retrofits. Substantial efficiency gains in industry can also be made by adopting best operating practices that do not require large capital investment. Unit investment costs per unit-of-energy-saved in industry are generally lower than in the transport or buildings sectors, where oil products (gasoline and diesel) and electricity are often more heavily taxed, incentivising the uptake of more expensive energy efficiency measures.

Figure 4.6 ▷ Average annual investment in energy efficiency in industry in the New Policies Scenario



6. The Property Assessed Clean Energy financing scheme is one way to overcome such misaligned incentives where the financing of the upfront capital cost is secured through a lien linked to the building and not the owner (Table 4.3).

Energy-intensive industries – chemicals and petrochemicals, iron and steel, cement, paper and pulp – account for almost two-thirds of industrial energy demand.[7] Energy costs account for a high proportion of production costs in these industries, thereby warranting the implementation of expensive energy efficiency measures with a longer payback period than investments in efficiency measures in non-energy intensive industries. Energy-intensive industries have been motivated to adopt much of the available efficiency potential, thereby reducing remaining opportunities, which is reflected in such industries accounting for only 38% of total cumulative industry-related energy efficiency investment in the New Policies Scenario. Among energy-intensive industries, chemicals account for the bulk of efficiency investment in the period to 2035, given its large share in total industrial energy consumption and the relatively long payback periods for efficiency measures. Efficiency investment in the steel and cement industries is lower because of recent large capacity additions in China and an expected peak in production within the next decade.

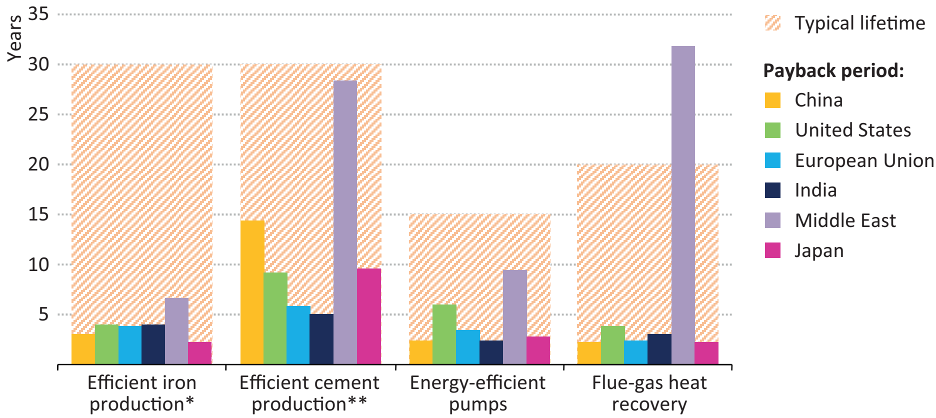
The regional distribution of efficiency investment in the period to 2035 largely reflects current energy consumption in the industrial sector. China, by far the largest industrial energy consumer in the world, accounts for almost 40% of global efficiency investment in industry, followed by the European Union (11%), United States (9%), India (8%) and Southeast Asian countries (5%).

Conditions for financing energy efficiency in industry differ between regions, as well as within them. In China, most of the energy-intensive industries are state-owned enterprises that, in general, enjoy relatively easy access to capital at low-cost. On the other hand, debt financing (mainly through local banks) is a major issue for Chinese small and medium enterprises (SMEs) and for energy service companies (ESCOs), which play a major role in the Chinese industry. SMEs face financing challenges not only in China, but also in many other parts of the world due to their limited access to capital. Utility financing or energy service agreements can play a bigger role in the future. As in other sectors, measurement of energy use is a first requirement, highlighting the need for active use of energy audits.

Energy prices are critical to determining the attractiveness of efficiency improvements in industry (Figure 4.7). In some countries, fossil-fuel subsidies keep energy prices artificially low, making efficiency investments less economic, or diminishing their cost-effectiveness; this applies in many countries in the Middle East. In general, the payback period for industrial energy efficiency technologies is shorter in China, the European Union and Japan, where energy prices are highest. The cost of installing efficiency equipment is generally lower in the United States compared with the European Union, but the payback period in the United States is longer, as a consequence of lower fuel and electricity prices. Another factor influencing the payback period is the fuel mix. For example, the payback period for an additional preheater cyclone stage in the cement industry is relatively lengthy in Japan and China because both rely to a large extent on cheap coal, while the cement industry in the European Union uses a higher share of more expensive alternative fuels.

7. This includes blast furnaces and coke ovens in the steel industry, as well as energy consumption for petrochemical feedstock.

Figure 4.7 ▷ Payback periods for selected industrial technologies and regions, 2013



* Heat recovery from sinter cooler. **Additional pre-heater cyclone stage for a dry kiln.

Note: Calculation is based on the weighted average fuel price in the respective sector and region.

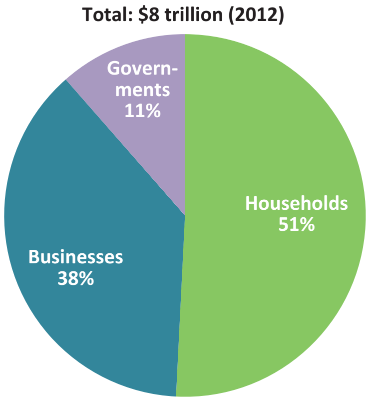
The influence of ownership

Whatever incentives might exist, the ultimate decision to make energy efficiency investment is reached by businesses, households and different levels of government all across the world. Their respective roles in carrying out the expenditure depend largely on the structure of the economy and the particular sector. In China, for example, energy-intensive industries, such as cement and steel, are largely dominated by state-owned enterprises, whereas such industries are usually private companies in Japan or the United States. The share of company cars in the PLDV segment varies from country to country, which influences whether households or businesses invest in more efficient vehicles.

Out of total energy efficiency investment of $8 trillion from 2014 to 2035 in the New Policies Scenario, about half needs to come from households, almost 40% from businesses and the remainder from governments (Figure 4.8). Access to capital is different for each class of investor, influencing their capacity to raise the necessary financing and its cost.

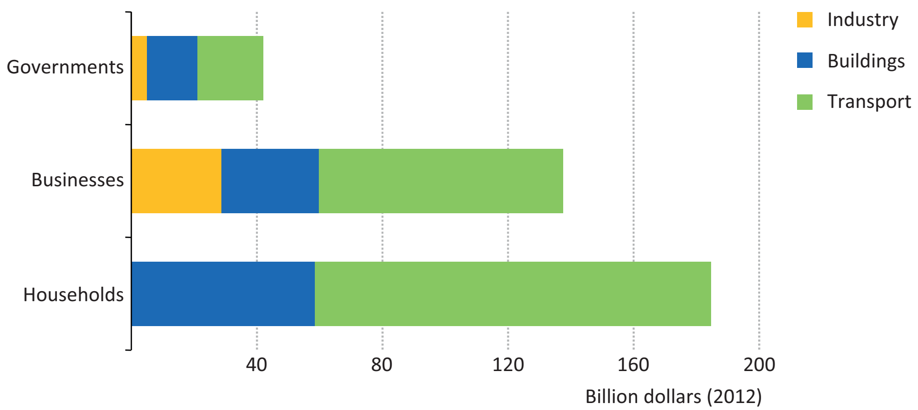
Businesses have a prominent role in making efficiency improvements in all sectors, for example, realising gains in process efficiency in industry, refurbishing commercial buildings, putting in place energy management systems and buying more efficient vehicles (Figure 4.9). Households invest mainly in more efficient vehicles, better appliances and the insulation of homes. Governments make direct energy efficiency investments in public transport, street lighting and public buildings; in some countries, they make indirect investments through state-owned enterprises.

Figure 4.8 ▷ Cumulative investment in energy efficiency in the New Policies Scenario by ownership category, 2014-2035



Notes: Governments include state-owned companies. The investment has been fully attributed to the main investor, although part of the investment might benefit from third-party support, for example, in the case of a government grant for building refurbishment.

Figure 4.9 ▷ Average annual investment in energy efficiency in the New Policies Scenario by ownership category and sector, 2014-2035



Source: IEA estimate using World Energy Model results and additional information on the share of ownership by sub-sector and region.

Businesses expenditure on energy efficiency is highest for transport, particularly for more efficient light-duty vehicles, trucks and aircraft. Almost one-third of investment in new road vehicles (excluding buses and two/three-wheelers) is made by businesses, which invest $16 billion/year in more efficient PLDVs alone in the New Policies Scenario. Businesses also invest actively in efficiency gains in commercial buildings (particularly in the insulation of new buildings and retrofitting existing ones) and industrial processes (mainly steam and motor systems, and process heat). Financing conditions can differ widely: while large companies with a turnover of billions of dollars may dedicate substantial sums each year to energy efficiency in the normal course of their business, many SMEs may lack the means to finance additional capital cost.

The financial crisis, which started in 2007, reduced capital available for energy efficiency investment, particularly for businesses. As a consequence, many companies reassessed their investment plans and, where they were not viewed as core to the business, efficiency expenditures were often among the first to be cut. Although credit availability is not back to pre-crisis levels, it has now improved notably and interest rates are historically low.

The financing challenge is even more significant for households. An estimated 2.1 billion households need to undertake half of the energy efficiency investment in the New Policies Scenario. Each household in industrialised countries invests about $250/year in the period to 2035, while those in developing and emerging economies each spend just $40/year. This is a huge task given the low priority to efficiency by consumers and prevailing economic preoccupations in many regions, particularly less developed countries.

Almost 70% of household efficiency spending in the New Policies Scenario is directed to the purchase of more efficient light-duty vehicles, generally financed through savings or debt. The remainder is spent within homes, most of it to reduce the need for heating and cooling through insulation and more efficient boilers. Without government support to overcome market imperfections (including poor information, financing hurdles, transaction costs and inertia), households will not sufficiently exploit available energy efficiency potential.

Governments are projected to undertake 11% of efficiency-related investment in the New Policies Scenario, with half going to the transport sector, almost 40% to public buildings and the remainder to efficiency improvements in state-owned enterprises. In the case of efficiency in buildings, almost all investment is undertaken by municipalities, which operate the majority of public buildings. In addition to direct investments, governments can play a decisive role in incentivising investment by businesses and households, for example by means of tax exemptions, grants or lowering the risks of investment through loan guarantees.

Financing energy efficiency investment

Risks facing energy efficiency investment

Financing today is not well structured to tap the vast potential of energy efficiency. It lacks the attractiveness of investment in clean energy, such as renewables, reflecting different policy frameworks. Financing energy efficiency investment must overcome a variety of hurdles and risks, including:

- **Energy efficiency is a cost-saving investment**. In contrast to an energy supply project, the investor in an energy efficiency project does not hold an asset producing a cash flow, but rather has the expectation of future cost savings (or increased asset value).

- **Small transaction size/high transaction costs**. Investment in efficiency is fragmented and includes many small-scale projects, involving high transaction costs.
- **Diverse nature of energy efficiency**. Energy efficiency is not a single market, rather it spans all sectors and a variety of technologies and stakeholders.
- **Efficiency performance measurement**. Reference levels for energy consumption need to be established and normalised to account for changes in consumption unrelated to efficiency projects (e.g. changes to weather conditions or building occupancy levels) if performance-linked payments are at stake.[8]
- **Split incentives**. Divergent incentives for energy efficiency projects mean that investors cannot appropriate the benefits of investment. Classic examples are the landlord-tenant situation or the interests of the current versus future building owner. Similarly, equipment purchasers may not be accountable for operating costs.

Energy efficiency investment in non-OECD countries faces additional obstacles. Since energy supply is often unreliable and universal access to modern energy is a challenge, supply policies usually have higher priority. Furthermore, in part due to a lack of strong organisation and institutional capacity, efficiency projects are perceived to be high risk. While increasing numbers of countries are seeking to create stable, long-term frameworks for energy efficiency investment, fossil-fuel subsidies continue to be an obstacle to energy efficiency investment.

Financing models

Energy efficiency financing has come a long way in several decades. Multiple financing models, adapted to the circumstances of energy efficiency projects, are now available (Table 4.3). Various categories of capital from financial institutions, such as mortgage finance, household and corporate loans, are relevant. Most financing models aim to address the "first-cost" hurdle of efficiency projects for the customer by providing the necessary upfront funds.

The most common source of energy efficiency investment is, by far, self-financing from savings or revenues or, in the case of governments, from tax revenue. A significant share of household investment in efficiency is realised without external financing. Next to self-financing, households depend mainly on loans, including unsecured consumer loans and credit card debt to buy goods such as more efficient vehicles, appliances and heating equipment. Most efficiency improvements in industry are carried out as part of normal business activity and do not require specific efficiency financing models.

8. The adoption of a standard measurement protocol, such as the International Performance Measurement and Verification Protocol, can build trust by increasing access to information about energy savings.

Table 4.3 ▷ Most common energy efficiency financing methods

	Self-financing	Consumer loan	Energy savings performance contract	Energy service agreement	Property assessed clean energy	Utility on-bill financing	Public loan programmes (syndicated loans / grants)	Mortgage-backed financing
Market penetration	High	High	Medium	Low	Low	Low	Medium	Low
Market segment	All	Transport, households	Services, industry	Services, industry	Services, industry	Households, services, industry	All	Households, services
Typical project size	Unlimited	\$1 000 - \$20 000	\$0.5 million - unlimited	\$250 000 - \$10 million	\$2 000 - \$2.5 million	\$5 000 - \$350 000	\$1 000 - \$10 million	\$2 000 - \$25 000
Repayment method	-	Credit card bill, loan payment	Service contract	Terms of service agreement	Property tax bill	Utility bill	Loan payment, none for grants	Mortgage
Collateral	-	None	Equipment	Equipment	Assessment lien	Equipment, service termination	Equipment, government backing	Property
Description	Energy efficiency project is financed through savings or available cash flow.	The loans are generally unsecured and include credit card financing, bank overdraft or personal loans.	Typically an energy service company (ESCO) designs the project and assures financing in exchange for a portion of the energy savings.	A special purpose entity is set up by a third-party and takes charge of financing and monitoring. It retains ownership of the equipment.	Capital provided by local government and repaid through assessments levied on the property.	A utility or third-party covers upfront costs and charges customer on monthly bill.	Public banks offer low-interest loans, grants or underwrite loans to lower capital costs and to leverage private capital.	Home mortgage is extended to cover cost of energy efficiency.

Diverse loan types have been established for financing energy efficiency investments. Energy Savings Performance Contracts (ESPC) are generally implemented for efficiency projects in the services and industry sectors by ESCOs that arrange the financing, implement the project and monitor the savings. The financial savings from lower energy use are split between the customer and the ESCO. The ESPC requires substantial negotiation to determine a guaranteed saving level for the customer, the share of the savings for the ESCO and the general legal framework, so it is applicable to projects above a certain size (>$0.5 million).

In an Energy Services Agreement (ESA), an energy service provider finances the entire efficiency investment with the customer paying back, for example based on a price-per-avoided-unit-of-energy consumed. Since the service agreement requires the creation of a special purpose entity (SPE), which is open for equity and debt investors, it involves high transaction costs and is thus suited only for large projects. During the contract period, the SPE retains ownership of the equipment and returns cash flows to its investors.

An approach to financing efficiency upgrades in buildings, mainly used in the United States, is the Property Assessed Clean Energy (PACE) financing model. This involves a local government providing the capital for an efficiency measure, which is repaid through an assessment on the annual property tax. An alternative for households to invest in retrofit measures is mortgage-backed energy efficiency financing, where additional borrowing from the original mortgage lender is provided to cover the energy saving measures. The investment cost is repaid through the mortgage payments. Preferential loan terms of such mortgages may become more widely available since a growing body of research suggests that energy-efficient buildings possess a lower risk of default and can thus justify lower cost financing.

Utility on-bill financing is a financing model where a utility or a third-party covers the upfront cost of an efficiency project and the customer repays the investment through an additional charge on the normal utility bill. This model makes use of the existing relationship between the utility and the customer and thus lowers the transaction costs. There are also diverse public loan and grant programmes to incentivise the uptake of energy efficiency in SMEs as well as in buildings and transport. They take various forms: public grants, low-interest loans and loan underwriting.

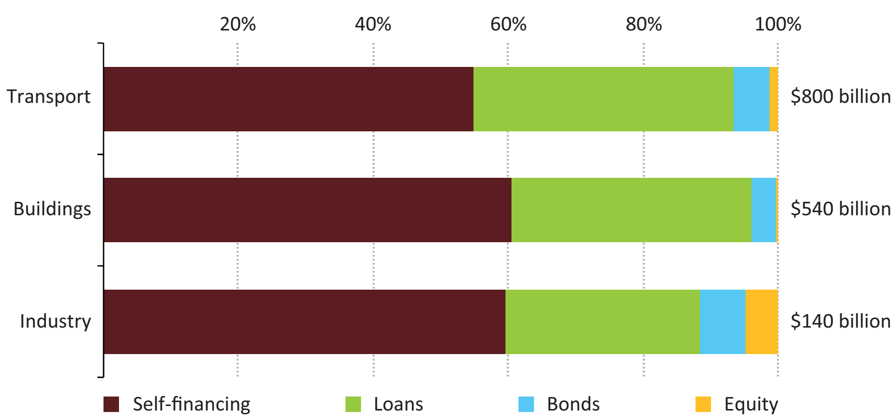
International sources of financing, including development banks, have become more active in energy efficiency in recent years. The IEA estimates funding for energy efficiency in developing countries from bilateral development banks in 2011 to have been around $19 billion, while that from multilateral development banks stood at $5.5 billion (Ryan, Selmet and Aasrud, 2012). The most common way of supporting local efficiency projects is through concessional loans and loan guarantees. Such instruments help to mitigate some of the initial risks associated with the repayment of energy efficiency loans and thereby catalyse private investment. Grants can play a further role in related capacity building measures.

Similarly, the Clean Development Mechanism (CDM), a part of the Kyoto Protocol, has been used since 2006 to finance energy efficiency projects, mostly in developing countries. A total of $31 billion had been invested in efficiency projects up to 2014 (mostly in the electricity sector), representing almost 10% of total CDM investment (UNEP Risø Centre, 2014). The use of CDM for energy efficiency has faced a multitude of difficulties, among them a complex certification process (the need to demonstrate the "additionality" of the project, i.e. that it would not otherwise have taken place), high transaction costs and uncertainty about continuation of CDM beyond the first commitment period (Ryan, Selmet and Aasrud, 2012).

Sources of financing

The New Policies Scenario does not make assumptions about methods of financing but assumes that financing needs will be met. However, based on existing literature and expert surveys, we have analysed for each sector financing sources that might be used for the required investment (Figure 4.10).

Figure 4.10 ▷ Estimated investment in energy efficiency by sector and financing source in the New Policies Scenario, 2014-2020



Note: This estimate looks at the primary market, so bonds include only primary bond issuances and exclude securitised bonds on the secondary market.

Sources: IEA analysis based on Accenture and Barclays (2011); KPMG (2012); EEVS and BNEF (2013); and World Bank (2014).

Financing sources on the primary market fall into four broad categories: self-financing, loans, bonds and equity. Self-financing describes capital expenditure financed directly from income, generally through retained earnings, available cash flow and, in the case of governments, tax revenue. Loans, mainly from financial institutions, come in a variety of forms, from standard consumer loans and credit card debt to energy savings performance contracting, energy service agreements, utility on-bill and mortgage-backed arrangements. Financing from capital markets is possible through debt, mostly bonds, or equity, usually through participation in the company via shares (see Table 1.5 in Chapter 1).

In our analysis, almost 60% of all investments in energy efficiency to 2020 are self-financed, with half originating from household savings, about 40% from businesses and the rest from governments. This means that almost 60% of the efficiency market between 2014 and 2020, $120 billion/year, is not accessible for debt or equity investors. Such transactions, carried out by households or businesses as part of more general expenditures, are rarely tracked and thus easily neglected when considering efficiency investments.

The other large source of energy efficiency financing is loans, which cover 37% of total financing. While loans for energy efficiency can take many different forms, the majority are provided by financial institutions, with almost two-thirds going to households, generally as standard customer loans, bank overdrafts or credit card financing. About one-tenth of all loans for efficiency purposes go to companies for improvements in buildings and industrial processes. Most of these are unsecured bank loans, with specific energy efficiency financing mechanisms, such as ESPCs, ESAs or utility on-bill financing (Table 4.3) making up a minor portion.

Given the importance of banks in energy efficiency financing, an effective local banking sector is needed for sustained and sizable financial flows, a situation which does not exist in some developing countries. Financing by banks of projects that aim to lower operating costs is not common, and knowledge about efficiency technologies is not widespread. Associated transaction costs are another hurdle: these are often prohibitive for small and non-replicable projects.

Loans account for around $540 billion of cumulative energy efficiency investments to 2020. When financing energy efficiency projects, financial institutions do not necessarily look at the incremental efficiency component, but appraise the value of the entire measure. Attributing the entire cost of the project to energy efficiency, the market for energy efficiency loan financing could amount to as much as $5.4 trillion to 2020.[9] Asset-backed loans (used in ESPCs or ESAs) generally enjoy lower financing costs compared to unsecured loans and could play a significantly bigger role for energy efficiency financing. As the size of asset-backed loans is too small for investors on capital markets, securitisation is expected to play a larger role in the future (Spotlight). In this context, development banks can provide a link between the primary and secondary markets by underwriting or granting loans, which are refinanced through bonds.

Bonds currently play a minor role in energy efficiency financing, accounting for only around 5% of the total. In almost all cases, the income from the bond is used to cover a variety of expenses, which may include energy efficiency investment. Several US municipalities have

9. This is based on the rough assumption that a 10% efficiency gain is achieved through an average efficiency investment.

issued "energy efficiency" bonds, the proceeds being used for loans to consumers and businesses. The bonds are offered on the secondary market; but the efficiency financing on the primary market happens through loans (in our classification, the financing source would therefore be a loan). Issuance of bonds on the primary market is very difficult due to the small size of efficiency projects. Equity financing currently plays a marginal role for energy efficiency. Usually, only a small share of the general revenue from equity issuance is likely to be dedicated to energy efficiency.

SPOTLIGHT

What role for securitisation?

Securitisation describes the practice of bringing together different items of debt and selling these as a package to investors on a secondary market. Securitisation obtained a bad reputation during the 2007/2008 financial crisis because of abuses related to debt backed by mortgage loans. Securitisation can, however, have an important role in improving liquidity for investments.

Current methods for financing energy efficiency – mainly self-financing and loans – are relatively expensive and too limited to support the large-scale increase in investment in the long-term, which is required for energy efficiency. Institutional investors, such as pension funds, require a large and liquid market with a minimum bond size issue estimated to be about $250 million (WWF and Credit Suisse, 2011). To make more capital available for the smaller scale investment generally inherent in energy efficiency, securitisation offers a possible bridge between the efficiency project and investors on capital markets.

How does securitisation generally work in the case of efficiency? Households or businesses invest in a more efficient technology financed by a loan where the cost savings resulting from the more efficient technology are used as the underlying asset. These loans are subsequently pooled with similar ones (or "securitised") by a bank or a special purpose vehicle. Then an asset-backed security, e.g. a securitised bond, is issued that is backed by cash flows generated from efficiency projects. For this process, banks need to build on existing structuring capabilities from other asset classes to create a liquid market for project-specific loans.

Currently, the market for such products is relatively small. In order for it to grow, several conditions need to be met: energy efficiency projects and the associated contract documents need to be standardised, generated cash flows need to be made stable to the extent possible and credit enhancements from retail or development banks might be necessary to bring the market to scale (CERES, 2014). Another way to get a superior credit rating is via covered bonds, where investors have not only a claim over a "pool" of assets, but also an unsecured claim against the issuer (usually a bank).

International climate finance is an important source of energy efficiency investment. The Green Climate Fund, set up through the United Nations Framework Convention on Climate Change (UNFCCC) in 2010, aims to provide developing countries with money for climate change adaption and mitigation. Energy efficiency is generally recognised as one of the most cost-effective sources of climate change mitigation in the near term. For the fund to be effective, it needs to use a range of financing vehicles to address the specific and diverse needs of efficiency projects, encourage project aggregation to lower transaction costs, and allocate a share of the capital to build capacity within local public administrations and financial institutions.

Trends in the 450 Scenario

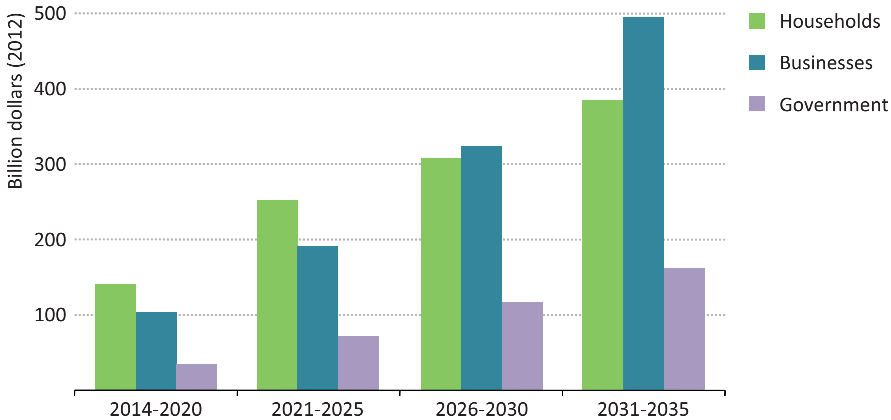
More than $13 trillion of cumulative energy efficiency investment is required in the 450 Scenario to enable the energy sector to make the necessary contribution to limit future global warming to 2 °C.[10] Global energy consumption rises in the 450 Scenario by 18% to 2035 (compared with 33% in the New Policies Scenario), but the fuel mix changes, with low carbon sources (including electricity) increasing their shares and natural gas increasing marginally, compared with today's fuel mix. Demand for coal and oil peaks around 2020 and declines after that. Fossil-fuel subsidy removal and rising CO_2 prices result in higher consumer prices in most regions and sectors, increasing the economic attractiveness of energy efficiency improvements. The increase in efficiency investment from $130 billion/year today to $1 100 billion/year in 2035 is driven by a set of targeted policies, including mandatory standards.

In the 450 Scenario, the cumulative level of investment is almost 70% higher than in the New Policies Scenario. The increase is spread fairly equally across the end-use sectors, with investment increasing by 85% in industry, by about 65% in transport and by about 75% in buildings. However, the incidence for the three categories of capital owners diverges over time: compared with the period prior to 2020, household investment nearly triples in 2031-2035, while businesses and government increase almost five times, respectively (Figure 4.11).

The incidence of the financial burden prior to 2020 looks very similar to the picture in the New Policies Scenario, with households providing about one-half of the financing and businesses almost 40%. Over time, businesses assume a larger share, as they finance efficiency investments directed to light commercial vehicles, trucks and aeroplanes, which are technologies with remaining potential and rapidly increasing demand. In the 450 Scenario, the share of total revenue that businesses invest today in energy efficiency increases five times to 2035 (although from a low level). Similarly, households around the world would have to invest four times more in energy efficiency in 2035 than they do today (whereas income per household increases by only 50% over the period).

10. Annual additional energy efficiency investments in the 450 Scenario (compared with the New Policies Scenario) are roughly $160 billion from 2014-2029, which compares to a median estimate of $336 billion in the IPCC's Fifth Assessment Report (Gupta, et al., 2014). The IPCC's estimate is partially derived from *WEO-2011* and compares the 450 Scenario against the Current Policies Scenario.

Figure 4.11 ▷ **Average annual investment in energy efficiency by ownership category in the 450 Scenario**



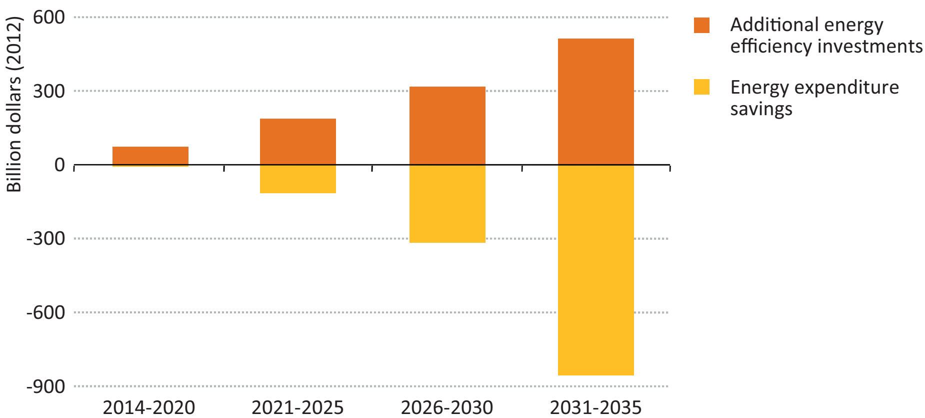
In the transport sector, cumulative efficiency-related investment in road freight more than doubles, compared with the New Policies Scenario, as a result of new policy measures, as well as higher gasoline and diesel prices. By contrast, efficiency investment in PLDVs increases by only around 20%, as the New Policies Scenario already incorporates policy measures in this area.[11] In the 450 Scenario, the residential sector accounts for about 60% of the additional investment in buildings. This is slightly more than in the New Policies Scenario, because the remaining efficiency potential is higher in households than in the services sector. These investments go mostly to insulation, and space and water heating as a result of the remaining potential to reduce heating needs. In industry, energy-intensive branches account for a similar proportion of additional investment in the 450 scenario, as efficiency measures are more costly but the efficiency potential is more limited than in non-energy intensive industries.

The regional distribution of efficiency-related investment in the 450 Scenario varies from that in the New Policies Scenario. While the European Union, North America and China account for two-thirds of cumulative investment in the New Policies Scenario, they account for less than 50% of the additional investments in the 450 Scenario. The larger part of the incremental investments occur in non-OECD countries, where current policies and those now under consideration leave a larger unexploited efficiency potential, particularly in transport and buildings. The 450 Scenario assumes the implementation of stringent emissions targets for PLDVs and the introduction of mandatory building codes and appliance standards in all regions. Thus, additional transport-related investment in non-OECD countries is more than twice as high as in OECD countries in the 450 Scenario, with China accounting for 28%, Latin America for 20%, India for 13% and ASEAN for 10%.

11. Additional investment in electric vehicles is not considered as efficiency investments (see Chapter 1).

The additional cumulative investment costs in energy efficiency of $5.5 trillion are more than offset by fuel savings of $6.5 trillion in the period to 2035, with further savings thereafter (Figure 4.12). Energy savings accrue over time as a result of earlier investment: in the period to 2025, the additional investment expenditure is higher than the savings on energy expenditures, but thereafter the savings exceed the additional investment and reach about $860 billion/year. Energy expenditure savings are highest in the transport sector. This is a result not only of the high share of transport in efficiency investments, but also of the stable end-user prices for energy in most regions compared with the New Policies Scenario, in contrast to increasing prices in buildings and industry.[12] The 450 Scenario includes the introduction of carbon capture and storage technology in industry — a technology that increases energy use while capturing CO_2 emissions — making sectoral energy expenditures slightly higher.

Figure 4.12 ▷ Average annual additional investment in energy efficiency and energy expenditure savings in the 450 Scenario compared with the New Policies Scenario



Financing in a low-carbon environment

Financing the energy efficiency investment of $1 220 billion/year required by 2035 in the 450 Scenario – a more than eight-fold increase over today's investment of $130 billion/year compared with a three-fold increase in the New Policies Scenario – will be a stiff challenge. Barriers to energy efficiency financing need to be overcome to facilitate such up-scaling; in particular, concerns that energy efficiency investment are unduly risky need to be allayed. Conditions, which need to be in place include:

- **Stable and favourable regulatory framework**. A policy framework needs to be in place that defines long-term expectations for the uptake of energy efficiency, keeping changes to a minimum. The supporting policies, in the form of standards or mandatory

12. The uptake of electric vehicles also reduces fuel expenditures.

energy efficiency assessments, complemented by energy labelling and financing support, also need to be as stable as possible.

- **Clear price signal**. Consumers and producers react to price signals to adapt their investment decisions. It is therefore essential to signal and implement a phase-out of fossil-fuel subsidies. The expectation of an increasing CO_2 price can also act as a reliable price signal to generate confidence that efficiency investments are economically sound.
- **Increase knowledge about energy efficiency across stakeholders**. Financial institutions rarely invest in cost-saving projects, such as energy efficiency. Knowledge about energy efficiency opportunities and their multiple benefits needs to be effectively communicated to banks, investors, decisionmakers, companies and households.
- **Clear and easy measurement.** Standardised methods of transparently measuring and verifying the performance of energy efficiency projects need to be put in place and promulgated. Providing performance analysis, which is reliable and easy-to-understand, increases market confidence in the value of efficiency projects.
- **Standardise the energy efficiency investment process.** All elements along the investment process, including legal contracts, procurement procedures, reporting and insurance, need to be standardised to the extent possible.

We estimate that today almost 60% of efficiency investment relies on self-financing, with capital markets playing a much lower role. Decarbonisation of the energy system, as projected in the 450 Scenario, requires significantly higher capital expenditures in energy efficiency, though they in turn result in lower energy bills, i.e. lower operating expenses. On-bill financing is a well-adapted tool, which uses such fuel savings to pay back the initial investment cost. Dedicated energy efficiency financing, including energy performance contracts and on-bill financing, currently make up only a small proportion of overall energy efficiency investments, but need to be significantly scaled up in the future.

Public funds play a crucial role in stimulating private investment in energy efficiency on the scale necessary for decarbonisation of the energy system. Direct investment in energy efficiency projects is only one aspect of government involvement; other forms – such as partial credit guarantees from development banks – are likely to play a more important role in stimulating the flow of private funds and adjusting the risk/reward profile. In summary, financing on the scale required in the 450 Scenario is unlikely to be realised without a determined effort to bring together the skills of financial and energy experts.

Investment tables

General note to the tables

The tables detail average annual investments and cumulative investments for energy supply (covering oil, gas, coal, power and biofuels) and energy efficiency (covering industry, transport and buildings). 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, Southeast Asia, the Middle East, Africa, Latin America and Brazil. By convention, in the table headings NPS and 450 refer to the New Policies Scenario and 450 Scenario, respectively. All investment data are presented in real terms in year-2012 US dollars.

In the absence of historical global investment data in all sectors, all historical investment numbers are estimated based on IEA data for supply, demand and trade, as well as IEA and industry data for investment costs, checked against actual historical data, where available. For consistency with our projections of future trends, these numbers reflect "overnight investment", i.e. the capital spent is generally assigned to the year production (or trade) is started, rather than to the year when it was actually incurred. Investments for biofuels, coal, gas and oil include production, transformation and transportation; those for the power sector include refurbishments, uprates, new builds and replacements for all fuels and technologies for generation, as well as investments in transmission and distribution.

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. Nil values are marked "-".

World

	Average annual investments					Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**1 230**	**1 772**	**1 759**	**1 830**	**1 963**	**40 165**	**39 387**
Oil	**427**	**637**	**608**	**613**	**621**	**13 671**	**11 062**
Upstream	320	510	509	513	520	11 284	9 014
Transport	54	50	42	39	46	986	902
Refining	52	77	57	61	55	1 401	1 146
Gas	**252**	**357**	**388**	**414**	**453**	**8 771**	**7 457**
Upstream	152	230	272	297	337	6 138	5 135
Transport	100	127	116	116	116	2 633	2 322
Coal	**61**	**54**	**40**	**42**	**50**	**1 034**	**690**
Mining	31	32	29	32	40	736	508
Transport	30	21	10	10	9	298	181
Power	**479**	**713**	**712**	**746**	**818**	**16 370**	**19 258**
Fossil fuels	106	120	117	117	125	2 635	2 877
Of which: Coal	55	68	66	71	74	1 528	1 918
Gas	46	49	49	43	49	1 054	930
Nuclear	8	46	56	51	41	1 061	1 722
Renewables	153	241	234	274	326	5 857	8 809
Of which: Bioenergy	17	22	23	34	39	639	892
Hydro	52	71	65	69	68	1 507	2 097
Wind	43	76	81	97	113	1 989	3 027
Solar PV	37	60	49	51	71	1 276	1 724
Transmission	48	84	80	78	82	1 787	1 586
Distribution	164	222	227	226	242	5 030	4 265
Biofuels	**10**	**11**	**11**	**15**	**22**	**320**	**920**

	2014-20	2021-25	2026-30	2031-35	NPS 2014-35	450 2014-35
Energy Efficiency *(billion, year-2012 US dollars)*						
Total	**212**	**334**	**436**	**533**	**8 002**	**13 531**
Industry	**21**	**31**	**40**	**48**	**739**	**1 371**
Energy intensive	8	11	15	19	284	529
Non-energy intensive	13	19	25	29	455	842
Transport	**115**	**193**	**276**	**356**	**4 928**	**8 120**
Road	109	179	250	317	4 496	7 267
Aviation, navigation and rail	6	14	26	39	432	854
Buildings	**77**	**110**	**120**	**129**	**2 334**	**4 040**

OECD

	Average annual investments					Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**500**	**676**	**632**	**647**	**674**	**14 494**	**14 883**
Oil	**129**	**237**	**205**	**201**	**191**	**4 645**	**3 840**
Upstream	102	205	183	179	168	4 087	3 334
Transport	9	9	4	3	5	124	113
Refining	19	23	17	20	18	434	393
Gas	**112**	**146**	**151**	**147**	**157**	**3 296**	**2 801**
Upstream	70	90	102	98	109	2 177	1 867
Transport	42	55	50	49	48	1 119	934
Coal	**16**	**13**	**10**	**10**	**11**	**250**	**167**
Mining	9	9	9	9	10	202	131
Transport	7	4	1	1	1	47	36
Power	**236**	**274**	**261**	**282**	**304**	**6 157**	**7 608**
Fossil fuels	44	39	39	36	41	852	1 046
Of which: Coal	12	14	15	19	20	367	616
Gas	30	25	24	16	20	471	422
Nuclear	4	17	18	20	16	389	643
Renewables	87	110	110	132	150	2 736	3 915
Of which: Bioenergy	11	14	13	21	21	371	450
Hydro	11	12	14	15	15	303	446
Wind	29	41	49	59	57	1 112	1 600
Solar PV	33	37	25	26	41	720	886
Transmission	22	27	23	23	24	546	527
Distribution	80	80	71	70	73	1 635	1 478
Biofuels	**7**	**5**	**4**	**7**	**10**	**146**	**467**

Energy Efficiency *(billion, year-2012 US dollars)*	2014-20	2021-25	2026-30	2031-35	NPS 2014-35	450 2014-35
Total	**142**	**208**	**247**	**273**	**4 630**	**6 807**
Industry	**6**	**9**	**12**	**13**	**219**	**425**
Energy intensive	2	4	5	6	85	196
Non-energy intensive	4	6	7	8	134	229
Transport	**75**	**114**	**143**	**163**	**2 629**	**3 540**
Road	73	110	138	157	2 536	3 406
Aviation, navigation and rail	2	4	5	6	93	134
Buildings	**61**	**85**	**91**	**96**	**1 782**	**2 842**

OECD Americas

	Average annual investments					Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**263**	**400**	**375**	**387**	**401**	**8 616**	**8 664**
Oil	**95**	**188**	**168**	**168**	**163**	**3 813**	**3 113**
Upstream	79	168	156	156	150	3 488	2 816
Transport	7	8	3	2	4	98	92
Refining	9	13	9	10	9	226	205
Gas	**64**	**89**	**92**	**88**	**100**	**2 019**	**1 703**
Upstream	46	61	66	62	74	1 433	1 186
Transport	18	28	26	26	26	586	517
Coal	**7**	**7**	**5**	**4**	**4**	**116**	**76**
Mining	5	5	5	4	4	100	62
Transport	2	2	0	0	0	16	14
Power	**92**	**114**	**106**	**122**	**127**	**2 567**	**3 467**
Fossil fuels	21	18	17	22	23	434	745
Of which: Coal	4	5	7	12	13	195	482
Gas	17	12	10	9	10	234	259
Nuclear	0	5	3	5	6	111	218
Renewables	21	39	42	50	52	1 002	1 603
Of which: Bioenergy	2	9	7	7	7	164	216
Hydro	4	4	6	6	6	122	139
Wind	10	12	15	23	23	394	623
Solar PV	4	10	11	10	12	234	317
Transmission	15	16	13	14	15	324	293
Distribution	34	34	29	31	31	696	609
Biofuels	**5**	**3**	**3**	**5**	**7**	**101**	**304**

	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Efficiency *(billion, year-2012 US dollars)*							
Total		**47**	**71**	**87**	**96**	**1 598**	**2 377**
Industry		**3**	**4**	**5**	**5**	**91**	**187**
Energy intensive		1	2	2	2	42	86
Non-energy intensive		2	2	3	3	49	101
Transport		**24**	**41**	**55**	**62**	**961**	**1 186**
Road		22	38	51	57	889	1 092
Aviation, navigation and rail		2	3	4	5	72	95
Buildings		**20**	**26**	**27**	**28**	**546**	**1 004**

United States

	Historical	Average annual investments – New Policies Scenario				Cumulative investments NPS	Cumulative investments 450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**188**	**283**	**263**	**273**	**270**	**6 012**	**6 468**
Oil	**53**	**114**	**105**	**104**	**84**	**2 260**	**1 903**
Upstream	41	98	95	95	77	2 021	1 683
Transport	5	5	2	0	0	46	45
Refining	7	11	7	9	7	193	176
Gas	**49**	**66**	**69**	**65**	**73**	**1 500**	**1 261**
Upstream	35	45	49	45	54	1 057	863
Transport	14	21	20	20	19	443	398
Coal	**6**	**6**	**5**	**4**	**4**	**102**	**65**
Mining	4	4	4	4	4	89	52
Transport	2	1	0	0	0	14	13
Power	**75**	**94**	**82**	**95**	**101**	**2 052**	**2 968**
Fossil fuels	19	16	14	19	20	373	705
Of which: Coal	4	5	6	12	12	185	472
Gas	15	10	8	7	7	183	230
Nuclear	0	5	2	4	5	90	180
Renewables	16	31	32	38	41	771	1 344
Of which: Bioenergy	2	8	6	6	6	143	192
Hydro	1	2	3	3	4	57	71
Wind	9	8	11	18	18	292	514
Solar PV	4	9	10	9	11	212	286
Transmission	12	13	10	11	12	254	235
Distribution	28	29	24	24	24	564	503
Biofuels	**5**	**3**	**3**	**5**	**7**	**98**	**270**

	2014-20	2021-25	2026-30	2031-35	NPS 2014-35	450 2014-35
Energy Efficiency *(billion, year-2012 US dollars)*						
Total	**40**	**59**	**72**	**79**	**1 331**	**1 930**
Industry	**2**	**3**	**4**	**4**	**70**	**140**
Energy intensive	1	2	2	2	35	68
Non-energy intensive	1	1	2	2	35	73
Transport	**20**	**33**	**44**	**51**	**778**	**904**
Road	18	31	40	46	710	816
Aviation, navigation and rail	2	3	4	5	69	88
Buildings	**18**	**23**	**24**	**25**	**483**	**886**

OECD Europe

	Average annual investments					Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**172**	**179**	**177**	**183**	**185**	**3 978**	**4 291**
Oil	**28**	**42**	**29**	**26**	**20**	**666**	**581**
Upstream	21	33	22	18	13	500	434
Transport	1	1	1	0	1	18	15
Refining	7	7	6	7	6	147	132
Gas	**37**	**32**	**38**	**40**	**40**	**815**	**716**
Upstream	20	18	25	27	26	512	477
Transport	17	14	13	14	14	303	239
Coal	**3**	**2**	**1**	**0**	**1**	**22**	**18**
Mining	1	1	0	0	1	13	10
Transport	2	1	0	0	0	9	9
Power	**103**	**102**	**108**	**115**	**122**	**2 434**	**2 838**
Fossil fuels	14	9	15	9	12	246	169
Of which: Coal	3	5	5	5	4	103	74
Gas	10	5	9	5	7	139	92
Nuclear	0	7	10	11	5	176	254
Renewables	56	50	49	63	71	1 264	1 693
Of which: Bioenergy	8	4	5	12	11	167	187
Hydro	5	6	7	7	7	144	227
Wind	17	25	27	29	29	599	803
Solar PV	23	14	8	9	15	258	314
Transmission	4	8	7	7	6	158	171
Distribution	28	28	27	25	27	590	551
Biofuels	**2**	**2**	**1**	**2**	**3**	**42**	**137**

	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Efficiency *(billion, year-2012 US dollars)*							
Total		**73**	**104**	**121**	**134**	**2 303**	**3 325**
Industry		**2**	**4**	**5**	**6**	**93**	**172**
Energy intensive		1	1	2	2	30	81
Non-energy intensive		2	3	3	4	62	91
Transport		**39**	**55**	**66**	**75**	**1 250**	**1 771**
Road		38	55	66	74	1 239	1 748
Aviation, navigation and rail		0	0	1	1	11	23
Buildings		**32**	**45**	**50**	**53**	**961**	**1 382**

European Union

	Average annual investments					Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**152**	**139**	**145**	**152**	**150**	**3 214**	**3 528**
Oil	**20**	**24**	**18**	**16**	**11**	**394**	**358**
Upstream	13	17	12	9	4	242	223
Transport	1	1	0	0	1	15	13
Refining	6	6	6	7	6	136	122
Gas	**30**	**20**	**26**	**27**	**25**	**531**	**453**
Upstream	12	8	14	15	12	254	236
Transport	19	12	12	13	13	276	217
Coal	**3**	**2**	**1**	**0**	**1**	**19**	**16**
Mining	1	1	0	0	1	12	9
Transport	2	1	0	0	0	7	7
Power	**96**	**92**	**99**	**106**	**111**	**2 227**	**2 566**
Fossil fuels	12	8	14	9	10	224	161
Of which: Coal	3	4	5	5	4	103	76
Gas	9	4	8	4	6	117	82
Nuclear	1	6	9	10	5	166	242
Renewables	53	47	46	59	67	1 182	1 513
Of which: Bioenergy	8	3	4	12	11	160	178
Hydro	3	4	5	5	5	100	147
Wind	17	24	27	27	27	574	727
Solar PV	23	14	8	9	15	254	306
Transmission	4	7	7	6	6	139	153
Distribution	26	24	24	22	23	516	497
Biofuels	**2**	**2**	**1**	**2**	**3**	**44**	**136**

	2000-13	2014-20	2021-25	2026-30	2031-35	NPS 2014-35	450 2014-35
Energy Efficiency *(billion, year-2012 US dollars)*							
Total		**68**	**98**	**114**	**126**	**2 170**	**2 998**
Industry		**2**	**3**	**5**	**5**	**82**	**154**
Energy intensive		0	1	2	2	29	77
Non-energy intensive		2	2	3	3	53	77
Transport		**37**	**52**	**63**	**71**	**1 187**	**1 560**
Road		36	52	62	70	1 175	1 535
Aviation, navigation and rail		0	1	1	1	13	25
Buildings		**29**	**42**	**46**	**50**	**900**	**1 285**

OECD Asia Oceania

	Average annual investments					Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**65**	**97**	**80**	**77**	**87**	**1 901**	**1 928**
Oil	**6**	**7**	**8**	**8**	**8**	**167**	**146**
Upstream	2	4	5	5	5	98	84
Transport	1	0	0	0	0	7	7
Refining	3	3	3	3	3	61	55
Gas	**11**	**25**	**20**	**19**	**18**	**463**	**382**
Upstream	4	11	10	10	10	233	204
Transport	7	14	10	9	8	231	178
Coal	**6**	**5**	**4**	**5**	**6**	**111**	**72**
Mining	3	3	4	4	5	89	59
Transport	2	1	1	1	1	22	13
Power	**41**	**59**	**48**	**45**	**55**	**1 157**	**1 303**
Fossil fuels	9	12	7	5	6	171	132
Of which: Coal	5	4	3	2	3	68	60
Gas	3	8	4	2	3	98	70
Nuclear	3	5	4	4	5	102	171
Renewables	10	21	19	19	26	470	619
Of which: Bioenergy	1	1	2	2	2	40	47
Hydro	2	1	2	2	2	37	80
Wind	1	4	7	7	5	120	173
Solar PV	6	13	7	6	13	227	255
Transmission	2	3	3	3	3	64	62
Distribution	18	18	15	15	15	350	318
Biofuels	**0**	**0**	**0**	**0**	**0**	**3**	**26**

		2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Efficiency *(billion, year-2012 US dollars)*							
Total		**23**	**33**	**38**	**43**	**729**	**1 105**
Industry		**1**	**1**	**2**	**2**	**35**	**66**
Energy intensive		0	1	1	1	13	29
Non-energy intensive		1	1	1	1	23	37
Transport		**13**	**18**	**22**	**26**	**418**	**583**
Road		12	17	21	26	408	566
Aviation, navigation and rail		0	1	0	1	10	16
Buildings		**9**	**14**	**14**	**14**	**276**	**456**

Japan

	Historical	Average annual investments				Cumulative investments	
		New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**27**	**40**	**31**	**27**	**34**	**741**	**827**
Oil	**2**	**2**	**1**	**1**	**1**	**32**	**29**
Upstream	0	0	0	0	0	2	2
Transport	0	0	0	0	0	1	1
Refining	1	1	1	1	1	30	27
Gas	**2**	**2**	**2**	**2**	**2**	**43**	**39**
Upstream	0	0	0	0	0	1	1
Transport	2	2	2	2	2	43	39
Coal	**1**	**0**	**0**	**0**	**0**	**3**	**2**
Mining	0	-	-	-	-	-	-
Transport	1	0	0	0	0	3	2
Power	**23**	**36**	**27**	**24**	**31**	**664**	**749**
Fossil fuels	5	7	5	3	2	104	69
Of which: Coal	3	1	1	1	0	21	19
Gas	2	6	4	1	2	79	49
Nuclear	1	2	-	-	-	12	67
Renewables	6	16	12	11	17	316	400
Of which: Bioenergy	0	1	1	1	1	24	26
Hydro	1	1	1	1	1	25	43
Wind	0	2	3	4	3	62	98
Solar PV	4	13	5	4	11	189	211
Transmission	1	2	2	1	2	33	33
Distribution	10	9	9	8	10	199	180
Biofuels	**0**	**-**	**-**	**-**	**-**	**-**	**7**

	Historical	2014-20	2021-25	2026-30	2031-35	NPS 2014-35	450 2014-35
Energy Efficiency *(billion, year-2012 US dollars)*							
Total		**14**	**21**	**24**	**25**	**445**	**692**
Industry		**0**	**1**	**1**	**1**	**17**	**31**
Energy intensive		0	0	0	0	7	14
Non-energy intensive		0	0	1	1	10	16
Transport		**8**	**11**	**13**	**15**	**252**	**339**
Road		8	11	13	14	246	329
Aviation, navigation and rail		0	0	0	0	6	11
Buildings		**6**	**9**	**9**	**9**	**176**	**322**

Non-OECD

	Average annual investments					Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**708**	**1 073**	**1 107**	**1 163**	**1 271**	**25 215**	**24 010**
Oil	**284**	**387**	**390**	**398**	**417**	**8 735**	**6 962**
Upstream	218	305	326	334	352	7 197	5 680
Transport	32	28	24	24	28	572	529
Refining	34	54	40	41	37	966	754
Gas	**136**	**205**	**233**	**264**	**293**	**5 381**	**4 578**
Upstream	82	140	170	199	227	3 961	3 268
Transport	53	65	63	64	66	1 421	1 310
Coal	**41**	**36**	**27**	**29**	**36**	**715**	**475**
Mining	22	23	20	24	30	534	377
Transport	19	13	6	6	5	181	98
Power	**244**	**439**	**451**	**464**	**513**	**10 212**	**11 649**
Fossil fuels	62	81	77	81	84	1 783	1 831
Of which: Coal	43	54	51	52	54	1 162	1 302
Gas	16	25	26	27	29	583	508
Nuclear	5	29	38	31	25	672	1 079
Renewables	67	131	123	142	177	3 122	4 894
Of which: Bioenergy	6	9	10	13	18	268	442
Hydro	41	59	51	54	53	1 204	1 651
Wind	14	35	31	38	56	876	1 427
Solar PV	5	23	24	25	30	556	838
Transmission	26	56	56	55	58	1 241	1 059
Distribution	84	141	156	156	169	3 395	2 787
Biofuels	**4**	**6**	**6**	**8**	**12**	**171**	**345**
Energy Efficiency *(billion, year-2012 US dollars)*							
Total		**68**	**119**	**176**	**238**	**3 140**	**6 214**
Industry		**14**	**21**	**27**	**35**	**520**	**946**
Energy intensive		6	8	10	14	199	333
Non-energy intensive		8	14	18	21	321	613
Transport		**37**	**72**	**119**	**170**	**2 068**	**4 070**
Road		36	69	112	160	1 961	3 860
Aviation, navigation and rail		1	3	7	10	108	210
Buildings		**16**	**25**	**29**	**33**	**552**	**1 198**

E. Europe/Eurasia

	Average annual investments					Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**131**	**169**	**185**	**214**	**229**	**4 329**	**3 678**
Oil	**54**	**59**	**63**	**76**	**80**	**1 510**	**1 185**
Upstream	44	51	56	68	73	1 345	1 034
Transport	6	2	4	4	3	71	65
Refining	4	5	4	4	3	95	86
Gas	**42**	**58**	**71**	**80**	**91**	**1 617**	**1 276**
Upstream	27	38	52	62	72	1 199	926
Transport	15	20	18	18	18	417	350
Coal	**6**	**5**	**2**	**3**	**3**	**76**	**55**
Mining	2	3	2	2	2	50	39
Transport	4	2	1	1	1	26	16
Power	**28**	**46**	**49**	**55**	**55**	**1 122**	**1 156**
Fossil fuels	3	15	16	15	12	324	219
Of which: Coal	1	7	9	8	7	168	95
Gas	2	8	8	7	5	155	124
Nuclear	2	7	7	13	10	200	238
Renewables	3	5	7	9	12	172	337
Of which: Bioenergy	0	1	1	2	3	33	70
Hydro	1	2	4	5	5	87	140
Wind	1	1	1	2	3	33	93
Solar PV	1	0	1	1	1	13	24
Transmission	6	5	5	6	6	126	110
Distribution	15	15	13	13	14	301	252
Biofuels	**0**	**0**	**0**	**0**	**0**	**3**	**7**

Energy Efficiency *(billion, year-2012 US dollars)*	2014-20	2021-25	2026-30	2031-35	NPS 2014-35	450 2014-35
Total	**9**	**14**	**21**	**26**	**373**	**694**
Industry	**1**	**2**	**3**	**3**	**51**	**112**
Energy intensive	0	1	1	1	16	47
Non-energy intensive	1	1	2	2	35	65
Transport	**5**	**9**	**14**	**18**	**239**	**430**
Road	4	7	10	12	174	331
Aviation, navigation and rail	1	2	4	6	64	99
Buildings	**3**	**4**	**4**	**4**	**83**	**152**

Russia

	Average annual investments					Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**80**	**108**	**105**	**121**	**129**	**2 528**	**2 112**
Oil	**36**	**40**	**34**	**38**	**42**	**849**	**676**
Upstream	28	34	31	34	37	750	586
Transport	4	1	1	2	2	28	25
Refining	3	5	2	3	2	70	64
Gas	**26**	**39**	**43**	**49**	**57**	**1 016**	**737**
Upstream	17	24	30	36	44	715	496
Transport	10	15	13	13	13	301	242
Coal	**4**	**4**	**1**	**2**	**2**	**49**	**34**
Mining	1	2	1	1	1	32	25
Transport	3	2	0	1	0	17	9
Power	**14**	**26**	**27**	**31**	**29**	**614**	**665**
Fossil fuels	2	8	10	10	7	187	122
Of which: Coal	0	3	4	5	4	84	47
Gas	2	5	5	5	3	103	76
Nuclear	1	6	5	8	5	125	162
Renewables	1	2	4	5	7	99	213
Of which: Bioenergy	0	1	1	1	2	25	53
Hydro	1	1	3	3	4	55	83
Wind	0	0	0	1	1	11	61
Solar PV	-	0	0	0	0	3	8
Transmission	4	4	3	4	4	81	71
Distribution	6	7	5	5	6	121	96
Biofuels	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Energy Efficiency *(billion, year-2012 US dollars)*							
Total		**5**	**8**	**12**	**15**	**212**	**373**
Industry		**1**	**1**	**2**	**2**	**31**	**66**
Energy intensive		0	0	1	1	10	31
Non-energy intensive		1	1	1	1	21	36
Transport		**2**	**4**	**8**	**11**	**135**	**219**
Road		2	3	5	6	78	129
Aviation, navigation and rail		1	2	4	5	57	90
Buildings		**2**	**2**	**2**	**2**	**46**	**87**

Non-OECD Asia

	Average annual investments					Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**296**	**487**	**463**	**467**	**522**	**10 670**	**11 459**
Oil	**63**	**94**	**73**	**68**	**72**	**1 724**	**1 394**
Upstream	36	61	47	44	40	1 079	895
Transport	7	10	6	4	8	161	153
Refining	20	23	20	20	24	484	346
Gas	**34**	**65**	**67**	**77**	**88**	**1 613**	**1 557**
Upstream	23	47	48	57	66	1 186	1 110
Transport	10	18	19	20	22	427	447
Coal	**32**	**27**	**21**	**23**	**29**	**556**	**363**
Mining	18	17	16	19	25	416	291
Transport	15	10	5	5	4	140	72
Power	**165**	**299**	**300**	**296**	**328**	**6 714**	**7 994**
Fossil fuels	47	49	46	47	53	1 073	1 311
Of which: Coal	42	42	37	38	40	867	1 093
Gas	5	7	9	9	13	200	213
Nuclear	3	20	26	15	12	405	730
Renewables	49	99	83	90	111	2 109	3 350
Of which: Bioenergy	3	6	7	8	10	167	291
Hydro	29	40	29	30	28	715	1 070
Wind	12	32	27	31	43	725	1 098
Solar PV	4	19	17	16	21	402	605
Transmission	14	38	36	34	35	793	673
Distribution	52	94	109	109	117	2 335	1 929
Biofuels	**1**	**2**	**2**	**3**	**5**	**63**	**151**
Energy Efficiency *(billion, year-2012 US dollars)*							
Total		**45**	**78**	**114**	**159**	**2 066**	**3 837**
Industry		**11**	**16**	**21**	**26**	**392**	**660**
Energy intensive		5	6	8	11	162	232
Non-energy intensive		6	10	13	16	230	428
Transport		**26**	**48**	**77**	**115**	**1 382**	**2 452**
Road		25	47	75	112	1 349	2 376
Aviation, navigation and rail		0	1	2	3	33	76
Buildings		**9**	**14**	**16**	**17**	**292**	**726**

China

	Average annual investments					Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**176**	**302**	**257**	**231**	**238**	**5 745**	**6 218**
Oil	**38**	**63**	**48**	**43**	**36**	**1 072**	**828**
Upstream	22	39	31	31	27	715	587
Transport	4	8	4	1	1	83	79
Refining	12	16	13	11	8	274	162
Gas	**9**	**25**	**27**	**32**	**37**	**657**	**654**
Upstream	6	17	18	22	27	448	417
Transport	3	9	9	10	10	209	236
Coal	**26**	**21**	**15**	**16**	**20**	**404**	**283**
Mining	15	14	13	15	20	335	239
Transport	11	7	2	1	1	69	44
Power	**103**	**193**	**166**	**138**	**143**	**3 587**	**4 361**
Fossil fuels	33	23	19	16	13	404	727
Of which: Coal	31	20	17	13	9	332	623
Gas	2	3	3	3	4	70	103
Nuclear	2	15	20	11	7	293	510
Renewables	36	72	41	39	54	1 174	1 720
Of which: Bioenergy	2	3	3	4	5	87	157
Hydro	22	28	10	7	6	311	339
Wind	9	25	19	20	28	508	744
Solar PV	3	13	9	6	8	207	320
Transmission	9	29	26	22	21	548	452
Distribution	23	54	60	51	48	1 169	951
Biofuels	**0**	**1**	**1**	**1**	**2**	**26**	**93**
Energy Efficiency *(billion, year-2012 US dollars)*							
Total		**35**	**59**	**86**	**119**	**1 566**	**2 526**
Industry		**8**	**11**	**14**	**18**	**270**	**420**
Energy intensive		4	5	6	8	125	165
Non-energy intensive		4	6	8	10	145	256
Transport		**21**	**39**	**62**	**91**	**1 106**	**1 660**
Road		21	38	61	90	1 091	1 614
Aviation, navigation and rail		0	1	1	1	14	46
Buildings		**6**	**9**	**10**	**10**	**190**	**446**

India

	Average annual investments					Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**50**	**76**	**93**	**110**	**132**	**2 203**	**2 521**
Oil	**9**	**10**	**10**	**12**	**19**	**277**	**244**
Upstream	4	5	3	3	3	78	66
Transport	1	1	1	2	5	53	51
Refining	4	4	5	7	12	146	127
Gas	**5**	**7**	**9**	**10**	**12**	**203**	**209**
Upstream	3	4	6	7	8	133	125
Transport	1	3	3	3	4	70	84
Coal	**3**	**3**	**4**	**5**	**6**	**94**	**52**
Mining	2	2	2	2	4	53	36
Transport	2	2	2	2	2	42	16
Power	**32**	**55**	**69**	**83**	**94**	**1 615**	**2 003**
Fossil fuels	7	14	14	17	20	358	374
Of which: Coal	7	13	12	14	17	302	314
Gas	1	1	3	3	3	54	59
Nuclear	0	3	4	3	3	72	136
Renewables	7	15	22	28	32	515	885
Of which: Bioenergy	1	1	1	1	3	34	59
Hydro	3	4	8	10	11	174	384
Wind	3	6	7	7	8	151	201
Solar PV	0	3	6	8	9	139	170
Transmission	3	4	5	6	7	119	113
Distribution	15	19	24	28	32	551	494
Biofuels	**0**	**0**	**0**	**1**	**1**	**13**	**13**

Energy Efficiency *(billion, year-2012 US dollars)*						
	2014-20	2021-25	2026-30	2031-35	NPS 2014-35	450 2014-35
Total	**4**	**8**	**13**	**22**	**245**	**660**
Industry	**1**	**2**	**3**	**4**	**57**	**120**
Energy intensive	0	1	1	1	17	30
Non-energy intensive	1	2	2	3	40	90
Transport	**2**	**4**	**8**	**15**	**151**	**416**
Road	2	4	7	13	139	396
Aviation, navigation and rail	0	0	1	2	12	19
Buildings	**1**	**2**	**2**	**3**	**38**	**124**

Southeast Asia

	Average annual investments					Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**52**	**79**	**78**	**87**	**105**	**1 909**	**1 855**
Oil	**14**	**18**	**13**	**12**	**15**	**331**	**282**
Upstream	10	15	12	9	10	261	220
Transport	2	1	0	1	2	18	16
Refining	2	2	2	2	4	52	46
Gas	**15**	**24**	**21**	**25**	**27**	**529**	**496**
Upstream	10	21	17	21	22	446	416
Transport	4	3	4	4	5	83	79
Coal	**2**	**2**	**2**	**2**	**3**	**46**	**22**
Mining	1	1	1	1	1	23	11
Transport	1	1	1	1	1	23	10
Power	**21**	**34**	**42**	**48**	**59**	**980**	**1 010**
Fossil fuels	5	9	9	11	14	229	162
Of which: Coal	3	7	6	8	11	175	122
Gas	2	2	2	3	3	52	38
Nuclear	-	-	2	1	1	18	45
Renewables	5	6	9	10	11	189	375
Of which: Bioenergy	1	1	1	1	1	21	41
Hydro	3	3	4	5	6	97	169
Wind	0	0	1	1	2	19	56
Solar PV	0	1	2	1	2	34	58
Transmission	2	3	4	4	5	88	73
Distribution	10	16	19	23	28	456	356
Biofuels	**1**	**1**	**1**	**1**	**2**	**23**	**45**

Energy Efficiency *(billion, year-2012 US dollars)*							
Total		**4**	**7**	**11**	**14**	**192**	**490**
Industry		**1**	**2**	**2**	**3**	**40**	**77**
Energy intensive		0	0	1	1	12	24
Non-energy intensive		1	1	2	2	28	53
Transport		**2**	**4**	**7**	**8**	**110**	**315**
Road		2	4	7	8	107	309
Aviation, navigation and rail		0	0	0	0	3	6
Buildings		**1**	**2**	**2**	**3**	**41**	**98**

Middle East

	Average annual investments					Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**107**	**124**	**144**	**155**	**172**	**3 229**	**2 762**
Oil	**62**	**78**	**87**	**92**	**103**	**1 956**	**1 523**
Upstream	46	58	73	76	85	1 578	1 213
Transport	11	6	7	9	13	186	167
Refining	6	14	7	7	4	193	144
Gas	**28**	**25**	**32**	**35**	**38**	**699**	**548**
Upstream	12	16	21	23	25	458	347
Transport	16	9	11	12	13	241	201
Coal	**0**	**0**	**0**	**0**	**0**	**1**	**1**
Mining	0	0	0	0	0	0	0
Transport	0	0	0	0	0	1	0
Power	**16**	**21**	**25**	**28**	**32**	**573**	**690**
Fossil fuels	7	7	5	7	6	141	125
Of which: Coal	0	0	0	0	0	2	1
Gas	6	6	4	6	6	120	116
Nuclear	0	1	3	0	1	26	35
Renewables	1	4	6	10	14	181	340
Of which: Bioenergy	0	0	0	0	1	8	15
Hydro	1	1	1	1	1	24	37
Wind	0	0	1	2	5	39	99
Solar PV	0	1	3	4	3	58	85
Transmission	2	2	3	3	3	60	57
Distribution	5	6	8	8	8	165	133
Biofuels	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Energy Efficiency *(billion, year-2012 US dollars)*							
Total		**3**	**7**	**10**	**13**	**169**	**365**
Industry		**0**	**0**	**0**	**1**	**5**	**21**
Energy intensive		0	0	0	0	1	4
Non-energy intensive		0	0	0	0	4	17
Transport		**2**	**4**	**7**	**10**	**113**	**250**
Road		2	4	7	10	113	235
Aviation, navigation and rail		0	0	0	0	0	15
Buildings		**1**	**2**	**3**	**3**	**50**	**93**

Africa

	Average annual investments					Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**94**	**138**	**137**	**147**	**171**	**3 238**	**2 853**
Oil	**63**	**66**	**60**	**57**	**68**	**1 395**	**1 151**
Upstream	56	61	56	53	63	1 291	1 057
Transport	5	3	2	2	3	50	46
Refining	2	3	2	2	2	54	48
Gas	**18**	**39**	**38**	**43**	**47**	**915**	**763**
Upstream	11	24	28	34	39	674	533
Transport	7	15	10	9	8	241	229
Coal	**2**	**2**	**2**	**2**	**2**	**46**	**33**
Mining	2	2	2	2	2	39	29
Transport	0	0	0	0	0	6	4
Power	**12**	**31**	**36**	**44**	**53**	**882**	**901**
Fossil fuels	2	7	7	8	10	176	137
Of which: Coal	0	5	4	6	6	114	106
Gas	2	2	2	2	3	55	27
Nuclear	-	-	2	2	1	22	49
Renewables	2	7	10	14	19	264	395
Of which: Bioenergy	0	1	1	1	1	21	26
Hydro	1	4	5	6	8	120	129
Wind	0	0	1	2	2	27	59
Solar PV	0	1	2	3	3	51	71
Transmission	2	5	6	6	8	135	108
Distribution	6	12	12	13	16	286	211
Biofuels	**0**	**0**	**0**	**0**	**0**	**0**	**5**

	Historical 2000-13	2014-20	2021-25	2026-30	2031-35	NPS 2014-35	450 2014-35
Energy Efficiency *(billion, year-2012 US dollars)*							
Total		**5**	**8**	**13**	**17**	**217**	**481**
Industry		**1**	**1**	**1**	**1**	**20**	**48**
Energy intensive		0	0	0	0	3	9
Non-energy intensive		0	1	1	1	17	40
Transport		**2**	**5**	**8**	**11**	**140**	**343**
Road		2	5	8	11	135	337
Aviation, navigation and rail		0	0	0	0	4	6
Buildings		**2**	**2**	**3**	**4**	**58**	**90**

Latin America

	Historical	Average annual investments				Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35
Energy Supply *(billion, year-2012 US dollars)*							
Total	**81**	**154**	**177**	**180**	**177**	**3 749**	**3 258**
Oil	**42**	**90**	**105**	**105**	**94**	**2 150**	**1 709**
Upstream	37	74	94	92	91	1 905	1 482
Transport	3	7	6	4	1	104	98
Refining	2	8	6	8	3	141	129
Gas	**13**	**18**	**25**	**28**	**29**	**537**	**435**
Upstream	9	14	21	23	24	443	352
Transport	5	3	4	5	5	93	83
Coal	**1**	**2**	**1**	**2**	**2**	**36**	**23**
Mining	1	1	1	1	1	28	18
Transport	0	1	0	0	0	9	6
Power	**23**	**41**	**41**	**41**	**45**	**921**	**909**
Fossil fuels	2	3	4	3	3	69	38
Of which: Coal	0	0	1	1	1	11	7
Gas	1	2	3	3	3	54	29
Nuclear	0	1	1	1	1	20	26
Renewables	11	16	17	19	21	396	472
Of which: Bioenergy	2	1	2	2	3	39	40
Hydro	8	12	12	12	12	258	276
Wind	1	2	2	2	4	51	78
Solar PV	0	1	1	2	2	32	54
Transmission	2	6	6	5	6	128	111
Distribution	7	15	14	13	15	308	261
Biofuels	**2**	**4**	**4**	**5**	**7**	**105**	**182**

Energy Efficiency *(billion, year-2012 US dollars)*						
Total	**6**	**12**	**19**	**24**	**315**	**837**
Industry	**1**	**2**	**3**	**3**	**52**	**105**
Energy intensive	0	1	1	1	17	41
Non-energy intensive	1	2	2	2	35	63
Transport	**3**	**7**	**12**	**16**	**195**	**595**
Road	3	7	12	15	189	583
Aviation, navigation and rail	0	0	0	1	6	12
Buildings	**2**	**3**	**4**	**5**	**69**	**137**

Brazil

	Average annual investments					Cumulative investments	
	Historical	New Policies Scenario				NPS	450
	2000-13	2014-20	2021-25	2026-30	2031-35	2014-35	2014-35

Energy Supply *(billion, year-2012 US dollars)*							
Total	**35**	**87**	**109**	**107**	**103**	**2 206**	**1 919**
Oil	**17**	**54**	**74**	**70**	**60**	**1 393**	**1 108**
Upstream	15	43	64	59	58	1 205	933
Transport	1	6	5	4	0	89	84
Refining	1	5	4	7	2	100	91
Gas	**2**	**5**	**7**	**9**	**9**	**157**	**128**
Upstream	1	4	6	7	7	127	101
Transport	0	1	1	2	2	30	28
Coal	**0**	**0**	**0**	**0**	**0**	**2**	**1**
Mining	0	0	0	0	0	0	0
Transport	0	0	0	0	0	2	1
Power	**14**	**25**	**25**	**25**	**28**	**565**	**521**
Fossil fuels	1	1	2	1	2	30	15
Of which: Coal	0	0	0	0	0	5	1
Gas	0	1	1	1	1	23	12
Nuclear	0	1	0	1	1	11	14
Renewables	8	11	10	12	13	248	260
Of which: Bioenergy	2	1	1	1	2	27	26
Hydro	5	7	7	7	7	158	167
Wind	0	2	1	1	3	40	41
Solar PV	0	1	1	1	1	17	19
Transmission	2	4	4	4	4	90	76
Distribution	4	9	8	8	9	186	156
Biofuels	**2**	**3**	**3**	**4**	**5**	**88**	**161**

Energy Efficiency *(billion, year-2012 US dollars)*							
Total		**3**	**7**	**11**	**14**	**183**	**457**
Industry		**1**	**1**	**2**	**2**	**33**	**65**
Energy intensive		0	1	1	1	14	31
Non-energy intensive		1	1	1	1	19	34
Transport		**1**	**4**	**7**	**8**	**101**	**303**
Road		1	4	6	7	96	292
Aviation, navigation and rail		0	0	0	1	5	11
Buildings		**1**	**2**	**3**	**4**	**49**	**89**

Units and conversion factors

This annex provides general information on units and conversion factors for energy and currency used in this report.

Units

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	Mtoe	million tonnes of oil equivalent
	MBtu	million British thermal units
	Gcal	gigacalorie (1 calorie x 10^9)
	TJ	terajoule (1 joule x 10^{12})
	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
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
	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)
	TW	terawatt (1 Watt x 10^{12})

Energy conversions

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
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

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