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Resources to Reserves 2013

Oil, Gas and Coal Technologies for the Energy Markets of the Future

International Energy Agency

Resources to Reserves

Oil, Gas and Coal Technologies for the Energy Markets of the Future

The availability of oil and gas for future generations continues to provoke international debate. In 2005, the first edition of *Resources to Reserves* found that the known hydrocarbon resources were sufficient to sustain likely growth for the foreseeable future. Yet the book also predicted that developing oil and gas resources – and bringing them to market – would become more technically demanding.

Resources to Reserves 2013 – a comprehensive update to the 2005 edition – confirms these earlier findings and investigates whether oil and gas resources can be produced at a reasonable cost and in a timely manner, while also protecting environmentally sensitive areas. Released amid a boom in shale gas and oil development in North America that is transforming the global energy landscape, the book surveys the cutting-edge technologies needed to find, produce and bring these reserves to the market, and it reviews the challenges on greenhouse gas emissions associated with fossil fuel production. With renewed interest in coal as a potential source of liquid and gaseous fuels, it also looks at technology advances for this fossil fuel.

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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 28 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

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

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International Energy Agency

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FOREWORD

The world's largest economies, and many of its smaller ones, remain heavily dependent on continued access to fossil fuels. Around 45% more oil, gas and coal is used today than 20 years ago, and today more than 80% of the world's primary energy supply comes from fossil fuels. Going forward, IEA projections show that growth in energy demand will continue to be met overwhelmingly by fossil fuels.

Concern about climate change has led to a noticeable and welcome increase in low-carbon alternatives. Nevertheless, even if the world were to commit itself to a low-carbon energy future tomorrow, our energy system would still require the use of large quantities of fossil fuels for decades. Heavy industry and transport are dependent on them, and coal-fired power generation is rising. Many have questioned whether the resources are there to handle this ever-growing demand.

The IEA has long argued that hydrocarbon resources around the world are sufficiently abundant to fuel the world through its transition to a sustainable energy future. In fact, we suggest the question might be more appropriately restated as: "are we running out of economically-accessible fossil fuels?" The answer lies in technology development. If capital investment in projects is sufficient, new hydrocarbon resources can be unlocked from unconventional resources, deepwater offshore locations, or in countries where geopolitical factors have restricted investment. Technology development decreases costs and reduces the environmental risks associated with resource extraction, providing more attractive returns for investors. It enables new resources to be developed in a cost-effective manner and accelerates the implementation of new projects.

Continued access to fossil fuels is less likely to be constrained by an insufficient resource base, and more by governmental policy and regulation. Fossil fuels are a major source of energy-related CO_2 emissions. The international community has announced its intention to reduce these emissions and positive movement in this direction has been taken in upstream extractive industries. Terms such as "social licence to operate" are more commonplace. Environmental responsibility has become an inherent part of project planning. But there is still much more to be done if fossil fuels are to continue to play a longer-term role in a low-carbon world.

Resources to Reserves 2013 reviews current and future technology trends in the upstream oil, gas and coal industries, and provides an overview of technological innovations on the horizon. Projections suggest we have sufficient fossil fuels for decades to come.

My hope is that this publication will make a significant contribution to broadening knowledge behind the petrol pumps, pipelines and power stations that make the headlines. Hydrocarbon resources are plentiful and, if accessed and used in a responsible and environmentally-sustainable manner, can have a beneficial impact on energy security.

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

Maria van der Hoeven

ACKNOWLEDGEMENTS

This publication was prepared by the International Energy Agency (IEA) Energy Technology Policy Division, under the leadership and guidance of Didier Houssin, Director of Sustainable Energy Policy and Technology, and Division Head, Jean-François Gagné.

Keith Burnard was the project manager and had overall responsibility for the implementation of the study. The completed manuscript, however, is a testimony to the dedication and expertise of many individuals, both from within the IEA and outside. Though many of these experts are recognised below, given the wide-ranging nature of this study, the time period over which the publication was prepared and the varied level of contribution, any attempt to cite all of the experts who provided input and advice is bound to fail.

The main authors and analysts of this study comprise many current and former colleagues at the IEA. They include: Kamel Bennaceur (Schlumberger); Michael Cohen; John Corben (Schlumberger); Anselm Eisentraut; Carlos Fernández Alvarez; Capella Festa; David Fyfe (Gunvor Group); Steve Heinen; Antonio Pflüger (German Federal Ministry of Economics and Technology); Wolf Heidug; Uwe Remme; and Andreas Ulbig (Eidgenössische Technische Hochschule Zürich [ETH, Zurich]); with the valuable support of Chris Besson worthy of particular note.

Outside of the IEA, Willem Schulte (Schulte Oil & Gas International Consultancy [SOGIC]) had a major influence on the final document, while important contributions came from Maggi Rademacher (E.ON) and Sandro Schmidt (Bundesanstalt für Geowissenschaften und Rohstoffe [BGR]). The guidance of the following experts is also gratefully acknowledged: Maurice Dusseault (University of Waterloo); Brian Heath (Coal Industry Advisory Board [CIAB]); Gilles Mercier (Natural Resources Canada); Frank Mourits (Natural Resources Canada); Hans-Wilhelm Schiffer (Rheinisch-Westfälisches Elektrizitätswerk [RWE]); John Topper (IEA Clean Coal Centre); Ian Torrens (independent consultant); and, Paul Zakkour (Carbon Counts).

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

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EXECUTIVE SUMMARY

Fossil fuels currently meet 80% of global energy demand. Even if current policy commitments and pledges made by countries to tackle climate change and other energy-related challenges were to be put in place, global energy demand in 2035 is projected to rise by 40% – with fossil fuels still contributing 75%. Demand over the coming decades will stem mainly from energy needs of emerging markets such as China and India. The use of coal, gas and oil to fuel the power, industry, buildings and transport sectors is set to rise. Although environmental concerns have led to a significant increase in lower-carbon options, these are not yet deployed widely enough to meet current or future demand for energy. Over the past two decades, the global share of power generation from non-fossil sources has decreased from 37% (in 1990) to 33% (in 2010); in contrast, the share of coal-fired power generation has risen from 37% to 42%. Fossil fuels will continue to provide the majority of global energy needs for the foreseeable future, but are there sufficient resources to meet the demand?

Given the major fluctuations witnessed in energy markets in the past seven years – notably the global economic crisis – *Resources to Reserves 2013* assesses the availability of fossil fuels and surveys the cutting-edge technologies needed to find, produce and bring them to the market, while avoiding adverse impacts on the environment to the greatest extent possible. This new edition also highlights the need for strategic approaches specific to each fuel type.

Availability of fossil fuels

Fossil fuels are abundant in many regions of the world and they are in sufficient quantities to meet expected increasing demands. However, most of them are still classified as **resources** and not yet as **reserves**. This distinction is important as it reflects the likelihood that the fossil fuels will be brought to the market. Resources are those volumes that have yet to be fully characterised, or that present technical difficulties or are costly to extract, for example where technologies that permit their extraction in an environmentally sound and cost-effective manner are still to be developed. Reserves are those volumes that are expected to be produced economically using today's technology; they are often associated with a project that is already well-defined or ongoing. As the more accessible, conventional supplies are exhausted, so more technically demanding resources will need to be exploited.

A key role for the industry is to convert resources into reserves. This reclassification relies heavily on the application of advanced technological solutions, which is strongly linked to fuel prices. High fuel prices stimulate the development and testing of more sophisticated solutions, and result in a growth of reserves. Exploring and extracting these reserves economically, and in an environmentally responsible manner, will require investment in new innovative solutions.

Fossil fuels, also collectively known as hydrocarbons, include oil, gas and coal. Any source of oil and gas that requires production technologies significantly different from those used to produce from conventional reservoirs is described as unconventional. A quick summary of known hydrocarbon reserves and resources demonstrates the potential supply:

- Proven reserves of **conventional oil** are estimated to be around 1.3 trillion barrels, with remaining recoverable oil resources representing about 2.7 trillion barrels. Globally, proven reserves have increased modestly since 1990, despite the growth in consumption. The global reserves-to-production ratio, based on current consumption levels, is in the range of 40 to 45 years. As resources are successfully converted into reserves, this period will be extended.
- Proven reserves of **unconventional oil** are around 400 billion barrels (bb), with estimated recoverable resources of 3.2 trillion barrels.
- Proven reserves of **conventional gas** are estimated at around 220 trillion cubic metres (tcm) – the equivalent of around 1.4 trillion barrels of oil – with remaining recoverable resources of 460 tcm.
- Proven reserves of **unconventional gas**, because of the heterogeneity of the rock formations, are very difficult to assess. Remaining recoverable resources (excluding methane hydrates) are estimated at 330 tcm.
- Reserves of **coal** are high, with proven reserves of hard coal estimated at 730 gigatonnes (Gt) (approximately 3.6 trillion barrels of oil equivalent [boe]) and proven reserves of lignite estimated at 280 Gt (approximately 0.7 trillion boe). Remaining recoverable resources of hard coal and lignite are estimated at around 18 and 4 trillion tonnes, respectively.

Developing various fossil fuel reserves is highly complex. As a means of assessing potential profitability, producers start by estimating the relative cost of development and the carbon intensity (the amount of carbon dioxide [CO_2] emitted for each unit of energy produced) of the fuel to be produced. Conventional natural gas typically has the lowest cost per energy unit and the lowest carbon intensity. All unconventional gas developments generally have low carbon intensity and diverge mainly in the cost of development. By contrast, unconventional oil developments (such as from bitumen, coal gasification and oil shales) are more expensive to produce and have higher carbon intensities. Coal has the highest carbon intensity of the fossil fuels.

As this edition of *Resources to Reserves* illustrates, the current increase in fossil fuel supply over recent years has been made possible thanks to impressive advances in technology. Future supply will require even more demanding technological innovations that can increase production in existing and new sources while also responding appropriately to relevant environmental challenges.

Using advanced technology to move from resources to reserves

Resources to Reserves 2013 provides an overview of the new technological developments and discusses the potential next steps for each fuel type.

Conventional oil and gas

There are various examples where technological developments have made it possible to extend oil production from a field over a much longer time than was initially foreseen. Securing future oil production will require greater output from brown fields (fields already in production) by employing improved and enhanced oil recovery (EOR) techniques. At the end of their anticipated lifecycle, most fields still contain significant volumes of oil. Technological advancements mean that a larger fraction of these volumes could be brought to the surface. For example, on average about 50% of the original oil-in-place volumes in reservoirs could be recovered by using the latest cutting-edge technology.

Even a 1% increase in the average recovery factor could add more than 80 bb, or 6%, to global proven oil reserves. Over the last 20 years, the average recovery factor from the Norwegian Continental Shelf has seen a significant shift – from 34% to around 46% today. This has largely been driven by technology with contributions from horizontal/multilateral drilling, improved seismic acquisition, four-dimensional seismic techniques and improved subsea facilities. With the recent accelerated developments in smart fields (fields that use a whole range of technological solutions), even higher recovery rates could be achieved. If the shift seen in Norway were to be achieved in all the basins of the world, it would double current proven reserves. A similar additional shift could be achieved by adopting EOR techniques on a much wider scale. Currently, there is a significant increase in the number of EOR pilot tests, especially those using chemical methods and CO_2 injection. Examples may be found around the world, from China, Russia, the Middle East and North America to Argentina. In spite of these efforts, the maturing of existing projects and the complexity of implementing EOR technologies will lead to decreased production levels in non-Organization of the Petroleum Exporting countries (OPEC) countries, with a corresponding increase in production of conventional oil from OPEC countries.

Natural gas is set to play an increasing role in meeting the global demand for energy, especially in power generation and heating. Whereas a few decades ago gas was often stranded (too remote to be financially viable to transport to market) and an unwanted by-product of oil production, many such gas projects are now being actively pursued. More often than not, the principal challenge in the past was in bringing the gas to market. However, today, liquefied natural gas (LNG) provides a cost-effective solution in many cases. Liquefying natural gas, shipping it in ever larger carriers and using regasification at an increasing number of locations close to the end-user is making it more financially viable to transport gas to market. Qatar and Iran in the Middle East, in particular, have seen a significant increase in capacity. Recent new technological developments are towards offshore floating LNG options (liquefaction on a boat), with the first to be built in the sea north-west of Australia. In Qatar, the first large-scale gas-to-liquids plant is already under construction.

The frontier locations for conventional hydrocarbons are now in ultra-deepwater and in the Arctic. Adding to the complexity of exploration and production in these locations is the imperative to do no harm to the pristine and sensitive environments. In these often remote locations, operations such as subsea processing and compression are required to allow transfer by pipeline to distant facilities. Important growth regions in deepwater exploration and production are Brazil and West Africa. Many of the technologies developed for deep water could eventually be used in Arctic regions. Additional challenges in the Arctic include protecting facilities from ice-related dangers and extending the drilling season. In future, technologies that enable very long tie-backs from field to coastal collection points could make it more viable for other developments to proceed. Technology is continuing to evolve at a rapid pace. Current developments, concentrated around the Barents Sea and the North Slope of Alaska, are outlined in this edition.

Unconventional oil and gas

The global potential for unconventional oil is high. Though the resources and reserves base is similar to that for conventional oil, there are potentially more resources awaiting technological solutions. The world's extra-heavy and oil-sands resources are largely concentrated in Canada and Venezuela. Mining operations to develop the shallow reserves are seeing a significant increase. Many of the deeper deposits are developed by using steam to reduce viscosity. Because of the energy intensity of these projects and the associated carbon footprint, many such developments now have to contain solutions for carbon capture and storage (CCS), *i.e.* processes by which CO_2 is captured at the emission source and then, usually, injected into underground sites for long-term, geological storage.

Unconventional gas – tight gas, shale gas and coal-bed methane – has seen substantial growth in the United States and Canada, driven mainly by the need to minimise reliance on imported fuel. Technology has been central to this growth. Driving vertical and horizontal wells, and creating hydraulically generated fractures to maximise and steer the flow of gas, has brought dividends. However, the financial viability of these developments remains very sensitive to the local gas price. Further cost reductions are possible through improved drilling and completion techniques, as well as enhanced understanding of the basic flow phenomena in stress-sensitive reservoirs. There is an enormous opportunity to export the experience and learning gained to other parts of the world where the exploration of such resources is still in its infancy.

With the increasing demand for natural gas, prospects are being explored for sour gas (gas contaminated with CO_2 or hydrogen sulphide). Key to such developments is the ability to separate out the contaminants and dispose of them in an environmentally friendly manner. The Middle East, Kazakhstan and South-East Asia have substantial volumes of such resources under consideration for development.

Methane hydrates offer a potentially enormous source of methane gas and are thought to be the most abundant source of hydrocarbon gas on earth. However, the technical challenges in accessing this resource in a cost-effective and environmentally acceptable manner are still being addressed. Significant production in the short to medium term is not anticipated and therefore global forecasts do not generally include production of methane from this source.

Coal

Coal production has seen a steep increase in the last decade, with projections pointing to a continued rise for the next decade. These increases are driven mainly by economic growth in emerging economies, particularly in China and India. Environmental imperatives demand that, in the longer term, CO_2 emissions from the use of fossil fuels must decline; this is particularly the case for coal, the most carbon-intensive of the fossil fuels. If the environmental issues can be resolved, there are sufficient coal resources to satisfy expected demand for many more decades. Reducing emissions from coal could be achieved by:

- developing technologies to improve the efficiency of coal use;
- using CCS.

The greater the effectiveness of these two options, the less will be the emphasis on switching to lower-carbon alternatives.

Moving towards ever thinner, deeper and less uniform coal seams poses a number of challenges for mining, all of which are likely to lead to an increase in the cost of production. Alternatively, it may trigger a move to exploit the abundant reserves of shallower but lower-quality coal. Technology is constantly being improved, offering opportunities for those with state-of-the-art mining techniques to export them to regions where such techniques have yet to be deployed.

Future improvements, for example, may come from the further development of underground coal gasification, in which coal is gasified in situ to generate power, or from generation using advanced technologies. Advanced ultra-supercritical steam cycles and integrated gasification combined cycle (IGCC) technology with state-of-the-art gas turbines are currently being developed. Further development of more cost-effective, energy-efficient CCS technologies will be essential to the future use of coal.

Mitigating the environmental impact

The future use of all fossil fuels is increasingly determined by political debates and governmental regulations reflecting concerns about local environments and greenhouse gas (GHG) emissions, particularly CO_2. The year-on-year rise in anthropogenic GHG emissions is a matter of global concern. Reducing them can only be achieved by switching to lower-carbon fuels, better management of GHG emissions, and more efficient production and consumption of fossil fuels – all of which become more effective with the development and application of improved technology.

While much emphasis is placed on switching from fossil fuels to non-fossil or renewable energy sources, as this edition of *Resources to Reserves* highlights, both technological improvements and fuel switching among fossil fuels also has significant potential to reduce GHG emissions. For example, while power generated from coal globally releases more than 1 000 grams of CO_2 per kilowatt hour (gCO_2/kWh), a state-of-the-art coal-fired generation plant releases around

740 gCO_2/kWh. So, there is much potential to reduce emissions simply by deploying more efficient technology. If a coal-fired generation unit were to be replaced by a state-of-the-art unit firing natural gas, emissions could be reduced even further, to 370 gCO_2/kWh. This potential to substantially reduce CO_2 emissions reflects both the higher heat content of gas and the higher efficiency of the gas-fired power generation process. Though the choice of fuel is largely determined by resource availability and cost, environmental factors now play an increasingly important role.

While the continued use of fossil fuels will inevitably produce CO_2 emissions, new technologies make it possible to limit their release into the atmosphere. CCS is now being piloted and demonstrated in various parts of the world. At present, saline aquifers, which are abundant in many parts of the world and potentially offer large storage volumes, are considered as the storage sites likely to dominate in the long term. Current technologies for storage in saline aquifers need further improvement, especially for long-term monitoring, understanding gas flow in aquifers and for evaluating the potential for leakage through overlying rock and fault systems.

In the long term, incentives for emissions reduction, such as carbon pricing schemes, could provide an essential stimulus to encourage CO_2 storage. Further efforts to resolve remaining issues associated with monitoring and long-term liability will also be needed. Carbon pricing will, of course, drive up the cost of producing fossil fuels. Some implications of carbon pricing assumptions are addressed in this edition.

In the Weyburn oilfield (Canada), CO_2 is being injected to enhance oil recovery while, at the same time, the oilfield is being monitored to assess the amount of CO_2 stored. In oilfield operations, the more energy-intensive oil recovery methods, *e.g.* steam injection for recovery of heavy oil and bitumen, may in future need to incorporate CCS. Another option is to store CO_2 in coal beds to prompt the release of methane. Some scientists suggest that such a process could eventually be used to release methane from methane hydrates, with some initial, small-scale trials having been successfully completed.

As releasing methane into the atmosphere is potentially much more harmful than releasing CO_2, methane released during exploration and production is often flared (methane is burnt on site to convert it to CO_2), particularly at oil drilling sites. However, priority should be given during exploration and production to using the gas rather than flaring it. For example, the gas may be reinjected back into an oil reservoir to maintain pressure for subsequent oil recovery, used to supplement local heat or power requirements, or transported for use elsewhere (if commercially viable). Such initiatives are under way in many parts of the world.

Key conclusions and recommendations

Fossil fuels dominate world primary energy supply. Resources are in place for this to continue well into the 21st century. Societal implications, particularly the demand for an environmentally sustainable, low-carbon future, will be pivotal to their continued use. Advances in technology will be absolutely essential to ensure that the use of fossil fuels remains affordable and clean.

In some regions, innovative technological solutions have led to a sizable increase in reserves. There is a significant opportunity to pursue a wider application of these state-of-the-art solutions by teaching others, learning from others and demonstrating rigour in their deployment. Innovation can often be found by applying existing technology to a new environment.

Flexibility in the use of fossil fuels can offset some of the environmental challenges. For example, switching from coal to gas for power generation or using high-carbon fuels for situations in which decarbonisation and integration with renewable fuels is possible without losing efficiency.

Resources of fossil fuels are available to meet the increasing energy demand; that much is clear. The emphasis now is on the technology, prices and policies that will ensure it is financially viable to develop the world's resources into proven reserves. Technology has developed by leaps and bounds since the last edition of Resources to Reserves was published, but a concerted effort in research and development (R&D) is still needed to go forward. Large-scale investment over the coming decades will be vital to this effort. Public policy will play a key role in providing the measures and incentives for industry to make the necessary investments.

Recommendations

Radical and co-ordinated policy action across all regions will be needed to support ongoing exploitation of fossil fuels, while addressing successfully the environmental, economic and technical challenges that arise. In particular, the carbon intensity of supply chains and subsequent use of oil, gas and coal must decrease.

Strong governance, with policies and legislation directed at reducing GHG emissions from the exploration, production and transport of fossil fuels, will be essential to guide the development of more complex technologies. This will be particularly important to ensure that operations in pristine and sensitive environments are completed without long-term environmental damage.

Continued use of fossil fuels will, of course, lead to emissions of GHGs. In this regard, governments must take steps to stimulate improvements in equipment in the power and end-use sectors. Efforts can be directed, for example, to increasing the fuel efficiency of vehicles, developing less carbon-intensive industrial processes, and improving the efficiency of power generation technologies. Policy also plays an important role in supporting the spread of best practice.

For deep cuts in emissions from the industry and power sectors, CCS is essential (particularly at large point sources). Policy measures to accelerate the development of CCS, to reduce its capital and operating costs, and to create an enabling regulatory environment are all necessary. Desirable, predictable incentives must be provided if the widespread deployment of CCS is to become a long-term reality.

Chapter 1 • Setting the scene

Oil, gas and coal have fuelled economic development around the globe for over a century. However, the extent of the world's hydrocarbon resources and reserves has sparked much public debate over the last decade. For example, there are widespread concerns that the world's oil resources will soon decline to a level where supply will become limited and unable to keep pace with increasing demand. In terms of quantities, the total amount of fossil fuels held in the Earth's subsurface is certainly finite.

Global energy demand

Studies on the future of world energy supplies point to the continuing dominance of fossil fuels well into this century. In the *World Energy Outlook 2012* (IEA, 2012), the International Energy Agency presented three scenarios with energy projections to 2035: the Current Policies Scenario, the New Policies Scenario and the 450 Scenario.

- **Current Policies Scenario** assumes no change in government policies and measures, *i.e.* the "business-as-usual" scenario;

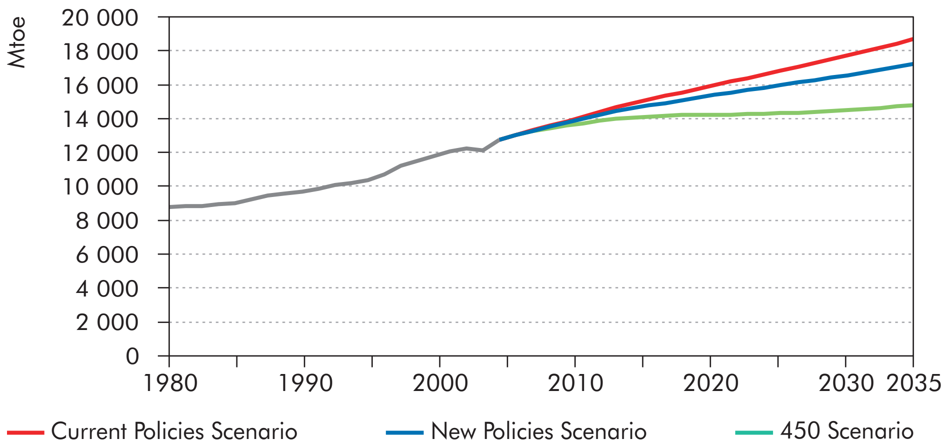
- **New Policies Scenario** assumes new measures have been introduced to implement broad policy commitments, including national pledges to reduce greenhouse gas emissions (GHGs) and, in some countries, plans to phase out fossil fuel energy subsidies;

- **450 Scenario** aimed at limiting the increase in the future global temperature to 2 degrees Celsius (°C), which assumes that GHG concentrations can be stabilised in the atmosphere at a level of 450 parts-per-million carbon dioxide-equivalent (ppm CO_2-eq).

Global energy demand is projected to rise under all three scenarios to 2035 (Figure 1.1) though, under the 450 Scenario, the demand for global primary energy would increase more slowly, reaching 14 870 million tonnes of oil-equivalent (Mtoe), which is only some 20% above the current level. Despite a sharp drop in 2009, a direct result of the global economic crisis, demand for energy will continue to increase, averaging a projected 1.76% in the Current Policies Scenarios and 1.10% per year in the 450 Scenario from 2010-20.

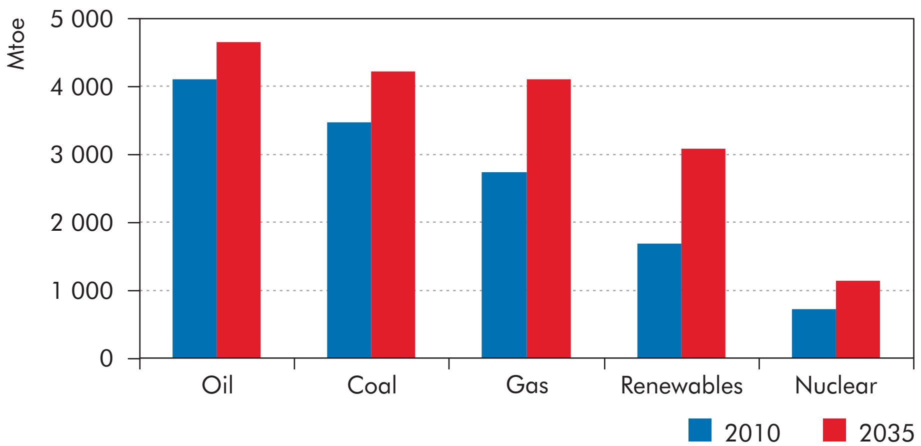
Even in the New Policies Scenario, fossil fuels remain the dominant contributor to the growth in energy demand, providing approximately 59% of incremental demand during the period (Figure 1.2). However, their share of global energy demand diminishes slightly from 81% to 75%. Oil remains the single largest fuel, though its share of the total falls from 32% to 27%. Gas shows the largest rise, increasing by about 50%.

Figure 1.1 • *Global demand for primary energy to 2035, by scenario*



Source: IEA, 2012.

Figure 1.2 • *World primary energy demand by fuel in the New Policies Scenario, 2010 and 2035*



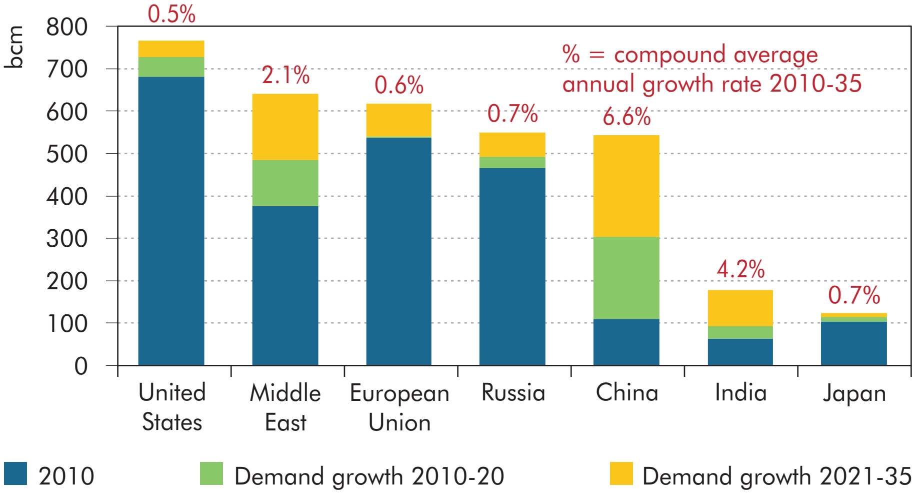
Source: IEA, 2012.

Organisation for Economic Co-operation and Development (OECD) non-member country regions generate the bulk of the increase in global demand for all primary energy sources. They are responsible for the entire net increase in coal demand to 2035. Although the share of coal in China's energy mix continues to decline, coal still meets more than one-half of its energy requirements in 2035. Driven by policies to limit or reduce carbon dioxide (CO_2) emissions, coal use falls sharply in each of the OECD member country regions, particularly after 2020. By 2035, member countries will consume 22% less coal than is currently the case.

The demand for oil from 2011 to 2035 increases the most in China (6.1 million barrels per day [mb/d]), followed by India (4.1 mb/d) and the Middle East (2.7 mb/d). Such increased demand is a consequence of rapid economic growth and, in the case of the Middle East, the continuation of subsidies on oil products. By 2030, China overtakes the United States to become the largest oil consumer in the world. Having reached a peak of 46 mb/d in 2005, oil demand in OECD countries continues to decline dropping to 33 mb/d in 2035. This decrease in oil demand is largely due to efficiency gains in the transport sector and continued switching away from oil in other sectors.

Unlike demand for the other fossil fuels to 2035, demand for natural gas increases in OECD countries, where it remains the leading fuel for power generation and an important fuel in the industrial, services and residential sectors. China and India account for one-third of the incremental demand, as gas use increases rapidly in the power sector and in industry. The Middle East, which holds a considerable share of the world's proven natural gas reserves, is responsible for one-sixth of the global increase in gas consumption (Figure 1.3).

Figure 1.3 • *Natural gas demand by selected region in the New Policies Scenario, 2010 and 2035*



Note: bcm = billion cubic metres.

Source: IEA, 2012.

Implications of a low-carbon scenario

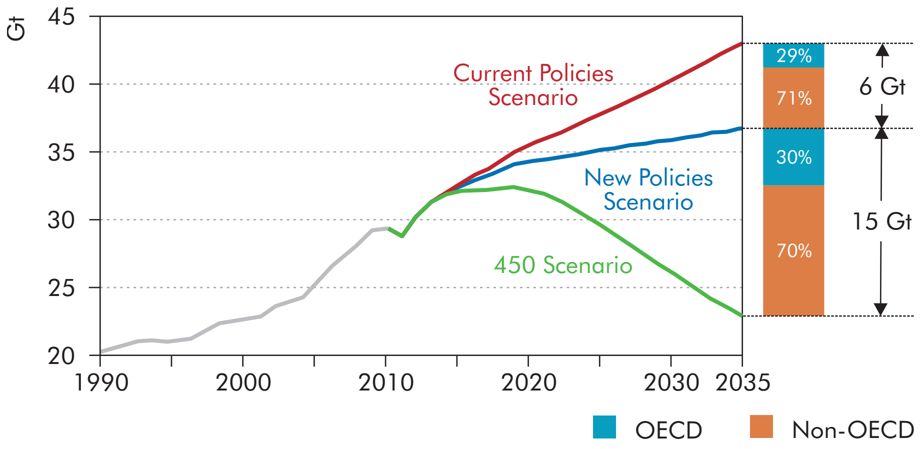
A degree of consensus is evident among climate experts that anthropogenic GHG emissions produced, for example, from the burning of fossil fuels, are primarily responsible for global warming. As a response, global leaders have indicated the desirability to limit the global temperature increase to 2°C. To achieve this, the concentration of GHGs in the atmosphere would need to be stabilised at a level around 450 ppm CO_2-eq. The *World Energy Outlook 2012* investigates how, despite increasing challenges, the objective for a maximum 2°C temperature rise can be achieved in its 450 Scenario through radical and co-ordinated policy action across all regions.

Reducing CO_2 concentrations in the atmosphere may be achieved in large part by reducing emissions of CO_2. The New Policies Scenario predicts that global CO_2 emissions will rise to a level of 36 gigatonnes (Gt) per year by 2035.

In the 450 Scenario, total energy demand in 2035 is approximately 12% lower than that in the New Policies Scenario, but still above 2011 levels. Crude oil demand in 2035 is about 21% lower than in the New Policies Scenario and, compared to 2009, about 8% lower. Energy-related CO_2 emissions in the 450 Scenario peak at 32.7 Gt just before 2020 and decline thereafter to 23 Gt by 2035, taking them significantly below the 2010 level of 29.4 Gt. A 2°C scenario presents an extremely demanding challenge (Figure 1.4).

The key steps to reducing the bulk of GHG emissions include: improving end-use energy efficiency; decarbonising the power and transportation sectors through improved efficiency and fuel switching; using alternative sustainable energy sources; and by deploying on a large-scale carbon capture and storage.

Figure 1.4 **•** *World energy-related CO_2 emissions, by scenario*



Source: IEA, 2012.

Classifying resources and reserves

Fossil fuels have had and continue to have a dominant role in fuelling the world's economy. But for how much longer? This has been a recurring question in public debate over recent years. Remaining resources and reserves of fossil fuels are finite. Some resources have yet to be found. There is considerable uncertainty about the magnitude of "undiscovered resources". Essential to the debate on resources and reserves, of course, is a clear understanding of the terminology.

Oil and gas

Before classifying resources and reserves, it is essential to understand the difference between conventional and unconventional hydrocarbons (Box 1.1 and Box 1.2). There is no universally agreed definition of what is meant by conventional oil or gas as opposed to unconventional hydrocarbons. Generally speaking, any source of hydrocarbons that requires production technologies significantly different from those used in currently exploited reservoirs is described as unconventional. However, this is clearly an imprecise and time-dependent definition. In the longer term, unconventional oil and gas may well become the norm rather than the exception.

Box 1.1 • Unconventional oil

Unconventional oil, as defined by the International Energy Agency (IEA), includes the following categories:

- ***kerogen shale**, also referred to as oil shale, generally refers to any sedimentary rock that contains kerogen, from which oil (or kerogen oil) may be produced by heating the kerogen;*
- ***oil sands** contain a dense and extremely viscous form of petroleum, technically referred to as bitumen;*
- ***light tight oil (LTO)** refers to light crude oil trapped in low permeability, low porosity shale, limestone and sandstone formations;*
- *oil derived from **coal-to-liquids (CTL)** technologies and oil derived from **gas-to-liquids (GTL)** technologies;*
- *various technologies may be used to convert **biomass-to-liquids**.*

Some experts, however, use a definition based on oil density, or API gravity. For example, all oils with API gravity below 20°,* i.e. *density greater than 0.934 grams per cubic centimetre, are considered to be unconventional. This includes heavy oils, bitumen and tar deposits. While this classification has the merit of precision, it does not always reflect technologies used for production. For example, some oils with 20°API gravity located in deep offshore reservoirs in Brazil are extracted by using entirely conventional techniques.*

Other experts focus on the viscosity of the oil. They regard as conventional any oil that can flow at reservoir temperature and pressure without recourse to viscosity-reduction technology. But such oils may still need special processing at the surface if they are too viscous to flow at surface conditions.

Another approach, used notably by the United States Geological Survey, is to describe oil or gas according to the geological setting of the reservoir. The hydrocarbon is conventional if the reservoir sits above water or water-bearing sediments and if it is relatively localised. If neither is the case, the hydrocarbon is unconventional. This type of definition has a sound geological basis, but does not always connect with the technologies required for production, which are a point of interest in this study.

* API gravity (American Petroleum Institute) is a measure of the density of oil. The API gravity scale is calibrated such that most crude oils as well as distillate fuels will have API gravities between 10° and 70° API gravity degrees. The lower the number, the heavier and the more viscous the oil is.

Box 1.2 • Unconventional gas

Definitions for "unconventional" are equally imprecise for gas as they are for oil. Generally, the industry classifies as unconventional the gas that is found in unusual types of reservoir.

The IEA divides unconventional gas into four broad categories:

- ***tight gas*** *is natural gas trapped in extremely low-permeable and low-porous rock, sandstone or limestone formations. Such gas may contain condensates;*
- ***shale gas*** *is natural gas contained in organic-rich strata dominated by shale. Because of the types of reservoir, it is sometimes considered a sub-category of tight gas;*
- ***coal-bed methane (CBM)*** *is methane adsorbed on to the surface of coal within coal seams;*
- ***methane hydrates*** *are made up of methane molecules trapped in a solid lattice of water molecules under specific conditions of temperature and pressure.*

CBM has an unambiguous definition and there is a continuum between conventional and tight reservoirs, without any sharp transition. While stimulation techniques are used in the production of tight gas and shale gas, they are also frequently used for conventional reservoirs.

The characteristics of methane hydrates are different from the other three and its potential lies in a longer-term time horizon.

"Lean gas" and "sour gas" may also be described as unconventional, i.e. gas contained in conventional gas reservoirs, but with a high concentration of impurities (nitrogen and CO_2 for lean gas, hydrogen sulphide [H_2S] for sour gas). The presence of such impurities negatively impacts the economics of production.

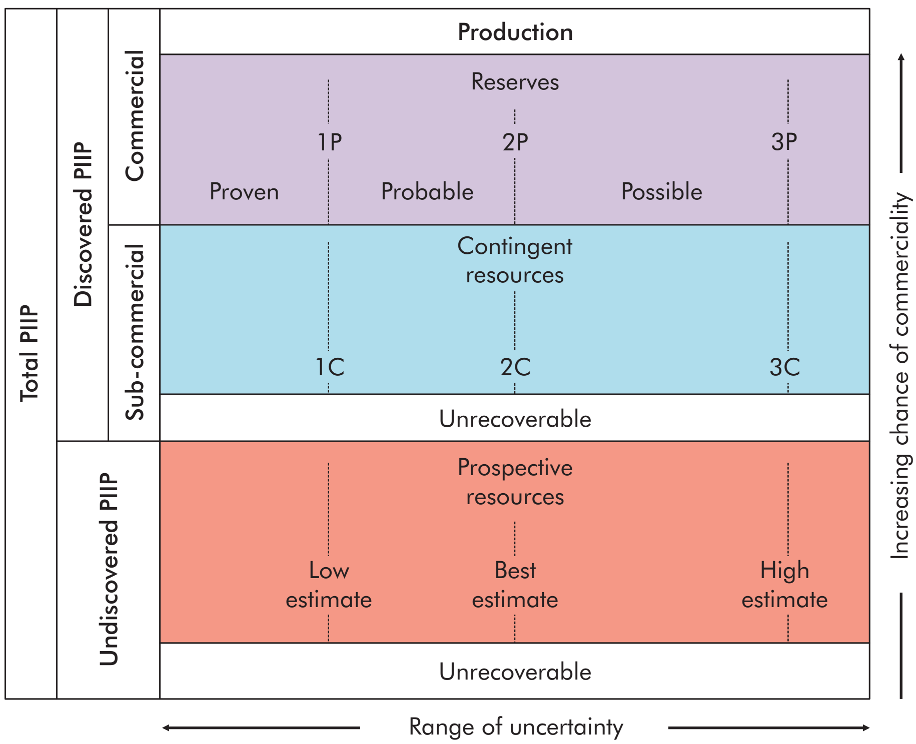
The definitions of resources and reserves often lend themselves to a degree of confusion. Different classification systems have existed in different parts of the world. The amount of fossil hydrocarbon resources (or hydrocarbons in place) can be categorised according to the degree of certainty that they exist and, in most cases, by the likelihood that they can be extracted profitably. Some international efforts have been made to harmonise approaches to classifying reserves. A joint publication of the Society of Petroleum Engineers (SPE), the World Petroleum Council, the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE), published in 2007, contained guidelines on the definition and classification of resources, called the Petroleum Resources Management System (PRMS).[1] This system is compatible with the 2004 UN Framework Classification for Fossil Energy and Mineral Resources (UNFC), developed by the UN Economic Commission for Europe (UNECE). The PRMS classifies resources and reserves according to the level of certainty about recoverable volumes and the likelihood that they can be exploited profitably. The classification applies to both conventional and unconventional resources.

1. www.spe.org/spe-app/spe/industry/reserves/prms.htm

The PRMS resources classification system is represented in Figure 1.5. The system classifies the major recoverable resources as follows: production, reserves, contingent resources and prospective resources, as well as unrecoverable petroleum.

The "range of uncertainty" reflects the estimated quantity that is potentially recoverable from an accumulation by a project. The vertical axis represents the "chance of commerciality", which is the chance that the project will be developed and reach commercial producing status.

Figure 1.5 • Resources classification system



Notes: PIIP = petroleum initially in place; the relative proportions of the various parts of this chart are not to scale. Reserves are designated as 1P (Proved), 2P (Proved + Probable), and 3P (Proved + Probable + Possible); the equivalent categories for contingent resources are 1C, 2C, and 3C.

Source: SPE, 2007.

To be classified as "reserves", a deposit must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming. Evidence of the firm intention to proceed with development within a reasonable time frame is required.

"Contingent resources" are volumes that could become reserves but for which exploitation is not yet properly defined and approved, or essential technology developments are not yet completed. The price of oil or gas is a key parameter for assessing the possible profitability of a potential project.

The US Securities and Exchange Commission (SEC), which imposes standards for reporting oil and natural gas reserves for companies quoted on US stock exchanges, adopted revisions to its rules (Box 1.3).

Box 1.3* • *New SEC reporting rules for reserves

The revisions aligned and incorporated many of the definitions in the SPE PRMS (SEC, 2008). The revised rules came into effect on 1 January 2010.

While significant changes have taken place in the oil and gas industry since the original reporting requirements were adopted more than 25 years ago, the SEC proposal now allows for the following:

- *The use of new technologies to determine which reserves may be classified as proven, if those technologies have been demonstrated empirically to lead to reliable conclusions about volumes of the reserves.*
- *Companies to disclose their probable and possible reserves to investors. Previous rules limited disclosure to proven reserves only.*
- *Previously excluded resources, such as mineable oil-sands, to be classified as oil and gas reserves. Previously these resources were considered to be mining reserves.*

The IEA uses a related set of definitions:

- **Reserves.** They are generally defined as the portion of energy resources that can be recovered economically by using current technologies and for which a project has been defined. The amount of reserves depends on two factors that are key to defining a project: current hydrocarbon price and available technology. Reserves are further categorised as proven, probable or possible, depending on the degree of certainty. For many years, the SEC only allowed the disclosure of proven reserves (Box 1.3). However, new rules came into effect at the beginning of 2010 that give more credit to better information provided by technological developments. Note that many operating companies already report proven reserves below the mean expected value (*i.e.* proven + probable, or 2P). The PRMS promotes consistent reporting, including reports of SEC reserves as well as reports from companies not listed on the US stock exchange, which is the majority of companies with resources.

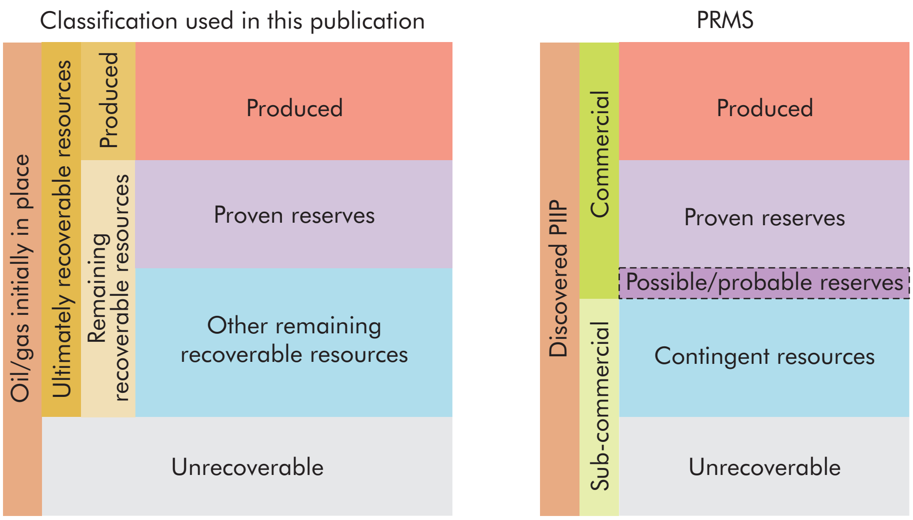
  Estimates of reserves in each category can change as the underlying assumptions are modified or new information becomes available. For example, as the oil price rises, some resources that were previously classified as non-commercial may become profitable and could be moved into the possible, probable or proven (3P) reserves category upon definition of a suitable project.

- **Remaining recoverable resources.** Refers to the volume of remaining hydrocarbons that could still be produced. The part of remaining recoverable resources beyond volumes already identified as reserves are referred to as “other remaining recoverable resources". These latter resources consist of volumes that are not financially viable to recover for a number of reasons. Such reasons could include: the oil price; lack of available technology; or resources that are based on geological research but are yet to be discovered. They are equivalent to the contingent resources plus possible/probable reserves in the PRMS definition.

- **Ultimately recoverable resources.** In a given reservoir, they are the latest estimates of the total volume of hydrocarbons that are judged to be ultimately producible for commercial purposes. In other words, the sum total of the amounts extracted plus remaining recoverable resources.

The relation between the classification used by the IEA and those from the PRMS are illustrated in Figure 1.6.

Figure 1.6 • Classifications for discovered fields, comparing this publication to the PRMS



Courtesy of W. Schulte.

Unlike either the SEC or the IEA, the classification of reserves used in Russia is based solely on an analysis of the geology and does not include economic assumptions associated with extraction. Generally, the Russian system classifies oil and gas deposits as reserves if the deposits are technically recoverable with available technology, even if their recovery is uneconomic. Although international standards are increasingly being adopted, the Russian classification is still used in many contexts and, therefore, remains particularly relevant to practitioners.

Coal

Two principal institutions that regularly publish data on global coal reserves and resources are the World Energy Council (WEC) and Germany's Federal Institute for Geosciences and Natural Resources (BGR). On the occasion of the World Energy Congress, the WEC publishes a "Survey of Energy Resources" every three years, most recently in 2010 (WEC, 2010). The survey provides a comprehensive examination of energy resources, covering production, consumption as well as quantities available. The WEC obtains most of its data from its members. BGR publishes annual studies on reserves, resources and the availability of energy raw materials worldwide (BGR, 2011). BGR also maintains country-specific data on reserves, resources, production and consumption of non-renewable energy sources (oil, gas, coal and nuclear fuels).

Other organisations, including the United States Energy Information Administration, the IEA, BP and the RWE Group tend to use either WEC or BGR sources as a basis for total hard coal and lignite reserves.

International surveys of global coal reserves and resources collate data by requesting reserves and resources from various associations, geological services, ministries or coal producers. As almost every country has its own classification system, cross-border comparisons of the quantities of reserves and resources are rarely possible.

The BGR classification is often used when classifying coal reserves and resources (Box 1.4). However, there is no internationally recognised and uniform procedure for recording, classifying and designating coal deposits. Reasons for the lack of uniformity are largely historic. In many regions, classification was introduced to provide an overview of potential deposits to inform the mining industry (Fettweis, Kelter and Nöstaller, 1999). In the West, though mining companies were the major stakeholders, classification was also developed to inform investors and banks involved in financing mining projects (Akin, 1997). Much of Eastern Europe was consistent in the particular classification applied there. Attempts have been made over many years to resolve this lack of uniformity. The UNFC launched in 1997, and updated in 1999 during a discussion with the Council of Mining and Metallurgical Institutions, has been adopted in important mining countries such as China (Bucci *et al.*, 2006) and Indonesia (Ersoy, 2003).

Box 1.4 • *BGR classification of coal reserves and resources*

Coal can be subdivided into soft brown coals (lignite) and hard coals (bituminous and sub-bituminous coals). Hard coals are all coals with a heat content of >16.5 megajoules per kilogram and are essentially those suitable for world trade. Soft brown coals are those with high moisture and lower energy content, which are usually converted into electricity at source. There are differences in categorising coal, depending on the country, and therefore also in differentiating between hard coals and lignites.

The following are definitions for coal reserves, resources and total resources, based on the BGR classification:

- ***Reserves.*** *Refer to the amount of known or proven coal resources that can be recovered economically by using available technology. The reserve figures depend on the price of coal as well as on technological progress. The following expressions are widely used as synonyms for the term reserves: "recoverable reserves" and "proven recoverable reserves".*
- ***Resources.*** *Refer to the amount of coal resources in place that are either: i) proven but not economically recoverable; or ii) based on geological research but as yet not discovered.*

Note that the reserves are not included in the resources. (The WEC refers to these resources as the estimated additional amount in place and does not include speculative amounts, leading to substantially different values.)

- ***Total resources.*** *Refer to the sum total of reserves plus resources.*

Resources are in situ *remaining quantities that take no account of losses due to a lack of mining technology needed to develop the resources.*

Note that the definition of resources for coal is different from the definition of resources for oil and gas, which includes produced volumes and reserves substantiated by using further classifications such as remaining recoverable and ultimately recoverable.

Resources and reserves

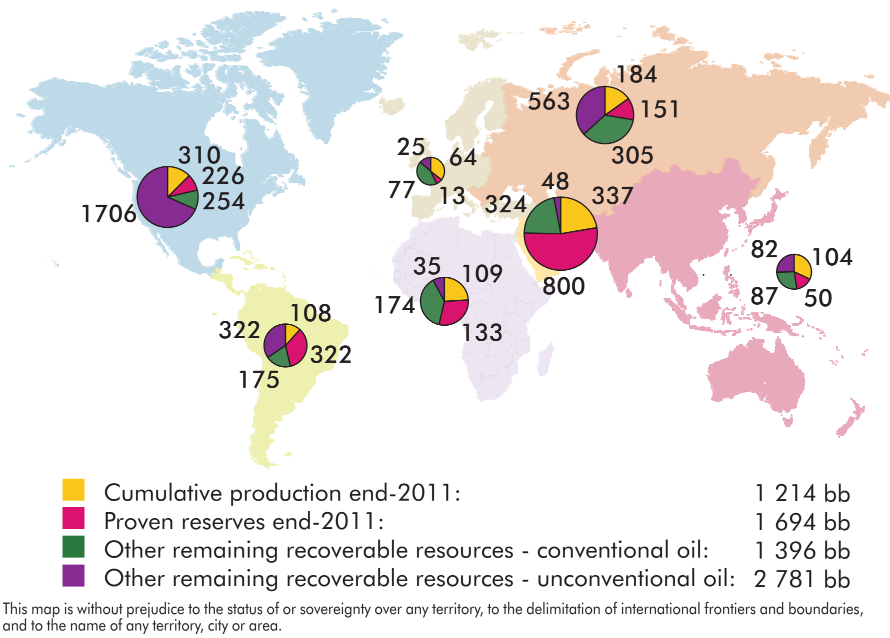
Estimates of the global total endowment of economically exploitable fossil fuels and renewable energy resources indicate that they are more than sufficient to meet the projected increase in consumption to 2035. There is, however, some uncertainty about whether energy projects will be developed quickly enough to bring these resources to market in a timely manner. Many factors could prevent investment such as: uncertainty about the economic outlook; developments in climate change and other environmental policies; depletion policies in key producing regions; changes to legal, fiscal and regulatory regimes; and delays in infrastructure and shipping capacity.

Oil resources and reserves

Various estimates of remaining economically recoverable reserves of global oil do not vary greatly, despite differences in the way they are reported. Most estimates of current proven reserves of crude oil amounted to almost 1 700 billion barrels (bb) at the end of 2011. Globally, proven reserves have increased steadily since 1990, despite increasing demand. One of the major changes in recent years has seen Venezuela become the leading country for proven reserves, having overtaken Saudi Arabia in 2010. Following the most recent assessment of its Orinoco belt, Venezuela's proven oil reserves jumped from 99 bb to 291 bb. On a regional level, the largest conventional resources are located in the Middle East and Russia (Figure 1.7).

Given current levels of production, the global reserves-to-production ratio (R/P)[2] is currently estimated to be 68 years (based on 2011 estimates). However, this value depends on the source and whether unconventional resources are included (O&GJ, 2009).

Figure 1.7* • *Regional distribution of crude oil resources, reserves and production in 2012



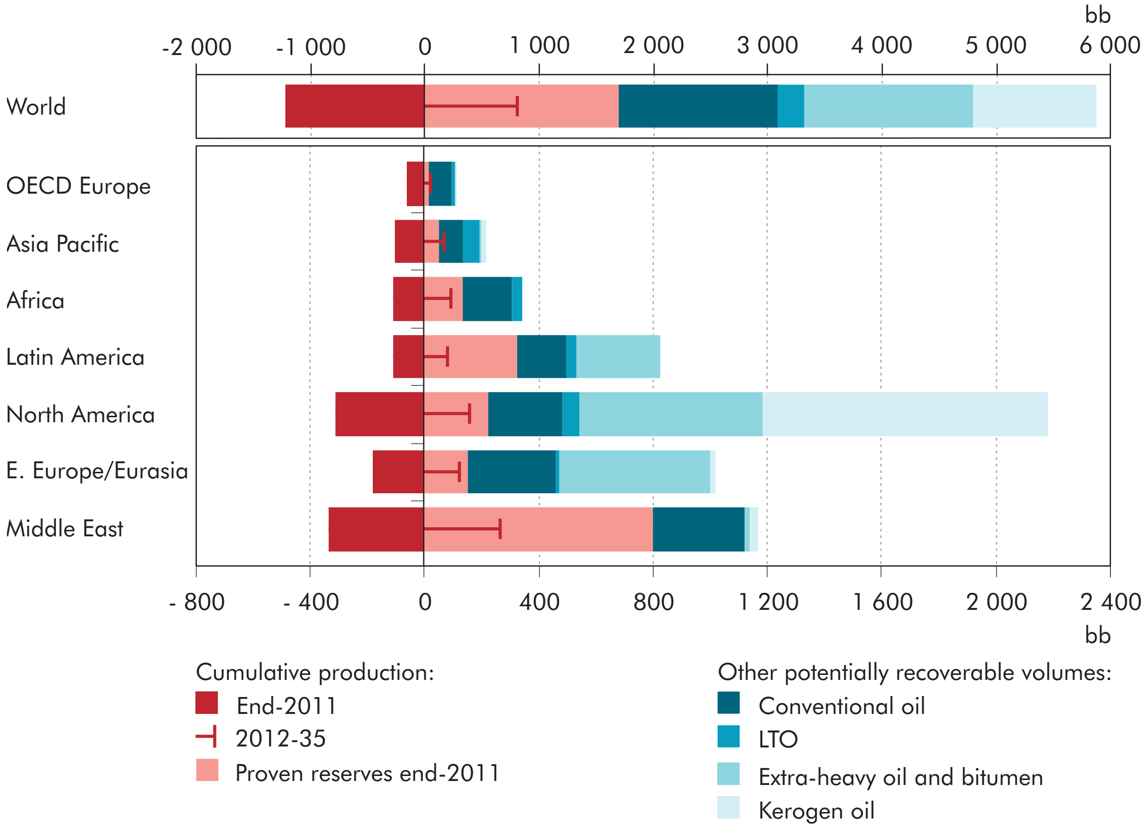
Source: IEA, 2012.

The Middle East holds the largest proven conventional oil reserves and other remaining recoverable resources, followed by Eurasia and Africa (Figure 1.8).

A closer look at the proven oil reserves (conventional and unconventional) on a country-to-country basis shows that Venezuela overtook Saudi Arabia as the country with the largest proven oil reserve, followed by Canada and Iran (Figure 1.9). Following the new reserves added in 2011, Venezuela has risen in ranking from fourth in 2009 to first place with an R/P ratio beyond 250 years.

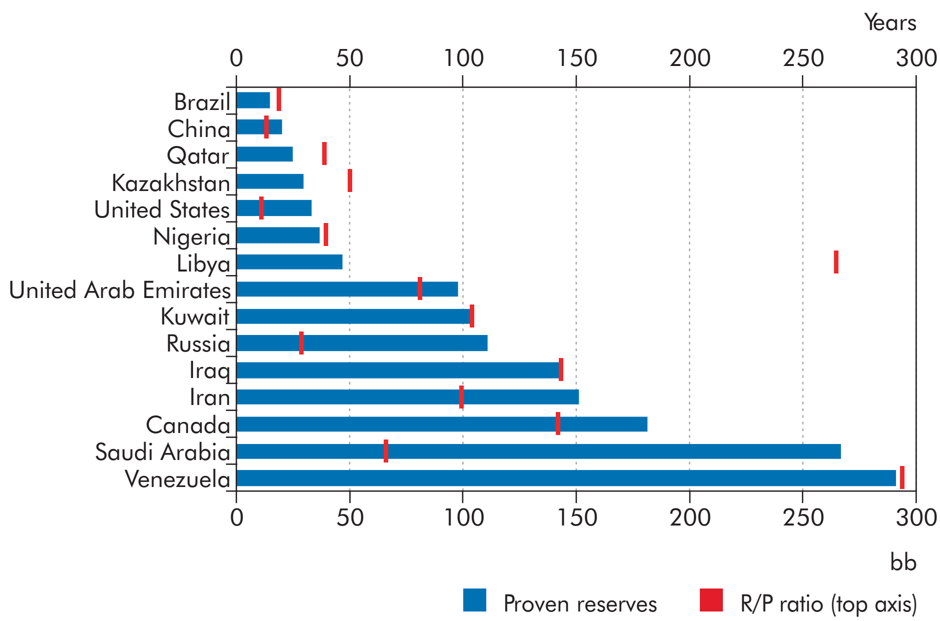
2. R/P ratios are commonly used in the oil and gas industry as indicators of production potential. However, the ratios do not imply continuous output for a certain number of years, nor that oil production will stop at the end of the period. They can fluctuate over time as new discoveries are made, reserves at existing fields are reappraised and technology and production rates change.

Figure 1.8* • *Ultimately recoverable resources of oil in the New Policies Scenario, by region



Source: IEA, 2012.

Figure 1.9* • *Proven oil (crude and natural gas liquids [NGL]) reserves in the top 15 countries, end-2011



NGL = natural gas liquids.

Source: IEA, 2012.

The volume of oil discovered every year has been higher, on average, since 2000 than in the 1990s, thanks to increased exploration activity and improvements in technology. However, despite some significant recent finds, such as in deep water offshore Brazil, the volume of oil in new discoveries has fallen well below the volume of oil produced in recent years.

Discoveries dropped from an average of 56 billion barrels per year (bb/yr) in the 1960s to 13 bb/yr in the 1990s. The number of discoveries peaked in the 1980s, but fell sharply in the 1990s. This sharp decline was largely the result of less exploration in regions with the largest reserves where access by international companies is most difficult. A drop in the average size of discovered fields was also a contributing factor. The downward trend in the volume of oil discovered reversed slightly in 2000-09, thanks to increased exploration activity (with higher oil prices). Since 2000, an average 14 bb/yr has been discovered.

Conventional oil resources

Ultimately recoverable conventional oil resources are estimated at 3.1 trillion barrels. This figure includes: initial, proven and probable reserves from discovered fields; increases in reserves; and oil that has yet to be found. Until now, only one-third of this total, or 1.2 trillion barrels, has been produced. Undiscovered resources account for about one-third of the remaining recoverable oil, the largest volumes of which are believed to lie in the Middle East, Russia and the Caspian region.

Unconventional oil resources

Unconventional oil resources, which have been barely developed to date, are also very large. It could now be financially viable to recover between 1 trillion barrels and 1.5 trillion barrels of oil sands and extra-heavy oil. These resources are largely concentrated in Canada and Venezuela. In Canada, deposits of bitumen amounting to 0.8 trillion barrels of original oil in place have already been discovered. In Venezuela, there are about 0.5 trillion barrels of extra-heavy oil in place in the Orinoco belt. Global kerogen shale resources in place are conservatively estimated at 4.8 trillion barrels and currently largely undeveloped owing to the high cost. This resource estimate is conservative in view of the fact that the kerogen shale resources of some countries are not reported and other deposits have not been fully investigated (WEC, 2010). An unconventional resource in the form of liquid oil, or LTO, that is trapped in low-permeability shales can also now be recovered by using current technology. Quantities could be considerable when global resource values are estimated. In 2010, estimates of unproved technically recoverable resources of LTO in the United States alone stood at 33.2 bb (EIA, 2012).

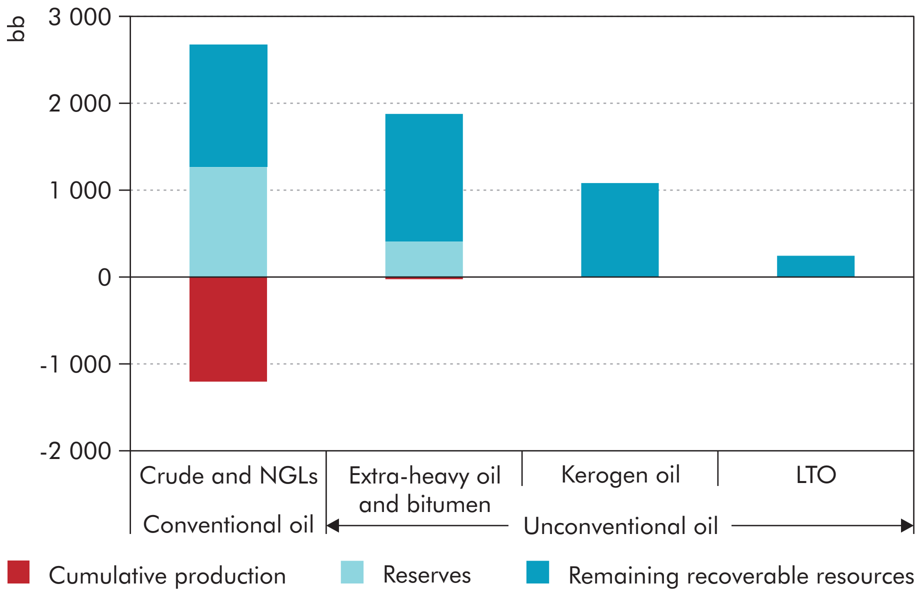
Currently estimated recoverable resources for unconventional oil are about the same as those for conventional oil (Figure 1.10). The potential total of long-term remaining recoverable oil resources, which includes: conventional oil volumes plus extra-heavy oil, oil sands, kerogen shale and undiscovered recoverable volumes is estimated to be almost

6 trillion barrels. Adding CTL and GTL could increase this potential to about 8 trillion barrels.

Converting coal to a liquid fuel, in a process known as coal liquefaction, enables coal to be used as an alternative to oil. The coal may be converted into liquid fuels, such as petroleum or diesel, using either direct or indirect liquefaction. Further information on coal-to-liquids (CTL) may be found in Chapter 7.

The term GTL refers to technologies designed to convert natural gas into liquid fuels, as an alternative to oil. Further information may be found in Chapter 3.

Figure 1.10* • *Conventional and unconventional oil reserves and resources in 2011

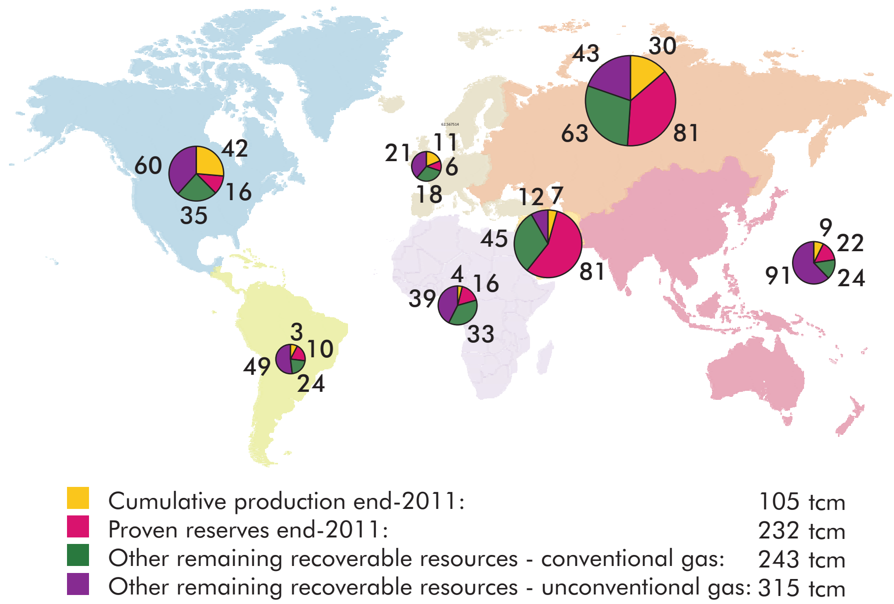


Source: IEA, 2012.

Natural gas resources and reserves

Global conventional natural gas resources are vast but, to an even greater degree than oil resources, are highly concentrated in a small number of countries and fields. Proven reserves amount to 232 trillion cubic metres (tcm) at the end of 2011, which is equal to more than 60 years of production at current levels. These reserves have more than doubled since 1980, with the biggest increases coming from the Middle East. Three countries, Russia, Iran and Qatar, contain 54% of global proven natural gas reserves, while just ten fields worldwide (including five in Russia) hold 27% of the total. Organization of the Petrolum Exporting Countries (OPEC) member countries also represent about 40% of global reserves (Figure 1.11).

Figure 1.11* • *Distribution of conventional natural gas in 2012



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

Source: IEA, 2012.

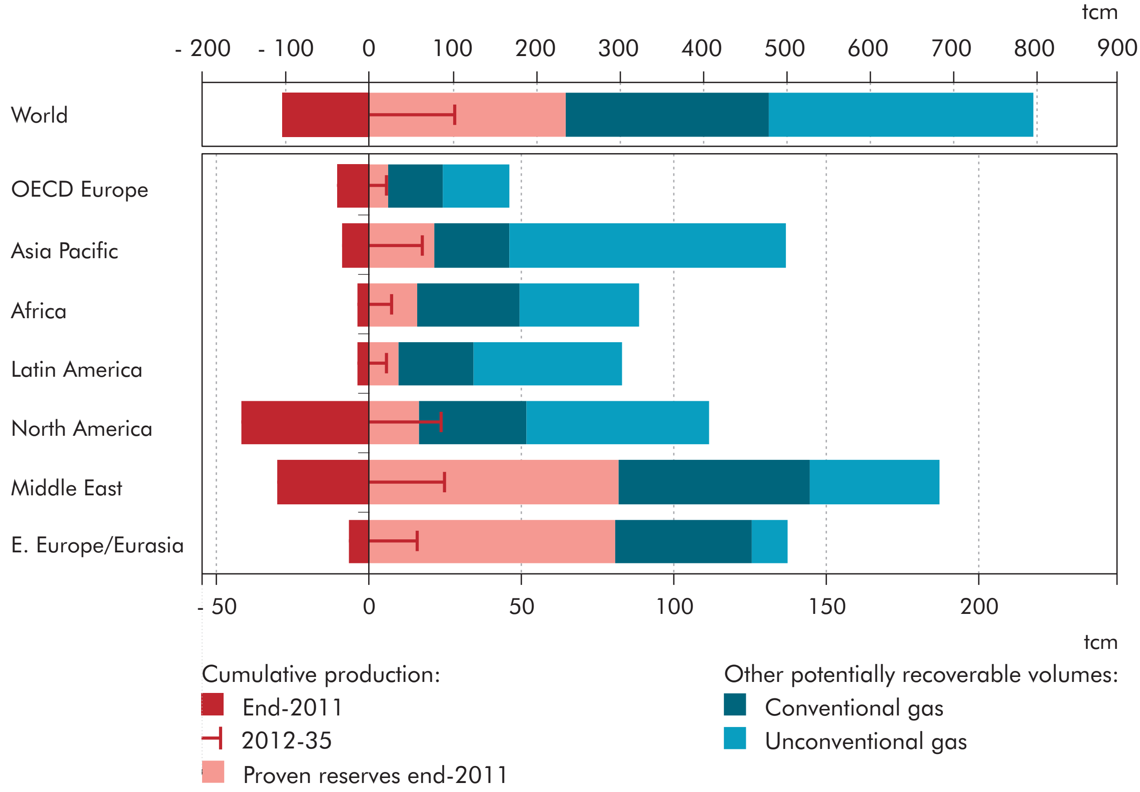
Conventional gas resources

Shares in global natural gas production are very different from shares in reserves. The Middle East, for example, accounts for only 11% of cumulative global production (Figure 1.12). North America contains only 4.5% of global conventional natural gas reserves but accounts for 26% of cumulative production: its reserves/production ratio is only 12. Europe has the second-lowest R/P ratio at 18. These disparities largely reflect differences in the proximity of reserves to markets and the investment climate.

As with oil, the bulk of the increase in proven gas reserves in recent years has come from upwards revisions for fields that have been producing or have been appraised and developed. Nonetheless, newly discovered volumes remain large. Except for the recent discoveries in Mozambique, the size of gas discoveries has been steadily declining in recent decades. Unlike oil, however, volumes discovered continue to exceed production. Reserve reappraisals, evaluations and new discoveries increased potentially recoverable resources by roughly 70 tcm from 2010 to 2011 (IEA, 2012).

Remaining recoverable resources of conventional natural gas, including proven reserves, reserves growth and undiscovered resources, could amount to some 463 tcm (IEA, 2012), representing more than a century of production at current levels.

Figure 1.12 • Cumulative production, proven reserves and resources for conventional natural gas, by region



Source: IEA, 2012.

Unconventional gas resources

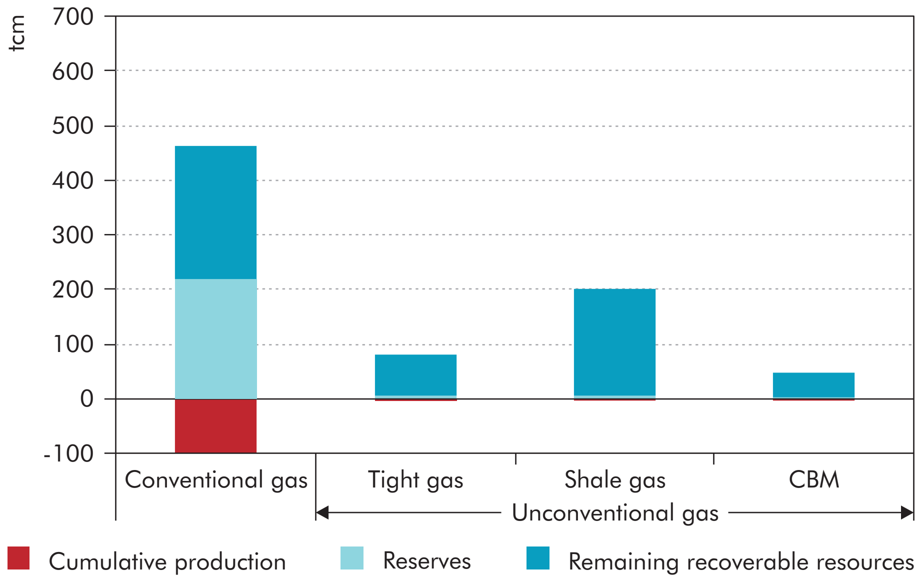
Unconventional remaining recoverable gas resources, including CBM, tight gas and gas shales, amount perhaps to an additional 327 tcm, with 20% in the United States and Canada combined.

These resources are described in more detail in Chapter 6. Reserve assessments are more difficult because of the heterogeneity of the rock formations, their very low permeability and the uncertainty in the volume of reservoir that can be connected to a production well. As unconventional gas has become a significant component of total gas supply, more accurate assessment of reserves and recoverable resources will become more urgent (Figure 1.13).

Australia-Asia, North America and the CIS[3] account for 92% of hard coal reserves, of which more than 43% are in Australia-Asia (almost exclusively China, India and Australia), almost 33% in North America (almost exclusively in the United States) and just under 17% in the CIS (Figures 14 and 15). A similar picture applies for resources. The United States has about 39% (almost half being in undeveloped regions of Alaska), China has 29% and Russia has nearly 16%.

3. CIS countries formally comprise Armenia, Azerbaijan, Belarus, Kazakhstan, Kyrgyzstan, Moldova, Russia, Tajikistan and Uzbekistan. Though they have not ratified the charter, Turkmenistan and Ukraine are here considered part of the CIS.

Figure 1.13* • *Conventional and unconventional natural gas reserves and resources (end-2011)



Source: IEA, 2012.

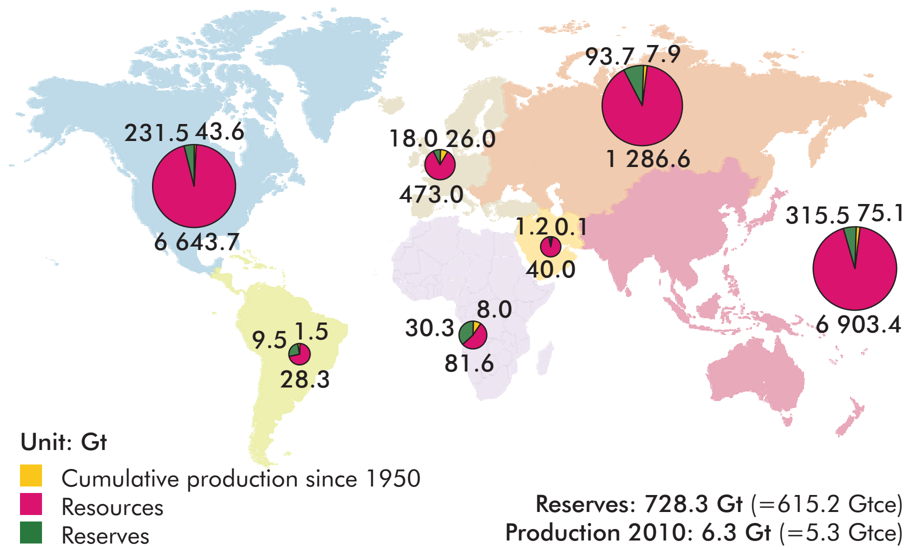
Coal resources and reserves

Coal is an important source of energy owing to its widespread and abundant supply. Different types of coal are usually referred to according to their rank, which is loosely related to the age of the coal. Hard coals are of higher rank and are usually older. Softer coals or lignites are generally younger. Classifications are discussed in more detail in Chapter 7. BGR estimated remaining recoverable resources of hard coal and lignite to be 22 362 Gt at end-2010.[4] Most of this is hard coal at 17 932 Gt (80%), with 4 430 Gt (20%) for lignite. Of the total hard coal resources, some 17 204 Gt, or nearly 96%, are classified as resources and 728 Gt (4%) as reserves (Figure 1.14).

Global coal reserves could meet demand for many decades if production continues at current levels. Given that remaining recoverable resources are even larger, it is unlikely that there would be a shortage of coal.

4. Hard coal and lignite have different energy content. The coal total resource of 22.4 trillion tonnes translates to around 16.8 trillion tonnes of coal-equivalent (tce) (1 tce is 0.7 tonnes of oil-equivalent and 5.145 barrels of oil-equivalent [boe]). The coal resource base is, thus, equivalent to more than 86 trillion boe. However, mining losses are not incorporated in this value, so recoverable resources are likely to be significantly lower.

***Figure 1.14** • Distribution of hard coal reserves, resources and production, by region*

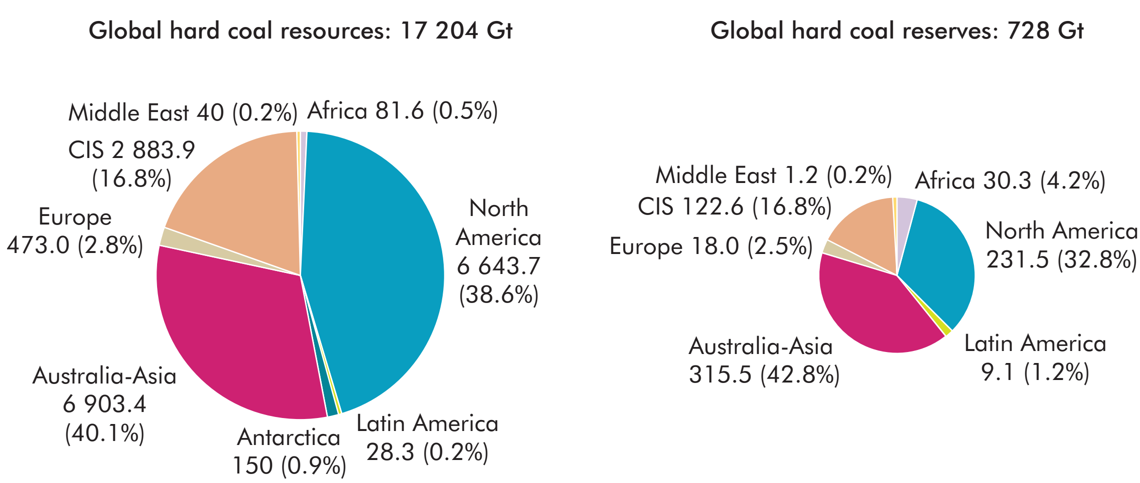


This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Note: Gtce = gigatonne of coal-equivalent.

Source: BGR, 2011.

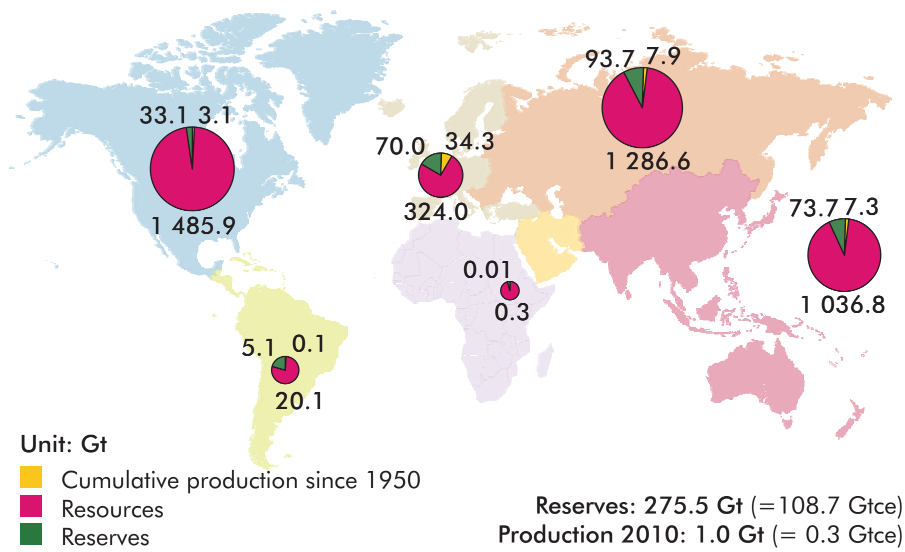
***Figure 1.15** • Global hard coal resources and reserves, by region*



Note: CIS = Commonwealth of Independent States.

Source: BGR, 2011.

Figure 1.16* • *Distribution of lignite reserves, resources and production, by region

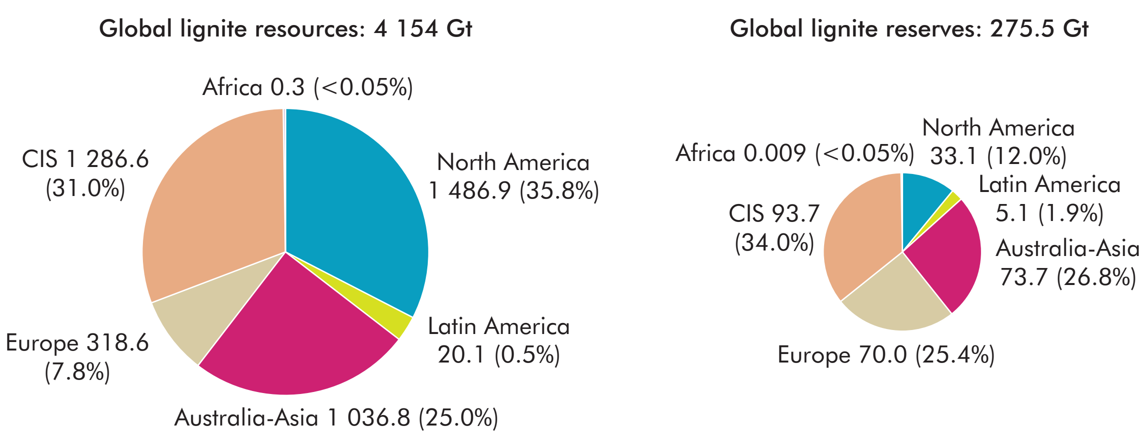


This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: BGR, 2011.

Reserves of lignite are distributed a little more widely than those of hard coal (Figures 1.16 and 1.17). Most are located in the CIS, Russia predominating with 33% of the global total. Australia-Asia has the second-largest lignite reserves (27%), most of which are in Australia, China and Indonesia. Europe has the third-largest reserves (25%), with Germany accounting for 15%. The United States has 11%.

Figure 1.17* • *Share of global lignite resources and reserves, by region



Source: BGR, 2011.

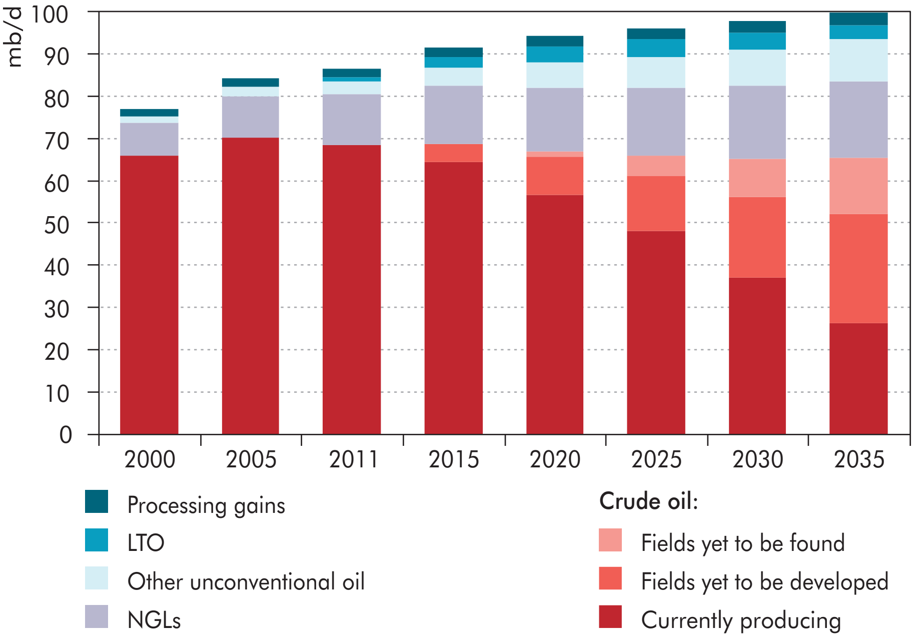
Most of the lignite resources are located in only three regions: North America, the CIS and Australia-Asia. About one-third of global lignite resources are located in North America (36%) and in the CIS region (31%). The largest lignite resources are in the United States (33%), Russia (31%) and China (7%).

Recent trends

The impact of declining oilfield production

The current forecast for global oil production shows an important phenomenon, namely that crude oil from existing fields will decline significantly. Given projected future demand, this decrease in output will need to be replaced by new developments or by new discoveries (Figure 1.18).

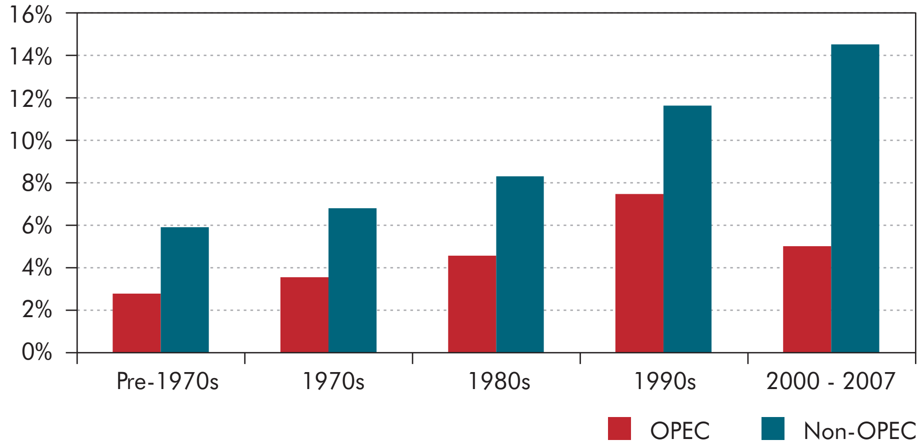
Figure 1.18* • *World liquid supplies, by type, in the New Policies Scenario



Source: IEA, 2012.

The rate at which production from oilfields declines once it has reached peak production is vital in determining the need for additional capacity. Such additional capacity can be found either by further developing existing fields or by bringing new fields into production. The average observed decline rate for oilfield production compared to the first year of production shows an increasing trend for non-OPEC countries, whereas the rate of decline is considerably slower for OPEC member countries (Figure 1.19). As decline rates are influenced by oil prices and technology, continued monitoring of this trend is essential to inform strategic decisions.

Figure 1.19* • *Average observed decline in oilfield production versus first year of production



Source: IEA, 2008.

Discussions about decline rates are often confused by a failure to make clear what is meant by the term and exactly how the rates are calculated. It is important to understand that, at any given moment, some oilfields will be ramping up to peak production, some will be at peak or plateau, and others will be in decline. Averaging rates across a group of fields does not, therefore, reveal any clear information on the decline rate of fields at different stages in their production lifecycle. Only a field-by-field analysis of production trends can shed light on this.

Global oil supplies are partly dependent on output from large, old fields. Although many of them have been in production for decades, output from super-giant (holding more than 5 bb of initial reserves) and giant fields (with more than 500 million barrels [mb]) has increased significantly over the past two decades through improved recovery rates.

Using its database, the IEA carried out a detailed field-by-field analysis of the historical production trends of 800 fields (IEA, 2008). The analysis indicated that observed decline rates are likely to accelerate in the long term in each major region of the world. This acceleration is caused by a reduction in the average field size and, in some regions, by an increase in the share of production expected to come from offshore fields. In general, the larger a field's reserves, the lower the peak relative to reserves and the slower the decline once the field has passed its peak. Rates are also lower for onshore than offshore fields (especially deepwater fields, *i.e.* at depths of over 400 metres [m]). Investment and production policies also affect the rate of decline.

Total supply in some countries from fields yet to be found or yet to be discovered will need to rise, in some cases significantly, just to offset decline. The implications are far reaching, with 1.6 mb/d of additional capacity (fields) needed each year by the end of the projection period just to offset the projected acceleration in the natural decline rate (Figure 1.19). An additional 55.5 mb/d in terms of supply, which is equivalent to roughly five times the current production rate of Saudi Arabia, would need to be brought on stream between now and 2035. This will require significant investment and advanced technological solutions.

Upstream oil and gas: volatility in oil price and impact on investments

In broad terms, investment becomes more attractive as oil prices rise. The higher and more stable the oil price, the more positive the climate for investment. The volatility of the oil price will increase uncertainty of project profitability, particularly if prices could fall as they did in early 2009. However, perceptions of relatively high prices, say USD 80 per barrel (/b) or higher, have now become entrenched, and the broader supply picture is much more robust than it was in 2008-09.

Events that impact on the economy will generally impact on energy demand and are more likely to lead to price volatility. In recent years, for example, the global financial crisis of 2007-08 that led to global recession and the "Arab Spring" that began in late 2010 have both illustrated the volatility of oil prices.

A significant increase in prices before the global financial crisis was followed by a slump to around USD 30/b during the crisis. The main impact of the dip in oil prices was that companies slowed down or even cancelled some of the more expensive project proposals. There was a reduced short-term need for new capacity. This crisis was followed by a succession of potentially destabilising events, notably the Arab Spring, sanctions in Iran, the Syrian conflict, the euro-zone crisis and China's "soft landing". For various reasons, these have all broadly acted to tighten supply and sustain relatively high prices.

Consequently, capital expenditure has now returned to levels seen before the global financial crisis. Oil companies have little problem in borrowing for investment. Global upstream investment totalled USD 572 billion in 2011 and is expected to rise by a further 8% in 2012 (IEA, 2012). This would increase investment by more than 20% on 2008 and five times the level of 2000. Higher costs, which have risen by 12% since 2009 and more than doubled since 2000, explain part of the increase.

In the long term, the increasing demand for oil will require new projects and new investments. Although the scale of investment and infrastructure remains significant, the view for global oil supplies has generally become more optimistic.

The impact of policies on oil forecast

As already highlighted, the IEA has created the following three scenarios for future energy demand and supply: the Current Policies Scenario; New Policies Scenario; and the 450 Scenario. These scenarios make projections based on current or potential policy measures adopted by governments worldwide. Each scenario projects a significant difference in production levels for the various resources. The case of oil is illustrated in Table 1.1. In the 450 Scenario, energy efficiency increases and the development of sustainable energy resources reduce the production of oil. These scenarios also show that, because of lower demand in the 450 Scenario, the oil price will be lower than in the New Policies Scenario. This is likely to have consequences on new developments, especially for the more costly unconventional resources. However, such developments may still be pursued, driven by a need to secure supply at the regional level.

Table 1.1* • *Production overview, by resource type (mb/d)

Resource	2011	2035		
		New Policies Scenario	Current Policies Scenario	450 Scenario
Crude oil	68.5	65.4	70.8	51.5
NGLs	12	18.2	19.5	14.4
Unconventional	3.9	13.2	15	10.8
Biofuels	1.3	4.5	3.7	8.2
Processing gains	2.1	2.9	3.2	2.3
World total liquids supply	87.9	104.2	112.2	87.2

Note: biofuels are expressed as energy-equivalent volumes of gasoline and diesel.

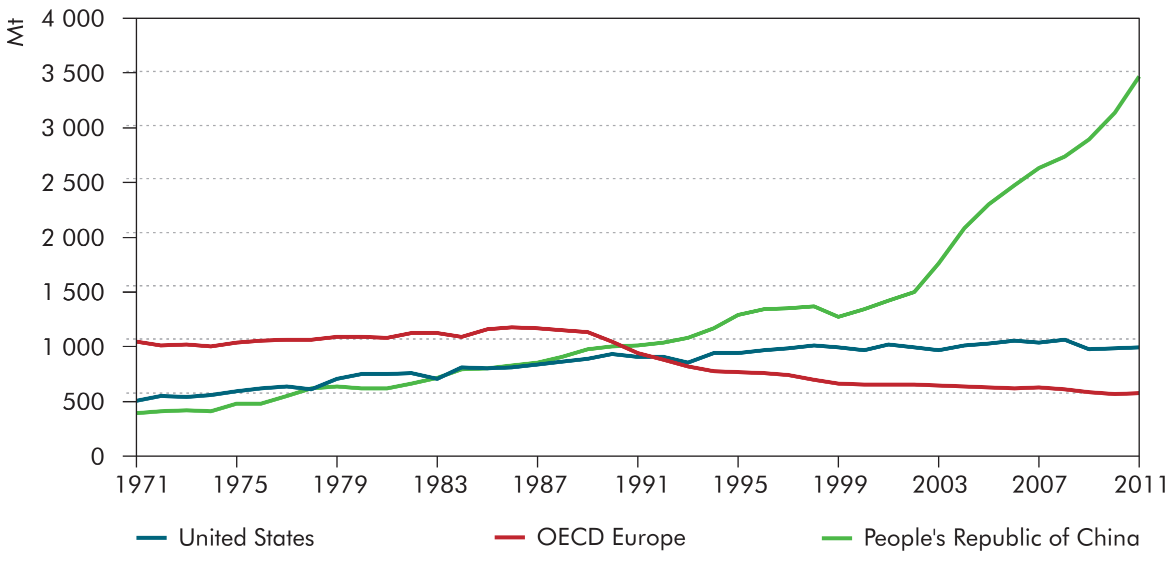
Source: IEA, 2012.

Though demand-side policies are important, it is worth noting again that the upstream investment environment and its perceived stability are probably the more important determinants influencing long-term oil supply.

Growth of coal consumption in China

China's dominant role in both the production and consumption of coal gives rise to some remarkable statistics. The period of sustained economic growth, particularly since its accession to the World Trade Organization (WTO), has led to a rapid increase in energy demand, an increase that has until now been satisfied largely by coal (Figure 1.20).

Figure 1.20* • *Annual coal production, by region



Note: Mt = million tonnes.

Source: IEA statistics.

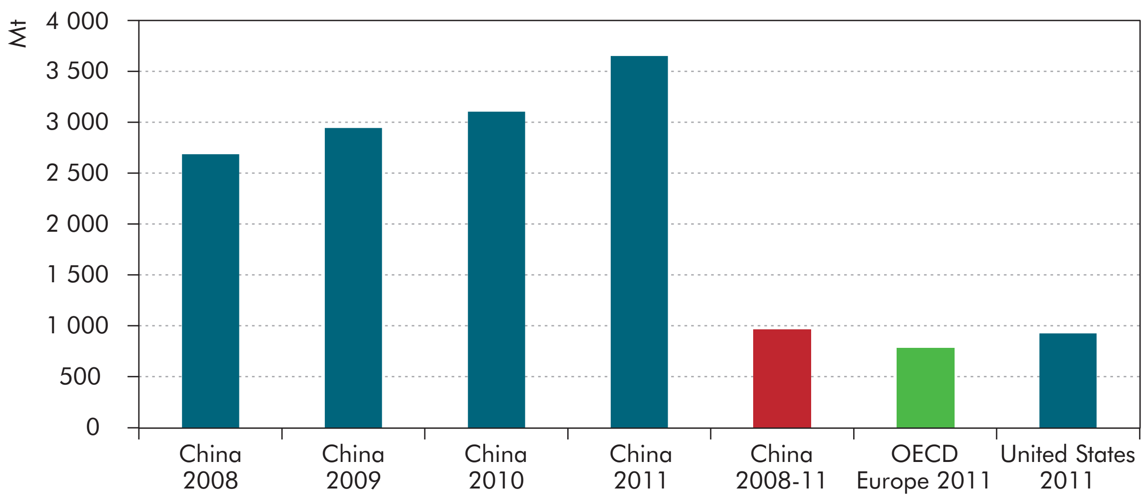
As for most countries, energy security is high among China's priorities and, predominantly as a result of its reliance on indigenous coal, the country is more than 90% self-sufficient in energy. In 2010, China produced an estimated 3 162 Mt of coal and imported a modest 177 Mt, leading to consumption of more than 3 300 Mt. China became a net importer in 2009 and became the world's largest importer of hard coal in 2011, surpassing Japan. It is clear that imports to China will have a significant impact on global coal trade. Given current trends, Chinese coal production may well reach 4 000 Mt by 2015. Factors such as an increase in gross domestic product (GDP), targeted reductions in energy intensity and deployment of competing energy sources will all determine the demand for coal.

The industry and power plants that consume most of the coal are concentrated in the east of China. However, with the centre of indigenous coal production moving westwards, coal reserves getting deeper and its east-west transport links under strain, China has turned to imported coal to meet increasing demand. As a result, the price of coal at Qinhuangdao, China's largest coal port, has become a key marker on coal prices, which increased through 2010 before levelling off through 2011.

Coal production in China has increased markedly over recent years. From 1 000 Mt in 1989, it took 15 years, to 2004, for production to reach 2 000 Mt but only a further five years to reach 3 000 Mt. The sharp increase in production in China is in stark contrast to the production in Organisation for Economic Co-operation and Development (OECD) member countries. While production has risen steadily in the United States, the decline in Europe has resulted in fairly stable coal production among all member countries (Figure 1.20).

The incremental increase in China's coal consumption for 2008 to 2011 is higher than total consumption in the United States in 2011 and significantly higher than the total coal consumption in OECD European countries for 2011 (Figure 1.21).

Figure 1.21* • *Comparison of coal consumption in China, Europe and the United States



Note: data estimated for 2011.

The need to manage water production

Although the key focus of this book is the production of fossil fuels, water is an inextricable part of the hydrocarbon recovery process, particularly in oil production operations. Some water is present naturally in the well and is displaced together with the oil. Though this water can be separated and reinjected, more water is required to sufficiently maintain well pressure. Water, either drawn from an aquifer or some other source, is often injected to push the oil towards the producing well.

As more and more water is injected, the percentage of water[5] in the well increases while the percentage of petroleum product declines. Oil wells are often only abandoned when the water content is above 98% of the wellstream. Global water production in 2007 was quoted to be around 250 mb/d compared with around 80 mb/d of oil, a water-to-oil ratio of around 3:1 (Dal Ferro and Smith, 2007). This situation will worsen as conventional oil reservoirs mature. The United States, a mature oil producer, produces on average around 8 barrels of water for each barrel of oil (Clark and Veil, 2009).

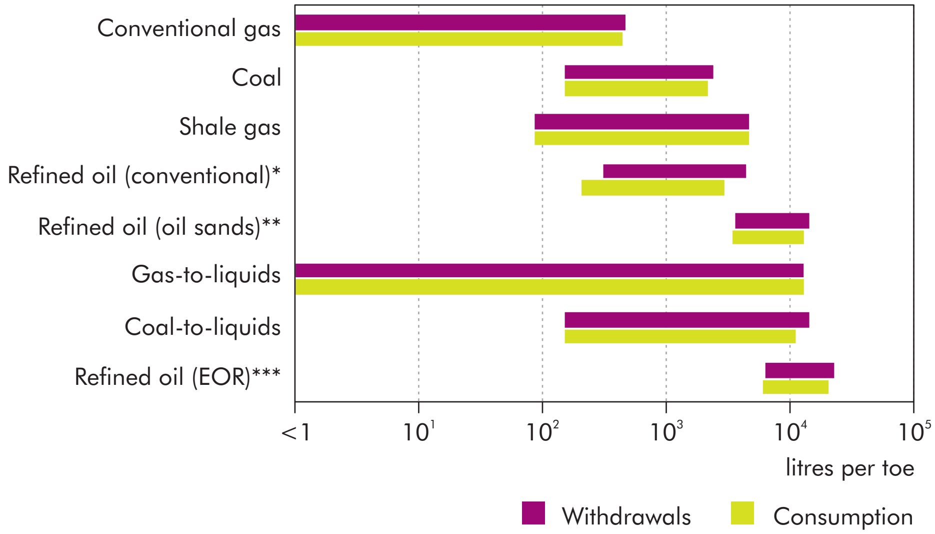
The water produced is then either discharged or treated so that it can be reinjected. In offshore production, the water produced is mostly discharged in the sea after proper treatment. In onshore production, the protection of potable water supplies is a major issue. Most of the discharged water must be treated because of contamination with traces of oil, heavy metals, boron and corrosive fluids such as H_2S, CO_2 and salt. Water treatment costs can be a substantial part of the total operating costs. Lack of adequate water discharge options can be a "show-stopper" for economic expansion of a project. However, the greatest value can come from reservoir management techniques that reduce produced water while maximising incremental oil recovery. Reducing water use is one of the key drivers for a substantial increase in smart field applications (see Chapter 2), in which measurement and control systems within the well (downhole) can shut off water if needed.

Water also plays a major role in unconventional oil and gas resources. Heavy oil is mostly developed through steam injection, requiring large amounts of clean water. The mining of oil-sands requires more barrels of water in its separation process than is produced as oil. In tight gas and shale gas production, the creation of fractures requires substantial amounts of water, often with additives to assist the fracturing process. Not all of this water is discharged with the gas during the production process, but those volumes that are will require special attention for disposal or reuse. In CBM operations, large volumes of water are initially extracted to reduce pressure in the reservoir, which promotes desorption of the methane. Water production subsequently tails off and methane production increases.

Water needs for fossil fuel production vary widely across all fuels, but overall gas extraction is less water-consuming than coal and oil (Figure 1.22).

5. Water discharged from a producing oil well is termed "produced" water.

Figure 1.22 *• Water use for primary energy production*



*The minimum is for primary recovery, the maximum is for secondary recovery. **The minimum is for *in situ* production, the maximum is for surface mining. ***Includes CO_2 injection, steam injection and alkaline injection, and in situ combustion. Ranges shown are for "source-to-carrier" primary energy production, which includes withdrawals and consumption for extraction, processing and transport.

Note: toe = tonnes of oil-equivalent.

Source: IEA, 2012.

Recent developments in technology

Innovations in oil and gas exploration and production

Over the past decade, a few key developments have had a considerable impact on the availability and development costs of oil and gas. Advances in computing power have led to a number of important developments. Four-dimensional seismic techniques have vastly improved the subsurface imaging that is required for effective reservoir management. Reservoir simulation models can now accommodate much more detailed geological data and contain complex production facilities, information essential to increasing their predictive power. Higher bandwidth communication, with real-time monitoring of drilling and production operations, has immensely improved field management.

Directional drilling, initially developed in the 1980s and 1990s, allows wells to follow complex paths, with their direction guided from the surface. The ability to drill multilateral wells, with side branches directed off the main borehole, has led to significant improvements in recovery rates. Modern drill bits are equipped with intelligent information technology that allows a thorough evaluation of rock layers while drilling, so that the well path may be revised as it progresses. In fact, steerable drill bits can now reach reserves more than 10 kilometres distant laterally, with an accuracy of some 2 m. This has substantially lowered the cost of developing fields and increased the recovery potential. It also enables near-offshore hydrocarbon deposits to be produced by drilling from onshore installations.

When oil or gas is trapped in low-permeability rock, hydraulic fracturing can stimulate the flow. Water containing high-viscosity fluid additives is injected under high pressure to open or create fractures in the rock. These fractures allow the hydrocarbons to by-pass a large part of the low-permeability rock and to move freely from the rock pores to a production well and thus to the surface. In most cases, longer and more complex wells are drilled, fractured in numerous stages along their length. This lowers the unit production costs. The process has recently been very successful in producing from tight oil and gas deposits in the United States that were previously not financially viable.

Developments in coal mining technology

Dramatic increases in equipment size and efficiency have significantly improved productivity at surface mines and reduced mining costs, despite more and more challenging geology. Further increases in the size and efficiency of surface mining equipment are likely to prove difficult. In underground mines, the extended use of highly efficient mining systems has also led to gains in productivity, improved yields and lower costs. These trends are currently occurring in China, where labour-intensive mines are being replaced by highly mechanised operations.

Competition for mining equipment has intensified worldwide and the relatively few equipment suppliers have struggled to keep pace. Moreover, costs of commodities, particularly steel, are high. Often the next generation of mining projects will be found in new mining countries like Mozambique and Mongolia or in new basins in existing coal-producing countries like Australia and South Africa. This leads to an increase in costs and new investments in infrastructure.

Gaps in clean energy RD&D funding

Technology plays a crucial role in finding and accessing hydrocarbon resources and for dealing with the environmental consequences of their consumption. As is typical for mature industries, the development of new technology is mainly driven by private investment. Nonetheless, public research, development and deployment (RD&D) investment is still important. While public expenditures on oil and gas RD&D have increased in recent years, largely as a result of high oil prices and of economic stimuli in many countries, expenditure on coal has continued to decline.

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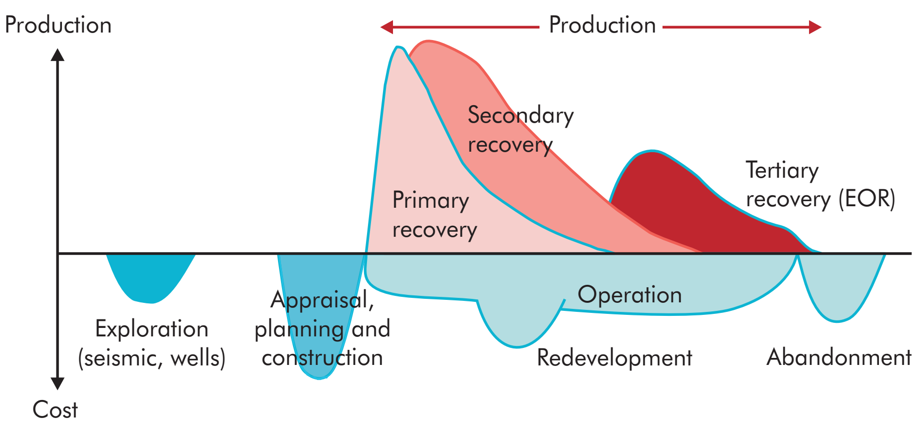
Chapter 2 • Raising recovery efficiency from oilfields

In recent decades, oil demand could be met by developing new fields, extending the development of existing fields or finding new fields in regions with known potential. However, mature fields still contain significant volumes of remaining oil and, as such, attention is shifting towards the challenge of achieving higher oil recovery and converting more remaining recoverable resources into reserves. In this chapter, the various phases of a field's lifecycle are explained together with the challenges they present and the technology applications needed to overcome such challenges.[1] It should be noted that, although a particular technology may be highlighted for one phase of development, it often plays a role in all phases, such as the use of seismic technologies.

Lifecycle of a petroleum reservoir

The lifecycle of a petroleum reservoir covers the period from discovery to abandonment. The phases of the lifecycle include: exploration; appraisal, planning and construction; primary recovery; secondary recovery; operation and redevelopment; tertiary recovery; and abandonment (Figure 2.1).

Figure 2.1* • *Schematic representation of the lifecycle of a petroleum reservoir



Note: EOR = enhanced oil recovery.
Courtesy of W. Schulte.

The lifecycle starts with the discovery of the presence of a petroleum reservoir. The first challenge for the engineer is to find the reservoir by exploring the subsurface. The exploration process begins with regional geological studies and deep-earth remote-sensing techniques such as seismic reflection to identify or infer the presence of the natural geological conditions that would be favourable for the creation of a hydrocarbon accumulation (Box 2.1).

1. The descriptions are not an exhaustive overview of technological progress in all areas (*e.g.* technologies specifically related to field abandonment are not described), but pertain to most phases of the lifecycle to demonstrate general progress.

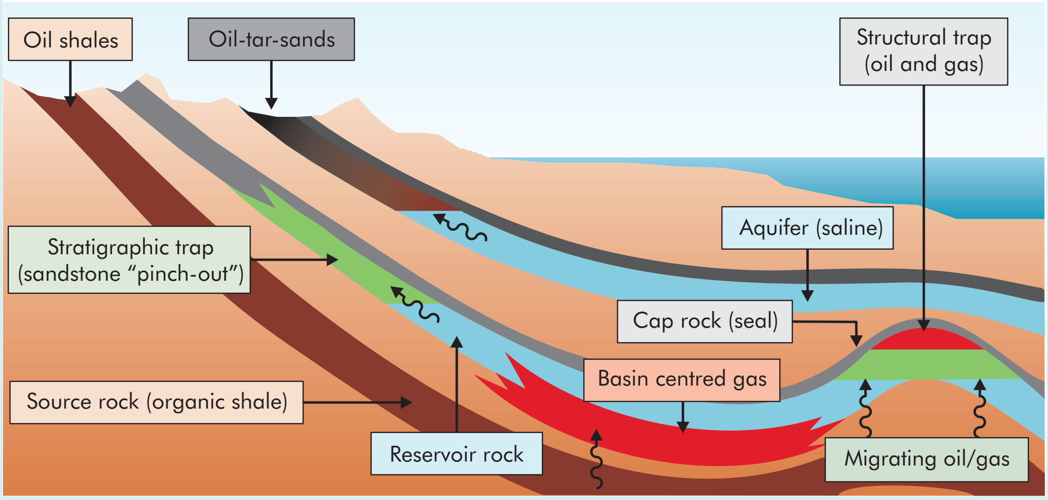
Box 2.1 • What exactly is a petroleum reservoir?

Petroleum reservoirs comprise rock formations with minute, porous spaces that contain trapped oil, gas or condensate. Volumes of these hydrocarbons in such accumulations can be huge, in the range of billions of barrels of oil or billions of cubic metres of gas. The Forties oilfield in the North Sea covers 93 square kilometres (km²) or 36 square miles, which is almost as large as the area of Paris (106 km²). The reservoir rock formations in the field are up to 190 metres (m) thick and originally contained between 4.5 billion barrels (bb) and 5 bb of oil. If all this oil were flooded onto the streets of Paris, it would, on average, be over 6 m deep.

Oil and gas are derived from organic material laid down in lakes, lagoons and oceans and preserved in anoxic conditions. As this material is buried deeper under layers of sedimentary rock, pressures and temperatures increase, thereby "cooking" the organic material and generating oil and gas. Land vegetation under high pressure and temperature tends to produce coal, while plankton, algae and other marine micro-organisms generate oil and gas. At greater depths, oil will "crack" to gas (under the influence of high pressure and temperature, oil molecules with longer hydrocarbon chains break apart forming shorter-chain gas molecules). After being generated, oil and gas, being lighter than formation water, will start to migrate upwards through the rocks.

For a rock volume to become a petroleum reservoir, several natural conditions have to be met. The reservoir must be linked with a generating source of petroleum; it must have pore space that the oil or gas can occupy; it must be permeable to allow the petroleum to move into its pores, displacing formation water; and finally the accumulated oil and/or gas must be prevented from moving ever upwards by an impermeable cap rock or seal, structured so that the hydrocarbons are trapped beneath it. These trapping "structures" are often dome-shaped anticlines (or "structural" traps), but can also be formed by a loss of permeability up-dip, preventing any further upward migration and forming a pinch-out, fault or unconformity, so-called "stratigraphic" traps (Figure 2.2).

Figure 2.2 *• Typical traps for oil or gas*



Courtesy of Allerton, 2008.

In some cases, oil can seep all the way to the surface, becoming progressively degraded (through bacterial influence, hydrocarbon molecules can often get entangled and combine to form larger entities that make the oil more viscous) and heavier, forming massive accumulations of oil- or tar-sands, especially after biodegradation at shallow depth. Such oil seeps were already used by mankind in ancient times.

Oil and gas are inevitably found together with water, sometimes more than 60% of the available pore space being water-filled. Some of this water is produced along with the oil and gas.

Exploration

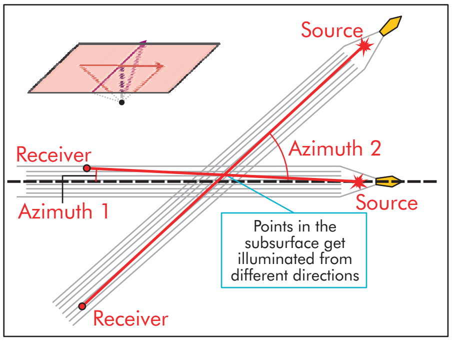
The key tool for exploration is seismic mapping of the subsurface. By creating sound waves at the surface and listening with specialist equipment to the echoes that come back to the surface, a picture of the subsurface can be made. When a wave traverses one rock type to another, part of the wave energy is reflected back to the surface. The reflected waves are collected and analysed to indicate where the major changes occur. A three-dimensional (3-D) picture can then be created that depicts the changes in geology, thus providing an indication of potential traps for oil and gas. The creation of this 3-D picture is a complex operation and often requires computers with high processing power. Seismic technologies to detect reflected waves and construct the 3-D pictures have improved significantly over recent years, providing much clearer pictures of the subsurface structures (Box 2.2).

Once it has been determined that the natural geological conditions are consistent with those required of a petroleum reservoir, its prospects are assessed, *i.e.* the potential reservoir size and possible rate of oil production are estimated, along with the uncertainties that apply to the assessment. The costs of further appraising the prospect by drilling an exploration well, together with the cost of developing and operating the field are estimated, as are the anticipated revenues from the production expected over the lifetime of the reservoir. Whether or not the exploration company decides to drill will depend very much on the quality of the underlying information. If considered worthwhile, an exploration well will be drilled, which could then lead to a discovery or to a dry well (no hydrocarbons present).

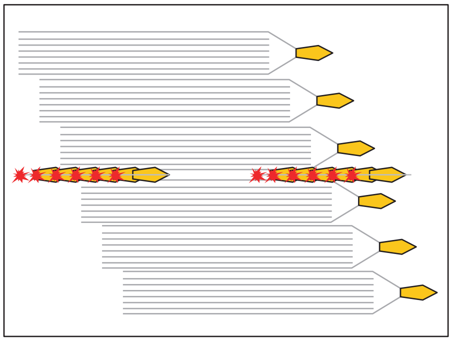
Box 2.2 • A step forward through wide azimuth seismic surveys

After the transition from two-dimensional to 3-D seismic surveys in the 1980s and 1990s, and the introduction of four-dimensional (4-D) seismic in the 1990s (OGP, 2011), one of the major seismic technology trends in the first decade of the 21st century has been wide azimuth seismic. Here the "azimuth" is defined as the angle between a line connecting a source and a receiver, and an arbitrary fixed direction in the plane of the acquisition. With this definition, it may be observed that conventional marine-towed streamer surveys always have a narrow range of azimuths: the hydrophones (the listening devices that pick up the reflecting waves) are in a long, but rather narrow spread behind the boat (Figure 2.3). Land surveys always have had a slightly wider range of azimuths, the width being determined by the width of the spread of receiver lines laid out in the field.

Figure 2.3 • Improvement in set-up of streamer configurations in marine seismic acquisition



Two narrow azimuth marine-towed streamer surveys each illuminate the subsurface from one direction.



Wide azimuth towed streamer acquisition is a multi-boat operation with a source or "shot" boat (creating the original wave) and one or more receiver boats (picking up the reflecting waves) sailing up and down until a wide range of azimuths has been acquired.

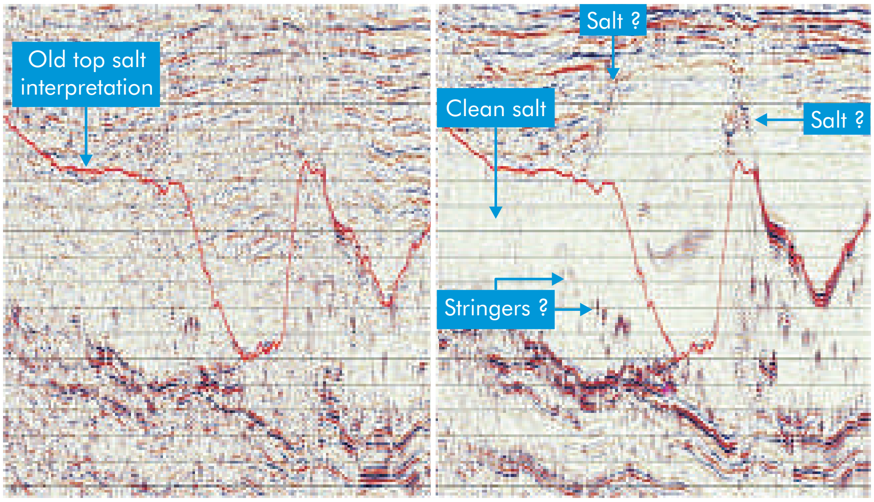
Source: Zwartjes *et al*., 2010.

Having more azimuths available is beneficial for imaging of seismic data, especially in complex geologies where it may be possible to "see" certain features in one direction, but not in another. Multiple azimuths provide different lines of sight and thereby improved illumination of the subsurface. Another aspect of wide azimuth surveys is that the fold, i.e, *the number of seismic traces per unit surface area, usually increases significantly. This has a beneficial effect on signal-to-noise ratio.*

First technology trials of wide azimuth towed streamer seismic surveys were carried out in the Gulf of Mexico in the period 2004-06. Only four years later, by 2010, the industry had covered most of the Gulf of Mexico by a number of very large multiclient-wide azimuth surveys.

Wide azimuth seismic has led to dramatic improvements in image quality in complex geological settings. This is illustrated for an onshore setting in Figure 2.4, which shows the uplift in image quality due to wide azimuth seismic acquired in the Southern Oman salt basin in 2007.

Figure 2.4 **•** *Improvement in seismically derived image by wide azimuth data acquisition*



Notes: the more modern wide azimuth data (right) provides much improved imaging of top salt compared with that obtained using narrow azimuth data (left), potentially leading to a different interpretation.
The much improved intra-salt signal/noise ratio is also highly relevant, as the reservoir is an intra-salt stringer play. (A stringer is a thin, discontinuous mineral vein or rock layer.)

Courtesy of Petroleum Development Oman.

Appraisal, planning and construction

Once discovered by one or more exploration wells, the reservoir is then appraised by drilling more wells to confirm assumptions on the type of rock and the content of its pore space. The appraisal process is designed to reduce the risks and uncertainties present in the initial prospect stage; to define the extent and limits of the reservoir(s) in the field; to assess the oil (or gas)-in-place and the likely production rates. After the appraisal process has confirmed that development of the field may be financially viable, a field development plan (FDP) is drawn up that provides a summary description of the development, and the principles and objectives that will govern its management. The plan typically spans 25 years and specifies the expected range of production and required injection rates; the number and placement of wells; the surface facilities required to separate the oil, gas and water; the various pipelines requirement;

and other transportation systems required to transport the products to market. The objective at this stage is to maximise the value of the development, given a whole range of assumptions about the long-term future – oil and gas prices, production rates over time, and costs. The predicted production profile over the economic life of the field defines its reserves.

Once the FDP has been approved by the oil company and the relevant authorities, field and reservoir development can proceed. The services identified in the FDP will be defined in more detail, contracts awarded to engineering companies, and facilities constructed. This phase of the project can take several years and it is during this phase when quality and cost control are of utmost importance. The cause of unsuccessful projects can often be traced back to a low-quality FDP.

Production

Once production starts, the engineer will focus on achieving the predicted production rates and exploring ways to further improve oil recovery. Out of the approximately 70 000 fields currently producing globally, the bulk of the world's oil supply comes from only a small number of large oilfields. These large fields are essential to global energy security. Improving production from such fields was a major driver behind the growth in Organization of the Petroleum Exporting Countries (OPEC) non-member oil supply during the 1990s. Incremental improvements in production from existing large fields in the United Kingdom and the Norwegian sectors of the North Sea contributed roughly 50% of the surge in OPEC non-member production during that decade.

Oil and gas production is made possible by reducing the pressure in a production well and allowing the pressure difference with the main reservoir to force the flow of hydrocarbons towards the well. In the early stages of production, under the so-called primary recovery, the oil flows with no assistance towards the well bore and up to the surface. For gas reservoirs, this stage is often enough to reach recovery factors (ratio of hydrocarbons produced to those hydrocarbons initially in place) of around 70% or higher. Gas, being much lighter than oil or water, normally flows easily up the well bore, although pumps may be used in later production stages to lift the column of accumulated water in the well bore that comes with the gas. For oil reservoirs, pressure depletion alone is generally not sufficient and yields low recovery factors, typically 5% to 15%. Additional injection of water or gas is required to stop the pressure from dropping below a minimum level, below which oil can no longer be recovered. This process is referred to as secondary recovery. Depending on the geology, sufficient pressure can sometimes be provided by the flow of water from a connecting aquifer: when the pressure in the oil column drops, the aquifer water flows towards the oil reservoir, supporting pressure and displacing oil. Recovery factors resulting from consecutive primary and secondary recovery are typically between 15% and 40%.

If more sophisticated fluids such as chemicals or steam are injected, the process is referred to as tertiary recovery. Tertiary recovery may also be referred to as EOR.

The global average recovery factor[2] was estimated at 35%, based on IHS-CERA data (Schulte, 2005). This implies that reservoirs are abandoned with, on average, two-thirds of their hydrocarbons still left in the ground. The recovery factor that can be achieved in an individual field is determined by the complexity of the reservoir and the method of extraction. A reservoir can be a sandstone reservoir or a carbonate reservoir. Sandstone reservoirs are formed from deposited sand grains, while carbonate reservoirs are formed from skeletons of marine life, such as reefs or shells. Carbonate reservoirs are often more brittle, and are often broken during their burial history, leading to faults and fractures that cause uneven flow through the reservoirs. Heavily fractured carbonate reservoirs often exhibit a low recovery factor, whereas homogeneous sandstone reservoirs under water-flooding can reach recovery rates of 60% or higher.

EOR techniques are not yet widely used because in the past they were considered too expensive. Consequently, the application of EOR will be closely dependent on the oil price. Recently more projects have been defined in which EOR techniques could increase recovery rates.

Abandonment

Once hydrocarbons in the reservoir have been depleted to a level that is no longer financially viable for further extraction, the wells are sealed off and abandoned, the facilities removed and the environment returned to its pre-drilling state.

Developing new reserves: getting the most for the lowest cost

Making a plan using integrated reservoir modelling

In theory, a single well at the crest of an underground trap would eventually drain all of the moveable hydrocarbons from a trap. However, doing so would take thousands of years and be financially unviable. Therefore, more wells are needed that can be drilled in an optimum pattern designed to sweep the petroleum from the reservoir to the wellbores in the most cost-effective manner. Such designs are currently made using complex and detailed 3-D computer models of the reservoir and its fluids, which are capable of predicting how the fluids will move through the reservoir. Computer modelling or integrated reservoir modelling (IRM) is used to define the optimum number and location of the wells, in order to maximise the value of the discovery.

As a result of ever increasing computer power, the last 20 years have seen a dramatic increase in the use of numerical reservoir modelling to support field development and management decisions. A multi-discipline methodology has been developed that integrates the work performed by each technical discipline and designs a computer model showing the potential assets for which the new development is being proposed.

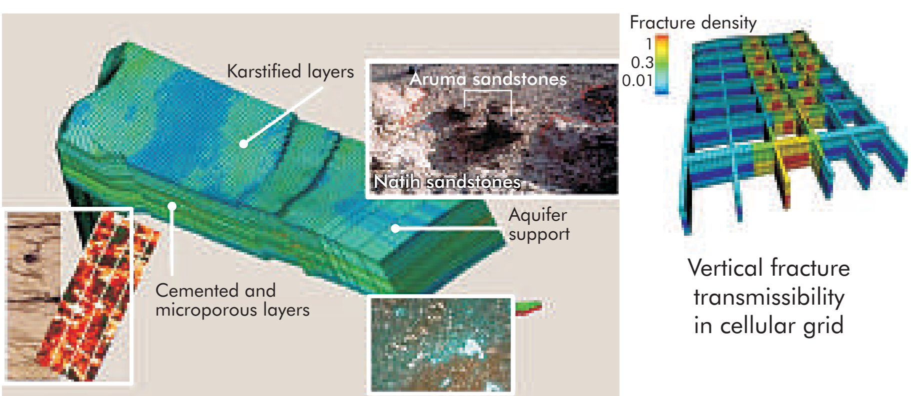
2. The recoverable amount of original or residual oil in place in a reservoir, expressed as a percentage of total oil in place. The recoverable amount includes produced oil plus the volume of proven reserves.

Computer models can forecast how the field is likely to perform according to different decisions taken and therefore the model can steer a decision on whether or not to develop a given reservoir. A large number of factors and uncertainty can determine the possible outcomes, including: the reservoir structure; the properties of the rock; the underlying geology of the reservoir (depositional environment) and the characteristics of the fluid.

In assessing the attractiveness of a particular development option, a range of other factors are taken into account as well, including: any constraints that surface pressures place on the development; evacuation and reinjection capacity; the cost of any new wells or facilities; and the uncertainties in the fiscal or economic environment. Taking such factors into account means that a number of possible models need to be designed and the results combined into a range of forecasts, together with an estimate of the probability of their occurrence.

In view of the complexity of the underlying geology and fluid behaviour, it is essential to make maximum use of all available data. An example of a complex model is shown in Figure 2.5. In this context, significant advances have been made in the quality of the data obtained and its interpretation for modelling purposes. In particular, improvements in seismic data acquisition and interpretation have enabled models to be more representative of the reality in the subsurface. The improvements also make it possible to measure the relative change in fluid content at various locations in the reservoir by comparing seismic signals at different times (often referred to as time-lapse seismic or 4-D seismic). This illustrates how the fluid moves as a result of injection into and production from specific geological layers. It gives vital information to decide which possible subsurface models can properly describe such movement and thus predict future flow more accurately.

***Figure 2.5** • Multi-layered carbonate integrated reservoir model*



Courtesy of Shell International.

Carbonate rocks are very complex and, because of their brittle nature, are prone to fracturing – large fractures across multiple layers and small fractures bound to one small interval. Fractures strongly influence the flow of fluids through a reservoir. Vertical transmissibility is a key factor and the image on the right of Figure 2.5 shows a simplified representation of a fracture system. In the case shown, the various layers are connected via the fracture system, particularly in the middle. The complexity of carbonate rock stems from the influence on its composition and structure of the movement of water and the effect of pressure (changes due to chemical, physical or biological processes) during its burial history. These changes during its burial history are referred to as diagenesis. Part of the rock can dissolve in water and then be deposited elsewhere, filling the pore space. This process is known as cementation. One extreme process is karstification, in which the rock fully dissolves, leaving large holes or caverns in the subsurface.

The integration boundaries for IRM continue to expand and it is now becoming standard procedure to include a detailed representation of the surface production system as part of the modelling exercise. Such models then represent the entire production process from developing the reservoir to sales point, and describe the flow through the subsurface, wells and surface facilities. The model can now predict how production will change if any of the various elements in the overall project change.

Because of the increasing complexity of many of today's asset developments, together with the underlying subsurface uncertainties, full IRM is, and will remain, a complex and challenging task.

Drilling technology for new reserves and lower costs

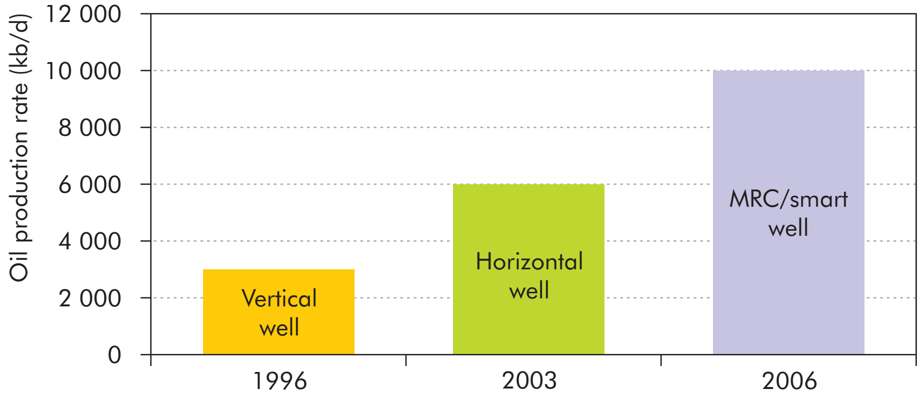
Drilling technology is subject to continuous development. The main aim is to enhance the drainage area,[3] *i.e.* for each well to access more oil, at the lowest possible cost. Different designs of well currently in use include new multilateral wells (wells with multiple branches that can extend dramatically the drainage area of a well); horizontal wells (which can extend the well laterally); and extended reach wells (those wells reaching a target far from the drilling platform). Expandable tubulars, which expand to a larger diameter after being placed in the well bore, are being used more frequently in well construction. They reduce significantly the extent to which the diameter of a well becomes narrower with depth. It is a particularly important innovation for deep wells. One of the latest developments in drilling technology is casing drilling, which can significantly reduce the time needed to create a well. In casing drilling, the drill bit sits at the end of the casing, such that when the bit is at its desired depth the full casing is already in place and only the drill bit itself is retrieved from the hole. This method prevents running different pipes in and out of the hole, thus saving valuable time.

A range of new technologies is also applied to the part of the well that directly connects with the reservoir. Maximum reservoir contact (MRC) is one concept recently developed by Saudi Aramco (Badri, 2008). The MRC concept is designed to address the challenges related to penetration of reservoirs with heterogeneous geology, which is often the case with carbonate reservoirs that are widespread in Middle East regions.

3. The drainage area of a well is the area of the reservoir that is drained by that well.

Field tests in Saudi Arabia's Haradh oilfield area showed a progressive game-changing effect on production from applying increasingly advanced drilling technology. Wells where MRC technology has been used can deliver three times the production output of an initial vertical well and almost twice the production rate of a horizontal well tested some years before the MRC demonstration (Figure 2.6).

Figure 2.6* • *Results from Haradh field tests



Note: kb/d = thousand barrels per day.

Courtesy of Saudi Aramco.

MRC wells can only have a limited number of laterally side-tracked wells coming from the main well or motherbore. This can cause a problem as water production rises. In Oman, where multi-laterals were tried aggressively, premature water breakthrough was present in some fields (Al-Khodhori, 2003). To get around this problem, Saudi Aramco conceived an intelligent completions[4] technology known as extreme reservoir contact (ERC). The industry is developing a range of new technologies for intelligent completions that enable better sweep efficiency and maximise recovery through monitoring and electrically activated down-hole control valves. This type of down-hole flow control does not require individual control lines from the well-head to each lateral zone in order to monitor and operate the well in real time. The control system associated with these wells is quite complex and would enable a theoretically unlimited number of intelligent laterals per well.

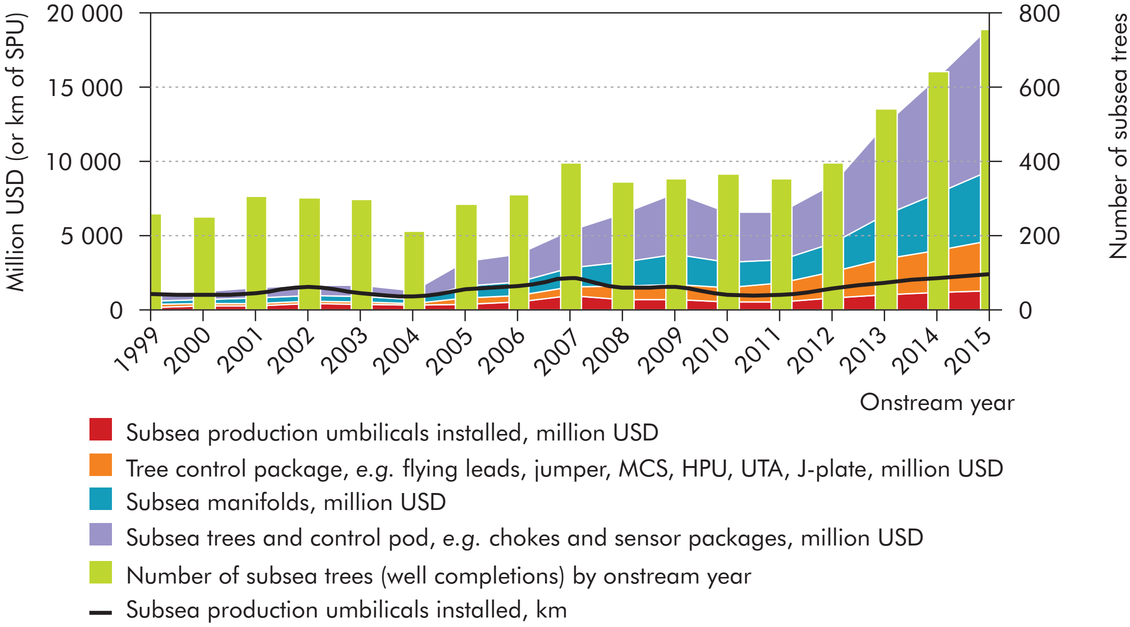
Test results from the application of ERC technology in oilfields in the Middle East are less well known. However, the improvement in reservoir drainage that can be expected from this technology could increase production output compared to other drilling and down-hole concepts currently in operation, especially in the very complex carbonate fields.

4. Well completion refers to the set-up of equipment at reservoir depth to enable safe and efficient production from an oil or gas well.

Going offshore: developments in subsea wells and facilities

The installation of subsea wells[5] has increased substantially during the past decade largely because of the need to develop more, and often smaller, offshore fields at an acceptable cost. This growth in subsea wells is set to continue and will also require a large increase in the drilling rig/vessel fleet (Figure 2.7).

Figure 2.7 • Growth in subsea wells



*Estimate.
Notes: MCS = master control station; HPU = hydraulic power unit; UTA = umbilical termination assembly; J-plate = junction plate; SPU = subsea production umbilcal; km = kilometre.
An SPU is a cable that supplies the required consumables to the well; it includes power and the fluids that prevent corrosion. A tree is the top part of the well containing the valves and flow line connections. A manifold is a point where multiple flow lines come together into one flow line or vice versa.

Source: Quest Offshore Resources, 2010.

Platform installations offshore often cause bottlenecks due to their limited ability to carry weight and to accommodate large production systems. Advances in subsea technology are making it increasingly feasible to move production equipment from the surface down to the seabed.

An important factor in designing subsea equipment is the weight. Their installation relies on the lifting capacity of the installation vessel and installing it can cost more than the equipment itself. Therefore it is important that the equipment is light and compact so that a cost-effective light installation vessel can be used.

Ultimate recovery for subsea wells is significantly lower than that for platform wells as any problems encountered are more difficult and more expensive to rectify. Consequently, the rapid growth in the number of subsea wells

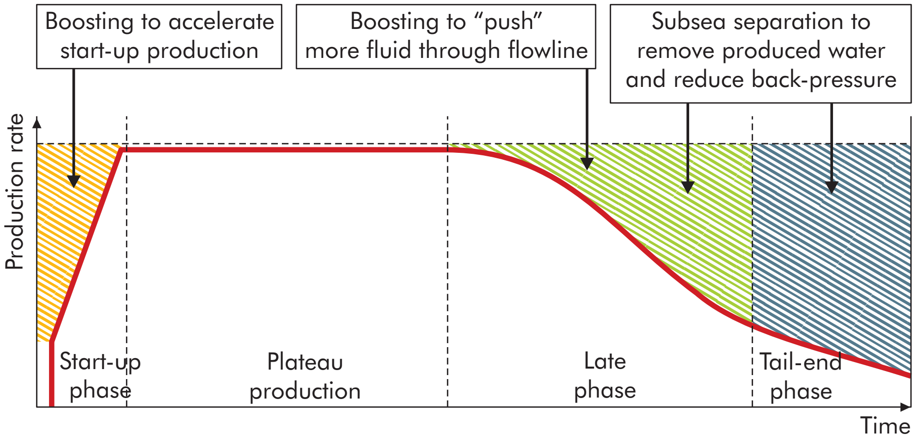
5. A subsea well is one in which the well head is at the sea bottom rather than located on a production platform at the surface.

accentuates the need to increase their recovery efficiency. A major technological challenge is therefore to extend available improved oil recovery (IOR) capabilities to subsea fields. Platforms offer direct access to the production equipment for continuous operation, inspection, intervention and maintenance and are therefore important for an optimum exploitation of the reservoir. The lower physical access to subsea wells creates gaps in applying the same range of technologies for subsea fields.

Step changes in communication technology have enabled new working methods in the industry, especially for subsea developments. By applying fibre optic-based broadband and digital infrastructure to integrated operations of subsea oil and gas fields, the facilities can be controlled remotely from onshore. Such advanced technology reduces the need to maintain costly offshore functions as well as the risk that such functions pose to offshore personnel.

The ability to remove water and sand from the wellstream on the seabed is also an important measure to boost production later in the lifecycle of the field (Figure 2.8). When water separation is introduced subsea, it reduces the amount of water produced and, similarly, the back-pressure in the production line. This in turn improves recovery, as represented by the blue-green stippled segment in the figure. Removal of water is also used in conjunction with subsea boosting of the wellstream pressure, as it lets more fluids through the production line. Subsea separation, boosting and multiphase separation are still the subject of intense research, development and deployment (RD&D).

Figure 2.8 • Effects from subsea boosting and separation



Courtesy of W. Schulte.

The cost of subsea wells is a major issue. Developing more cost-effective installation methods and intervention concepts for subsea wells will be a key to successfully addressing the challenge of improving recovery. Currently, a number of concepts are being developed for different types of subsea intervention, ranging from light vessels that can only execute simple measurements on wire-line (tools lowered into the well on an electric cable) through to heavy intervention installations and integrated drilling and completion concepts (pulling tubing out of the well, replacing part of tubing and down-hole equipment, drilling). After a period of technology qualification, a range of solutions for lighter subsea intervention vessels is now also commercially available. In addition, constant attention is given to the environmental aspects of subsea operations because of the impact that subsea equipment may have on wildlife and the risk of leaks or spills.

Applying technologies for IOR

IOR and EOR measures are used to increase recovery factors from a reservoir (Box 2.3).

Box 2.3 • *IOR and EOR*

As there are no precise definitions of these terms, an understanding of them often depends on the context and on the user.

IOR

IOR refers to all measures that result in an increased oil recovery factor from a reservoir as compared with the expected value at a particular point in time. In practice, the term is often used synonymously with optimisation of the secondary recovery operation. IOR comprises both conventional and emerging technologies.

EOR

EOR refers to advanced recovery techniques beyond those considered conventional. It focuses only on the tertiary recovery operation. In theory, EOR is a sub-set of IOR.

In the secondary recovery phase, the pressure in the reservoir is maintained by injecting water and/or gas behind the oil to drive it towards the production wells. In this phase, often a lot of additional wells are drilled to reach untapped oil pockets and reduce the distance between injection and production wells. Facilities will have to be capable of handling large volumes of water both on the injection and on the production sides. Often production wells are fitted with artificial lift[6] systems to assist in lifting oil that contains increasing levels of water. In many mature fields significantly larger volumes of water than oil are produced.

6. Any system that adds energy to the fluid column in a well-bore with the objective of initiating and improving production from the well. Artificial-lift systems use a range of operating principles, including rod pumping, gas lift and electric submersible pump (Schlumberger, 2012).

IOR techniques and their potential

The use of more advanced and efficient technologies in assessing and recovering hydrocarbons in place has extended the lifecycle of many oilfields and, consequently, made an important contribution to securing long-term oil supply. Many of these fields have had their initial reserves revised upward. If reserve growth in already discovered fields worldwide continues as in the past 70 years, as much as 1 trillion barrels of additional oil could be added to reserves in these fields during the next seven decades. This represents an addition equivalent to the total amount of oil produced to date.

The fraction of oil in place that can be produced by water alternating gas injection (WAG) (secondary recovery) depends on the reservoir and oil characteristics. Typically, primary recovery can extract between 5% and 15%, and secondary recovery can add a further 10 to 25 percentage points. This broad range in recovery rates is due to the large variations in oilfield characteristics such as types of rock, fluid saturations, reservoir temperature and pressure. At the moment, primary and secondary recovery operations typically leave behind two-thirds of original oil in place.

A 2007 study by the National Petroleum Council in the United States lists advances in technology that can improve oil recovery factors (NPC, 2007). New well architecture helps significantly. In the recent past, very long horizontal wells (wells with a large horizontal section inside the reservoir) have become commonplace. Further developments are currently shifting towards multi-laterals with in-well control valves. Repeat seismic is also used to make pictures of the subsurface at different moments in time. The differences between these pictures can often show where oil is left behind because of the geological complexity of the reservoir and if new wells could help. In recent years, the focus has been on well and reservoir management (WRM) and the installation of more equipment to measure and monitor an oilfield more intensely (reservoir surveillance). From the large amount of data in combination with numerically simulating the reservoir, the operator can learn how best to manage the injection and production levels. If such measurements are combined with additional valves in the wells and facilities, so that the inflow in sectors of the wells can be controlled remotely on a day-to-day basis, the field is often called a smart field or eField. This type of WRM could improve recovery by between 5% and 15% of oil initially in place.

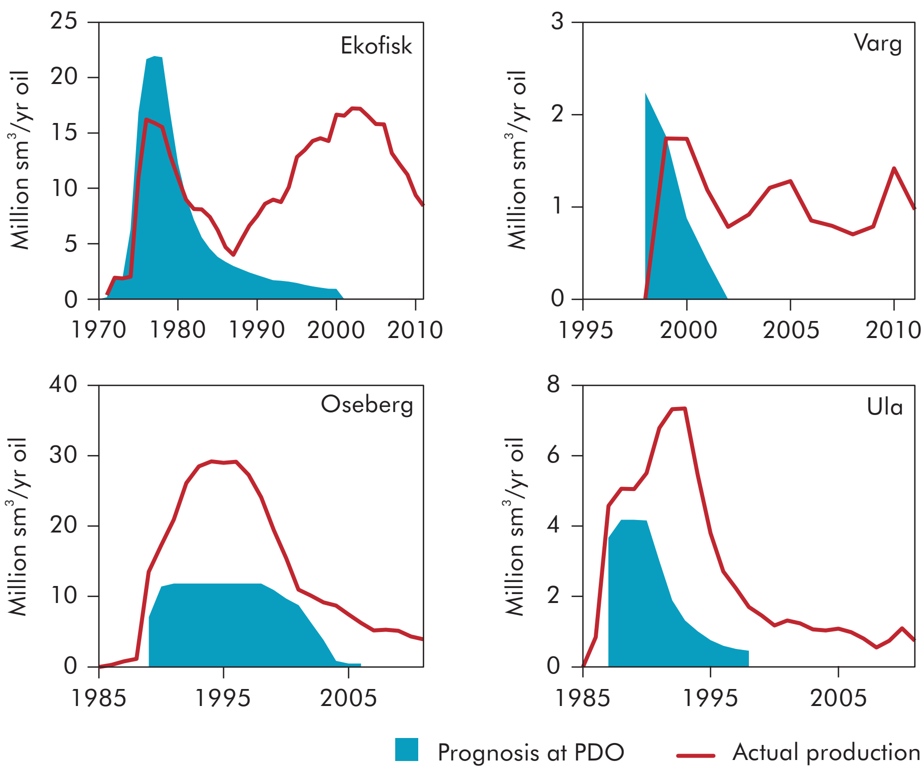
Improvements in the North Sea and Norwegian Continental Shelf

The efficiency of oil recovery in the Norwegian Continental Shelf (NCS), defined as the aggregate percentage of oil in place estimated to be ultimately recoverable at the end of NCS production history, increased from 36% in 1992 to 44% in 2000 and 46% in 2008 (NPD, 2009). Technology improvements over that period led not only to an increase in recovery rate and consequent higher output from producing fields, but also to a growth of estimates of the total in-place NCS oil resources and of the estimated recoverable reserves.

Technological developments and the application of IOR methods were key factors in this increased production. Water injection, WAG, drilling technology, and static and dynamic reservoir management[7] have made major contributions to improving production trends in the NCS.

Comparisons of production forecasts with actual production for selected oilfields on the NCS illustrate the impact of IOR technology. Longer-term production trends for the Ekofisk, Varg, Oseberg and Ula fields show how actual production from these fields increased substantially during 1981-2005 compared to estimates made when the original development plans were submitted for government approval (Figure 2.9). On the basis of the original plans, these fields should have been closed down by now. Thanks to more efficient operations and the application of new IOR technologies, the fields will now remain in production for years. Sometimes the benefits of IOR can exceed expectations, such as the benefits of injecting water into chalk reservoirs (Box 2.4).

Figure 2.9 • Production trends for the Ekofisk, Varg, Oseberg and Ula fields



Note: PDO = plans for development and operation. These are submitted prior to receiving formal approval to proceed from the Norwegian Ministry of Petroleum and Energy. Sm³/yr = standard cubic metres per year.
Source: NPD, 2011.

7. Static (rock-related) and dynamic (flow-related) reservoir management are two components of real-time reservoir management designed to maximise production and recovery rates.

Actual production from the Ekofisk, Oseberg and Ula fields in 1995 was nearly triple the production levels officially forecast ten years earlier. An assessment of the production history of the 18 largest oil-producing fields on the NCS in the same period shows a similar aggregate production trend (NPD, 2009).

Box 2.4* • *Technological breakthrough: water injection in the Ekofisk field

Major technological achievements resulting from ongoing research and development by the industry and programmes supported by the Norwegian government became a key factor behind the improved production trends experienced on the NCS. Water injection in the Ekofisk field was successful in boosting oil production by enabling more oil to be recovered from the field's chalk reservoir. Injecting water into oil-bearing chalk formations was not normal practice at the time. The breakthrough was achieved despite broad scepticism in the international community because of the perceived risk of seriously damaging the reservoir by the so-called "yoghurt effect" resulting from chalk mixing with water. As a result of this pioneering technology, the Ekofisk field is now the largest oil-producing field on the NCS.

The case of two of the larger North Sea oilfields, Statfjord and Gullfaks, both with already good levels of expected oil recovery, further illustrates how the application of a number of improved technologies significantly increased recovery levels. The most important technologies used included:

- drilling and well technologies;
- extended use of gas and water injection;
- static and dynamic modelling aimed at predicting and controlling reservoir behaviour.

The improved technology and increased knowledge of the reservoirs in the Statfjord and Gullfaks fields from 1986 to the present has had a significant impact on the percentage of total oil recovery over the lifespan of the fields (Table 2.1).

Table 2.1* • *Expected ultimate percentage recovery from Statfjord and Gullfaks fields

	1986	1996	2006	2008	2010	2011
Statfjord	49%	61%	66%	66%	66%	66%
Gullfaks	46%	49%	60%	60%	61%	61%

Courtesy of Norwegian Petroleum Directorate.

The technologies applied to increase production from the reservoirs also provided improved information about the reservoir and better estimates of the amount of oil in the fields and the amount judged to be recoverable reserves.

More examples can be quoted from different parts of the world. In the largest oilfield in North America, the Prudhoe Bay field on Alaska's North Slope, approximately 13 bb of oil are expected to be recoverable by using current technology, compared to the 9.6 bb originally estimated.

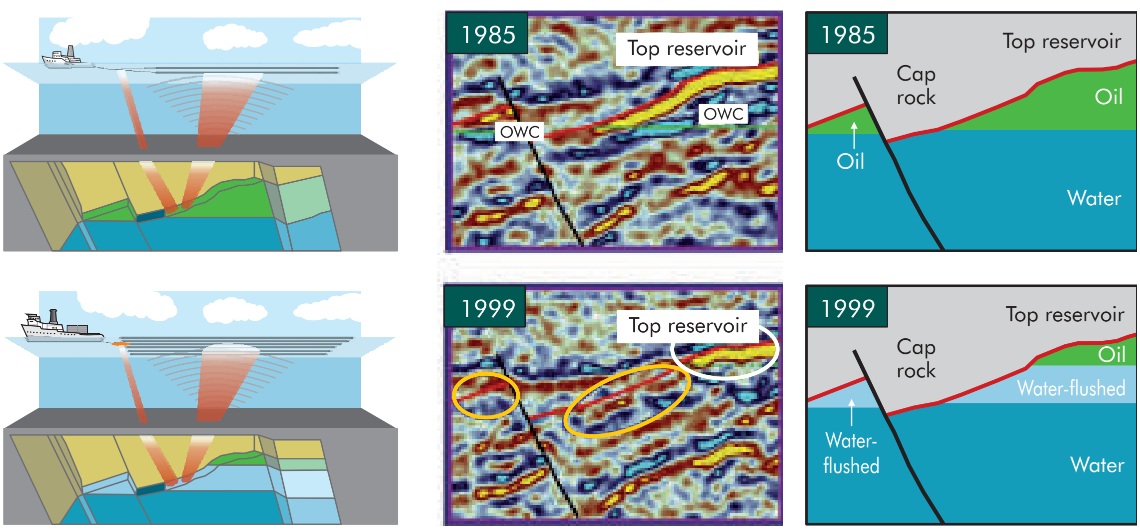
Since many of the technologies used in various success stories are relevant to fields elsewhere, wider application of these technologies is likely to lead to increases in the global recovery rates and in global reserve and resource estimates. A one percentage-point increase in the average recovery factor would add more than 70 bb (or 6%) to the world's proven conventional oil reserves. If the average recovery factor worldwide were to be raised from about 35% today to 50%, this would increase global conventional oil reserves by about 1.1 trillion barrels, almost equal to the current level of proven reserves.

Experience with 4-D seismic

Numerous examples over the years have demonstrated that seismic technology is key both for oil and gas exploration, and for IOR. Over the last couple of decades seismic resolution has improved so much that when surveys are repeated they can be compared to highlight any changes in fluid content or pressure levels. This technique is called repeat 3-D or 4-D seismic.

One prominent example is the use of 4-D seismic in the Gullfaks field since 1996, which enabled better geophysical monitoring of the reservoir (Figure 2.10). In this field, improvements in production depend largely on more effective water injection to flush the oil-bearing reservoir zone. Better imaging by means of 4-D seismic provided improved understanding and monitoring of the reservoir properties and behaviour during production, which led to more accurate production forecasts. The application of 4-D seismic has so far resulted in more than 60 million barrels (mb) of additional oil being produced from the Gullfaks field.

Figure 2.10 • *Application of 4-D seismic in the Gullfaks field*

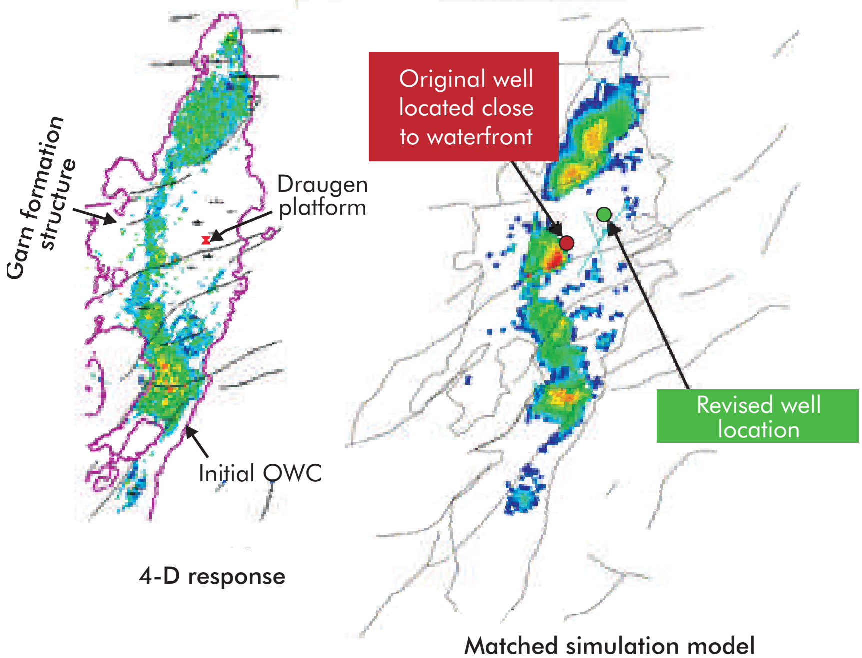


Notes: the left diagram shows a schematic of data acquisition; the middle shows the seismic image; the right shows a schematic interpretation of the seismic image. OWC = oil-water contact.

Courtesy of Statoil.

In the Draugen field in the North Sea, the use of 4-D seismic helped to direct new wells by providing information on the movement of the water-flood front[8] and by comparing changes in the fraction of water in a given pore space (water saturation) as derived from the 4-D seismic with those from matched simulation results (Figure 2.11). This analysis led to an infill well (additional well expected to increase recovery by reducing well spacing) being redirected from a location where it would have been watered out[9] immediately to a position where it produced more than 70 000 barrels per day (b/d) of dry oil, a record in the North Sea. Repeating 4-D seismic surveys at regular intervals for optimal reservoir management could lead to an expected ultimate recovery factor of 66%.

Figure 2.11 • *Change of drilling location based on 4-D seismic results*



Courtesy of Shell.

Potential improvements in recovery in the Middle East

Oilfields in the Middle East are likely to benefit from capabilities and technologies developed internationally for better exploitation of existing resources. Compared with decades of efforts focused on improving recovery in OPEC non-member regions, countries in the resource-rich Persian Gulf, such as Saudi Arabia, are still largely in the early phase of oil production. This

8. Water-flood, a method of secondary recovery, is the term used to describe the process of increasing oil recovery by injecting water into an oil-producing reservoir. The water-flood front refers to the front of the flow of water as it sweeps the reservoir.
9. A "watered-out" well is one where the volume of water produced with the oil is sufficiently high to render the well uneconomic to operate.

means that less attention has been paid in the past to improving recovery methods compared to more mature producing regions such as the United States and maturing parts of the North Sea. In some areas, such as in Oman, which has smaller resource volumes, dedicated improvements through IOR and EOR are already well under way.

The Persian Gulf region is dominated by carbonate reservoirs. These are particularly heterogeneous, with small features that are difficult to detect by using seismic or other measurements and can sometimes dramatically affect the movement of fluids. Often the presence of large faults and fracture systems make a classical water-flood not practical because water will flow through the fracture system and will by-pass the oil. In addition, the rocks tend to be "oil wet", meaning that oil tends to stick to the rock better than water, which reduces recovery from water injection.

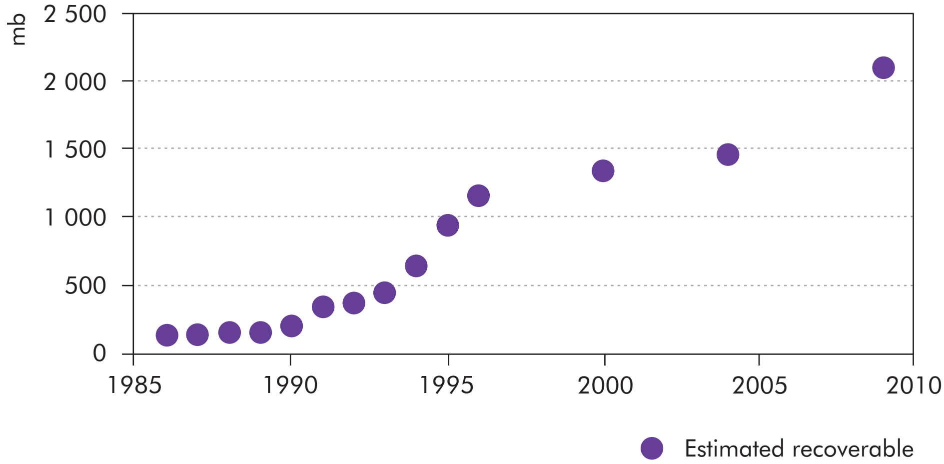
Still, many oil developments concern huge fields where, for a long time, peripheral water injection involving large well spacing was sufficient. However, the proportion of water in the total liquids extracted from the producing wells is increasing and therefore there are many new initiatives to improve recovery in these complex fields. So far most of these developments concern drilling horizontal and multilateral wells and applying 4-D seismic. Research and pilot testing on EOR methods is also ongoing. EOR methods are being used in Oman where, owing to an average smaller field size, development is more mature than in other areas of the Middle East. In Abu Dhabi in the United Arab Emirates, gas injection has been piloted already for many years. Recently a pilot project involving the use of carbon dioxide (CO_2) was announced in Abu Dhabi, and Saudi Arabia is also planning a CO_2 test. The officially reported recovery efficiencies of the larger resource holders have not changed in recent years as operators still feel that there is insufficient evidence to warrant a change. By using infill drilling (drilling extra wells in between existing wells) in existing fields, the production levels in the larger countries of the Middle East have steadily increased. All activities towards better wells, using more seismic technology; introducing smart-field technology, and piloting EOR techniques, all point to a desire to raise recovery levels significantly and secure years of plateau production.

Using well technology to boost recovery from thin oil rims

Thin oil rims describe reservoirs where the oil sits in a thin layer between a large volume of gas above it and water below. Oil production from thin oil rims is typically difficult. A well placed in the rim will usually produce mainly large volumes of water and gas. A prominent example of technology enabling IOR from thin oil rims is the development and production of the thin oil rim in the Troll field offshore Norway. For a long time, it was uncertain whether the resources in the 12 m to 14 m thin oil zone in the Troll Vest gas province would be technically and commercially exploitable.

However, total estimated recoverable reserves have gradually increased from 145 mb in 1986 to 2 100 mb in 2009 (Figure 2.12). The increase was the result of advances in horizontal and multilateral drilling, which enabled wells to be drilled with a tolerance of +/-1 m in relation to the water zone underneath the oil reservoir.

Figure 2.12* • *Evolution of recoverable oil reserves in the Troll field



Courtesy of Norwegian Petroleum Directorate.

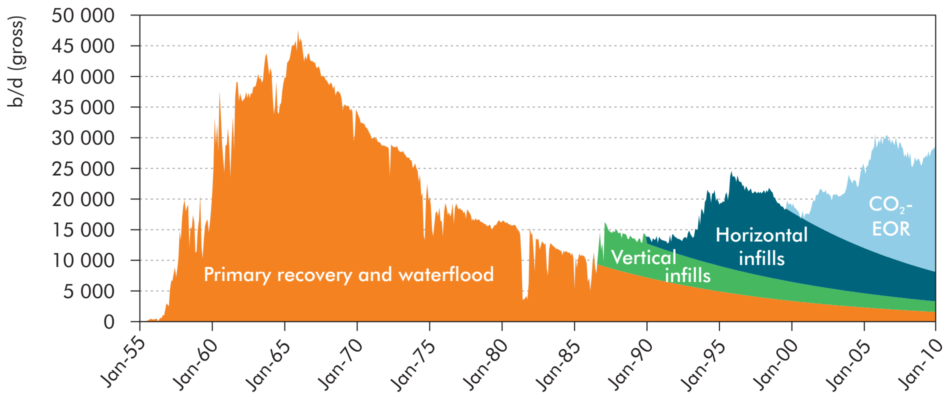
Horizontal drilling reduces interference from the nearby water and gas layers, which again increases the productivity of the wells. By 1998, almost all producing wells in Troll were horizontal, with wells reaching up to 3 100 m in horizontal range. The growth of recoverable reserves realised during the subsequent lifetime of the field has been possible because of the use of increasingly longer well paths, (up to about 12 000 m) combined with multi-branch wells that allow additional reservoir drainage. To date, more than 1 bb of oil have been produced from the Troll field.

Mature reserves: technologies for EOR

In the later so-called "tertiary" stages of production, sophisticated methods to improve the displacement process and reduce the remaining oil in the reservoir can be introduced, assuming they are profitable. These include CO_2 injection, detergent injection and even the growth of micro-organisms that can enhance oil production. Thermal methods, such as steam injection and pumping down oxygen to ignite the oil nearest the injector well, increase reservoir temperature and so reduce oil viscosity.

The Weyburn and Midale fields in Saskatchewan, Canada, provide a good example of the various stages that can take place, leading to implementation of an EOR scheme. Production at the Weyburn field started in the mid-1950s with conventional vertical wells. Primary production, followed by water-flooding, infill drilling of vertical wells in the mid-1980s and horizontal wells in the 1990s, recovered a total of 370 mb or approximately 26% of the 1.4 bb of original oil in place. In 2000, a carbon dioxide-enhanced oil recovery (CO_2-EOR) scheme was implemented using CO_2 piped from a coal-gasification plant in North Dakota in the United States, which added a further 155 mb taking total recoverable reserves to 525 mb. The contribution of EOR resulted in the oil production level reaching a 35-year high in 2006 (Figure 2.13).

Figure 2.13* • *Impact of EOR technology on oil production from the Weyburn field, Canada



Notes: vertical infills = infill of vertical wells by water injection; horizontal infills = pre-CO_2 infill of horizontal wells by water injection.

Courtesy of Cenovus Energy.

A later section on CO_2-EOR for greenhouse gas mitigation discusses in greater detail the role of EOR, using CO_2 as a solvent, at Weyburn-Midale and addresses the issues involved. The section also describes the Weyburn-Midale CO_2 monitoring and storage project currently in progress.

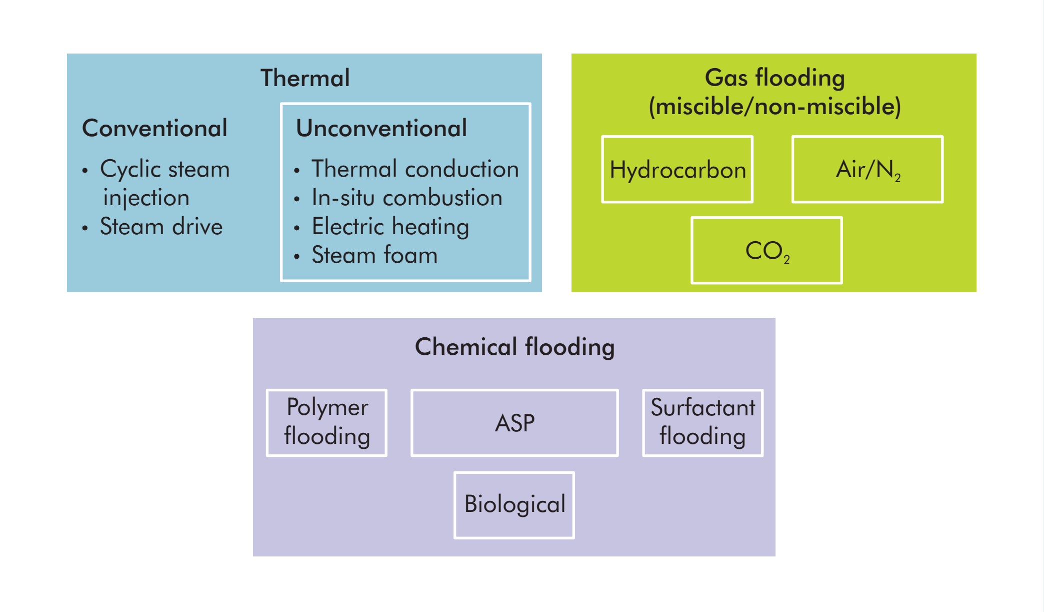
The move towards EOR technologies

In the late 1970s and early 1980s, operators in the United States were already considering the use of EOR technologies. The sharp increase in oil price, a favourable tax regime and a decrease in outputs in the United States had spurred interest. Technologies were developed and field applications triggered. EOR applications in California and West Texas are still ongoing. In the late 1980s and the 1990s the oil price had collapsed and many initiatives to develop EOR technologies were stopped. EOR was not the mainstream growth activity of the exploration and production industry in that period, which explains why there was only moderate progress in establishing higher global recovery factors. In recent years, increase in oil price and concerns over the security of supply have led to a renewed interest for EOR technologies by both national and international oil companies.

Box 2.5 • Landscape of EOR techniques

In most reservoirs, EOR or tertiary recovery is needed to extract a greater proportion of the oil-in-place or in some cases it is the only means to produce oil. Figure 2.14 shows the common EOR techniques in current use. The feasibility of the various methods depends largely on the type of oil, type of reservoir and additional field-specific conditions. Most types of EOR involve the application of techniques to reduce viscosity and improve flow, e.g. gas flooding, chemical flooding and/or the application of heat.

Figure 2.14 *• Common EOR techniques currently in use*



Notes: conventional refers to methods that have been in use for many years, whereas unconventional refers to novel or unproven technologies. ASP = alkaline-surfactant-polymer; N_2 = nitrogen gas.

Courtesy of Shell (adapted).

In gas flooding, the gas reduces the viscosity of the oil, thereby making it flow more easily. "Associated natural gas", or the gas produced naturally with oil, is often used for flooding especially when there is no significant local market for it. When the gas is miscible (i.e. it mixes fully) with the oil at reservoir conditions, the gas will also displace the residual oil. Miscible gas injection will produce more oil than gas that is not miscible. CO_2 injection, often miscible with the oil, is increasingly popular in the United States and accounts for about 4% of domestic oil production.

Chemical EOR mainly involves polymer injection to increase the viscosity of the displacing fluid and ASP flooding to mobilise residual oil. Polymer injection helps when the oil viscosity is high and/or the reservoir is very heterogeneous. ASP will reduce the interfacial tension between the in-place crude oil and the injected water, mobilising residual oil. However, the cost of surfactants and polymers can be high and chemical EOR is a complex process (Box 2.6). In thermal EOR, heat is introduced into the reservoir to reduce oil viscosity. This is applicable mostly to heavy or viscous crude oils.

In the future, nanoparticles may provide the solution. Currently, research and development is under way to explore the potential for nanoparticles to measure and to modify reservoir properties. If particles can be developed to modify reservoir rock and fluid attributes, they may be deployed to enhance recovery from the reservoir.

Whether or not EOR technologies are suitable depends on the characteristics of the oilfield and its state of depletion. Over the years, key criteria for assessing the suitability of EOR technologies have been developed (Table 2.2). The crude oil gravity (or API[10]) is generally the first parameter to be considered, as most miscible flooding techniques work only for lighter crudes. The second parameter is the amount of oil left in the field due to by-passing areas or a high residual oil saturation (Box 2.6). Chemical EOR is an option, while CO_2-EOR can be used when more than 20% of the oil is still recoverable. The oilfield temperature is the next variable, *e.g.* polymer flooding and ASP require more expensive chemicals when the temperature is over 95°C.

Table 2.2 • Pre-screening criteria for EOR

Technology	API	Remaining recoverable resources (% of initial reserves)	Formation type (carbonate/ sandstone)	Depth (metres)	Permeability (md)	Temperature (°C)	Required additional recovery factor (%)
Nitrogen	> 35	> 40	Carbonate	> 2 000	190	–	–
Hydrocarbon	> 25	> 30	Carbonate	> 1 350	–	–	20-40
CO_2	> 25	> 20	Carbonate	> 700	–	–	5-25
Polymer	> 15	> 70	Sandstone	< 3 000	> 10	< 95	5-30
Surfactant/micellar	> 18	> 35	Sandstone	< 3 000	> 10	< 95	5-30
Thermal/combustion	> 10	> 50	Sandstone	> 50	> 50	> 40	–
Thermal/stearm	> 8	> 40	Sandstone	< 1 500	> 200	–	10-60

Note: md refers to millidarcy, unit of permeability. Here it is used as a measure of the permeability of rock.

Source: IEA, 2008.

10. API (American Petroleum Institute) gravity is a measure of the density of oil. The API gravity scale is calibrated such that most crude oils, as well as distillate fuels, will have API gravities between 10° and 70° API. The lower the number, the heavier and the more viscous is the oil.

Box 2.6* • *Remaining oil and chemical EOR

There are two types of remaining oil: residual oil, in which hydrocarbons are trapped in small pores of the rock after water passed through this rock; and by-passed oil, in which hydrocarbons are left behind in unflooded rock areas owing to high oil viscosity or rock heterogeneity. Chemical flooding may be used to access the remaining oil and is one of the main techniques to have received a lot of attention in recent years.

One class of chemical flooding uses surfactants to lower the surface tension and alter the wettability of the residual oil. Surfactants are molecules with hydrophilic and hydrophobic components. They can therefore accumulate at the interfaces between oil and water; changing the interfacial tension between the two allows small droplets of oil to be "solubilised" in water (e.g. soap in the dishwasher). Surfactants can be added to water injected into the reservoir and will help entrain more oil into the water, ideally leaving no oil behind in the flooded parts.

Another class of chemical flooding injects polymer solutions, which improve recovery by increasing the viscosity of the injected water used to flood the reservoir. Polymers are longer molecules which, added to the injection water at concentrations of a few tenths of a per cent, can play several roles depending on the nature and properties of the polymer used. By making the injected water more viscous, approximating it to the viscosity of oil, polymers can promote a more regular and complete displacement of oil by water.

Although chemical techniques, such as surfactants and polymer floods, were developed in the 1980s, they have not been widely used because of their cost. Often substantial quantities of chemicals are required to fill a large fraction of the pore space.

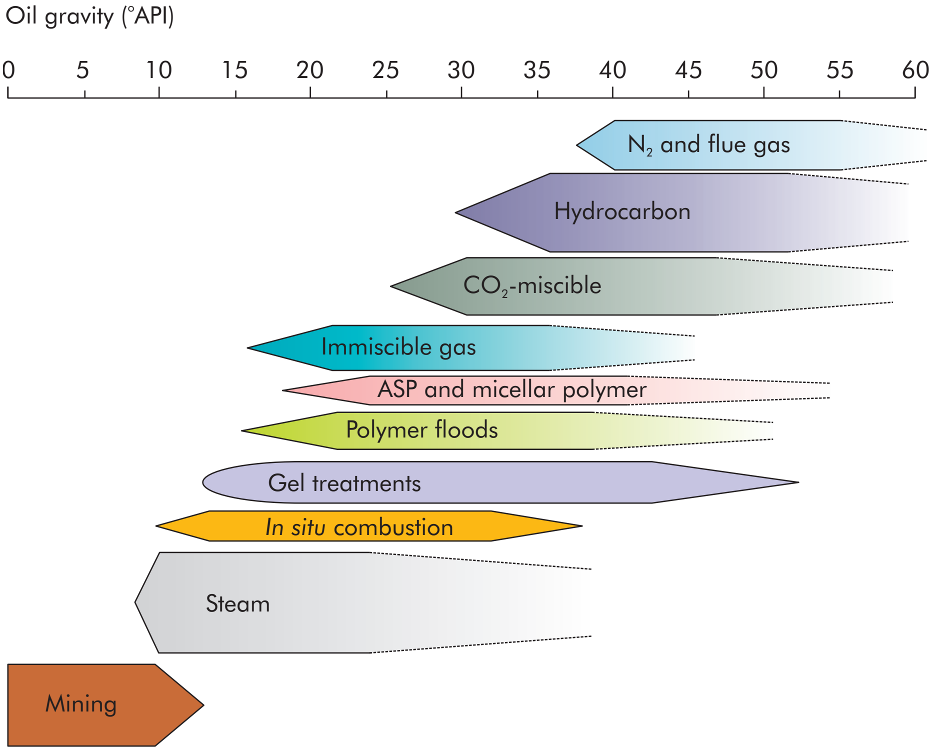
Different EOR methods can be applied for the different ranges of oil gravity (Figure 2.15). The size of the bar in the figure indicates the relative amount of production in which that method is used.

Predicting the complex subsurface flow behaviour in EOR projects via computer simulation is an important step in designing the tertiary recovery method. Such simulations help to optimise injection profiles, well patterns and sweep efficiency.

EOR-associated oil production amounts to about 2.5 million barrels per day (mb/d) (O&GJ, 2008; IEA, 2008). The largest share is from thermal processes (United States, Canada, Venezuela, Indonesia and China); CO_2 injection (United States); hydrocarbon gas injection (Venezuela); nitrogen (Cantarell field in Mexico); and polymer/surfactant flooding (China) (Table 2.3). CO_2 injection, which has been used for 30 years in West Texas, is currently of considerable interest around the world because of its potential to sequester CO_2 and improve oil recovery.

The implementation of EOR is dependent not only on production levels and oil prices but also on the cost (Box 2.7).

Figure 2.15 • Effectiveness of different EOR methods



Source: Taber, Martin and Seright, 1997.

Table 2.3 • Estimated incremental production from EOR projects (1 000 b/d), 2007

	Thermal	Nitrogen	CO_2/ hydrocarbon	Chemical	Total
United States	300	10	340	–	650
Canada	330	–	50	–	380
Mexico	–	500	–	–	500
Venezuela	200	–	170	–	370
China	160	–	5	200	365
Indonesia	190	–	–	–	190
Others	20		35	–	55
World	1 200	510	600	200	2 510

Source: IEA, 2008.

Note: kb/d = thousand barrels per day.

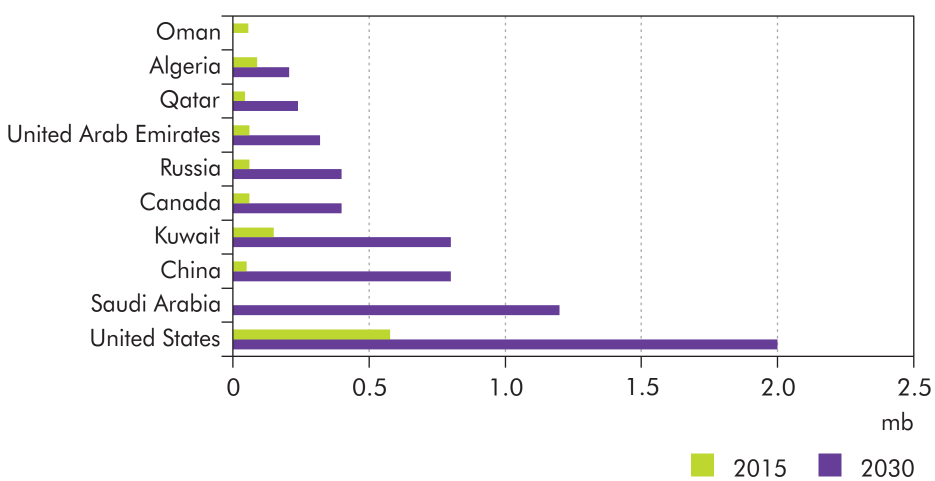
Box 2.7 • The power of market prices

The prospects for IOR and EOR have recently been boosted by higher oil prices. However, energy feedstock prices for thermal processes and hydrocarbon displacement, increased demand for CO_2, and the impact of higher oil prices on surfactants and polymers have all led to a sharp rise in costs in recent years. Nonetheless, the cost of EOR is still acceptable and ranges from just under USD 20 to USD 80 per incremental barrel of oil.

Hydrocarbon gas EOR can also be attractive when gas is available in the same, or nearby, fields. Indeed, if transport infrastructure to market does not exist, it is essentially a zero-value product, which is likely to be flared, producing significant CO_2 emissions. Hydrocarbon gas injection EOR schemes are used in many places around the world and have increased recovery between 5% and 10%. The EOR schemes can be combined with water injection, either by alternating WAG or by simultaneous injection as a water/gas mixture or as foam.

EOR production is set to increase with time. In the Reference Scenario of the IEA World Energy Outlook 2008, additional production resulting from EOR (over and above current EOR output) was projected to contribute an additional 6.4 mb/d to world oil supply by 2030, with most of the increase occurring after 2015 (Figure 2.16) (IEA, 2008).

Figure 2.16* • *Production from EOR in the* WEO 2008 *Reference Scenario, by country



Source: IEA, 2008.

Three-quarters of this increase comes from four countries: the United States, Saudi Arabia, Kuwait and China (in ranked order). Cumulative production in 2007-30 amounts to 24 bb, out of an estimated potential of about 300 bb, of which one-third is in Saudi Arabia.

Most of the new EOR projects implemented during the projection period 2007-30 involve CO_2 injection. In total, about 9.8 gigatonnes of CO_2 are captured and stored in CO_2-EOR oil projects over the period. These projects are exclusively onshore, as the projection assumed that the technology for offshore CO_2-EOR would not be sufficiently advanced for it to be deployed before the end of the projection period.

CO_2 injection for EOR

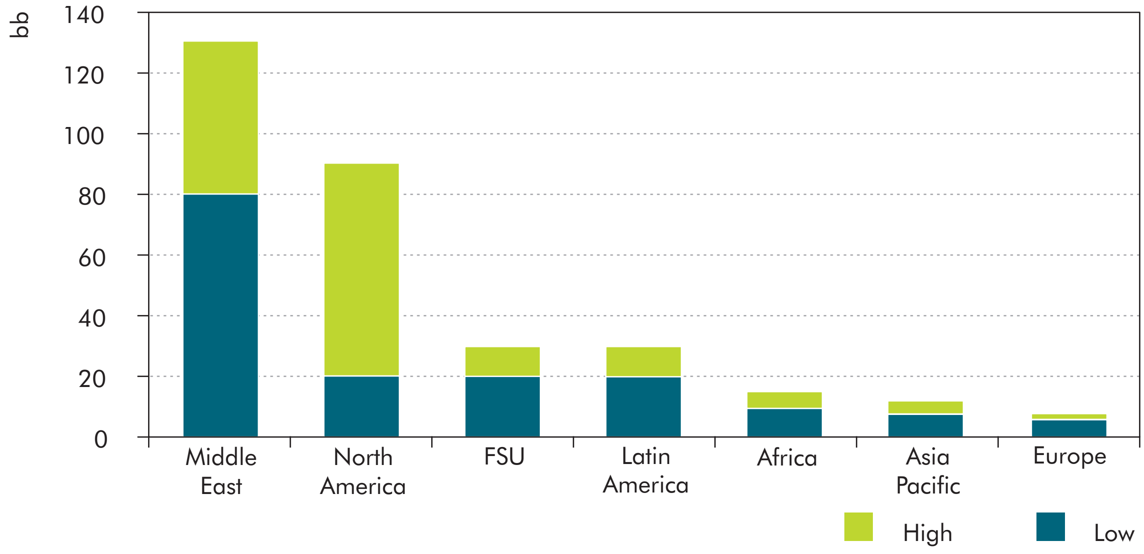
The attraction of CO_2 injection is that it is miscible with oil at a much lower pressure than natural gas and under reservoir conditions it has a similar density to oil. CO_2-EOR was initially deployed in the 1970s and is used mostly onshore with a small inter-well distance. In addition to expanding the use of the technology to new onshore areas, recent work has suggested there may indeed be considerable future potential for using it offshore (ARI, 2010a) and in larger reservoirs (USDOE/NETL, 2010). Experience in Texas shows that in suitable reservoirs, oil recovery may increase to between 5% and 15% of the oil initially in place. An assessment of the potential in the United States shows that improved CO_2-EOR, in combination with 4-D seismic, advanced well monitoring and control, and reservoir simulation could add 119 bb of technically recoverable oil and 66 bb of economically recoverable oil (ARI, 2010b) in the United States alone.

In Texas, it is estimated that there are about 48 billion additional barrels of oil, primarily in the Permian Basin, eastern Texas and the Gulf Coast, that can only be reached by using CO_2-EOR together with advanced monitoring and control (ARI, 2010b). Texas is working at full capacity of available CO_2 supply (predominantly from natural sources) and uses about 30 million tonnes (Mt) of CO_2 annually.

The worldwide potential for CO_2-EOR is between 200 bb and 300 bb, equal to between 10% and 15% of current remaining recoverable conventional oil resources using primary and secondary recovery techniques. The Middle East and North America are thought to hold the greatest potential (Figure 2.17).

The potential is greatest for newer fields with relatively low depletion levels because the costs of installing the required equipment and facilities are substantial, particularly for offshore fields (Tzimas *et al.*, 2005). Older facilities are also often not resistant to corrosion by CO_2/water mixtures and thus incur large replacement costs. Incremental recovery rates with EOR from offshore fields are expected to be lower than from onshore fields because of different well configurations and complex facility issues.

Figure 2.17* • *Potential additional recoverable oil resources using CO_2-EOR, by region



Note: FSU = former Soviet Union.

Source: IEA, 2008.

The growing sense of need to capture CO_2 emissions from major energy installations and storing it in reservoirs or formations underground is leading to increased interest in using the gas for EOR or enhanced gas recovery. However, most CO_2-EOR projects have hitherto obtained CO_2 from natural sources. There are more than 90 CO_2-EOR projects worldwide, most of them in North America, producing in excess of 300 kb/d of oil. In the United States, it has been projected that the contribution from CO_2-EOR can increase from the 2007 level of 250 kb/d to 1 300 kb/d by 2030 (Caruso, 2007). The economics of CO_2-EOR can be attractive. Current experience suggests that about 0.17 tonnes (t) to 0.28 t of net CO_2 will provide one barrel of oil.

The United States has the most experience in CO_2-EOR and therefore exporting its know-how will provide other regions with an excellent quick start.

CO_2-EOR for greenhouse gas mitigation: a future win-win situation?

Limiting the increase in global temperature by reducing CO_2 emissions to the atmosphere is one of today's key challenges. Fossil fuels dominate global energy supply and will continue to do so for the foreseeable future. To achieve pledges made at both COP15 and COP16[11] to address future emissions, a

11. The 15th and 16th sessions of the Conference of the Parties to the United Nations Framework Convention on Climate Change, held in Copenhagen (2009) and Cancun (2010), respectively.

significant adoption of carbon capture and storage (CCS) is projected over the coming decades (IEA, 2011). The CO_2 captured must be permanently[12] stored in geological formations selected such that virtually all of the CO_2 will be trapped in the subsurface. The types of formation chosen for geological storage include saline aquifers (*i.e.* porous and permeable bodies of rock containing salty water), depleted oil and gas reservoirs, or oil reservoirs that still contain mobile oil that may be displaced by injection of CO_2 and then recovered. Saline aquifers, although the least well characterised at present, appear to offer the greatest potential for storing CO_2 in the long run. However, it has been proposed that using the CO_2 captured from new power stations for CO_2-EOR will not only be economically attractive and benefit the environment but could also lead to increased energy security (ARI, 2010c).

In fact, a study on optimising CO_2 storage in CO_2-EOR projects predicts a much larger EOR target worldwide than suggested in Figure 2.17 and concludes that captured anthropogenic CO_2 should be seen as a long-term supply source for affordable, reliable CO_2 needed to mature these targets (ARI, 2010c). Currently, most CO_2-EOR operators believe that the relatively low availability of CO_2 is limiting the industry's capacity to expand the application of CO_2-EOR.

Storage aspects

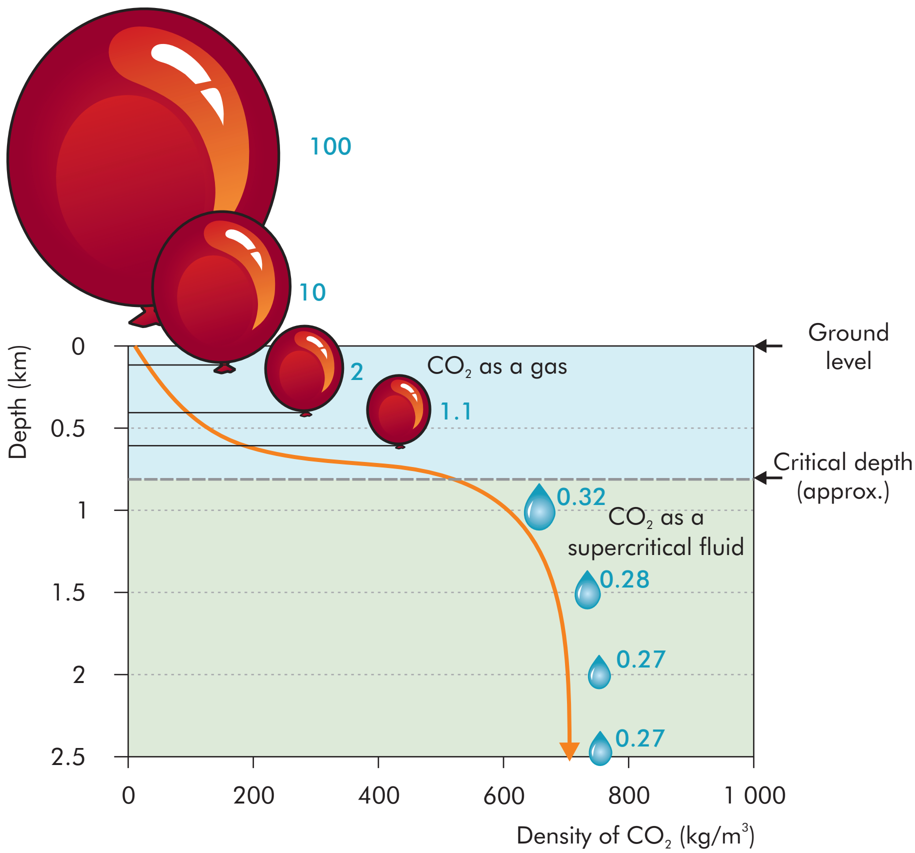
In geological storage, CO_2 is injected under pressure into suitable geological structures that contain natural trapping mechanisms like anticline-shaped impermeable cap rocks. The gas is injected at sufficiently high pressures and temperatures that it becomes a supercritical fluid that can still flow easily through the pore spaces but occupies much less space than gases. High pressure at sufficient depths (over 800 m) maintains the supercritical fluid state. Supercritical CO_2 compresses further with depth, increasing the amount that can be stored in the same volume (Figure 2.18). The blue numbers show the volume occupied by CO_2 at each depth compared to a reference volume of 100 volumetric units as a gas at the surface.

Oil and gas reservoirs occur in natural traps that have contained oil, gas and water for millions of years. If this were not the case, today's predominantly hydrocarbon energy economy would not exist. The geology of most oil and gas fields is well understood. Injecting CO_2 into hydrocarbon fields under development does incur some risk because these fields have experienced previous human intervention. The greatest risk of CO_2 leakage is not from the injection well but from other wells, such as abandoned production wells, that penetrate the storage formation and may be improperly sealed (Ide, Friedmann and Herzog, 2006). Before deciding on CO_2 injection into oil or gas reservoirs as a means of permanently containing the CO_2, prior drilling activity in the area needs to be investigated, *e.g.* against information that has previously been recorded, and well conditions verified. The existence of older, poorly documented wells in the area being proposed for injection could pose leakage risks.

12. In this context, "permanent" means that the injected CO_2 will be stored safely and securely over geological time scales, *i.e.* very long periods of time by any human measure (tens of thousands of years or longer).

Traditionally, most CO_2-EOR projects have been designed to minimise the amount of CO_2 injected per incremental barrel of oil produced. However, there are opportunities to modify reservoir management strategies to optimise and increase the capacity for CO_2 storage in CO_2-EOR fields. Such optimisation could include reducing water injection and leaving the pore space filled with CO_2 at field abandonment. Another option would be to flood reservoir zones below the OWC to release any residual oil that could not be recovered under a water-flood. Such zones are known as residual oil zones.

Figure 2.18 • *Density and volume occupied by supercritical CO_2 at different injection depths*



Note: kg/m^3 = kilogram per cubic metre.

Source: CO_2CRC, 2009.

CO_2-EOR could be viewed as a component of CCS, where the revenues from EOR contribute to the overall cost of the CCS operation. Subsequent to the EOR phase, instead of abandoning the field, activities could then be switched to focus on CO_2 storage.

The Weyburn-Midale project

A key pilot project in which CCS and EOR are combined is the Weyburn-Midale project. In 2000 a CO_2-EOR project began at the Weyburn oilfield. Production in the field, which is now operated by the Cenovus Corporation following a split from Encana at the end of 2009, began more than a half century ago. Primary and water-flooding stages, augmented with vertical and horizontal-well infill drilling, had already been carried out on the oilfield before the start of the EOR project. In 2005, Apache Canada implemented a similar CO_2 flood in its neighbouring Midale field and both projects are now managed as a single project.

The CO_2 is produced and supplied by the Dakota Gasification Company lignite gasification plant in Beulah, North Dakota. The plant produces 13 000 tonnes per day (t/d) of CO_2, although not all is captured. Approximately 8 000 t/d are compressed to 15 megapascals (MPa) and transported as a supercritical fluid via a 325 km pipeline to the oilfields in Saskatchewan, Canada (Figure 2.19).

Figure 2.19 • Weyburn-Midale CO_2 pipeline

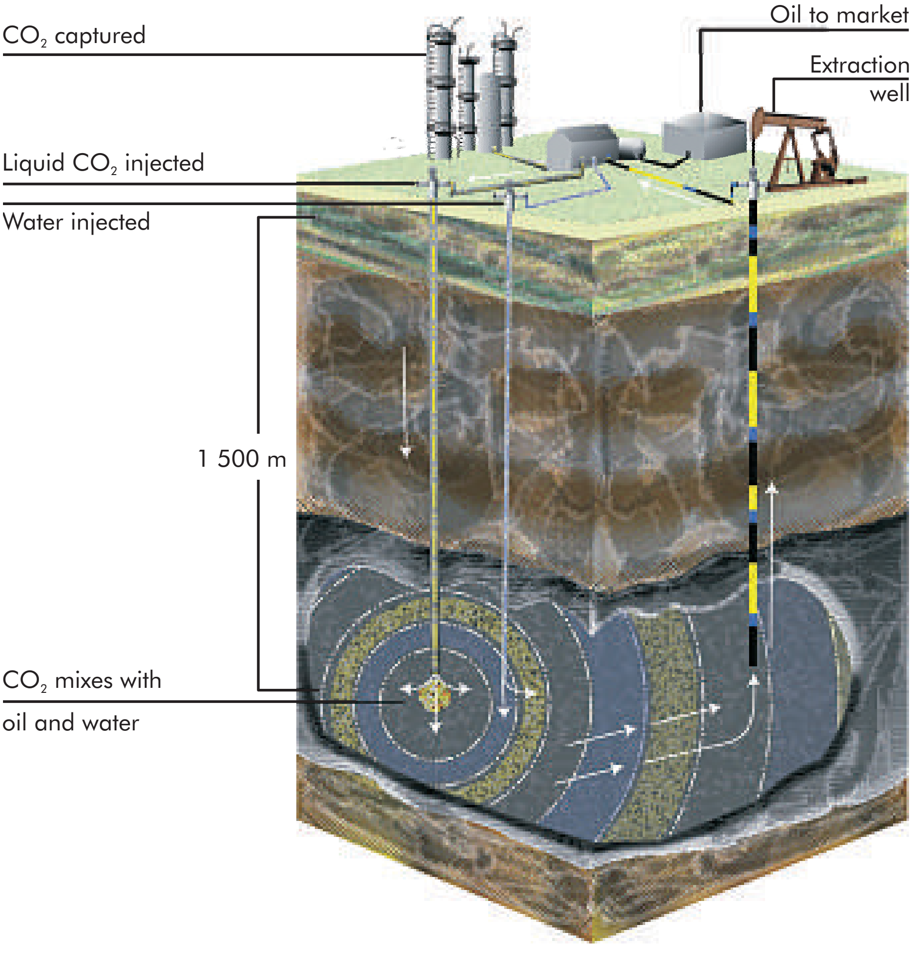
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: IEA GHG,[13] 2006.

13. The "Implementing Agreement for a Co-operative Programme on Technologies Relating to Greenhouse Gases Derived from Fossil Fuel Use" (or "IEA GHG") is one of more than 40 Implementing Agreements that comprise the IEA energy technology network. It is often referred to as the IEA Greenhouse Gas Research and Development Programme (IEA GHG). Further details may be found on accessing its website (www.ieaghg.org).

The CO_2 is injected to a depth of 1 500 m (Figure 2.20). The operating strategy at the field is to alternate CO_2 and water injection; this approach helps to mitigate the tendency for the lower-viscosity CO_2 to break through to the producing well, as gas injected afterwards would follow that path and reduce the overall efficiency of oil production. The CO_2 is miscible with the oil, enabling oil to escape from rock pores and flow towards the production wells. During the process, about half of the injected CO_2 returns to the surface along with oil and water, where it is separated and reinjected. At the end of the oil recovery period, virtually all of the injected and recycled CO_2 is permanently stored.

Figure 2.20 *• The Weyburn-Midale CO_2-EOR storage project*



Source: PTRC, 2009.

At Weyburn, Cenovus currently injects 6 500 t/d of freshly piped liquid CO_2 and, at Midale, Apache injects 1 250 t/d. In total, over 18 Mt of CO_2 had been injected at the end of 2010. When both projects are completed, total CO_2 stored will amount to over 40 Mt. This amount of CO_2 is equivalent to removing nearly nine million cars from the road for one year.

However, much more storage capacity still remains available. Modelling results indicate that at Weyburn alone an additional 25 Mt of CO_2 could be stored. If appropriate financial incentives, such as offset credits, were to be made available to cover the costs, the operators might consider using this extra storage capacity.

The net CO_2 used for the Weyburn oilfield is between 85 standard cubic metres per barrel (Sm^3/b) to 115 Sm^3/b or around 0.17 tonnes per barrel (t/b) to 0.22 t/b (see Table 2.4). The Midale field indicates slightly lower usage. The volume of the CO_2 stored during the EOR phase is currently around 13% of the hydrocarbon-filled pore volume. As mentioned above, this number could increase by a factor of two in a possible follow-up stage to maximise the CO_2 storage in the field. Future technology such as CO_2 foam could increase the amount of CO_2 that could be stored by reducing the mobility of the CO_2 and displacing more water from the reservoir. Table 2.4 shows the operating statistics for the Weyburn and Midale CO_2-EOR projects.

Table 2.4* • *Weyburn and Midale CO_2-EOR operating statistics

	Weyburn (Cenovus) (December 2010)	Midale (Apache) (April 2011)
Start of CO_2 injection/duration	2000/30 years	2005/30 years
Injection pressure	10-11 MPa	10-11 MPa
Daily injection rate of fresh CO_2	6 500 t/d	1 250 t/d
Recycle rate of CO_2 and produced gas	6 500 t/d	630 t/d
Total daily CO_2 injection rate	13 000 t/d	1 880 t/d
Annual amount of fresh CO_2 injected	2.4 Mt	0.46 Mt
Total amount of fresh CO_2 injected to date	16.4 Mt	2.5 Mt
Incremental/total oil production	18 000/28 000 b/d	2 540/5 600 b/d
Projected total incremental oil recovery due to CO_2	155 mb	60 mb (17% OOIP)
CO_2 utilisation factor	3-4 million cubic feet/barrel (mcf/b)	2.3 mcf/b
Projected amount of CO_2 stored at project completion	Over 30 Mt (gross)	Over 10 Mt (gross)
	Over 26 Mt (net)	Over 8.5 Mt (net)
Total capital cost of EOR project	Estimated CAD 1.3 billion	Estimated CAD 400 million

Notes: OOIP = original oil in place; 1 million cubic feet = 28.3 thousand cubic metres.

Source: Mourits, 2011.

At the same time that the CO_2-EOR project started at Weyburn in 2000, an international research project was also launched under the auspices of the IEA GHG. The project set out to study CO_2 injection and geological storage at the Weyburn field and develop appropriate measuring, monitoring and verification technologies.

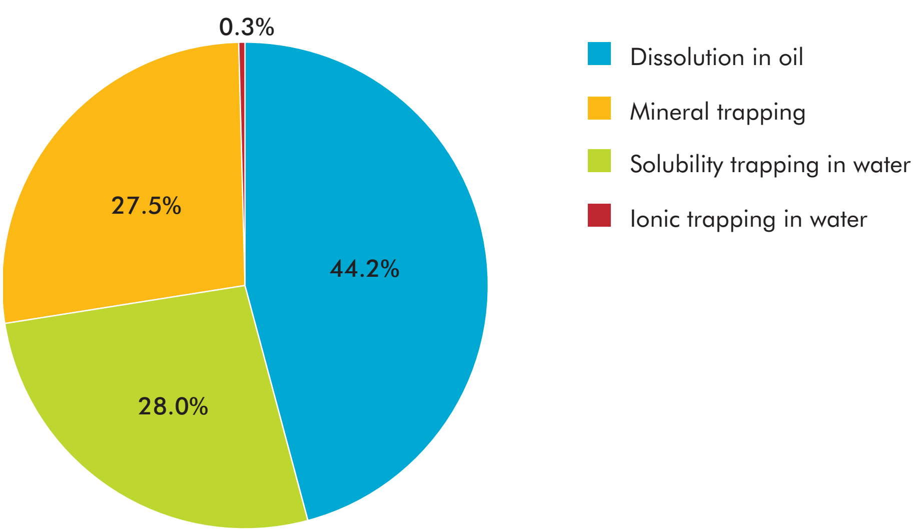
Specifically, the objectives of the first phase of the study were to develop monitoring and modelling methods to address the long-term migration and fate of the injected CO_2. A comprehensive analysis of various methodologies also set out to verify that oil reservoirs could contain CO_2 securely and economically (IEA GHG, 2006; Mourits, 2008).

A key advantage of Weyburn and an important reason for starting the IEA GHG research project at the field was the availability of 50 years of production data, and the large number of wellbores with associated geological and geophysical logging data. In addition, the pre-existing wellbores also presented an environment suitable for testing the potential for CO_2 leakage to the surface.

On the basis of the results from Phase I, the geological setting at Weyburn-Midale appeared to be highly suitable for the long-term geological storage of CO_2. The results included an estimation of the storage capacity of the field and a risk assessment of the injected CO_2 over a period of 5 000 years.

Probability analyses and numerical simulations, based on geochemical fluid sampling and seismic surveys, indicated that after 5 000 years all but a negligible amount of CO_2 would remain in the Weyburn reservoir and adjoining regions (IEA GHG, 2008). It was also found that, within the time period, almost 75% of the CO_2 would be trapped by dissolution in the reservoir fluids (brine and oil). All of the remainder would be trapped through mineralisation, hence precluding any further upward movement of the CO_2 (Figure 2.21). While the ultimate goal is mineral trapping of CO_2, storage of injected CO_2 in the short term (over the next 50 years) is most likely to be accomplished by solubility trapping in water and ionic trapping of CO_2 as bicarbonate ions.

Figure 2.21 • *CO_2 trapped by different mechanisms*



Source: Wilson and Monea, 2004.

The final report from Phase I contains the most complete and comprehensive peer-reviewed data for the geological storage of CO_2 in the world. Phase I was completed in 2004.

A second phase, entitled the IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project, started in 2005 and ran until 2012. Project participants comprised six governments or government agencies, including Natural Resources Canada (NRCan), the provincial governments of Alberta and Saskatchewan, the United States Department of Energy (US DOE), the Japanese Research Institute of Innovative Technology for the Earth and the IEA GHG, as well as ten Canadian and international energy companies. The Petroleum Technology Research Centre managed the technical components of the project, while NRCan managed the non-technical components.

The technical and non-technical accomplishments of the second phase are described in a best-practices manual (Hitchon, 2012) that contains both technical and non-technical components. The technical components are intended to serve as protocols for the design, implementation, monitoring and verification of EOR-type CO_2 storage projects. The technical part also includes guidance on topics such as site characterisation/selection; well-bore integrity; monitoring and verification; and risk assessment. The non-technical part of the manual addresses measures to accelerate the development of appropriate regulations for CO_2 storage; of effective public communication and outreach; and of public policy that provides effective incentives to ensure the widespread deployment of CCS in the long term. Many of the methodologies and findings of the project are applicable to CO_2 storage in other types of geological formations.

The Weyburn-Midale CO_2-EOR operations demonstrate that the technology could, given the right circumstances, provide a win-win approach for CCS as an important contributor to global climate mitigation in the decades to come.

Costs and carbon credits

When considering the commercial viability of a CO_2-EOR project involving the capture of CO_2 at a power-generating plant, several factors must be taken into account. Clearly, energy costs are substantial for CO_2 capture, transportation and injection, all of which emit CO_2. The process adds infrastructure to a power plant with associated capital costs, pipeline costs depending on the distance transported, and infrastructure needed to inject the CO_2 into the reservoir. Purity requirements for CO_2 can lead to the added cost of separating the gas at the power plant. Monitoring, measuring and verification costs post-injection will be part of the regulatory compliance requirements. All of these added costs need to be balanced against the value of the incremental crude oil produced plus the value of CO_2 credits, if and when these are available. All of these factors need to be taken into account in order to assess the commercial viability of a CO_2-EOR project.

In many cases, CO_2-EOR is not considered financially viable because of the high price of CO_2 from power station capture. Therefore, a carbon credit or other financial incentives are needed to cover the difference. So far, CCS projects are not entitled to such credits. At the end of 2010 in Cancun, the United Nations Framework Convention on Climate Change (UNFCCC) decided that CCS could qualify for credits from the Clean Development Mechanism (CDM) provided that a number of issues are resolved. Issues included monitoring, site selection, risk assessment, definition of liability and others. However, given the low prices (less than USD 5/t CO_2) at which CDM credits have been and are still being traded, it is unlikely that CDM credits will provide a strong stimulus for CCS projects, at least for some time to come. Therefore, CO_2-EOR could be viewed as a way to offset part of the cost of CCS projects. In areas with multiple fields in close proximity, a CO_2 pipeline infrastructure could help to improve economics, but the initial costs of such systems are still a hurdle.

Being smart with smart fields

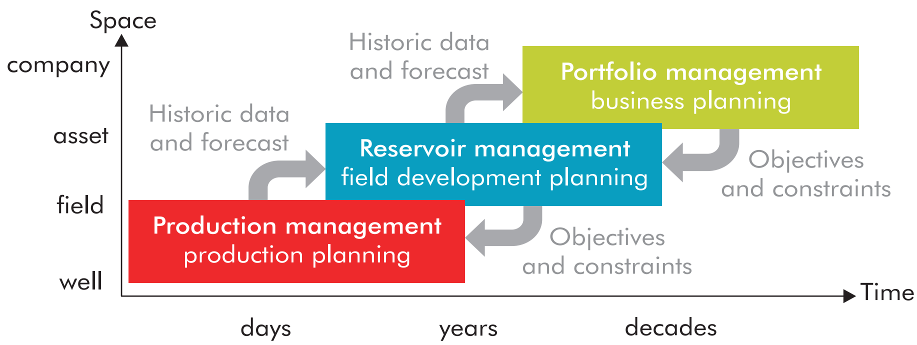
Since the end of the 1990s, a number of large oil companies, including Shell, BP, Saudi Aramco and Statoil, have been piloting so-called smart field technology. The concept of smart field is also known as "intelligent field", "digital oilfield", "integrated operations" or "field of the future". These days, many national and international oil companies have integrated smart fields as part of their strategy. For example, in 2010 Kuwait Oil Company (KOC) started the Kuwait Integrated Digital Field programme.

Smart field technology is not just a single technology but covers a whole range of new and advanced technologies. The technologies range from sophisticated wells, to fast communication technology (*e.g.* fibre and wireless) to virtual collaborative working environments. New information and communication technology plays a key, central role in any implementation, which explains the adjectives intelligent and digital. An important aspect of a smart field is that these advanced technologies are used in an integrated manner to maximise their potential.

Smart fields are not only about technology but also about people and work processes. To exploit the opportunities of smart field technologies, work processes have to be adapted. Integration is also the key word here (integrated operations). Companies, such as the KOC, position digital field projects as company-wide transformation projects that prepare the company for the future (field of the future).

The overall objective of smart fields is to optimise planning and operations, resulting in higher shareholder value and improved health and safety performance. Hence, a smart field is one that can be in continuous use 24 hours a day, seven days a week. The underlying philosophy is that the total value that can be created from a field depends on: how precisely the hydrocarbons in the ground can be determined; how efficiently those hydrocarbons can be recovered; how to optimise production and well facilities; and how to improve the overall field performance throughout the field lifecycle on time scales ranging from seconds to field life. Optimising the use of equipment for maximum efficiency is achieved over differing time scales. For example, for gas lift, improvements can be seen in real time, for production or pipeline systems it could be days or even weeks, and for water-flood management it can take months or even years (Figure 2.22). The concept is not to focus on portfolio management but, instead, to consider the complete system in a more holistic manner.

***Figure 2.22** • Smart fields focus on short-term production and longer-term reservoir management*



Courtesy of W. Schulte.

Smart field technologies

Applications of leading oil operators to create smart fields reveal five technology enablers that are key to the successful implementation of smart fields. These are:

- **Measurement (sensors).** The basis of providing high-quality data lies in measuring the processes that are vital to the business of the company, particularly in drilling and production. Examples include the traditional measurement technologies that are deployed in the production process for wells (pressure, temperature, flow), for topside equipment such as compressors and separators (pressures, temperatures, revolutions per minute, densities) and for drilling (logging while drilling, measuring while drilling, wire-line logging). Recent years have seen the uptake of advanced technologies, as illustrated by Shell's experience in Brunei Champion West and BP's experience at Plutonia. These technologies involve distributing sensor technologies in wells to acquire measurements along the (full) trajectory of a well during production. Such sensor technologies include fibre optic technology, down-hole pressure and temperature sensors, and (down-hole) multiphase flow metering.

- **Communication.** Communication technologies are used to transport measurement data to central data-acquisition servers in control rooms set up at the field. Typically this is real-time data, which is acquired every ten seconds by remote terminal units. Subsequently, these technologies are used to link up control rooms and support centres and/or central offices. A range of well-established technologies is successfully used for this, such as wireless solutions and fibre optics.

- **Database management systems (DBMS).** For storing and retrieving large amounts of real-time data and other data, information technology companies provide a whole host of existing solutions (relational and time-stamped DBMS). These generic DBMS are customised into solutions that are geared towards usage by oil companies.
- **User interface.** Typically, data will be interfaced to three distinctly different types of locations and users: operations (central control rooms for drilling and for production), operations support in special support centres at offices typically located far from field operations and field development teams.
- **Control (actuators).** Once a decision has been taken on how to manage a certain process, remote-controlled actuators are required to change the control parameters of that process into one that is cost-effective, convenient and timely. For example, to change a choke setting, the personnel no longer have to go out to the well-head, which is labour-intensive, inconvenient and takes time before choke settings are changed. Other examples of processes that can be remotely controlled include separator trains, routine well testing, manifold valve settings, and subsurface well inflow. In an advanced smart field process, parameters may be set automatically by dedicated software tools, such as the automatic shut-down of a well in case certain limits (*e.g.* water-cut levels) are violated. In a very advanced smart field, processes may even be controlled automatically on a continuous basis by closed-loop, model-based optimisation programmes. An optimisation programme triggers changes in operational settings based on calculated responses, reads the actual response of the field to these changed settings and analyses how best to further improve the settings.

Smart field collaboration

The best examples of changed work processes are the impressive control rooms with their wall-covered monitors. Such facilities create a virtual, collaborative working environment. It brings together petroleum engineers, well services, and offshore operations staff in virtual real-time decision making. This embeds a completely new way of working in the organisation, based on the philosophy of how the field should be managed. It really means one operation based on one dataset, one plan and one common set of priorities. That does not sound like rocket science, but it is a huge step for oil companies and leads to better, faster decision making.

The advantages of smart field

Having the vision to use smart fields in practice is not one-size-fits-all, because every field has unique features. Geological, environmental, economic and even political circumstances differ from case to case. Such circumstances change the way in which fields can be optimised and necessitate a customised solution for the whole field operation.

When assessing the added value of implementing smart field technology and work processes, it is worth considering that just as the smart field touches upon needs on multiple levels of the organisation, the value created is also many-faceted. Some advantages are easy to quantify, such as increased production rates. Some may only be estimated, for example the ultimate recovery factor. Others are harder to quantify as many people forget to compare the situation before and after specific work flows and programmes have been changed. There are also advantages that cannot be quantified, such as the achievement of higher health, safety and efficiency levels because travel to and from offshore platforms is no longer as necessary.

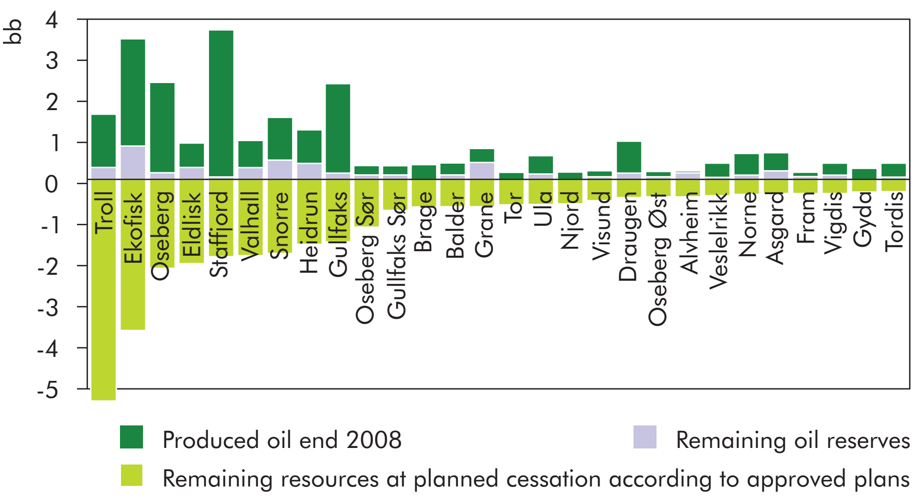
The following two examples illustrate the potential of smart fields.

- **BP.** Increased production from more than 700 wells, including 80% of the company's most prolific producers, by 50 mb of oil-equivalent per year for each of the years 2006 to 2009.
- **Shell.** The Champion West field in Brunei was developed some 40 years after discovery by using smart field technology, making it more financially viable with a peak production of 50 000 b/d.

Importance of future technology RD&D

Despite the technological progress described above, most of the oil initially in place in a given field remains in the ground after production in the field has ceased because it is no longer financially viable to continue with current technology. On the NCS, despite the improvement in the average rate of recovery to around 46%, more than half of the oil existing in the fields will remain unexploited after production has ceased (Figure 2.23). The challenge is greater still on a global scale, since the global average recovery rate is lower than that of the NCS.

Figure 2.23* • *Distribution of oil resources and reserves in producing NCS fields



Courtesy of Norwegian Petroleum Directorate.

In order to recover more of this remaining oil, the Norwegian Petroleum Directorate has set an objective for NCS reserve growth of 5 bb of oil before 2015. This amount is equivalent to the original oil in place in the Gullfaks field. This is seen as a stretch target for both the Norwegian government and the industry. Its realisation requires more efficient recovery from fields in production, development of discoveries in the vicinity of existing infrastructure, proving and developing new resources, and constantly operating fields more cost-effectively.

The challenges are:

- **Time.** The remaining time, as well as increasing cost in mature fields, poses a challenge. In a mature oil province, many fields incur increasing costs as production declines. In order for advanced technology to be deployed economically and efficiently, the deployment needs to be optimised within the economic lifecycle of the field. However, IOR/EOR projects applied at a later stage in the field's lifecycle have a shorter available time-frame for their implementation. This time-frame is further limited by the production cut-off when the field is abandoned and when the potential for improving total recovery is reduced. This stresses the urgent need to accelerate development of advanced oil recovery technologies. For example, the huge Brent oilfield in the North Sea will be abandoned in the coming few years with around 45% of its original oil still in place. Technology for further oil extraction is currently too costly and the window for application of still-to-be-discovered solutions will be too late.
- **Available technology.** The necessary measures for IOR/EOR projects may depend on more sophisticated or cheaper technology that is not available within the duration of the initially planned production. Implementation of IOR measures that extend production can open a window for implementing EOR at a later stage. Offshore CO_2-EOR is an example. Large-scale application of CO_2-EOR offshore is not expected before 2020 (IEA, 2008). This may make CO_2-EOR less relevant for a number of maturing offshore fields currently approaching their production cut-off, unless the development of the required technologies is accelerated or other IOR measures are applied to extend the window of implementation.
- **Lifecycle view.** A lifecycle view on field development, which early on makes choices to enable later IOR/EOR or starts testing novel concepts in time. The best timing to prepare for EOR is when the first wells are drilled so that fluid sampling can be carried out and EOR pilot tests can be integrated into the early development phase. A risk is that, in order to reduce the cost of the secondary development, choices are made that will preclude later options. CO_2-EOR is again an example. Choices of material for constructing the facilities may make later refurbishment towards CO_2 in the production stream too expensive.

Therefore it remains a key task of government and industry to research, develop and deploy technologies that will reduce the cost of current options and develop novel ways to extract more oil from existing reservoirs. There are a lot of technologies that could be applied throughout the world if their cost were to be reduced. Also a number of technologies have shortcomings or cannot yet be applied to all fields. A few examples of technological challenges for conventional oil that require significant RD&D and governmental support include:

- permanent seismic acquisition on the surface or in wellbores;
- new remote surveys using electro-magnetic fields;
- cheap and reliable sensors along wellbore;
- more accurate information on remaining oil (*e.g.* via nanotechnologies);
- more stable CO_2 displacement in high-permeability reservoirs (*e.g.* using foams);
- availability of polymers for higher temperatures;
- surfactant flooding using a lower concentration of chemicals;
- accelerated thermal heavy oil production by using solvents or catalysts;
- producing heavy oil economically by using cold methods (*e.g.* emulsions or polymers);
- cost reduction for offshore installations;
- improved separation techniques for contaminated gas.

It will take hard work, finance and dedication to achieve the targets for IOR/EOR outlined in this chapter.

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Chapter 3 • The growing importance of natural gas

Natural gas is set to play a central role in meeting global energy requirements. It is a versatile and abundant energy source for the power, industry, buildings and transport sectors. A few decades ago gas was still seen as an unwanted by-product of oil production because it could not be easily stored. Gas that was produced with oil was, therefore, either released directly to the atmospphere or flared – both operations producing greenhouse gases (GHGs). Over the years, however, gas collection systems have been built either to export the gas or to reinject it. More profitable ways now exist to transport gas over large distances and natural gas fields far away from markets are being developed around the globe, such as in Qatar and Western Australia.

Natural gas is a clean burning fuel producing mainly carbon dioxide (CO_2) and water, and requires no post-combustion waste treatment. Its low carbon-to-hydrogen ratio makes it substantially less CO_2 emitting, *i.e.* a less carbon-intensive fuel, than either oil or coal. For these reasons, it is becoming the fuel of choice in many regions of the world. Over the next two or three decades, gas consumption will continue to rise as the world commits itself to a low-carbon scenario. Coal demand is likely to be displaced by gas and other lower-carbon energy sources, such as nuclear energy and renewable energy technologies, in the overall energy mix. However, gas is also a fossil fuel and, at some point in time, its continued unabated use may, too, become inconsistent with meeting a more challenging scenario, one that aims to limit atmospheric temperature rise by 2 degrees Celsius (°C).

After a short discussion on natural gas sources and lifecycle aspects, the chapter will focus on the transportation of natural gas to global markets. This is a central issue for any natural gas development because of its complexity and cost implications. It is followed by a short discussion on the implications of sour gas and the contribution of components from natural gas to liquid production levels.

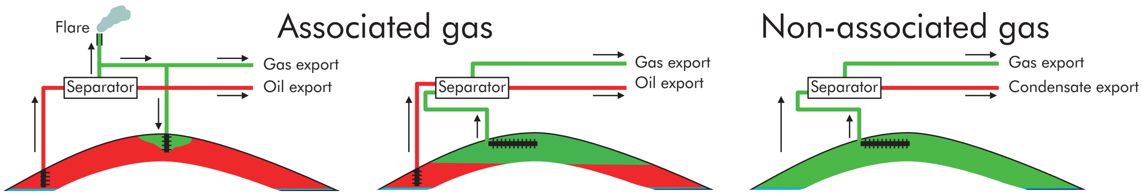
Natural gas sources and lifecycle aspects

Natural gas comes from various sources that may be categorised as:

- associated gas: found in oilfields (Figure 3.1);
- non-associated gas: found in natural gas fields (Figure 3.1);
- unconventional gas: which includes gas sources such as methane from tight gas, shale gas, coal beds and methane hydrates (Chapter 6).

The majority of natural gas comes from the first two sources, but the importance of unconventional gas is growing. Unconventional gas comes from unusual types or extremely low-permeability reservoirs, which require very special extraction methods that are discussed separately in Chapter 6.

Figure 3.1* • *Sources of conventional gas



Courtesy of W. Schulte.

The development of associated gas is linked to the development of oil whose lifecycle is described in Chapter 2. The phases are exploration, appraisal, development (including primary, secondary and tertiary recovery) and abandonment (Figure 2.1). The gas production rate is linked to the oil production rate as the gas evaporates from the oil in the surface facilities. Gas from gas caps (shown in green in Figure 3.1) are often produced towards the end of the lifecycle of an oilfield when the reservoir pressure is allowed to drop significantly.

The lifecycle for non-associated gas follows much the same characteristics as that of an oilfield. For example, the reservoir has to be found, appraised and developed through wells and surface facilities. The main difference is that development is often through primary recovery only. As gas expands significantly when pressure decreases, most of the gas can be recovered by merely dropping the reservoir pressure without any injection scheme. Recovery factors for non-associated gas fields range between 60% and 80%, which is significantly higher than those of oil in an oilfield. Limiting factors are often compression costs and water production. Compression is required when the tubing head pressure (pressure at the top of the well) drops over time below the export-pipeline pressure owing to pressure depletion in the reservoir. Water influx into a producing well makes it harder to lift the gas-water mixture to the surface (an effect referred to as liquid loading of a well). In a mature gas field, gas recovery can be increased by lowering the pressure at the surface (thus allowing a further reduction of pressure and gas expansion downhole) and re-compressing the gas to export-pipeline pressures. The commercial viability of such a process depends on the balance between additional gas recovery and cost of compression.

In some fields, a secondary recovery phase, called enhanced gas recovery (EGR), is also considered. In an EGR scheme, a depleted, low-pressure gas field is flooded with a waste gas displacing some extra hydrocarbon gas to the wells. If the injected gas is CO_2, GHG sequestration would have some extra benefits. Pilots are being conducted, *e.g.* in the K12-B field in the Dutch sector of the North Sea (Vandeweijer et al., 2009).

If the non-associated gas contains a high level of liquids (condensates), which condense from the gas when the pressure drops, the primary production phase is preceded by a so-called recycling phase. In a recycling phase, the gas is produced, the liquids collected in a separator and the dry gas reinjected to avoid a lowering of pressure inside the reservoir. Only when the reinjected dry gas starts being back-produced and the production of liquids is reduced significantly, can the process be switched to a primary phase with gas export allowing the reservoir pressure to drop. This recycling mode is also an option if no gas export route is available and recycling allows some early income from the development.

Gas may contain impurities like hydrogen sulphide (H_2S) and CO_2. When such impurities have a high concentration, field developments are hampered by the high cost of separating the contaminants out of the gas stream. Separation technology solutions are essential to field development, as will be discussed.

Abandonment operations for gas fields are much the same as those for oilfields.

More natural gas developments

In the 1960s and 1970s, natural gas developments were only considered when proximity to markets allowed transport of gas directly to consumers (as there were no storage options). The development of the Groningen gas field in the Netherlands triggered a national network of gas pipelines in the 1960s and nearly all Dutch households switched to heating and cooking on gas. Very early in the development of the North Sea oilfields, gas export pipelines were built to export the associated gas to shore. On the other hand, gas produced on the Alaska North Slope is still reinjected today because of the absence of such export pipelines. In recent decades, some long-distance gas pipelines have allowed gas fields to be connected to markets, such as Russia and Western Europe. A number of very large gas fields have been developed over the last two decades because it became possible to export gas via liquefied natural gas (LNG) terminals, such as in South-East Asia, Western Australia (USEIA, 2003) and, more recently, the Middle East and Western Africa. Qatar has built large-scale gas-to-liquids (GTL) facilities, a new way to commercialise stranded natural gas resources.

Almost three-quarters of global natural gas reserves are located in the Middle East and Eurasia. Russia, Iran and Qatar together accounted for about 55% of global natural gas reserves as of 1 January 2010.

Iran has the world's second-largest reserves of natural gas, after Russia, and is currently the Middle East's largest natural gas producer. Iran is also the Middle East's largest user of reinjected natural gas for enhanced oil recovery (EOR) operations. In 2007, Iran reinjected more than 28 billion cubic metres (bcm) of natural gas, or 16% of its gross production. In 2009, Iran began EOR operations at the Agha-Jari oilfield, where it plans to raise oil production by 60 000 barrels per day (b/d) by injecting 37 bcm of natural gas annually (USEIA, 2010). The largest production increments in the next 25 years will be coming from the Middle East (especially Iran and Qatar), Africa and Russia, and the other countries of non-Organisation of Economic Co-operation and Development (OECD) Europe and Eurasia. A significant share of the increase is expected to come from a single offshore field, which is called North Field on the Qatari side and South Pars on the Iranian side.

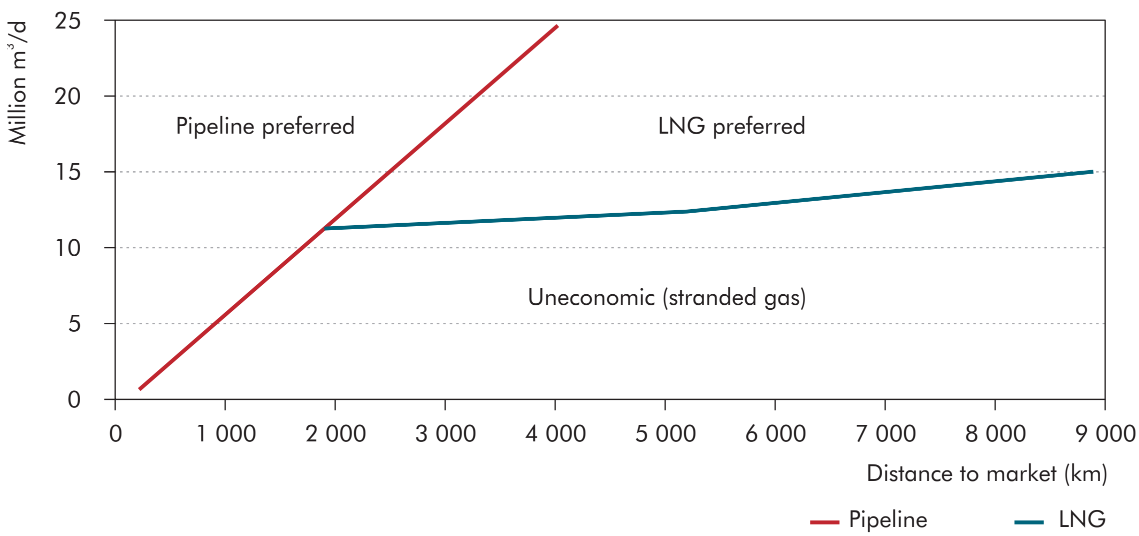
Despite significant growth in natural gas production over the past decade, several countries in the Middle East have experienced shortfalls in domestic supply, which have resulted from rapidly growing demand in the electric power and industrial sectors. As a result, some of those countries have established policies assigning priority to using natural gas domestically rather than for export.

Key element: getting gas to markets

Getting gas to global markets is the central issue as major conventional reserves tend to be remote from demand centres and natural gas transportation, mainly because of the properties of natural gas, is more complex and more costly than that of crude oil or coal. The main choices for gas transportation are by pipeline or by converting it into a liquid, *i.e.* into LNG.

Depending on the quantities transported and the distance to market, it may be more cost-effective to transport gas via pipeline than converting it to LNG (Figure 3.2). At short distance gas will be transported via pipeline, while for large gas fields, large distances can be covered through LNG. If the field is large enough, intermediate long-distance pipelines can still be more cost-effective than LNG. In some instances, as illustrated in Figure 3.2, neither pipeline nor LNG is cost-effective, which leaves the gas resource "stranded".

Figure 3.2* • *Quantity and distance regimes for LNG and pipeline gas transportation



Note: m^3/d = cubic metres per day; km = kilometre.

Source: adapted from Hanrahan, 2006.

Distance is not the only factor in choosing how to transport gas. Other factors include: land versus sea; separation of source and market; water depth or land contours; and political, right-of-way, or supply security issues along the route.

For many years, LNG was unable to compete with more nearby sources brought to market by pipeline because of the cost of processing and transportation. Therefore, for several decades it had a limited market, centred mainly on Japan. However, growing demand for gas, coupled with limited availability of pipeline sources, caused a rapid expansion of global interest in LNG. This increased interest brought with it a growth of investment in new projects worldwide and the beginnings of a global market for LNG during the last decade. The Asia/Pacific region is expected to continue to dominate LNG trade. Most LNG already goes there and the share is expected to increase over the period to 2035.

Total flows to and within non-OECD Asia are projected to rise from a net export of 26 bcm to a net import of 112 bcm in 2020 and 335 bcm in 2035. Imports into OECD Europe are not likely to rise as much, increasing from 265 bcm to 335 bcm in 2020 and 454 bcm in 2035, while OECD Americas[1] changes from being a net importer (of 29 trillion cubic metres [tcm]) to being a net exporter in 2035 (of 34 bcm).

While the LNG value chain is discussed further later, an alternative to liquefaction is to convert gas into a true liquid at normal pressure and temperature, allowing more transportation and storage options. Though the global capacity remains low, large-scale GTL plants are gaining increasing attention in some gas exporting countries, such as South Africa, Qatar and Malaysia, and on all continents. A novel development to monetise small gas accumulations located a long distance from markets is to transport them by compressing the gas at moderately low temperatures.

The LNG value chain

The LNG value chain consists of natural gas production, liquefaction, transportation in specialised ships at a temperature of -161°C, and regasification at the importation site. The largest component of the total cost of the LNG supply chain is usually the liquefaction plant. Of the total cost of delivering gas to markets via LNG, production and processing at the producing gas field make up about 15% to 20%; liquefaction about 30% to 45%; shipping some 10% to 30%; and regasification and distribution about 15% to 25%. Improvements in technology have reduced costs in all parts of the LNG value chain during the past three decades, though the trend has reversed more recently because of cost overruns created by a large number of new projects stretching the industry's supply chain.

Liquefaction

Before liquefaction, natural gas is treated to remove some unwanted components and subsequently condensed into a liquid by cooling it to -161°C at near atmospheric pressures, whereupon the volume of the gas is reduced 600-fold for transportation.

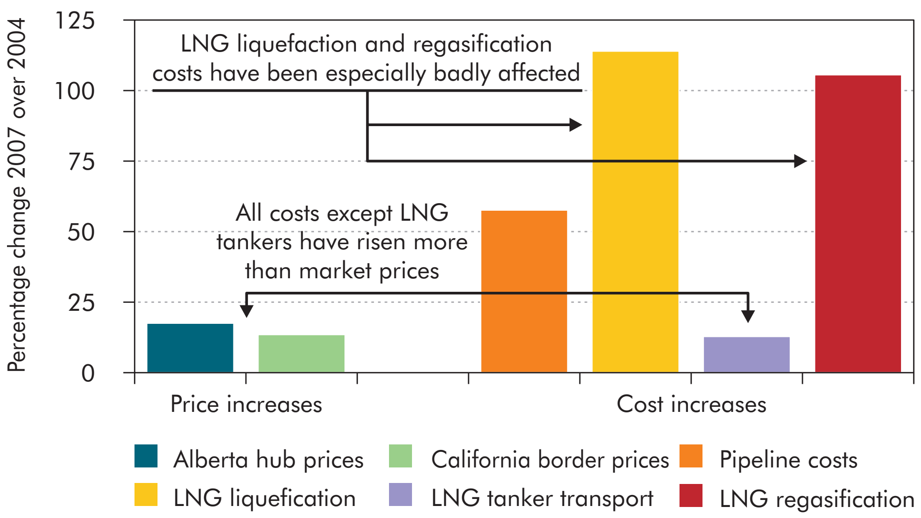
1. Includes Canada, Chile, Mexico and the United States.

Cost of liquefaction

Early liquefaction trains in the 1960s produced some 350 000 tonnes per year of LNG. The unit size has grown each decade, with new production trains reaching almost 8 million tonnes per year (Mt/yr) (11 bcm). This increase in scale accounts for a substantial part of the cost reductions achieved in gas liquefaction. Furthermore, improved design and competition among manufacturers led to a fall in capital costs for liquefaction plants from roughly USD 600 per tonne (/t) of capacity in the late 1980s to about USD 200/t in 2001. The trend in declining costs for gas liquefaction was interrupted around 2004, owing to increased prices for raw material caused by global increase in demand, especially in Asia. During the period 2004-12 the global surge in demand for plant construction overwhelmed the capabilities of plant construction firms and equipment suppliers, leading to substantial inflation and project delays. The trend between 2004 and 2007 has been estimated by Jensen (Figure 3.3). Costs of both LNG and pipelines rose substantially, but LNG costs are estimated to have increased by 100% to 125% over this three-year period, compared to some 50% for pipeline costs.

The LNG sector of the future's largest LNG exporter, Australia, is challenged by slow construction times and large capital expenditure (BREE, 2012). Costs of around USD 3 000/t for the Gorgon and Wheatstone projects, and USD 4 000/t for the Ichthys project, feature among the highest in the world, particularly when compared to the USD 1 700/tonne for the Angola LNG project and even lower costs in the United States.

Figure 3.3* • *LNG and pipeline cost inflation, 2004–07



Source: Jensen, 2007.

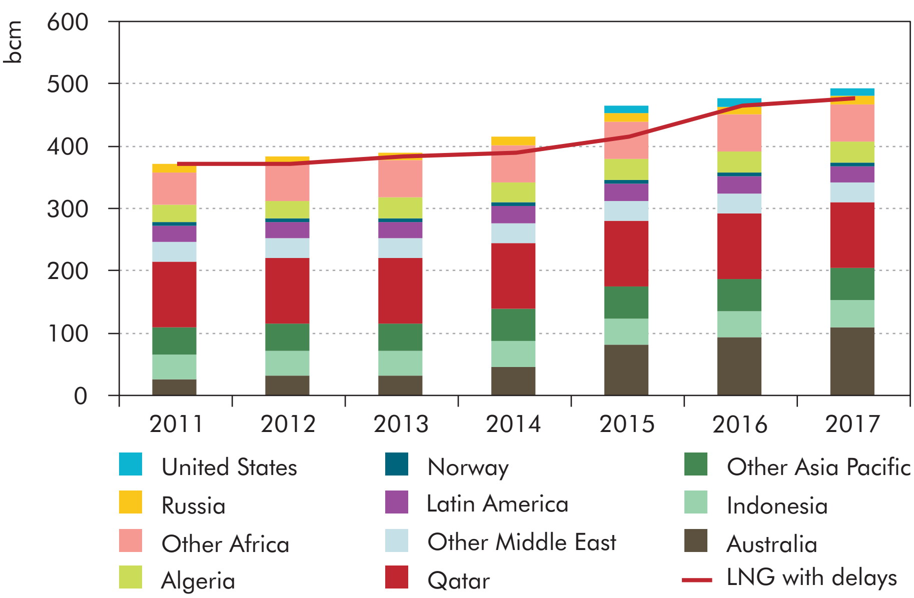
Outside the inflationary period, advances in refrigerant compressors and heat transfer equipment, together with the use of highly efficient gas turbines as drivers, have lowered unit costs. The search for more efficient technologies and processes for liquefaction, combined with an increased number of potential technology suppliers, should continue to be a force for cost reduction.

The development of a more global market for LNG now in progress has reinforced the trend towards larger trains and a greater degree of versatility. Producers are increasingly willing to accept up front the risk associated with a part of the train's production rather than secure all of the production by long-term agreements before proceeding to construction. The feasible size of new trains could continue towards the 10 Mt/yr mark, providing increased operational economies of scale, or perhaps they will be standardised at 5 Mt/yr as a way to reduce costs through increased fabrication volumes. The addition of new trains to existing LNG plants also provides further cost advantages through lower incremental costs than new greenfield projects by benefiting from existing infrastructure.

Plans for major liquefaction plants

A number of major liquefaction plants are due to be commissioned in the next few years (IEA, 2012). Thirteen projects, amounting to 114 billion cubic metres per year (bcm/yr) LNG, are under construction worldwide and expected to be in operation by 2018. This will increase LNG liquefaction capacity by 33% from a total of 370 bcm at the end of 2011 to nearly 500 bcm by the end of 2017 (Figure 3.4).

Figure 3.4* • *Natural gas liquefaction capacity in operation and under construction



Note: data refer to peak capacity (in bcm) at the date when first production is due.

Source: IEA, 2012, with updates from September 2012.

LNG capacity additions until mid-2014 will remain limited to a mere 25 bcm, a 6.7% increase in capacity. Two projects came on line in 2012, namely the Pluto LNG project, which started in May 2012, and the Angola LNG project that is currently being commissioned. Algeria's Skikda project is likely to begin operation in 2013, followed by a second Algerian project, Gassi Touil, due for operation in 2014. A second wave of LNG exports will begin in late-2014, this time from Australia, which is expected to overtake Qatar as the largest LNG exporter by 2020. Six LNG projects have reached final investment decision (FID) since the end of 2010. In 2014, the first train of several LNG projects will be completed, with Gorgon LNG, PNG LNG, Queensland Curtis LNG and Donggi Senoro LNG together amounting to 20 bcm/yr. Additional trains of these projects will follow during the period 2015 to 2017, while further projects such as the Wheatstone project are completed. All these projects should be operational by 2018. However, given the delays observed on many of the LNG plants commissioned over the past three years, there would be little surprise if some of these projects failed to enter operation on schedule.

All projects entering operation after mid-2014 are Australian-based, except the Donggi Senoro and PNG LNG projects, which are located in Indonesia and Papua New Guinea, respectively. Most will be technically challenging and may incur delays resulting from either workforce shortages or capital costs overruns or infrastructure bottlenecks. They include four first-of-a-kind projects – three coal-bed methane to LNG projects in Queensland (Gladstone, Queensland Curtis and Australia Pacific) and the Prelude LNG project.

Shipping

LNG is transported in special ships where the LNG is carried in insulated tanks. In 1959, the world's first LNG tanker, the Methane Pioneer, carried LNG from Lake Charles, Louisiana, to Canvey Island, United Kingdom, initiating LNG shipping. In 1964, the British Gas Council began importing LNG from Algeria, making the United Kingdom the world's first importer of contract LNG and Algeria its first exporter (CEC, 2004; USDOE, 2005).

Modern LNG carriers are sophisticated double-hulled ships designed for the safe and efficient transportation of cryogenic liquid. The emphasis is on containment of the cargo as well as efficient thermal insulation. About half of the current LNG fleet is of the membrane design type (Figure 3.5), where the inner hull is fully used to store the LNG.

The other half of the fleet has the spherical or Moss design (Figure 3.6), where the LNG containers are a series of spherical containers placed in a row along the ship axis. Since 2004, most new LNG ships under construction or planned were of membrane design because of innovations in increased cargo capacity in a given hull size, reduced capital costs and overall construction time. Membrane design is, however, more sensitive to sloshing, which is fluid motion inside the container at resonant conditions brought about by external forces on the ship.

Figure 3.5 • *Membrane design LNG ship Puteri Intan*

Courtesy of STX Europe.

Shipping has recently become the main constraint in the LNG value chain. As of early 2012, there were 380 LNG tankers operating worldwide, while another 70 were under construction. The daily charter rate of LNG tankers has increased markedly as a result of the shortage of spare tanker capacity. The rise was mainly driven by the higher spot LNG demand in Asia following the Fukushima disaster in Japan, which led to an increasing average transportation distance for LNG.

Figure 3.6 • *Moss design spherical containment LNG ship*

Courtesy of Moss Maritime.

Cost of shipping

LNG shipping costs depend primarily on the size of the vessel and the distance between the liquefaction and regasification terminals. The size of LNG ships increased from about 40 000 cubic metres (m^3) for the first LNG projects to between 125 000 m^3 and 145 000 m^3 from 1975 to 2005. Currently, however, new "super-sized" vessels with a capacity of 210 000 m^3 to 263 000 m^3 have been constructed and delivered for transporting LNG from Qatar. These will lower transportation costs by reducing the number of trips necessary per year.

Because of the entry of a larger number of shipyards into the LNG construction field, the capital costs of ships decreased substantially over the past two decades, from USD 280 million in the 1980s to USD 155 million in 2003 for a standard size vessel (USEIA, 2003). There have been cost increases during the 2004-07 period, but they remained low compared to cost inflation in other parts of the LNG chain.

Widespread adoption of the new larger size of ship would necessitate additional capacity at the receiving terminals. This is not a problem for new LNG receiving terminals, which would be designed to accommodate the larger ships. The limit for most existing terminals, however, is about 145 000 m^3, so the larger ships constructed for new LNG projects would have less flexibility to deliver LNG to them.

Regasification and storage

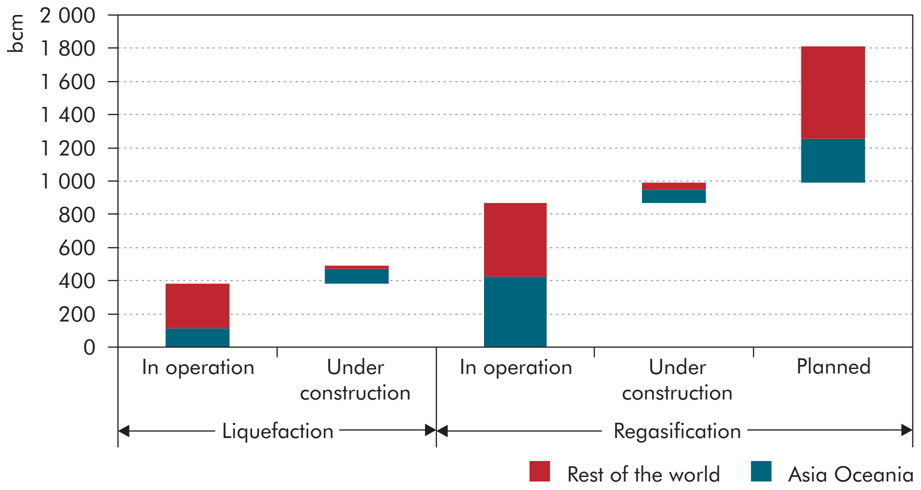
At a receiving terminal, the LNG is stored in tanks waiting to be reheated and turned into gas again for transport by pipeline according to demand.

LNG regasification capacity in importing countries is expanding to meet the surge in supply (Figure 3.7). At the end of 2012 there were 870 bcm/yr of regasification capacity worldwide, more than twice the amount of liquefaction capacity. In 2011, 327 bcm of LNG were traded, which translates into a world average utilisation rate of regasification plants of 37.6%[2] (IEA, 2012). The surplus of regasification capacity serves to balance seasonal loads and to trade off periodic regional price differentials. The relatively low cost of regasification terminals compared to liquefaction plants (at 10% to 20% of the capital cost of an equivalent capacity liquefaction plant) and the importance of being connected to the LNG market also supports the expansion of regasification terminals.

The amount of regasification capacity under construction, at around 121 bcm per year in 30 projects, is slightly larger than that for liquefaction. Once all capacity is brought on stream, the ratio of the two is likely to remain around 2:1. However, almost 800 bcm/yr of regasification capacity is under consideration. If all this additional capacity were to materialise, the utilisation rate of regasification terminals would decrease significantly. On the positive side, regasification overcapacity could increase the rate of discharge from LNG carriers. Compared with LNG regasification terminals, pipelines are more capital-intensive and less flexible.

2. Liquefaction plants have a utilisation rate of 88% globally.

***Figure 3.7** • Liquefaction and regasification capacity in operation, under construction and planned, 2011*



Source: IEA, 2012.

Regasification or receiving terminal construction costs depend on throughput capacity, land development and labour costs, and storage capacity. Marine facilities can be another major cost, especially if significant dredging of the ship channel is needed, which could add as much as USD 100 million to the cost of the terminal.

The most expensive items in a regasification terminal are the storage tanks, which can account for one-third to one-half of the entire cost. These special insulated tanks normally use concrete and high-nickel alloy steel. LNG storage tanks are required to build in a high degree of safety. The walls can be more than 1.5 metres (m) thick with an outer layer of reinforced concrete and an inner layer of nickel steel alloy, separated by an insulation layer. Cost reductions in storage have mainly been achieved through improvements in schedule and scale. Tanks with a storage capacity of about 200 000 m^3 are currently the largest feasible size. Future reductions in storage costs may be possible by further increasing tank sizes[3] or by innovations in construction methods.

The cost of regasification has not fallen as much as other parts of the LNG chain have since the 1960s. Technology and productivity gains have been largely offset by higher storage costs, the largest single cost component.

Going offshore: floating LNG systems

Increased demand for offshore natural gas has also led to a great deal of interest in the development of offshore floating liquefaction and regasification systems. Offshore regasification systems are now penetrating the LNG market, but offshore liquefaction is just beginning to move from the planning and design phase to actual ordering of installations.

3. As gas can be stored relatively cheaply on land in gas storage locations close to consuming centres, there may be little advantage for tank capacity to be greater than LNG tanker capacity.

Many floating LNG (FLNG) schemes envisage subsea well completions, thereby eliminating the need for costly production platforms and large diameter transmission pipelines to transport the gas to shore. Other advantages of an offshore facility include: eliminating site preparation; harbour or breakwater developments; continuous dredging generally required for a land-based plant; and reducing cost by avoiding the construction of new pipelines and compression facilities that would otherwise be required. An FLNG project can be 20% to 30% cheaper than a comparable size project with land-based facilities and the construction time can be 25% faster (Chiu, 2006).

FLNG could also be cost-effective in developing stranded gas fields, isolated, small in size or too remote from land and other infrastructure. These fields may be primary or associated gas reserves.

Offshore liquefaction from concept to operation

Floating production-storage-offloading vessels (FPSOs), which are the floating equivalent of fixed production platforms and which would facilitate the export of LNG are still in the design phase and are not yet operational. However, the liquefaction unit of Statoil's Snøhvit project (Statoil, 2010), though not strictly speaking an FLNG station, can be considered a transitional measure. In the Snøhvit project, the offshore gas field is developed through a subsea production unit and the full well stream is transported over 143 km via a multiphase flowline to onshore facilities at Melkøya, near Hammerfest (northern Norway), where the stream components are separated and the gas liquefied for export. Liquefaction is carried out on a barge that was constructed in Spain, transported to Norway and installed in the Melkøya facility's dock in 2005. The final investment decision for Shell's Prelude FLNG, the world's first FPSO project, was taken in 2011. It will be located in the Browse Basin, off the north-west coast of FLNG Western Australia. Several other projects have since been proposed, for example in the United States and Indonesia.

Offshore liquefaction has begun to move from a concept and planning phase to a more operational mode with the recent contract between Shell and Technip-Samsung Heavy Engineering to design and construct multiple FLNG facilities over a period of up to 15 years (Shell, 2009). The first application will be the recent Prelude and Concerto gas discoveries, located in the Browse Basin. Prelude was discovered in January 2007 and Concerto in late March 2009. Production is expected to start in 2016 at Prelude (Shell, 2010). The dimensions of the Prelude FLNG facility will be approximately 480 m by 75 m, with the capacity to produce around 3.5 Mt/yr of LNG, as well as condensate and liquefied petroleum gas. When fully ballasted, the facility will weigh some 600 000 tonnes (t). To put the size into context, the vessel is much larger than an aircraft carrier. The US Navy's new nuclear supercarrier reaches barely 100 000 t, while the world's largest passenger ship reaches only 220 000 t. Such FLNG facilities would be suitable for the more distant offshore fields as they could remain in operation during harsh metocean[4] conditions, such as cyclones, and would be capable of processing a wide range of gas compositions.

Safety and operability are important issues when designing offshore FPSO systems because of the proximity and complexity of all elements of the facility. In addition to the offloading operation, the tanker approach, connect, disconnect and departure phases all include operations that are weather-dependent that may impose restrictions on operability.

Offshore floating regasification and storage units

At the receiving end of the LNG chain, difficulties in finding suitable sites to build LNG regasification terminals have stimulated substantial interest in the possibility of using offshore floating storage and regasification units (FSRUs), such as a barges or ships connected to the shore by pipeline. Offshore systems reduce time-to-market compared to onshore development, and obtaining permits is often easier.

An offshore LNG receiving facility would consist of an FSRU moored offshore, to which a conventional LNG ship can connect as it would to an onshore regasification facility. The offshore facility would have its own LNG storage capacity as well as regasification facility. The storage facility would allow LNG to be unloaded as gas based on the regasification and pipeline transmission rate. At a water depth of 25 m to 30 m the FSRU would be able to accept LNG carriers in the 125 000 m^3 to 250 000 m^3 capacity range.

GTL: an alternative way to bring gas to market

The challenge of how to bring natural gas resources, often located in remote regions, to their markets in both industrialised and developing countries, would be less of a barrier if the gas could be converted into a liquid that could then be stored and distributed at normal temperature and atmospheric pressure, as is the case with crude oil and oil products. This has led to efforts on and off during the past century aimed at developing an effective and efficient means of converting gas to liquid fuels. GTL technology has reached the stage where it is possible to produce clean liquid products from natural gas.

Whereas LNG will be converted back to gas at the receiver end and thus needs special pipeline transport, GTL converts natural gas directly into products like diesel-type fuel, kerosene, base oils for lubricants, paraffin for detergents and naphtha as chemical feedstock, which are all stable at normal atmospheric conditions. Therefore, GTL gives natural gas a much broader market in liquid form as it can overcome transport problems that have limited the use of natural gas until now. The products can be transported through conventional infrastructure, such as tankers and pipelines, stored in existing facilities for liquid hydrocarbons and marketed through existing retail distribution systems.

4. Metocean is a contraction of the words "meteorology" and "oceanology", referring to the weather conditions, the waves, winds and currents that affect offshore operations.

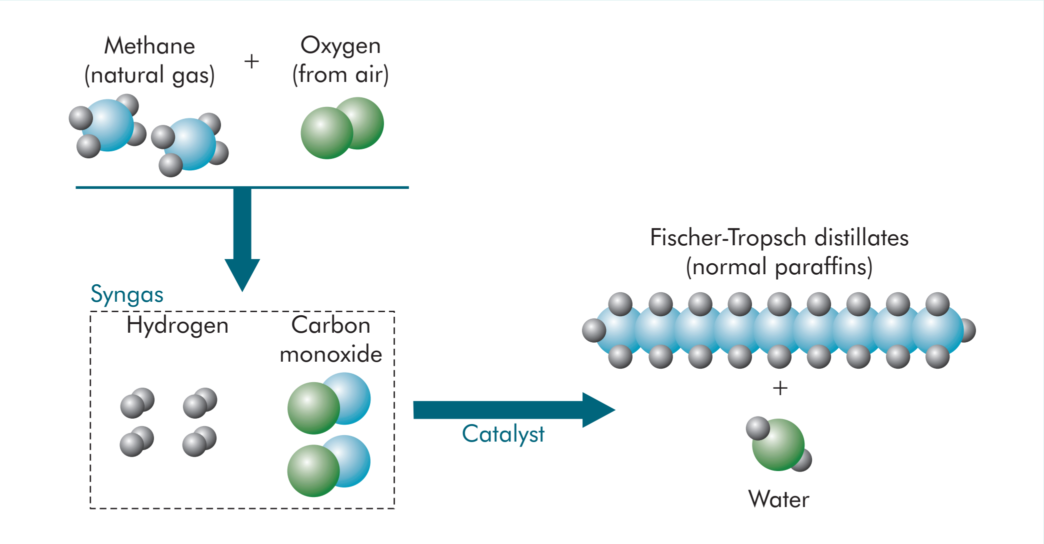
GTL conversion process

The GTL process is complex. It will first combine the natural gas molecules in much longer paraffinic molecules, then break them up again and rearrange the molecules. Chains of different lengths have different properties, making a range of GTL products. The technology behind GTL is explained in Box 3.1.

Box 3.1 • The technology behind GTL conversion

GTL conversion is a staged process, as illustrated in Figure 3.8. Natural gas is partially oxidised with pure oxygen (extracted from air) at high temperature and pressure to convert it to synthesis gas (or syngas), a mixture of hydrogen and carbon monoxide that will more readily react with catalysts. The second stage turns the syngas into a liquid hydrocarbon through a series of catalysed chemical reactions. The catalysts (chemical substances that trigger and accelerate a chemical reaction without being consumed in the process) are crucial to GTL production. This part of the process is called the Fischer-Tropsch chemical synthesis process, and was invented by Karl Fischer and Hans Tropsch in the 1920s (Fischer and Tropsch, 1926). The low-temperature process, which is cobalt catalyst-based, produces heavy paraffinic hydrocarbons that are virtually free of sulphur and aromatics. These heavy liquid hydrocarbons are converted into a range of high-quality liquid products by selective cracking and fractionation to separate the desired middle distillate products, which include fuel for transport use, naphtha for chemical feedstocks, normal paraffin for detergent feedstock, and lubricant base oils to blend premium lubricating oils.

***Figure 3.8** • The GTL process*



Source: Mansar, 2008 (Courtesy of Shell International).

The GTL process requires operating temperatures ranging from – 180°C (for an air separation unit) to 1 350°C (for a gasification unit), which requires a sophisticated control and operating philosophy to ensure reliability and safe operation.

The process is designed to minimise environmental emissions. Sulphur is removed from the gas and both nitrogen oxides (NO_x) and volatile hydrocarbons are controlled. Process heat is recovered and reused. The thermal efficiency of the GTL process is in the range 55% to 65%. Another potential advantage of the GTL process is that generated CO_2 becomes available at high concentration and part of it in high-pressure streams from which it can more easily be captured and sequestered.

The process yields high-quality diesel or can be blended with lower-quality crude oil-derived diesel fuel to help the latter meet more stringent engine exhaust standards and increased performance requirements. This process produces less carbon monoxide and fewer particulates than conventional fuel.

Commercial developments

Sasol has been operating large coal-to-liquids plants in South Africa since the 1950s, but the world's first large-scale commercial GTL plant of this type was commissioned by Shell in Bintulu, Malaysia in 1993 (Figure 3.9). It manufactures more than 14 000 barrels (b) of GTL products each day.

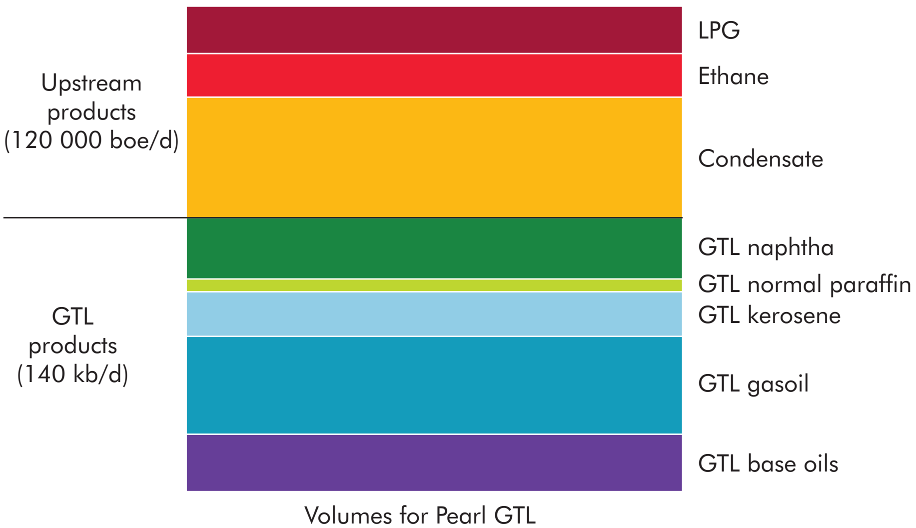
Figure 3.9* • *The Shell middle distillate synthesis process plant at Bintulu, Malaysia

Courtesy of Shell International.

A few major projects have recently been commissioned or will enter in operation in the near future. In 2008, the Oryx GTL plant in Qatar, owned by Qatar Petroleum and Sasol, became operational with a capacity of 34 000 b/d. The Pearl GTL plant in Qatar, completed in 2012, builds on the Bintulu experience, but with the capacity to produce 140 000 b/d of GTL products through two production units and associated facilities. Pearl's daily output will also include around 120 000 b of other products, such as condensate, liquefied petroleum gas and ethane

(Figure 3.10). Nigeria's Escravos GTL is expected to begin operation in 2013 with an initial capacity of 34 000 b/d, followed by an expansion to 120 000 b/d over the next ten years. In the United States, Sasol is currently investigating the feasibility of a GTL facility with a capacity ranging from 40 000 b/d to 80 000 b/d. Other current projects include the Tinhert plant in Algeria, the Sasol project in Uzbekistan, and the Sasol/Talisman proposal in Canada.

Figure 3.10 • *Pearl GTL plant product slate*



Note: kb/d = thousand barrels/day; boe/d = barrels of oil-equivalent/day.

Source: Mansar, 2008 (Courtesy of Shell International).

The GTL process is energy-intensive and, as a means to produce transportation fuel, may at first glance appear inefficient. However, a true comparison would consider the full chain of processes from extraction of the gas to the energy supplied to the wheel (Chapter 9). Furthermore, on a well-to-wheel basis, GHG emissions for GTL are close to those for traditional oil.

Compressed natural gas for smaller accumulations

Instead of cooling gas to reduce the volume and facilitate the transportation of natural gas, as done for LNG, it is also possible to reduce the volume of a natural gas stream by compressing the gas to between 200 bar and 275 bar, although energy density is less than that for LNG. Storage tanks thus need to be able to hold such pressures.

The use of specialised ships to transport compressed natural gas (CNG) to markets is being seriously considered for some situations such as stranded gas resources that are too small for LNG and too remote for pipelines, including reserves in some hostile climates, such as the Canadian Arctic Archipelago. About one-third to one-half of global natural gas reserves is considered stranded, and there are possibilities of exploiting a significant fraction of these by using either small-scale FLNG or CNG.

At the point of origin, most likely a small natural gas reservoir, the natural gas is produced through production facilities and subsequently compressed to approximately 150 bar to 275 bar. This process produces an energy density of about one-third that of LNG and sometimes the natural gas is chilled to a temperature in the range -20°C to -40°C. After transport by the CNG ship, the gas may be offloaded either to a land-based installation or to an offshore mooring buoy connected by pipeline to land. The physical assets are technically simple and much less extensive than LNG at either end. The major cost element is the CNG ship.

There are three basic approaches to storing the compressed gas on board the CNG ship:

- coiled small diameter pipe wound into cylindrical storage containers known as "coselles";
- vertically or horizontally stacked cylinders made from light-weight composites;
- cylindrical steel or fibre-reinforced plastic cylinders built to fit into a standard inter-modal shipping container.

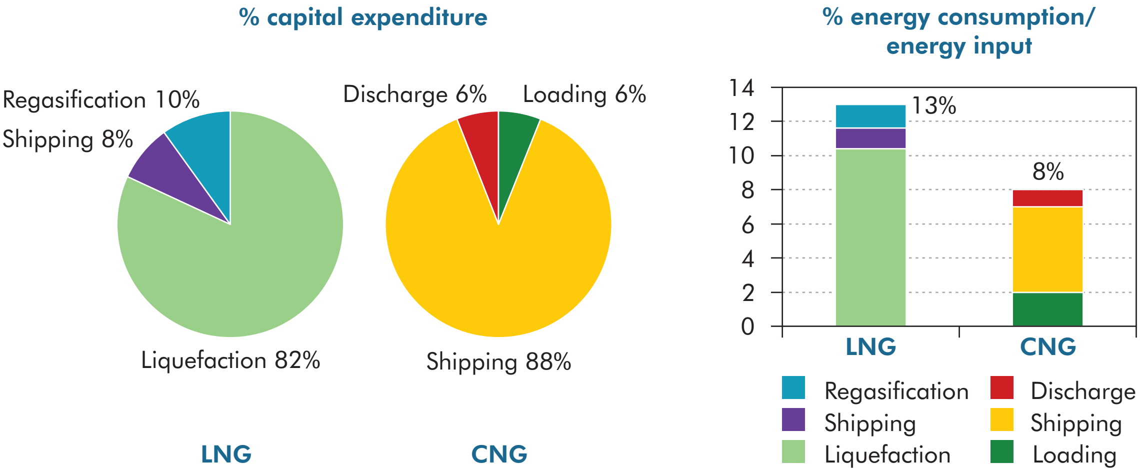
The third of these approaches seeks to reduce the capital cost of the ship (which can be a retrofitted container ship), and the handling costs of the transfer to overland transport. It can also make use of existing rail and road transportation equipment designed to handle containers.

The number of ships required for a CNG project depends on the distance travelled and the time required for a round trip. A rule of thumb would be three ships for an 800 km route, adding a ship for every additional 800 km, so that a 4 000 km route would need seven ships. Since the cost of the ships represents some 90% of the total project cost, this determines the break-even point with LNG projects, as LNG ships can carry a much greater amount of gas in terms of thermal content.

CNG is more energy-efficient than LNG, requiring the consumption of some 5% to 8% of the gas compared to about 13% for LNG. Its flexibility is greater: some 80% to 90% of its assets are flexible compared to 20% for LNG (Figure 3.11). It is also more flexible with regard to market location, reservoir size and production profile.

Another advantage of CNG projects over LNG ones is the lead-time for getting the project up and operating. An LNG project might need five or more years from the planning stage to deployment and delivery of the first cargo. For a CNG project the corresponding period is two and half to three years.

Figure 3.11 **•** *CNG versus LNG capital expenditure and energy efficiency*



Source: Siciliano, 2009.

In terms of cost, since shipping is a much larger part of the total CNG project cost, the cost of delivering additional gas increases more rapidly than it does for an LNG project, though it starts from a lower base. The unit LNG cost is lower for larger-volume projects, while CNG does not have the same economies of scale. So CNG is more economical than LNG for shorter distances and lower volumes. In approximate terms (and situations where pipelines are not practical), CNG could be the choice for annual volumes up to 5 bcm and distances less than 2 000 km.

Several companies and consortia are developing variations on CNG sea and land transportation systems (Biopact, 2007). As yet, no CNG project has reached commitment to proceed.

Sour gas and contaminated gas resources

Sour gas is any natural gas containing large amounts of H_2S. In some references, sour gas is defined more narrowly as a natural gas containing more than 1% H_2S. The odour of H_2S is detectable in the air at very low concentrations, as low as 10 parts per billion.

Contaminated gas contains high levels of non-hydrocarbon molecules such as H_2S and CO_2, or other impurities such as water vapour, nitrogen and helium, which are removed from the natural gas at processing plants. Acid or sour gas[5] could thus be considered a sub-class of contaminated gas. In the Middle East there are high resource volumes of acid/sour gas that contain around 30% H_2S, 10% CO_2, and the rest mainly methane. In Asia, there are huge gas reserves with up to 70% CO_2. Russia's giant Astrakhan field contains 40% acid gases, comprising around 25% H_2S and 15% CO_2.

5. An acid gas can form acidic solutions when mixed with water. The most common acid gases are H_2S and CO_2. The term sour gas is sometimes reserved for natural gas that contains significant quantities of H_2S only. However, the terms acid gas and sour gas are often used synonymously.

H_2S can be formed from sulphur compounds during the anaerobic (without oxygen) decomposition of organic materials. This occurred during the formation of oil and gas millions of years ago. H_2S is also produced by chemical reactions within some sedimentary rocks. At temperatures above 140°C, the calcium sulphate ($CaSO_4$) in gypsum reacts with hydrocarbons to produce large volumes of H_2S, up to 90% of the gas contained in some reservoirs, in deeply buried sedimentary rocks such as those found in the foothills of the Canadian Rockies. Many petroleum-bearing rock formations also contain iron that bonds with sulphur. When there is ample iron present, the result is sweet gas containing little or no H_2S.

About one-third of the natural gas produced in Canada's Alberta and British Columbia provinces is sour. The average H_2S content of sour gas produced in Alberta is 10%, although the concentration of H_2S can range from trace amounts to more than 80%. In Asia and the Middle East, there are huge reserves of sour or contaminated gas, such as the Natuna gas field in Indonesia (more than 6 tcm) of gas in place with a 70% CO_2 content). Of the gas reserves of Abu Dhabi, about 6 tcm, a large fraction is sour with some fields having 30% of H_2S plus 10% CO_2. The huge Kashagan and Tengiz oilfields in Kazakhstan (together about 50 billion barrels original oil in place) contain large volumes of sour associated gas. The Tengiz field was initially stockpiling the sulphur but now is also reinjecting the sour gas for EOR.

Processing sour gas

Sour gas-processing plants use physical and chemical processes, in the presence of catalysts, to remove H_2S and other by-products from the natural gas. The sour gas is run through a tower containing an amine solution; this has an affinity for sulphur, and absorbs it much like glycol absorbing water. The two principal amine solutions used are monoethanolamine and diethanolamine. The effluent gas is virtually free of sulphur compounds. The amine solution used can be regenerated (that is, the absorbed sulphur is removed), allowing it to be reused to treat more sour gas. Amine-based separation solutions are expensive. New technology development is aimed at using cryogenic, centrifuge and membrane solutions to reduce the separation costs for high contaminant concentration and large flow rates.

In Western Canada, most of the elemental sulphur recovered is sold to customers and used mainly in the manufacture of phosphate fertilisers. When the sulphur production rate is higher than the demand, the elemental sulphur must be stored, usually in large blocks at the plant site. Canada accounts for more than one-quarter of world sulphur production.

Flaring has been used primarily to dispose of sour gas in oilfields where the gas volumes are too small, or the sites too remote, to make pipelining and gas processing more cost-effective. Because of government and industry commitments to reduce the amount of flaring, as well as the rising economic value of natural gas, more sour gas is now being pipelined to processing plants. Flaring H_2S produces water vapour and sulphur dioxide (SO_2); as SO_2 is a precursor of acid rain, many countries now have legislation controlling the flaring of sour gas. At some facilities, flares have been replaced by more efficient incinerators. Previously, incineration had been used primarily at smaller gas-processing plants where the gas volumes or H_2S concentrations were too low to make sulphur recovery economic.

An increasing proportion of the formerly incinerated H_2S, along with CO_2 and salt water removed from the natural gas, is now being injected into underground rock formations. This process is known as "acid gas injection" because H_2S and CO_2 are both gases that can form acids when combined with water. Acid gas injection has been adopted at some 45 gas-processing plants in Alberta and British Columbia since 1990. It disposes of H_2S safely, and also reduces CO_2 emissions. The gas mixture can be injected into either salt-water formations or depleted oil and gas fields, or can be used in working oil reservoirs to enhance production.

Sour gas and public safety

Exploration and development of sour gas, because of its toxic and corrosive nature, give rise to concerns about public safety. These concerns are understandably somewhat marked in Alberta, given the amounts of sour gas produced there.

To address these concerns, in 2000, the Energy Resources Conservation Board (ERCB)[6] established an independent body, the Provincial Advisory Committee on Public Safety and Sour Gas (PSSG), to review and assess the province's regulatory regime as it related to public health and safety, including the requirements being applied to the approval, development, and operation of sour gas facilities.

At the end of 2000, the Advisory Committee provided the EUB with a report containing 87 detailed recommendations directed towards four key areas:

- providing a better understanding of sour gas;
- improving the sour gas regulatory system;
- reducing the impact of sour gas on public health and safety;
- improving the consultation that takes place with the public on all sour gas matters.

The EUB worked with the Advisory Committee, the oil and gas industry, and other stakeholders, to address these recommendations, and a final report was issued in March 2007 (EUB, 2007). The report groups the actions taken with respect to the 87 recommendations into five categories:

- health effects and sour gas research;
- sour gas development planning and approval;
- sour gas operations;
- emergency preparedness;
- information, communication and consultation.

The final report issued by ERCB and PSSG contains details of the specific actions taken to address each of the recommendations as they concern these

6. Until 1st January 2008, the ERCB was known as the Alberta Energy and Utilities Board (EUB).

five categories. ERCB has several website pages targeted directly to the public interest, addressing health and safety, sour gas and the public interest, the environment, and emergency preparedness and response.

NGL: a key contributor to global oil production

Natural gas liquids (NGLs) are light hydrocarbons that are dispersed in associated or non-associated natural gas in a hydrocarbon reservoir and are produced within a gas stream. They comprise propane and butane (collectively LPG), plus pentane, hexane, heptane and gas condensate. The condensate is recovered in the field separators while the remaining NGLs are extracted from the gas stream in gas treatment facilities. NGLs are often under-reported or misrepresented in global oil balances. The conditions for NGLs reporting are not always clear and in some areas the condensate is not reported separately but included in reporting of the crude stream (IEA, 2010).

NGLs contributed in 2009 close to 11 million barrels of oil per day, which represents about 13% of world oil production and thus forms a very important contribution (Chapter 1). The level is related directly to the global natural gas production level and the liquid content of the gas being produced.

Impact on the lifecycle of a gas development

As already indicated NGLs can influence a gas development plan significantly, particularly as they are playing an increasing role in the economics of gas production. In the case of a natural gas well with a high NGL content (often referred to as rich or wet gas), extracting the dry natural gas will result in a decrease in well pressure that may result in a significant portion of the NGLs condensing in the reservoir, *i.e.* the reservoir basically acts as a separator. These liquids will become trapped in the porous medium and be “lost”. To maximise the recovery of NGLs, such reservoirs are often initially “recycled”; this is where the wet gas is produced (including the NGLs) and the NGLs extracted, with the remaining dry gas reinjected to maintain the pressure in the reservoir. When much of the gas has been recycled and NGL production levels have fallen significantly, the dry gas is then exported and the reservoir pressure is allowed to drop.

Even when there is no gas export route or gas demand is low, there may still be significant value in recycling the gas and only producing NGLs.

Trends in global NGL production

There are four trends that will have a significant impact on global NGL production. The first three trends drive increasing NGL supply, while the last has a negative impact on production levels (IEA, 2010):

- The increasing scale of natural gas developments, associated with the development of some large gas condensate fields and some big new LNG projects.
- Increased use of associated gas, owing to new gas infrastructures and the drive towards reduced flaring and venting.
- Wetter non-associated gas gradually replacing traditional dry non-associated gas in some countries, among other reasons because of the development of deeper reservoirs with high pressure and temperature. Also unconventional gas, such as tight gas and shale gas can contain significant NGL volumes (in contrast to coal-bed methane and hydrate methane, which are pure methane streams).
- The increasing replacement of wet associated gas by dry non-associated gas in some other countries in order to meet gas demand or because of significant growth in coal-bed methane production.

Production levels are all linked to the production of the prime gas source. There are some specific projects in which the aim is to export both the NGL and the gas, while maintaining reservoir pressure through reinjection of an inert gas such as nitrogen. In these cases, the level of subsurface mixing of injectants with the natural gas is an important fundamental question that determines how much condensate will be produced.

With the huge natural gas resources in the world and an increasing contribution of natural gas in the total energy mix, the contribution of NGLs to the overall oil production level will likely remain high in the coming decades.

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Chapter 4 • Trends and challenges of frontier oil and gas

Over the past decade, deepwater offshore reserves in several regions of the world and ice-prone areas of the Arctic have been considered the frontier areas for exploring and producing conventional hydrocarbons. More than half of all conventional oil discovered since 2000 was in deepwater offshore reservoirs (IEA, 2010) and the Arctic is one of the world's largest remaining prospective areas for oil and gas. Developing resources in deepwater and ice-prone areas in the Arctic can be considered the most complex and expensive challenges currently facing the oil industry. This chapter provides an overview of the technologies that have been and are currently being developed to mitigate these challenges. Also covered are key technologies for deep water and Arctic regions, while the section on environmental issues provides more extensive information on developing fields in the Arctic.

Main challenges of frontier oil and gas exploration

In previous chapters, the challenges for conventional resources have focused mainly on improving the recovery of resources in a mature branch of activity. For deepwater and Arctic reserves, the focus is directed towards developing resources in a safe and cost-effective way, thus making the first step possible in the lifecycle of a field (as discussed in Chapter 2). The cost of developing deepwater and Arctic reserves can be a major obstacle.

The fundamental issue for deepwater exploration and production is that all activities on or below the seabed must be handled remotely from the ocean surface, and even in some cases remotely from a distance of many kilometres. In offshore Arctic regions, the same issue often applies and is further complicated by having to deal with icebergs or pack ice. The ongoing development of deepwater/subsea technology has led to solutions that can be applied to field development in the Arctic.

In both deep water and Arctic frontiers, it is imperative to "do no harm" by ensuring a high degree of protection for pristine and sensitive environments, in addition to the health and safety of those manning the surface facilities. As a consequence, risk assessments, emergency preparedness and response planning are extremely important. At the end of the field lifecycle, care is needed with the decommissioning of facilities, especially in the Arctic as it takes a long time for nature to recover from any damage.

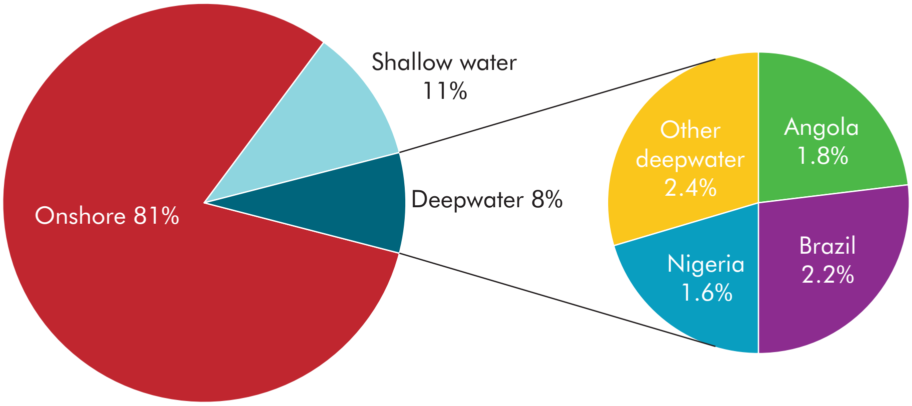
The offshore shallow-water Montara oil spill in the Timor Sea on 21 August 2009 and the deepwater Macondo blow-out in the Gulf of Mexico on 20 April 2010 illustrate the severe consequences of inadequate decisions and responses in a complex drilling operation, especially offshore. The Montara oil spill flowed for over two months and the Macondo oil spill flowed for three months. The latter was the largest accidental marine oil spill in the history of the petroleum industry. The leak released about 4.9 million barrels of crude oil into the ocean. As a consequence, permit processes and operational procedures have been re-examined and improved further to reduce the likelihood of such spills in the future. This vital policy review has led to a delay in new developments off the Gulf of Mexico.

Potential of deepwater reserves

Out of the 2 700 billion barrels (bb) of remaining recoverable conventional oil (excluding tight oil) (Chapter 1), 45% is in offshore fields. Of those offshore fields, roughly a quarter or 300 bb is referred to as "deepwater", loosely defined as being at depths of over 400 metres (m). Depths of more than 1 500 m are referred to as "ultra-deepwater". Most deepwater discoveries have been made in the Gulf of Mexico in the United States and offshore Brazil, Angola and Nigeria. Following the 2010 Macondo disaster and other smaller oil spills, increased scrutiny by regulators and higher costs in some instances could potentially hinder new developments to some degree.

As offshore technologies continue to advance, the depth threshold at which the industry's production capabilities begin to be stretched changes and, in some cases, the change can be quite rapid. Total global production from deepwater fields was around 5.7 million barrels per day (mb/d) in 2012 and is expected to rise to 8.3 mb/d by 2017, representing about 40% of all offshore production (Figure 4.1). Total production from all offshore reserves (including deepwater) makes a key contribution to oil supply and by 2017 will represent approximately 20% of global crude production. Since ultra-deepwater field production began to contribute in 2004 its contribution has been steadily rising.

Figure 4.1 • Global offshore and deepwater oil production (2010-15)



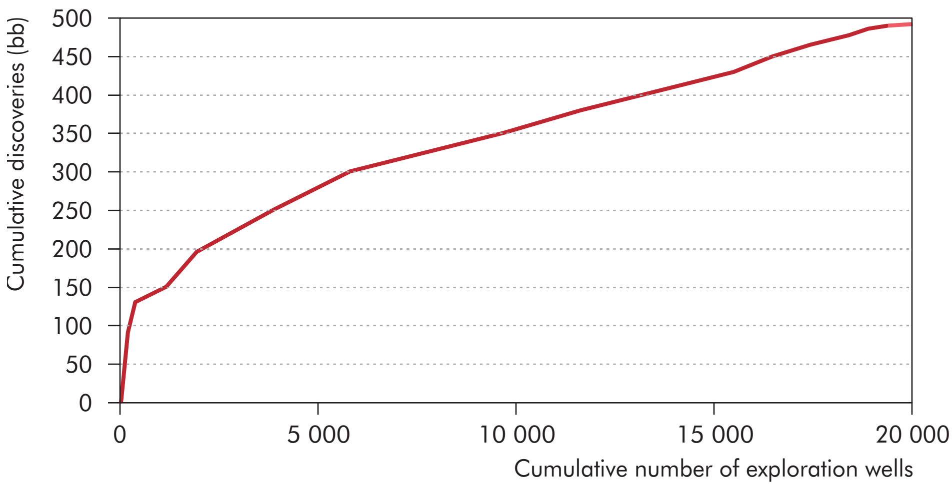
Total production capacity in 2017: 102 mb/d

Fields are now producing or being developed in water depths of over 2 000 m in the Gulf of Mexico in the United States, offshore West Africa and offshore Brazil. The current world record for water depth is 3 107 m off the coast of India, set in 2011 in a Reliance Industries offshore India project. Records for total drilling depths are also being broken. The Tiber Prospect well, approximately 400 kilometres (km) south-east of Houston, is the deepest offshore oil well drilled to date (10 685 m), albeit at a water depth of 1 259 m (BP, 2009). The field may contain up to 3 bb of oil. Some ultra-deepwater areas of Angola, yet to be licensed, are located at around 4 000 m water depth.

Advances in seismic data gathering and processing technologies (see Chapter 2) that provide images of areas located beneath thick layers of salt zones have improved discovery rates. Brazil will lead output growth in Latin America where major deepwater offshore discoveries have emerged in the last few years in pre-salt layers. The discovery of the of the giant Tupi (renamed Lula) field in the Santos Basin was followed by several other fields in the same basin, including Iracema (renamed Cernambi), Jupiter, Carioca, Iara, Libra, Franco and Guara. If the resource estimates for Lula, Cernambi and Guara are confirmed, Brazil's proven reserves could increase by two-thirds. Brazil is set to become the fastest-growing oil producer outside the Middle East and production could increase to 4 mb/d by 2020 (from 2.2 mb/d in 2011).

Global deepwater discoveries accounted for over one-half of all discoveries between 2000 and 2009. Cumulative global oil discoveries in deepwater offshore areas, plotted against the number of exploration wells, remain on a linear trend (Figure 4.2). This trend would suggest that larger finds could also be made in the future, such as the recent huge Brazilian Lula field with a potential 6.5 billion barrels of oil-equivalent (boe), or the Tiber field in the Gulf of Mexico.

Figure 4.2* • *Global deepwater oil discoveries to end-2006 versus exploration wells

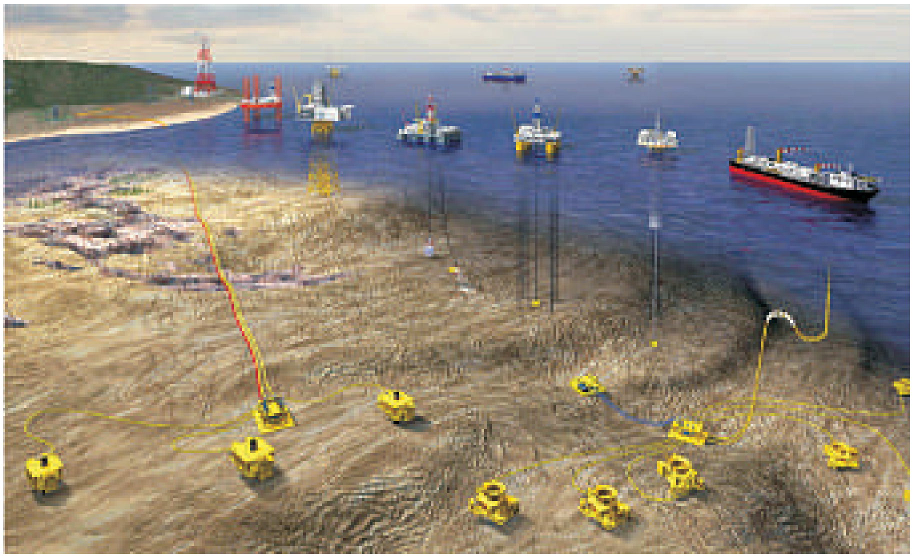


Source: Sandrea and Sandrea, 2007.

Developing deepwater reserves: applying new technology

Deepwater technologies are continuing to evolve at a rapid pace and not only reduce the cost of deepwater offshore exploration, but also the time needed to bring deepwater fields into commercial production. Successive new generations of technologies (*e.g.* subsea processing and multilateral wells) mean that previously inaccessible oil and gas fields (*e.g.* small deepwater offshore fields and small hydrocarbon accumulations that are further away from a main production platform) are now also cost-effective to develop. Alternative configurations are evolving, where an ever more complex subsea infrastructure connects a multiple of smaller reservoirs to one floating production unit, tension-leg platform, floating production, storage and offloading vessel (FPSO) or even directly to shore (Figure 4.3).

Figure 4.3* • *Alternative evolving configurations of deepwater subsea oil and gas production

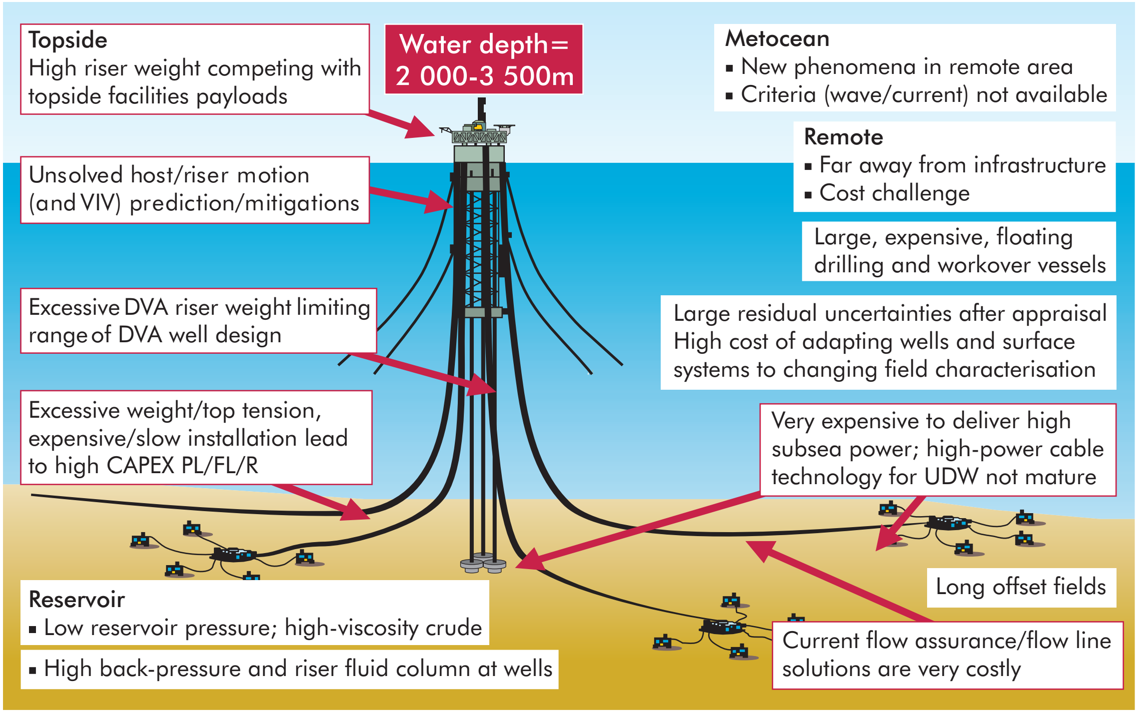


Courtesy of FMC Technologies.

Despite technological advances, deepwater operations still pose major technical and engineering challenges and involve substantial costs. The deepwater environment is extremely challenging, with high pressures and near-freezing temperatures on the seabed. All interventions at and below the seabed have to be handled remotely and measures need to be taken to prevent the oil and gas from forming methane hydrates (crystalline structures of gas and water) that block underwater pipes. Figure 4.4 summarises some of the challenges associated with an ultra-deepwater production complex. Specific challenges include those linked to: issues with the riser,[1] which provides subsea power; flowline[2] issues at the seabed; and challenges due to remoteness.

1. A "riser" is the pipe that connects the seabed to the floating facilities.
2. A flowline is a pipeline through which oil travels from a well to processing equipment or to storage.

Figure 4.4* • *Key technological challenges for ultra-deepwater



Notes: CAPEX PL/FL/R = capital expenditure on the platform, the flow lines and the riser; DVA = direct vertical access; UDW = ultra-deepwater; VIV = vortex-induced vibration.

Courtesy of Shell International.

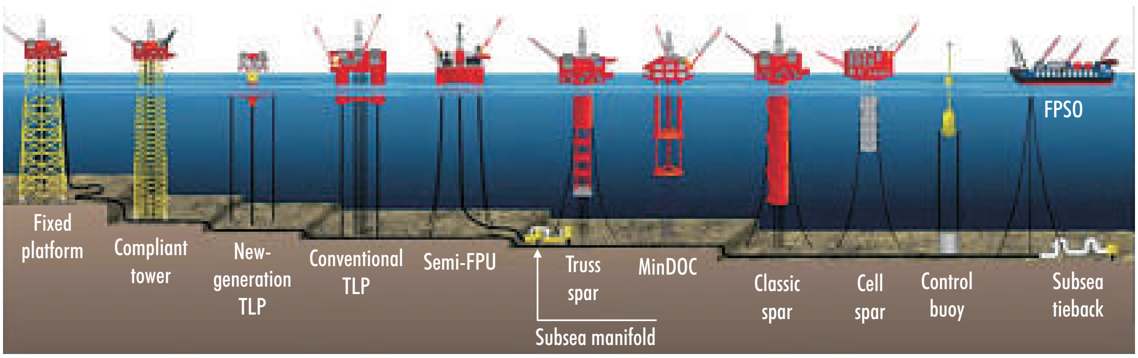
The remainder of this section concentrates on some of the new technologies that enable the subsea costs to be reduced and remote reserves, not previously financially viable, to be exploited at water depths of 2 500 m or more. The section incorporates, for example, floating facilities, subsea processing and multiphase flowlines.

Evolution of deepwater offshore production surface facilities

Installations on the sea surface have had to evolve as the depth being tackled increases. The fixed platforms on the sea floor that were used in shallow waters were replaced by floating platforms of various types such as the tension-leg platform (TLP) and FPSO to allow developments in ever deeper seas (Figure 4.5).

In a TLP, the surface installation is floating, but secured to the seabed by a number of steel tendons, each of which can weigh some 900 tonnes, that keep the platform stable. One limitation of the TLP was that as the depth increased beyond the 2 000 m mark, the weight of the tension legs and of the pipes to reach the wells became too much for the floating part of the platform. This led to the TLP being replaced by various other types of floating surface installations, such as FPSOs, attached to the subsea facilities by only the cables and risers required to transmit gas, liquids and power between the surface and the seabed. Fields at a record depth of nearly 3 000 m are now being developed. Since the early 1990s, most new developments use an FPSO as production moves to ever deeper water and further offshore (Figure 4.6).

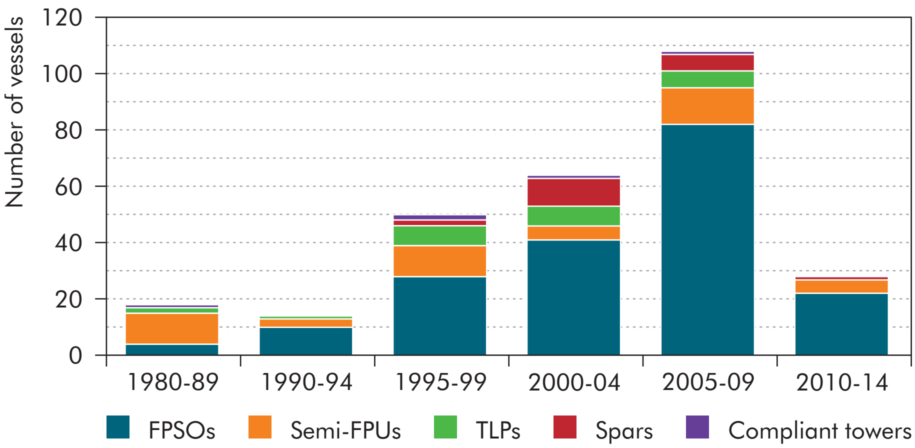
Figure 4.5* • *Evolution of surface production facilities with increasing water depth



Note: FPU = floating production unit; MinDOC = minimum deepwater operating concept.

Courtesy of Mustang Engineering.

Figure 4.6* • *Increase in surface facilities for deepwater production, by type



Courtesy of Mustang Engineering.

Though exploration normally takes place from a ship or platform, a more recent innovation has been the use of floating drilling, production, storage and offloading vessels (FDPSOs) or FPSOs with drilling capacity. The concept has been around for some time, but not commercialised because of regulatory and technical concerns. Reducing the time from drilling to production has been the main driver behind this development.

Evolution of seabed facilities

Major changes are also occurring in facilities on the seabed. Often small deposits are identified, separated by distances of tens of kilometres. In deepwater regions, it is not cost-effective to produce these reserves individually via independent floating platforms. Similarly, connecting each individual producing well by a pipe directly to the centralised platform is complicated and often not financially viable. Seabed production wells at each deposit must be connected via pipes to a centralised complex on the seabed below the platform with fluid-processing facilities. Such a system has been used by Shell for the Na Kika project to develop six independent fields in the Gulf of Mexico, where individual fields are up to 43 km from the host (Schofield, 2007).

Taking this concept a step further, the number of pipes on the seabed can be reduced by drilling horizontally below the sea floor to access deposits of oil and gas within a 15 km radius. The Perdido development project in the Gulf of Mexico, which first produced oil in 2010, has used this concept for one of its producing fields. The surface floating platform is of a spar-type,[3] which has a long vertical shape like a buoy to increase its stability in rough sea. It is the first application of wet-tree DVA wells from a spar (Shell, 2009). This configuration allows a larger number of subsea wells to be accessed by the facility's drilling rig, resulting in significant savings in the drilling programmes for these wells. The DVA system is designed to use a single high-pressure riser suspended from the host to access 22 subsea trees[4] directly below the host. This has the advantage of allowing use of a surface blow-out preventer for drilling, completion and later side-tracking wells. The Perdido also has low-energy reservoirs with low temperatures and pressure, so that liquids and gas have to be separated at the seabed and pumped to the surface using 1-megawatt pumps.

Clustering the wells below the surface platform eliminates the need to move a platform large distances to maintain each well. Instead, winches attached to the mooring lines can position the spar above any one of the wells in a radius of 45 m in order to carry out repairs and routine maintenance.

Subsea processing

Subsea processing refers to fluid treatment at the seabed rather than on a platform, where it is normally done. It may entail processes such as: water removal, with reinjection or disposal; sand and solids separation and sand-handling system; gas/liquid separation and liquid boosting; gas treatment; gas compression; and monitoring, control and safety systems. Subsea separation has a number of significant advantages for deepwater developments.

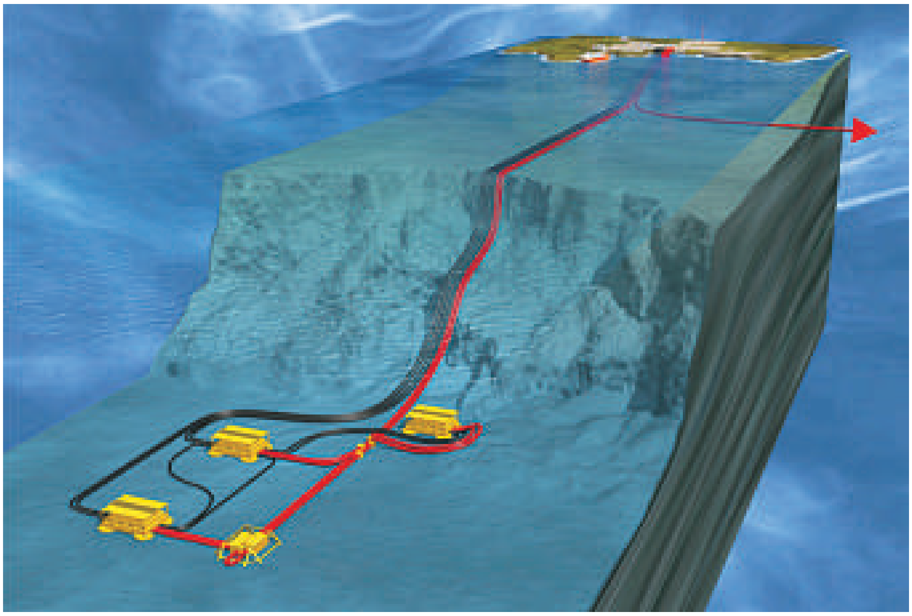
Subsea separation of the well fluids and local reinjection of produced water and/or gas means that flowlines and surface processing equipment can be used more efficiently. The separation has a positive impact on flow management and assurance, and reduces the cost of topside processing equipment and pipelines (FMC Technologies, 2008). It also helps prevent the formation of hydrates.

3. A spar is a deep-draft, floating, water-tight, hollow cylindrical structure.
4. A "subsea tree" is the top of the well at the seabed that monitors and controls the production from a subsea well.

Subsea gas/liquid separation and liquid boosting can increase the production rate in low-energy reservoirs and counter-pressure loss in long pipelines. For maturing fields, a subsea processing plant can contribute to increased production and recovery; improve and extend the lifecycle of the field; and optimise the use of the existing infrastructure.

For a new field development located not too far offshore, subsea processing can even negate the need for platforms, and the field can be "tied back" through multiphase flow pipelines directly to an existing offshore facility or directly onshore. Such a subsea system has been developed for use in the Ormen Lange natural gas field offshore Norway, which began production in 2007. All of its production facilities are on the seabed, with six subsea wells at depths between 800 m and 1 000 m (Figure 4.7). The full stream of natural gas, water and condensate produced by the field is sent in two 120 km multiphase flow pipelines to the processing complex onshore where the streams are treated further. All control support facilities and power supplies required to operate the subsea production systems are supplied from the onshore plant.

Figure 4.7 • Ormen Lange natural gas field and tieback to Nyhamna onshore facility



Courtesy of Statoil.

The initial pressure of the fluids in the wellstream from the reservoir was adequate to push the wellstream up the steep Storegga embankment to the land-based gas-processing facility. But as the pressure diminished over time during production in this gas field, the pressure eventually reached the point where natural pressure was no longer sufficient to move the wellstream to land. At that point, subsea compression had to be installed. Subsea compression is currently being designed for installation in 2015.

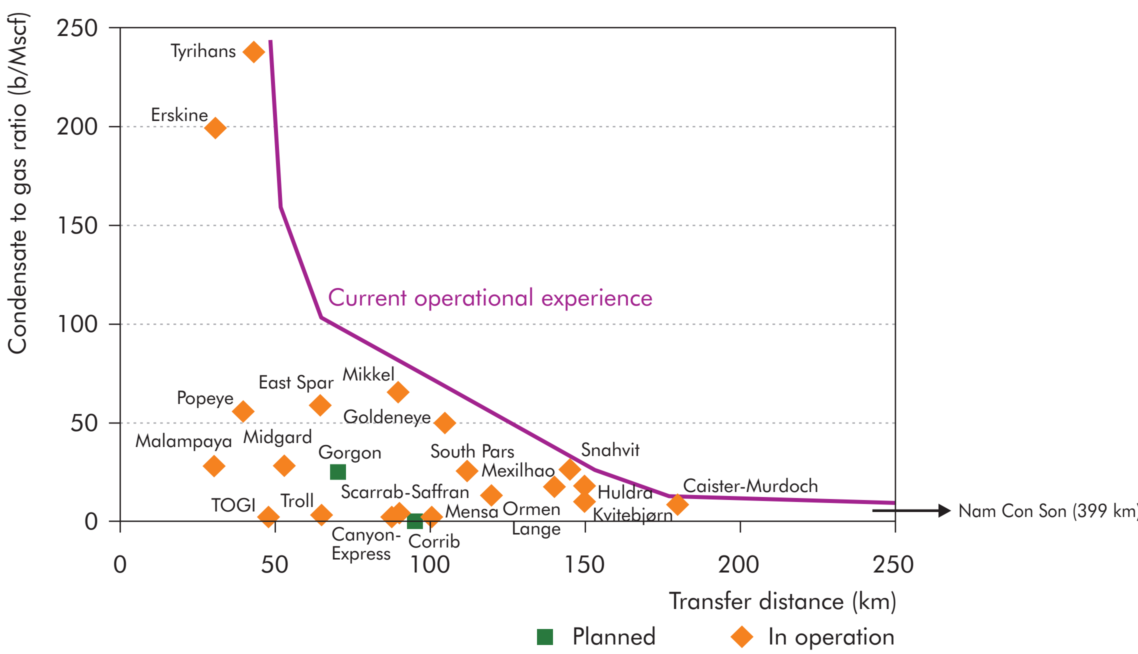
There are various economic and environmental reasons for placing a compression facility on the seabed. Such a facility would yield significant cost savings in building and maintenance compared to the conventional platform solution. The subsea facility would not be affected by the extreme weather conditions in the Norwegian Sea, and therefore has certain safety and environmental advantages.

Increase in subsea flowlines

The trend to explore and produce conventional hydrocarbon in deeper waters and ice-prone regions results in increased flowline and tieback[5] distances. The total length of subsea flowlines has been on an exponential growth trajectory since the 1980s. The length of individual flowlines has also increased. The less complex the stream, the more feasible it becomes to transport it over a longer distance, with simple natural gas or oil pipelines being used for extreme distances.

To indicate the envelope of current operational experience, the condensate-to-gas ratio (CGR) has been plotted against transfer distance for a number of existing and planned multiphase flowfield development projects (Figure 4.8).

Figure 4.8 • Current experience in hydrocarbon multiphase flow



Notes: b/Mscf = barrels per million standard cubic feet. 1 Mscf = 0.0283 million standard cubic metres (Msm^3).

Courtesy of Statoil (adapted).

5. A tieback is a connection between a new oil or gas discovery and an existing production facility. It can extend the life of production infrastructure.

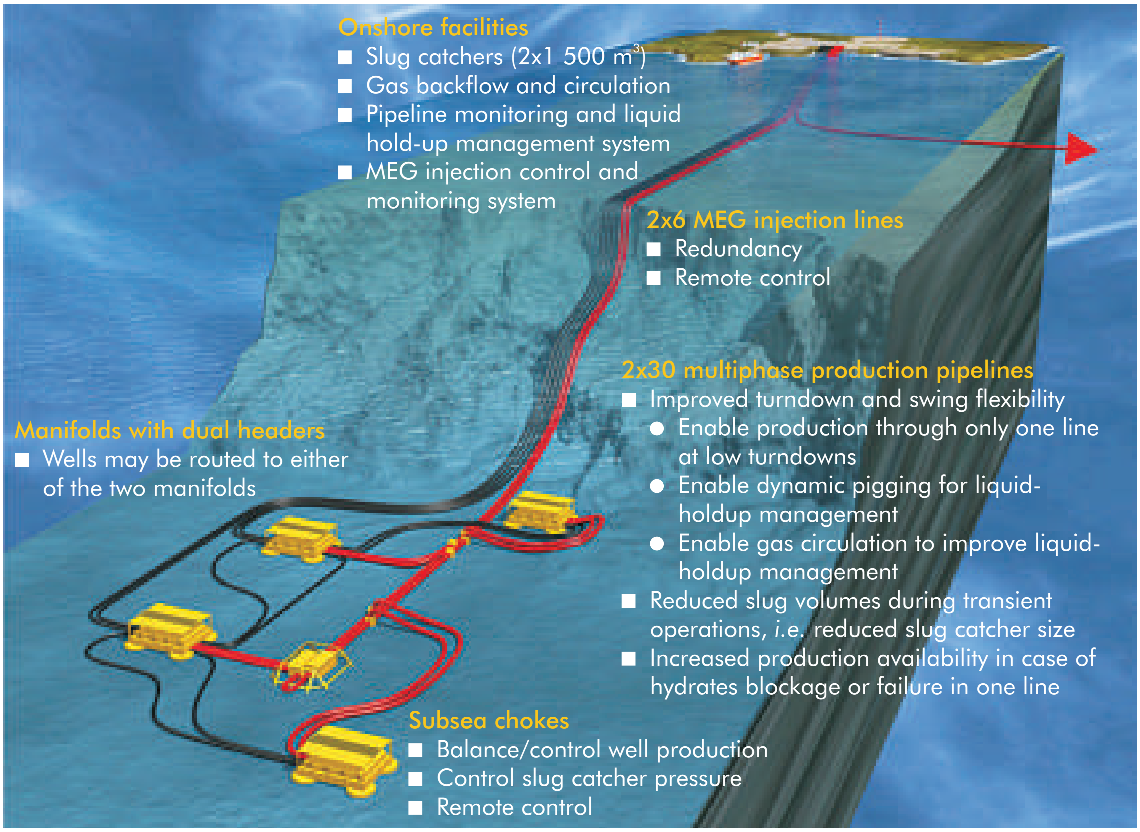
Rich gas developments with a high condensate-to-gas ratio clearly cannot yet be transported over long distances. Integration with subsea processing and compression solutions may be one of the answers to enhance the operating envelope.

Multiphase flow assurance

Wellstreams are complex and often consist of liquid, gaseous and solid components. Their properties and flow dynamics are affected by the surrounding environmental conditions, particularly temperature and pressure. A key challenge is "multiphase flow assurance", which implies taking the necessary measures to ensure that the stream reaches its destination safely and uninterrupted.

Again, taking the Ormen Lange natural gas field as an example, its development provides a good illustration of the many-faceted and technically demanding problems of multiphase transport, and how they may be handled (Figure 4.9). The subsea production templates are attached to two 30-inch pipes that transport the untreated multiphase flow wellstream (condensate, water and natural gas) to the onshore facility.

Figure 4.9 • *Facets of the multiphase flow at Ormen Lange*



Note: m³ = cubic metres. MEG = monoethylene glycol, which prevents hydrates from plugging; Pigging refers to a method for cleaning the interior walls of a pipe. A slug catcher refers to equipment installed to catch an unwanted accumulation (slug) of liquid in a pipeline.

Courtesy of Statoil (Kjaernes, 2008).

The water temperature on the seabed poses a challenge. The polar currents in the area bring cold water down from the North and generate water temperatures below freezing for most of the year on the seabed around the pipelines and subsea installations. A particular challenge has been the potential for formation of methane hydrates, a crystalline structure of gas and water that can form in pipelines in seabed areas where the water temperature is at or below freezing point (see also Chapter 6). Methane hydrates, like ice, can fully block the flow through a pipeline. The solution is to treat the raw wellstream with monoethylene glycol (commonly used as an anti-freeze) to prevent the hydrates from plugging. Alternative solutions are being studied, such as cold flow (Box 4.1).

Box 4.1 • *Cold flow to prevent hydrate plugging: a potential solution*

Low temperatures and high pressure can encourage well fluids to form methane hydrates and paraffinic wax solids that can build up and plug the flowline.

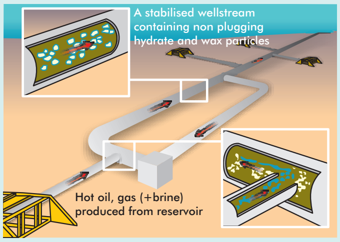
Problems caused by wax occur when the fluid containing hydrocarbons cools from the reservoir conditions. Paraffins (or alkanes) form either in the bulk fluid and are transported with the liquid flow, or deposit and build up on a cold surface.

Natural gas hydrates (or methane hydrates) form when water and natural gas come into contact at low temperatures and high pressures (Figure 4.10). Like wax, hydrates can also form a plug, posing a threat even during normal operation. During operations where temperatures drop slightly and pressure increases, or where flow through a valve results in a cooling of the valve walls, hydrates can form. Plugging from hydrates may be a particular problem for deep-water drilling, where low temperatures and high pressures are the norm.

Figure 4.10 • *Gas hydrates plug in flowline*

Source: Henriques, 2008.

Figure 4.11 • *Cold flow principle*



Courtesy of SINTEF.

One possible solution to hydrate plugging (Larsen, 2008), though one which has yet to be implemented in practice, could be to cool the hot well fluids rapidly with a cooled stream containing hydrate particles. Under the right conditions, the hydrate particles would continue to grow outwards, soaking up more – and eventually all – of the water in the stream. No free water would be available to create a sticky surface and plug the flowline. Under these circumstances, the hydrate particles would become individual sub-millimetre particles that behave like a dry powder suspension in liquid that, like a slurry, would flow without sticking or plugging. This condition is known as "cold flow".

In practice, the rapid cooling from about 80°C (degrees Celsius) to around 4°C near the well-head can be done by recycling an already cold stream of stabilised dry hydrate slurry, taken from a point on the pipeline several kilometres downstream from the subsea well, and returning it to a point near the well-head where it is mixed with warm fluids (Figure 4.11). This acts as a seed to induce further dry hydrate growth. When the slurry reaches the host platform, it is converted back to free water and gas.

Phasing a development and leveraging technology along the way

In many cases, companies acquire ultra-deepwater permits before the technology necessary to develop these reserves are mature. Resolving this issue pushes the boundaries of technology even further, opening up new frontiers for ultra-deepwater oil and gas developments. Moving to subsea separation and subsea compression, as discussed in the previous section, is one of many examples.

For offshore developments in Brazil, a single system will be used to develop a number of reservoirs with quite different crude properties (*e.g.* light or heavy crude). An example is the Parque das Conchas development where crude oil in various reservoirs ranges from light oil (41°API[6]) to heavy oil (16°API). The development first targets the light- to medium-gravity crude, moving on the learning curve and providing an income, before focusing on the more difficult development of the heavy crude. Subsea booster pumps, which increase the pressure of the liquid stream, have recently been switched because the pressure in the reservoir was no longer sufficient to transport the fluids to the production vessel. The experience with booster pumps is essential for designing additional boosting when the heavier crude reservoirs are added to the system.

The Parque das Conchas development is further complicated by the challenging nature of drilling horizontal wells in the shallow reservoirs just below the seabed. These reservoirs consist of unconsolidated sands that require special drilling and control techniques. Experience will be especially relevant when developing the heavy crude reservoirs as the challenges of unconsolidated reservoirs are larger.

Thus, the complex set of reservoirs requires a lifecycle approach in which initial design recognises the various phases of development and the technology required so that enhancements can be incorporated throughout the entire process. It will be important to incorporate the technology developed and used in Parque das Conchas to overcome specific challenges in future design specifications.

6. API (American Petroleum Institute) gravity is a measure of the density of oil. The API gravity scale is calibrated so that most crude oils, as well as distillate fuels, will have API gravities between 10° and 70°API. The lower the number, the heavier and the more viscous is the oil.

Technologies for meeting the Arctic challenge

The Arctic continental shelves constitute some of the world's largest remaining prospective areas of oil and gas (Figure 4.12). Because of remoteness and technological challenges, coupled with abundant low-cost petroleum available elsewhere, less exploration for oil and gas has traditionally occurred in the Arctic. In the late 1970s, oil production on Alaska's North Slope (ANS) and natural gas production in West Siberia were the first developments to lead the way. Today, the exploration and production of Arctic oil and gas extend further to include a number of offshore and onshore locations in Canadian, Norwegian, Russian and US territory, and offshore Greenland.

Figure 4.12 • *View from the top*

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

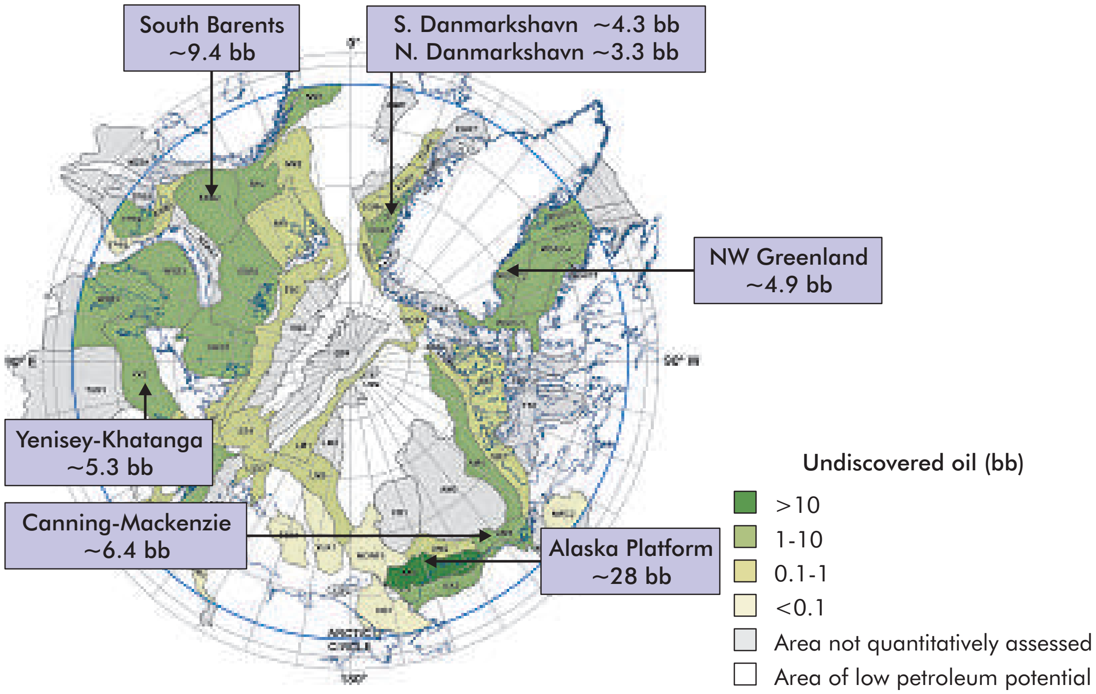
Source: Rekacewicz, 2005.

The growing global demand for hydrocarbons and the fact that the Arctic may contain almost one-quarter of the world's undiscovered reserves, provide powerful incentives for governments and industry to develop the necessary technology to further explore and develop reserves in the Arctic.

Aggregated United States Geological Survey (USGS) figures for oil and gas prospects in the Arctic indicate a polar region more prone to natural gas than oil, with most hydrocarbons located in offshore geological basins (USGS, 2000; Bird *et al.*, 2008). According to one USGS assessment (Gautier *et al.*, 2009), geological basins north of the Arctic Circle may contain approximately 30% of the world's global undiscovered natural gas volumes. The assessment suggests there could be as much as 90 bb of oil, 44 billion boe of natural gas liquids (NGLs) and 47 trillion cubic metres (1 670 trillion cubic feet or 290 boe) of natural gas. This would mean that natural gas and NGLs represent approximately three-quarters of fossil fuel resources in the Arctic. In terms of recoverable volumes, this ratio could be even higher. Though the Arctic could provide fossil fuels comparable to those found in today's major petroleum basins (Bishop *et al.*, 2010), the extent to which the resources will in fact be exploited will depend a great deal on future energy and environmental policies.

Figures 4.13 and 4.14 describe the distribution of Arctic oil and gas resources. The darker the coloured segments, the higher the probability of finding oil or gas in the depicted areas.

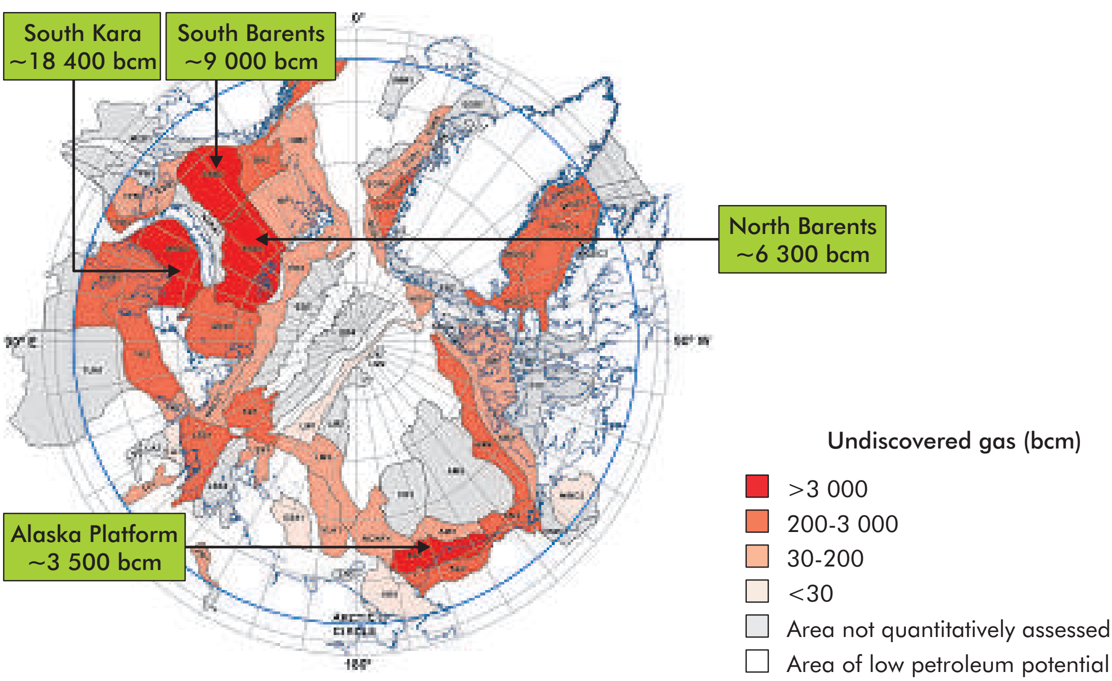
Figure 4.13* • *Distribution of undiscovered oil accumulations



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

Source: Bird *et al.*, 2008.

Figure 4.14* • *Distribution of undiscovered natural gas resources



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

Note: bcm = billion cubic metres.

Source: Bird *et al.*, 2008.

Two-thirds of the undiscovered natural gas resource in the Arctic is located in just four areas: South Kara Sea, South Barents Sea Basin, North Barents Sea Basin and the Alaska Platform. The South Kara Sea, the offshore part of the northern West Siberian Basin, contains almost 39% of undiscovered gas and is the most prospective hydrocarbon province in the Arctic (Bird *et al.*, 2008). The largest accumulations of oil are also expected to be found in the same basins, with the most prospective areas assessed located in offshore Alaska and Greenland, as well as in areas within and adjacent to the South Barents Sea.

Trends in Arctic frontier exploration and production

Arctic hydrocarbon exploitation began in the 1960s to 1970s with exploration in the Canadian Arctic and Beaufort Sea. First production from the ANS came in 1977 from the Prudhoe Bay Complex, the largest oilfield in the United States. A complete infrastructure had to be installed before the Prudhoe Bay Unit of oil-producing fields could be developed. The first delivery of oil to domestic markets came some ten years after its discovery (Thomas *et al.*, 1991). A 1 300 km-long pipeline, known as the Trans-Alaska Pipeline System (TAPS), carries ANS oil to tidewater, where it is transferred to tankers for transport to downstream markets. Because of the long distance to markets, and the lack of an export pipeline, gas is used only in field operations, leading to some interesting enhanced oil recovery projects by injecting gas. Conversion of NGLs for transport in TAPS has also been considered but not implemented.

Nearly all producing fields in the Russian Arctic are located onshore, including the giant Yamburg oil and gas condensate field, which is also the third-largest gas field in the world. There are also some very large hydrocarbon recoveries offshore not yet in production. The Prirazlomnoye field in the Pechora Seas is expected to begin production in 2013.

Offshore exploration involves constructing artificial islands in shallow waters (<10 m) and caissons systems[7] out to around 25 m in order to allow year-round drilling. In deeper waters (up to 200 m), drilling ships with strengthened hulls or ice-resistant floating drilling units have lengthened the drilling season by one or two months, with icebreakers used when needed.

In the next few decades, exploration and production activity in the offshore Arctic is likely to increase, particularly in the Barents Sea and adjacent areas, and in ANS offshore basins. In the South Barents Sea, investment in new production capacity is likely to involve the development of the Goliat field offshore the northern tip of the Norwegian mainland (with expected first production in 2013) and the Shtokman field in the Russian sector (development decision postponed). In the Kara Sea, major fields discovered provide opportunities for next-generation field developments. In April 2012, Rosneft and Exxon announced a partnership to work together to develop offshore untapped reserves in the Kara Sea. Permits have also recently been awarded to Shell for exploratory drilling offshore Alaska in the Beaufort Sea and the Chukchi Sea in the Arctic Ocean. First oil discoveries off the west coast of Greenland in 2010 seemed too low for commercial exploitation

7. Caissons systems are iron structures built around a drilling ship or platform to protect it against ice. They serve a similar purpose to the structures used to build the pillars of a bridge or make a dry dock.

but the country has expanded the exploration area by announcing a bidding round for hydrocarbon licences off the north-eastern coast in 2012-13.

Realising the potential of Arctic resources will depend not only on market success and conditions in finding them, but also on technological innovation and the ability to exploit these resources in a safe and environmentally sound manner. The cost of bringing Arctic resources to markets is substantial, so projects will require a high market price and more cost-effective technology to attract investment.

The TAPS oil export pipeline has been important for the development of oil in the region. However, there is no such export option for gas, partly as it would require liquefied natural gas (LNG) transport from south Alaska or a longer export line to the border with the United States. As a consequence, produced hydrocarbon gas is largely reinjected in the oil reservoirs, for example in the gas cap of fields such as Prudhoe Bay, or middle gas components such as miscible gas are added in the oil rim. Prudhoe Bay has the most extensive miscible gas injection projects in the world. If a gas export route can be established, a large volume of gaseous hydrocarbons would become available for export.

Technological challenges for the Arctic

Technological advances for the Arctic can build on the solutions used to develop the current offshore reserves, which are well adapted for normal water temperatures and suitable for ice-free Arctic regions. Experience from recent field developments operated by Statoil, such as the Snøhvit field in the Norwegian sector of the Barents Sea and the Ormen Lange and Åsgard fields offshore mid-Norway, will benefit the next generation of field developments in offshore Arctic.

However, exploring and producing oil and gas resources in the Arctic pose a number of challenges that go beyond current technological capabilities. The specific objectives of any developments in Arctic technology are to extend the drilling season; protect surface drilling, production facilities and their inhabitants from ice-related dangers; improve subsea exploitation technologies; and also increase the distance for transporting produced hydrocarbons to onshore processing facilities. The Arctic-related findings of the task force on Oil and Gas in the 21st Century (OG21) established by the Norwegian Ministry of Petroleum and Energy are summarised in Box 4.2.

Technological challenges for ice-prone areas

Ice poses a particular challenge for offshore Arctic field development and it needs to be managed or completely avoided. The conditions that prevail in different geographical zones depend on the extent of ice coverage. In the Barents Sea, for instance, there are typically several differing conditions of ice coverage (Figure 4.15):

- waters with ice cover during parts of the year;
- waters with a permanent ice cap;
- shallow waters (< 50m water depth) near shore, with permanent or part-year ice coverage.

Box 4.2 • Arctic technologies: findings of the OG21 Project

The Norwegian OG21 Task Force identified a number of research and development (R&D) priorities for developing technology specifically for: Arctic exploration and production; remote offshore development; and environmental protection.

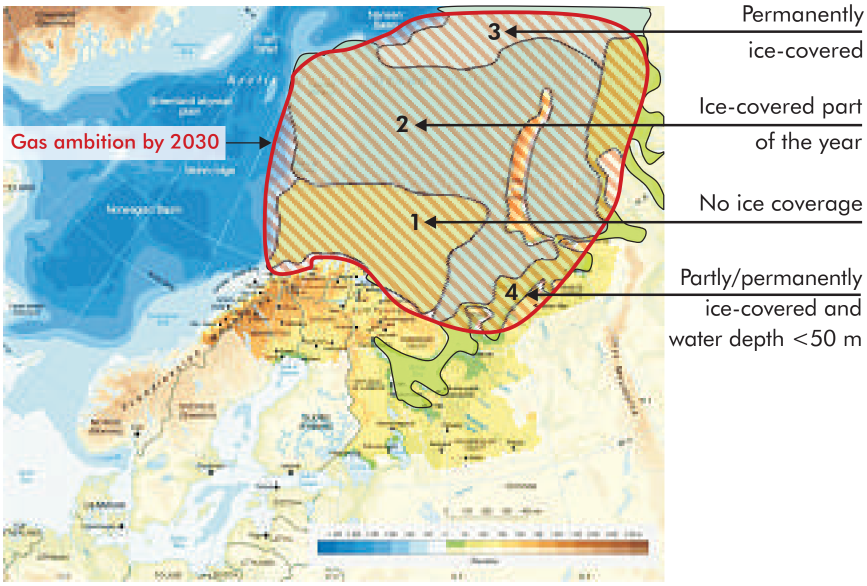
- ***Arctic exploration and production:*** *technologies to be developed to deal with ice, ice loads, icebergs, pack ice or floes, and pressurised ice regions. Different aspects of ice properties and ice loads need to be addressed, and remedies sought to manage all installations and pipelines, whether floating, fixed, above sea or subsea.*
- ***Remote offshore development:*** *technologies to be developed to deal with long flowlines and tiebacks, involving multiphase flows over extreme distances and a cold environment. Included in this, solutions to be sought for operational safety aspects, burial, ice challenges, permafrost and shore approach solutions. Integrated operations and human factors were important issues for remote developments.*
- ***Environmental protection:*** *technologies to be developed to deal with operations in sensitive areas, particularly those exposed to harsh climatic conditions. Issues addressed would include the effects of emissions to air and discharges to water, impact assessment and monitoring, new methods and related technology to prevent emissions and discharges.*

More specifically for Arctic development in ice-prone regions, the OG21 project identified the following requirements:

- *More detailed and reliable information on ice characteristics and iceberg movements.*
- *A better understanding of the effects of ice loadings on platforms of varying types, aimed at designing the best platforms for different ice regimes.*
- *A clearer picture of the depth requirements for pipelines in different regimes to manage the risks of ice gouging (narrow ditches in the seafloor created by moving ice).*
- *Development of floating systems for drilling and production in an Arctic environment that can remain in the area all year-round rather than having to dismantle the structures during winter and return to operations in the following summer.*
- *Development of an Arctic floating platform with minimum facilities to support a subsea development, including power generation, controls, well intervention and chemicals storage.*
- *Further development of floating systems with disconnect capability, thereby enabling disconnection and sail-away of a system in an emergency, such as an approaching iceberg. This solution would normally be combined with an iceberg (and ice) management system.*
- *Adaptation of existing subsea solutions for operation in an Arctic environment, including drilling subsea wells in ice-prone conditions, well intervention, protection of subsea systems from ice gouging and transportation of well fluids from well-head to host.*
- *Development of Arctic offloading systems for moving oil or gas liquids to a tanker from an offshore storage unit, e.g. from an FPSO platform, operating in an Arctic environment, including offloading unit design, weather vaning*, ice management and an ice classification system to define ice conditions.*
- *Development of floating systems with a liquefaction plant (LNG plant or similar) to enable transportation of gas to remote markets.*

* Weather vaning is used to maintain stability of the floating structure under exposure to harsh climatic conditions.

Figure 4.15 • Ice coverage in the South Barents Sea



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

Courtesy of Statoil.

Figure 4.16 • Ice hazards

Sources: ice drift and offshore icing photographs courtesy of Statoil; iceberg photograph courtesy of the International Ice Patrol of the US Coast Guard; subsea sketch courtesy of Petro-Canada.

Among the typical Arctic technical challenges are the extremely low temperature, drifting of ice and icing of vessels and surface pipelines. Furthermore, iceberg or ice plates can scour the seabed in shallower waters and damage subsea facilities (Figure 4.16). As the distances involved are large and access to infrastructure via air and sea difficult, especially for year-round operations, logistics and emergency evacuation requirements are important challenges.

Most of these challenges are evident on oil and gas development projects offshore Sakhalin Island. For much of the year, the thickness of ice in the region can reach and sometimes exceeds 1 m to 3 m, and ice ridges can extend down to 30 m in depth. The ice can move at speeds of 0.25 m per second (m/sec) to 0.5 m/sec, sometimes attaining speeds up to 2 m/sec, with unpredictable changes of direction. The seabed in shallow water is deeply scoured by ice keels, presenting a hazard to any subsea pipelines or facilities.

Current solutions in the offshore Arctic often aim to protect surface facilities from the ice, as at the Sakhalin-2 project. Each of the two project platforms installed offshore Sakhalin Island have four-legged concrete gravity base substructures which protect wells and platform topsides against ice (Figure 4.17). Future options will move more towards avoiding the ice by staying well below it.

Figure 4.17* • *A gravity-based structure to protect against the ice

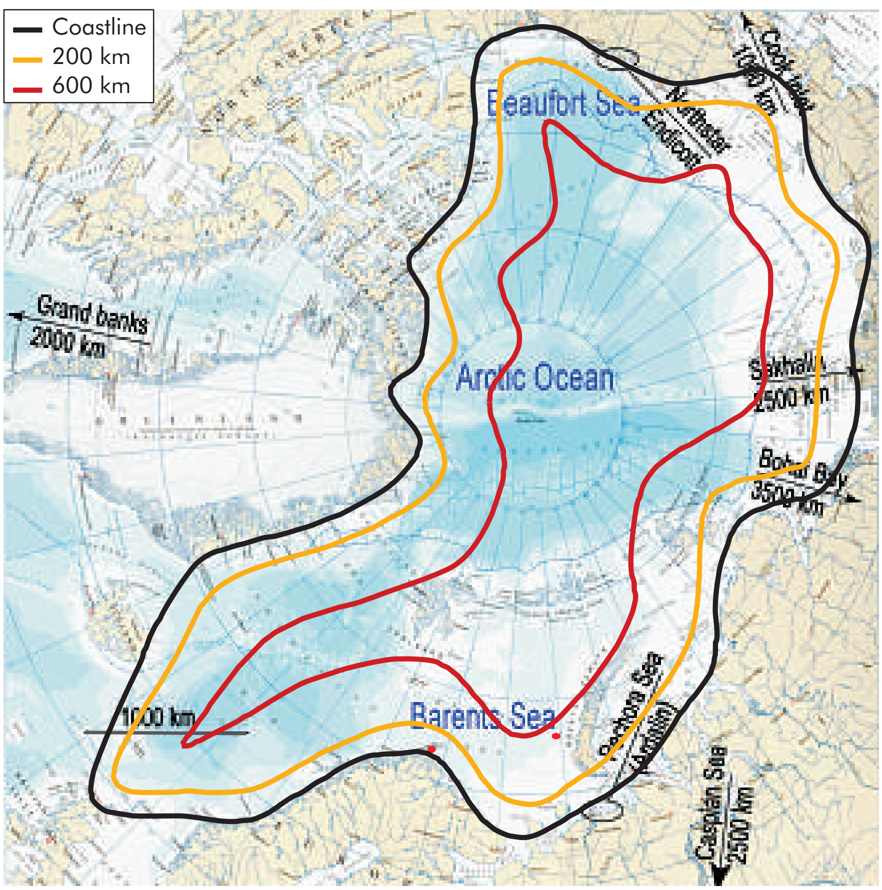
Courtesy of Sakhalin Energy.

Long-range, multiphase transportation of Arctic wellstreams

The long-term goal for offshore, ice-prone regions would be wholly subsea developments, in which the produced hydrocarbons were piped to onshore facilities, as is the case in the Snøhvit and Ormen Lange gas fields. These fields, however, do not have to deal with the added problem of surface ice cover, which would further complicate the development and operation of subsea facilities. When ice extends to the shore, an additional problem will be the potential for damage to flowlines and tie-backs resulting from ice scouring in the shallower waters near the shore.

To exploit the huge potential resources in the Arctic over the longer term, it will be necessary to assess fields that are further offshore than those currently developed. Existing infrastructure lacks the capabilities to process the wellstream from fields in such remote locations. Extending the distance for wellstream multiphase transport from the current 120 km to 150 km distance of the Ormen Lange and Snøhvit fields to 600 km would enable coverage of most of the prospective offshore basins in the circumpolar region (Figure 4.18).

Figure 4.18* • *Distances to shore for long-range transfer of wellstream



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

Courtesy of Statoil.

To achieve this, more sophisticated technology is required, such as next-generation multiphase transport of fluids, gas and particles over extreme distances with highly reliable flow assurance plus the ability to make any necessary interventions remotely under the ice. These requirements present significant technological challenges.

Protecting the Arctic environment

Arctic operations take place in highly pristine, natural environments. The responsible development of Arctic resources requires adherence at all times to the principle to "do no harm" to surrounding social and physical environments (Box 4.3).

Box 4.3 • Studies undertaken by operators on the Alaska North Slope to safeguard the environment

Examples of studies undertaken by operators on the Alaska North Slope to safeguard the environment include:

- ***Environmental assessments*** *documenting the baseline conditions before any new development. The data are used to assist project engineers with the routing and placement of gravel roads and pads to minimise environmental impact. Examples of such studies include mammal and bird surveys, and habitat mapping to determine important wildlife habitats.*
- ***Studies to support permits for exploration activities*** *that comply with environmental laws and regulations. Examples of such studies include water source sampling for ice road construction and cultural resources protection to ensure that activities avoid known cultural or historic sites.*
- ***Wildlife studies to assess the impact of ongoing operations.*** *Examples include aerial surveys of spectacled eiders as a threatened species and acoustic surveys of bowhead whales to understand their response to offshore operations.*

The Arctic environment is a very delicate ecosystem. Safeguarding the environment has sometimes resulted in restricted access to specific regions for oil and gas activities, such as to the Alaskan Arctic National Wildlife Refuge (ANWR), even though these areas are seen as having significant oil and gas prospects. Over the years, these areas have been subject to extensive impact assessments, such as investigating the effects of exploration and production on the environment and the interests of the various stakeholder groups involved. Impact assessments are complex and can take many years before they meet the requirements of the permits to proceed.

Because of the vulnerability of the social and physical environments, it is vital to continue collecting and analysing information on the physical, biological, and human environments. Learning from these activities will help decision makers to develop and implement effective management strategies to protect the natural environment.

Minimising the environmental footprint

Forty years of Arctic technological advancements, including the use of extended reach and horizontal drilling, have dramatically reduced the environmental footprint of operations, and made it possible to access more of the subsurface area from a limited surface space.

Some best practices have been developed from valuable international experience accumulated during the development and operation of a growing number of onshore and offshore oil and gas fields in the Arctic, with minimal environmental footprint. Governments and industry are increasingly moving towards the principle of zero harmful effects to the environment in Arctic exploration and production. The evolution of environmental practices over the past few decades may be illustrated by two examples from the ANS, *i.e.* the Endicott and Alpine oilfields.

The Endicott Field

The Endicott Field, located about 15 km north-east of Prudhoe Bay, is the first continuously producing offshore field in the Arctic. It originally held 1 bb of oil in place. Discovered in 1978, the Endicott Field began production in October 1987 and by mid-1992 was producing about 120 000 barrels per day (b/d). The field includes 100 wells and development costs were slightly more than USD 1 billion. The Endicott Field was the first example of a greatly reduced environmental footprint – 70% less than the traditional size. The field was developed with deviated wells drilled from two artificial islands in 5 m of water, connected by an 8 km man-made gravel causeway. The 18 hectare (ha) main production island contains the operations centre and processing facilities. Processed oil is transported through a 38 km pipeline to the TAPS.

The Alpine Oilfield

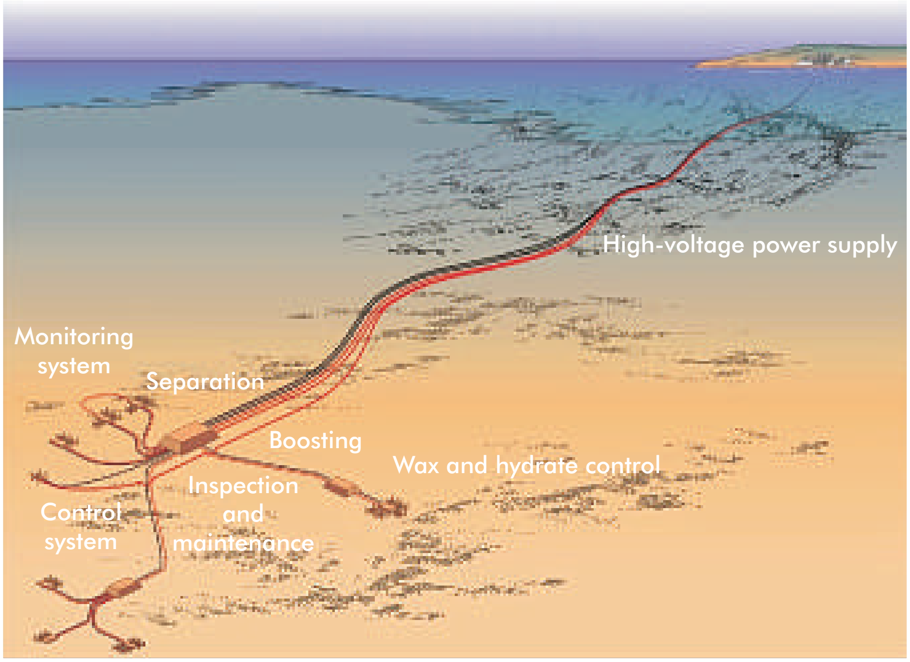
More recently, the Alpine Oilfield, also located close to Prudhoe Bay and declared commercial in 1996, began production in late 2000. The average annual gross production at Alpine is approximately 125 000 b/d. From the outset, the Alpine development incorporated the use of water alternating with miscible gas injection (generated from the existing gas in the field) to sweep oil towards wells and achieve a high recovery efficiency of the oil. The Alpine Oilfield is a near zero-discharge facility designed to minimise the environmental footprint from the physical layout of the field. The waste generated is reused, recycled or properly disposed of. There is no permanent road to the field and, in the winter, ice roads are constructed for transportation of materials to and from the site. These roads thaw in summer, avoiding permanent damage to the tundra (Figure 4.19). Aircraft provide service to the field year-round, and are the main means of field support when ice roads are melted. During the summer, operations on the Alpine Oilfield are closed down and the drilling installation is removed. The original 16 000 ha oilfield was developed from two drill sites on just 40 ha or 0.25% of the field area.

Figure 4.19* • *Layout of the Alpine Oilfield during winter operations and summer close down

Courtesy of ConocoPhillips Alaska.

Offshore Arctic field developments of the future may not require surface facilities in the vicinity of the field (Figure 4.20). The development of long-distance multiphase flow technologies, exemplified by the Snøhvit and Ormen Lange gas fields, points the way to future exploration and development of oil and gas deposits in regions where ice is present some or all of the time. The aim will be zero-surface facility developments.

Figure 4.20* • *Arctic field development of the future: zero-surface facilities



Courtesy of Statoil.

Development of zero-surface facilities requires extending the scope of subsea equipment, with a strong focus on monitoring remote operations and increasing recovery by applying smart field technologies (see Chapter 2). Bringing the Arctic hydrocarbon resources successfully to shore, while assuring the protection of the pristine Arctic environment, will require a continued and strengthened focus on research, development, demonstration and deployment. This can only be done with a high degree of international co-operation, facilitating convergence of technology development and best practice.

Challenges to risk and response capabilities

Following the Deepwater Horizon drilling accident in the Gulf of Mexico, the industry is faced with key questions related to the risk of and response to major accidents while drilling offshore. The Arctic is of particular concern as it is an even more fragile ecosystem. Given this and the icy conditions, several aspects require additional attention, such as:

- the ability to respond rapidly to an accident (noting there is limited infrastructure in the Arctic);
- sufficient resources to respond rapidly (*e.g.* staff, equipment, accommodation and number of ships);
- complications with the flow of spills caused by the presence of ice (the spill may be trapped under ice);
- the suitability of current response methods (oil collection and oil burning is more complicated in Arctic conditions than in warmer, open water, and chemicals may have a larger impact on the environment);
- slow regeneration (Arctic ecosystems do not regenerate as quickly as elsewhere).

All of these aspects require special attention and assurances must be provided as part of any field development proposal. A development option may need to be selected that provides the best response to large accidents.

Non-governmental organisations are putting these aspects at the forefront of debate and argue that a large gap between risk and present capabilities still remains (WWF, 2010). Though much is being done to address the environmental challenges of hydrocarbon exploration in vulnerable and sensitive ecosystems, as illustrated in the next subsection, it is important that learning continues and that the lessons learned are used to inform policy and practice.

Environmental impact assessment

Developing oil and gas reserves in the Arctic region will, in all cases, require a careful review of the potential impacts on the environment. The industry will typically prepare an extensive environmental impact assessment (EIA[8]), a well-established tool used during the planning phase of major projects, to highlight any potential threats that development could pose to flora, fauna and the physical environment. The EIA also identifies potential mitigation measures. Most jurisdictions around the world have established EIA regulations and procedures, including in some cases specific requirements for oil and gas, and offshore activities. All jurisdictions with interests in the Arctic region have national and provincial regulatory regimes, including EIA requirements (Table 4.1).

8. Not to be confused with the US DOE's Energy Information Administration (EIA).

Table 4.1* • *Examples of EIA legislation in Arctic countries

Canada	United States	Russia	Norway
The Canadian Environmental Assessment Act. Increasingly, approvals for activities in the northern provinces are being delegated to aboriginal people, facilitated through Indian and Northern Affairs Canada. This applies in Nunavut, Yukon and the Northwest Territories.	The National Environmental Policy Act requires federal authorities to consider the environmental impact prior to authorising activities on federal lands, typically through production and assessment of an environmental impact statement. For oil and gas production, the Minerals Management Service oversees this process.	The Federal Law on Ecological Expertise and the Regulations on Assessment of Impact from the Intended Business and Other Activity on the Environment in the Russian Federation set out requirements for developers to prepare an EIA. The Federal Service for Ecological, Technological and Nuclear Control (Rostechnadzor) oversees this process.	The Petroleum Act requires operators to prepare a project-specific EIA as part of its plan for development and operation and its plan for installation and operation of facilities. It is subject to oversight by the Ministry of Petroleum and Energy.

In addition to national regulations, the Arctic Council,[9] which addresses the environmental protection and sustainable development in the Arctic, produced the latest edition of the Arctic Offshore Oil & Gas Guidelines in 2009. These guidelines set out overarching guidance for Arctic nations for managing the environment, respecting the rights of indigenous peoples, and assessing the long-term impact of oil and gas activities during planning, exploration, development, production and decommissioning (PAME, 2009).

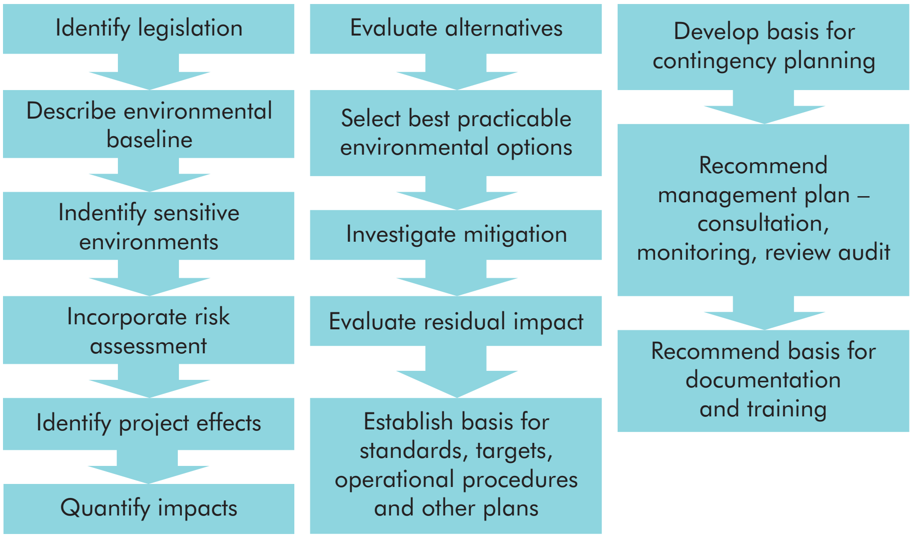
International financial institutions, *e.g.* the International Finance Corporation (IFC) and the European Bank for Reconstruction and Development (EBRD), and private-sector banks through the Equator Principles, apply additional guidelines and standards when providing finance for such projects (Figure 4.21). In addition, when there is a possibility of a transboundary impact – a particularly challenging aspect for Arctic projects – the United Nations Economic Commission for Europe's Convention on EIA in a Transboundary Context (also known as the Espoo Convention, 1991) can apply, requiring signatory parties to notify and consult with each other collectively on environmental impacts.

Approaches to EIA

The EIA process usually starts with a preliminary EIA carried out at early stages of development, *e.g.* surveying, then moving to a full EIA with updates through the exploratory, appraisal and development stages. All regulatory approaches tend to require similar issues to be assessed in relation to a development, covering: atmospheric emissions; discharges to water; solid and liquid waste issues; noise; and the potential impact of spills. Additionally, approaches often include risk assessment, emergency preparedness, response planning and decommissioning impacts (lifecycle aspects). Some examples of approaches to EIA are highlighted in Figure 4.21.

9. The Arctic Council is an advisory body formally established by the Ottawa Declaration of 1996. In addition to its member states – Canada, Denmark (including Greenland and the Faroe Islands), Finland, Iceland, Norway, the Russian Federation, Sweden and the United States – the Arctic Council has a category of permanent participants that comprise a number of indigenous peoples' groups.

Figure 4.21* • *Examples of EIA approaches for requirements of EIAs



Source: E&P Forum/UNEP IE, 1997.

Going beyond standard practice

Specific requirements for EIAs will vary by jurisdiction. In most cases, third-party guidelines such as those of the IFC can be used to reinforce national legislation if needed (Box 4.4). Increasingly, the IFC performance standards are considered as the international benchmark for EIA best practice. Following IFC guidance means that EIAs are increasingly covering environmental, social and health impact assessments (ESHIA). The EBRD has also developed its own performance requirements for projects in its portfolio.

Box 4.4* • *IFC's standards for lenders

The IFC set out eight performance standards for social and environmental sustainability, as follows:

PS 1: social and environmental assessment and management;

PS 2: labour and working conditions;

PS 3: pollution prevention and abatement;

PS 4: community health, safety and security;

PS 5: land acquisition and involuntary resettlement;

PS 6: biodiversity conservation and sustainable natural resource management;

PS 7: indigenous peoples;

PS 8: cultural heritage.

Each standard is accompanied by guidance notes and resources to support implementation. The IFC also produces industry-specific guidelines, including environment, health and safety (EHS) guidelines for offshore oil and gas. These standards are applied by the World Bank, IFC and the Organisation for Economic Co-operation and Development (OECD) to export credit agencies and almost 70 Equator Principles signatory banks and financial institutions.

Risk assessment is also an increasingly common feature of EIAs, and will likely feature more prominently in oil and gas developments in light of the Deepwater Horizon oil spill in the Gulf of Mexico in 2010. Some key features for EIAs and ESHIAs in Arctic environments are highlighted in Table 4.2.

Table 4.2* • *Issues for EIAs in Arctic regions

Social impacts and indigenous peoples	Arctic biodiversity
For the Arctic regions, the inclusion of social aspects in impact assessment is crucial. The livelihoods of indigenous people are fully entwined with the natural resources of the Arctic environment. Fishing, reindeer husbandry and hunting rights are important issues in this context. Therefore, establishing the right approach to engaging with these communities is a key step. This can be particularly challenging given the small, dispersed nature of Arctic communities. Providing assurances to communities that their livelihoods and cultural heritage will not be affected by developments is vital, especially as many of these communities and their associated groups are increasingly involved in the approvals process for major projects (as in Northern Canada).	Arctic biodiversity varies significantly and the distribution of species is patchy and variable from season to season. Arctic flora and fauna are highly valued because of their low numbers and low density. They tend to be very old specimens with low adaptability to change and vulnerability to external impacts. At present, the Arctic has 43 mammal species, 16 bird species, 12 fish species and 73 plant species on the Red List of Threatened Species of the United Nations (UN). In 2000, the Arctic contained 44 Ramsar sites (wetlands of international importance), six biosphere reserves and three World Heritage sites. The Arctic oceans are also highly productive and many important fish breeding grounds are located in the region. Protecting these areas and the consideration of local and transboundary effects arising from any impact on fisheries will be an important consideration in Arctic ESHIAs. The mobile nature of fish stocks may also trigger the considerations of the Espoo Convention for Arctic developments.
Risk assessment and emergency planning	**Climate change in the Arctic**
Since the Deepwater Horizon oil spill, increased attention will be given to assessing the potential impact of high-magnitude events that could arise during exploration and production. The pristine environment and the specific challenges posed for operating oil and gas infrastructure in Arctic conditions – such as icebergs, sea ice, ice scour and equipment freezing – will be difficult to characterise in terms of possible features, events and likelihood of occurrence. Mitigation of the potential risks, potential response measures and the possible impact of such response measures will also be particularly difficult to define given the remoteness of locations and extreme climatic conditions.	Relative to other parts of the world, the Arctic is particularly vulnerable to the effects of climate change. Decreasing sea ice coverage (9% to 10% reduction in summer sea ice over the last 30 years), reduction in ice thickness, shifts in vegetation zones and thawing of permafrost create additional complications for design and construction of oil and gas infrastructure in the region. Changes in the distribution of species and the effects of climate change on the communities of indigenous peoples mean that current ESHIAs will need to take into account the future effects of climate change on the environment and people within a given area.

Key references for Arctic EIAs

Several references include information about Arctic environments, its peoples and the threats and the impact they face from infrastructure development and climate change. These should all be reviewed and considered when preparing ESHIAs for Arctic projects. Examples of sources are given in Table 4.3.

Table 4.3* • *Reference sources for Arctic EIAs

Sources of further information on Arctic environmental issues	
Arctic Council	www.arctic-council.org/
World Wildlife Fund (WWF) Arctic Programme	http://wwf.panda.org/what_we_do/where_we_work/arctic/
United Nations Environment Programme (UNEP) GRID-Arendal	www.grida.no/
Arctic Institute of North America	www.arctic.ucalgary.ca/index.php
International Polar Foundation	www.polarfoundation.org/
US Department of Environment, Arctic Energy Office	www.netl.doe.gov/technologies/oil-gas/AEO/main.html
Further information on Arctic communities	
Arctic Council Indigenous Peoples Secretariat	www.arcticpeoples.org/about
Inuit Circumpolar Council (Canada)	http://inuitcircumpolar.com/
Aluet International Association	www.aleut-international.org/
RAIPON	www.raipon.org/
Gwich'IN Council International	www.gwichin.org/
General guidelines on EIA and approvals	
IFC Performance Standards	www.ifc.org/ifcext/sustainability.nsf/Content/PerformanceStandards
Equator Principles	www.equator-principles.com/
United Nations Environment Programme Industry and Environment (UNEP IE) Technical Report 37	www.ogp.org.uk/pubs/254.pdf
Indian and Northern Affairs Canada (oil & gas section)	www.ainc-inac.gc.ca/
The Alaska Outer Continental Shelf (OCS) Bureau of Ocean Energy Management, Regulation and Enforcement	http://alaska.boemre.gov/
Norway Ministry of Petroleum	www.regjeringen.no/en/dep/oed.html

Legal aspects

Several international legal instruments may be relevant to offshore oil and gas activities conducted in the Arctic, such as the *United Nations Convention on the Law of the Sea* (UN, 1982) and the *International Convention for the Prevention of Pollution from Ships* – MARPOL 73/78 (IMO, 1973). However, there is currently no comprehensive, dedicated international legal regime relevant to these activities in place for the Arctic.[10] The Arctic is governed by a "soft law" regime with the

10. This is in contrast to the Antarctic, where the Antarctic Treaty System provides a legal framework for the governance of the region. The Antarctic is preserved for peaceful purposes and scientific endeavours under the treaty system, precluding oil and gas activities in the region.

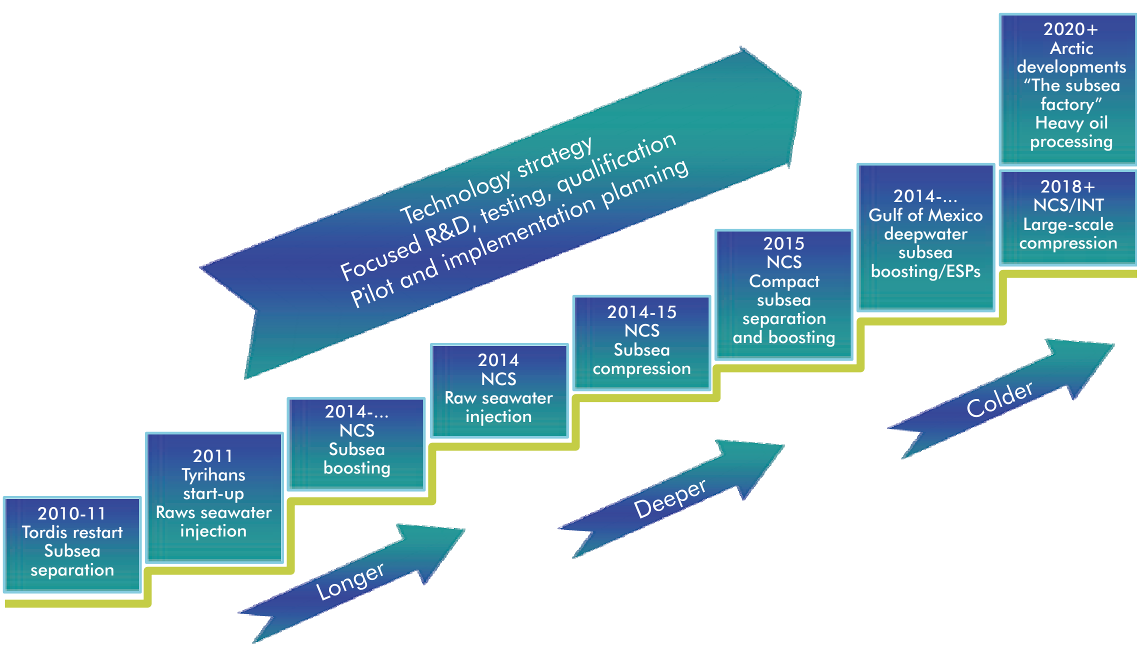
Arctic Council at its head. As an advisory body, the Arctic Council can propose policies and guidance documents (such as those mentioned above) but it cannot make binding law or enforce its policies. This means that, in practice, legal and regulatory oversight of oil and gas production in the Arctic falls to individual Arctic states. It should be noted that, to the extent that areas of the Arctic remain disputed, regulatory authority over these areas is unclear.

Future directions

New technological innovations are essential to the responsible development of large resources in the pristine environments of deepwater and Arctic regions. The best solutions will be those that reduce the environmental footprint, the risks involved and cost. Sometimes, such solutions can be adapted from the best practices and experiences in other areas, such as subsea compression applied to Arctic conditions.

A roadmap towards the vision of a zero-surface facility has been developed (Figure 4.22). To achieve the final goal of a subsea factory under the ice, there are some clearly identified milestone projects that need to be successful to achieve the vision. In view of the complexity of the total system, research, development and demonstration with a high degree of international co-operation, multi-company pilot testing and exchange of best practices will be required.

Figure 4.22* • *Subsea technology enables growth: Roadmap to the subsea factory



Note: NCS = Norwegian Continental Shelf; NCS/INT = Norwegian Continental Shelf/International; ESPs = electric submersible pumps.

Courtesy of Statoil.

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Chapter 5 • Making light of unconventional oil

A large share of the world's remaining oil resources is classified as unconventional. As there is no universally agreed definition of conventional or unconventional oil, several definitions are in current use to differentiate between them (Box 1.1 in Chapter 1). Roughly speaking, any source of hydrocarbons that requires production technologies significantly different from the mainstream in currently exploited reservoirs is described as unconventional. However, this is obviously an imprecise and time-dependent definition; advances in technology, changes in the economics, new environmental requirements or energy policy incentives, can shift the demarcation line between conventional and unconventional resources. In the long term, unconventional heavy oils may well become the norm rather than the exception.

Unconventional oil is generally accepted as having a high viscosity or is complex to extract; it usually includes kerogen shale, oil-sands (and natural bitumen), light tight oil (LTO), and oil derived from coal, gas and biomass. Natural gas liquids[1] (NGLs) are occasionally included within this category, though more often as conventional. Although it is often more costly to produce, unconventional oil will almost certainly make an increasing contribution to future oil production.

Heavy oil and oil-sands

There are three different types of heavy oils: heavy oil that is able to flow in the reservoir; near-solid bitumen in shallow oil-sands that can be mined; and bitumen in deeper reservoirs, beyond 75 metres (m), which needs significant stimulation for recovery. Oil-sands are unconsolidated sands that contain bitumen.

The world's extra-heavy oil and oil-sands resources are largely concentrated in Canada (mainly in Alberta) and Venezuela (in the Orinoco belt). Canada has proven reserves of 175 billion barrels (bb), while Venezuela has proven reserves of 220 bb. The total remaining recoverable resources[2] will likely be a multiple of these numbers (IEA, 2012). The exact amount of other remaining recoverable resources depends on several factors, including the price of crude oil; the development of new technology; the demand for energy; and solutions for reducing the impact on the environment. As these factors are successfully addressed, the volume of reserves is likely to increase.

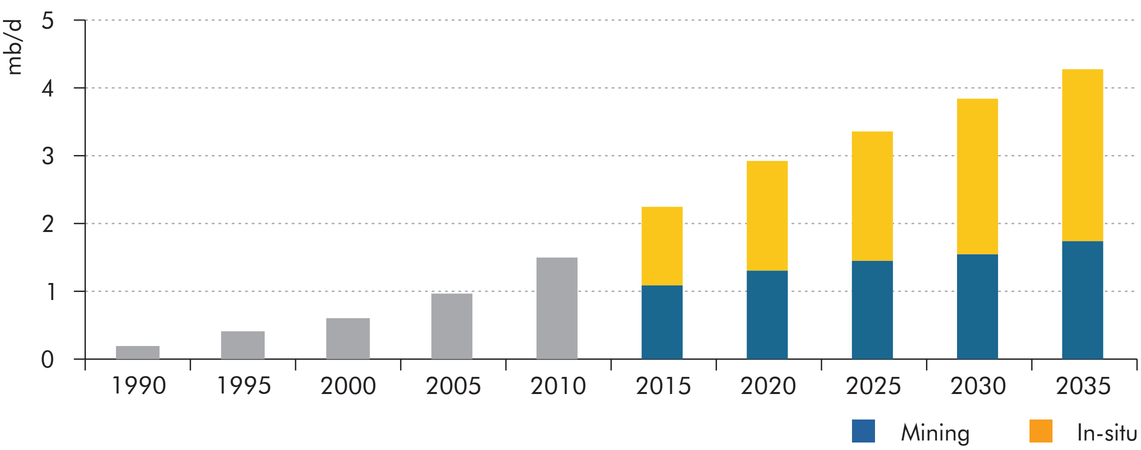
The two main challenges are extracting the viscous oil or bitumen from porous rock, and diluting or "upgrading" the extracted oil so that it can be transported by pipeline to a refinery. To cope with these challenges, very large volumes of water, steam, light hydrocarbons and hydrogen are used.

1. Natural gas liquids or field condensates are components of natural gas that are liquid at the surface in field facilities. They include propane, butane, pentane, hexane and heptane.
2. Definitions of resources and reserves can be found in Chapter 1.

When viscosity is low enough for the oil to flow (albeit slowly) to the surface, long horizontal or multilateral wells are used to maximise well-bore contact with the reservoir and reduce the drop in pressure in the well bore. This method is referred to as "cold production" and is used for several of the heavy oil deposits in the Orinoco belt. The main drawback of such conventional production techniques is a low recovery factor, typically less than 15%. The amount of heavy oil that could be recovered from the estimated 1 600 bb in place in the Orinoco belt is less than 300 bb. For more viscous oils, more complex recovery methods such as mining and *in situ* heating are needed.

Heavy oil production is expected to increase in the foreseeable future despite the need for significant capital investment (CERI, 2012). Much of this growth has been planned in Canada, where total production from oil-sands (Figure 5.1) is currently equally split between surface mining and *in situ* production methods, but with *in situ* production expected to grow faster in the future. New heavy oil resources have been identified in Colombia (up to 110 bb), Ecuador, Peru and other countries along the Andes. China, Russia, Kazakhstan and countries in the Middle East, such as Kuwait and Iran, have reported increases in heavy oil resources and production.

Figure 5.1* • *Past and projected production of oil-sands from Canada, in the New Policies Scenario



Note: mb/d = million barrels per day.

Source: IEA databases and analysis.

High oil prices at the start of 2008, in combination with new and emerging production technologies, made it more financially viable to produce oil-sands resources in Canada. However, the subsequent drop in oil prices after mid-2008 made exploitation less attractive and new projects, involving around 1.7 mb/d of peak capacity and worth around USD 150 billion of investment, were either suspended or cancelled (IEA, 2009). By mid-2010, oil prices had rebounded and many projects were reactivated as higher oil prices meant it was profitable again to extract and develop heavy oil resources. While these existing projects continue to produce, investment in new projects will hinge on sustained high oil prices or reduced production costs. In 2012, there were more than 110 oil-sands projects in operation with a total raw bitumen capacity of 2.1 mb/d. On the assumptions of the *World Energy Outlook 2012* New Policies Scenario, the IEA projects that Canadian production from oil-sands will reach 2.3 mb/d in 2015 and 3.4 mb/d in 2030 (IEA, 2012).

Upgrading viscous oil

Upgrading viscous oil involves methods to increase the ratio of hydrogen to carbon typically by coking[3] or hydrocracking.[4] Either process results in an upgraded crude oil with a significantly lower viscosity, allowing it to be transported by pipeline.

To generate oil feedstock that is suitable for refineries, initial upgrading of heavy oil and bitumen is necessary. Carbon removal (coking) and hydrogenation, using methane as the source of hydrogen, are used to upgrade heavy crude oils of 20°API[5] to light crudes of 40°API gravity, with a narrow range of molecular weights of around 90 to 180. Upgrading methods using only hydrogenation generate about 1.1 barrels of oil from a barrel of raw bitumen (b/b). If only coking is used, the yield is about 0.85 b/b. In five different upgrading facilities in Alberta, yields lie in a range of 0.82 b/b to 0.92 b/b. Depending on the quality of the heavy oil and bitumen, and the desired standard of the upgraded crude oil, by-products from the upgrading process may comprise large volumes of elemental sulphur and petroleum coke. The potential for disposal or use of the by-products have an impact on the environmental footprint of the operation.

In Canada, upgrading[6] costs between USD 9.5 and USD 11.5 per barrel (/b) (Canadian Oil Sands, 2012). These costs account for the price differential between heavy oil (Western Canadian Select) and the benchmark conventional light crude (West Texas Intermediate). Over the period January 2005 to September 2012, the monthly average price varied from a low of USD 6/b in April 2009 to USD 42/b in December 2007 (Baytex, 2012). This substantial price differential has persisted for several decades because of limited upgrading capacity in Canada and an export market that consists mainly of the United States.

Any technology that could enable upgrading to take place closer to the source, potentially even inside the reservoir, would improve and facilitate the development of heavy oil and oil-sands. It would make recovery easier, reduce the amount of heat or solvents wasted at the surface and improve energy efficiency. The Nexen-CNOOC Long Lake Project is a commercial project that operates with in-field upgrading. The project employs steam-assisted gravity drainage (SAGD) to recover bitumen that is too deep to mine. The bitumen is pumped to the surface, where it is treated to remove water, then fed into an upgrader to produce synthetic crude oil. Laboratory tests on *in situ* upgrading are ongoing but, so far, there has been no field pilot project.

3. Coking is a thermal cracking process that converts the heavy fraction of heavy oils to elemental carbon (coke) and to lighter fractions, including naphtha or heavy gas oils.
4. Hydrocracking is a catalytic cracking process that occurs in the presence of hydrogen, where the added hydrogen saturates or hydrogenates the cracked hydrocarbons.
5. API (American Petroleum Institute) gravity is a measure of the density of oil. The API gravity scale is calibrated such that most crude oils, as well as distillate fuels, will have API gravities between 10° and 70° API. The lower the number, the heavier and the more viscous is the oil.
6. Upgrading costs include the production and ongoing maintenance costs associated with processing and upgrading of bitumen to synthetic crude oil.

Mining oil-sands

Two major categories of extraction can be used, which include mining if the deposit is very shallow or applying heat down-hole (*i.e.* within the well) if the deposit is deeper.

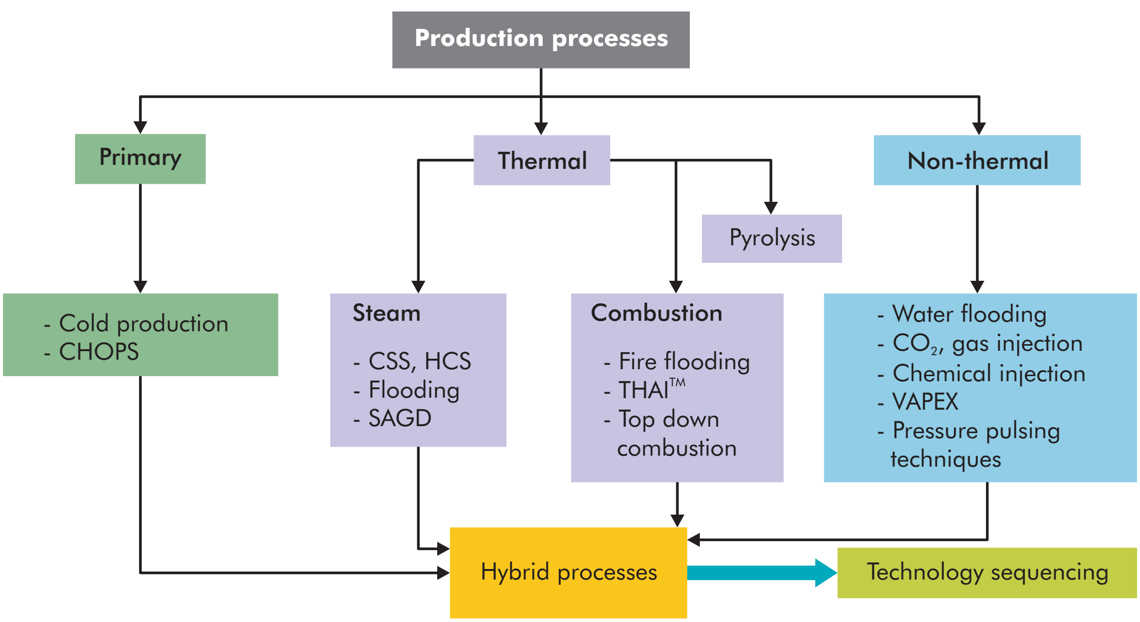
If the deposit is near the surface, the oil-sands are mined (surface mining) by using large power shovels and dump trucks. One cubic metre of mined "ore" (the mixture of sand, water and bitumen) contains on average approximately 22% of raw bitumen by volume. The bitumen is extracted from the ore using heat and water in a separation method known as "hot froth flotation". This method is effective at recovering about 90% of the oil, yielding approximately 1.3 barrels (b) of raw bitumen per cubic metre of ore.

Canada is the only country where large-scale bitumen surface mining is practised. In 2010, around 50% of the 1.5 mb/d of oil produced from oil-sands came from upgrading mined bitumen, while the rest was recovered using *in situ* processes.

Technologies for *in situ* production of heavy oil and oil-sands

The various *in situ* production methods can be grouped as primary (only drilling wells and producing), thermal (using heat to lower the viscosity of the oil), and non-thermal (mostly based on creating miscibility between the oil and the injectant) (Figure 5.2). In Canada, oil production from oil-sands is split equally between mining and *in situ* recovery methods, though the share from *in situ* recovery is increasing with time (Figure 5.1).

Figure 5.2 **•** In situ *methods of viscous oil production*



Notes: CHOPS = cold heavy oil production with sand; CSS = cyclic steam stimulation; HCS = horizontal-well cyclic stimulation; THAI™ = Toe-to-Heel Air Injection (THAI is a trademark of Petrobank); CO_2 = carbon dioxide; VAPEX = vapour-assisted petroleum extraction.

Source: Dusseault, 2009.

Box 5.1 • Technologies for **in situ** *production of oil-sands*

Primary

- *Cold production is a process in which bitumen is produced by long, often multi-branched, horizontal wells. Recovery factors are low, less than 15%.*
- *CHOPS allows sand to be produced along with the oil. It simplifies downhole well designs and increases the productivity of a well. It has been highly successful in Canada since 1985, especially for extracting oil from thin zones.*

Thermal

- *In CSS a small amount of steam is injected into the producer well, after which it is closed in for some time before reopening it for the production of heated oil. Several Canadian operators have applied it to horizontal wells, a process known as HCS.*
- *SAGD marks an important advance in heavy oil production. Oil flows along the walls of a steam chamber down to a producing well (see Box 5.2).*
- *THAI™ is a technique based on either injecting air into a vertical injection well located within close proximity to the toe of a horizontal producing well or injecting it directly from the toe. The injected air promotes partial combustion of the bitumen. Though still very much experimental, the technique has been undergoing preliminary field tests. Commercial projects based on THAI™ are perhaps five to eight years away, if tests prove successful.*

Non-thermal

- *Gas injection is being developed as a post-steam recovery method in Canada, helping to recover more of the heated oil while reducing the need for steam.*
- *Pressure pulsing techniques are based on the discovery that large-amplitude, low-frequency pulsing wave energy enhances flow rates in porous media (Veil and Quinn, 2008). They involve applying sharp pressure impulses to the liquid at the bottom of a well. The impulses generate displacement waves that facilitate oil production. Though the technology has not gained wide acceptance, it is starting to be used in cold heavy oil production.*
- *VAPEX is similar to SAGD, but injects a diluent rather than steam to reduce viscosity. As dilution and gravity drainage using solvents yield slow production rates, this technique will likely be limited to heavy oils of lower viscosity or as an aid to SAGD methods.*

The two most widely used *in situ* production methods for heavy oil and bitumen recovery are CSS and SAGD.

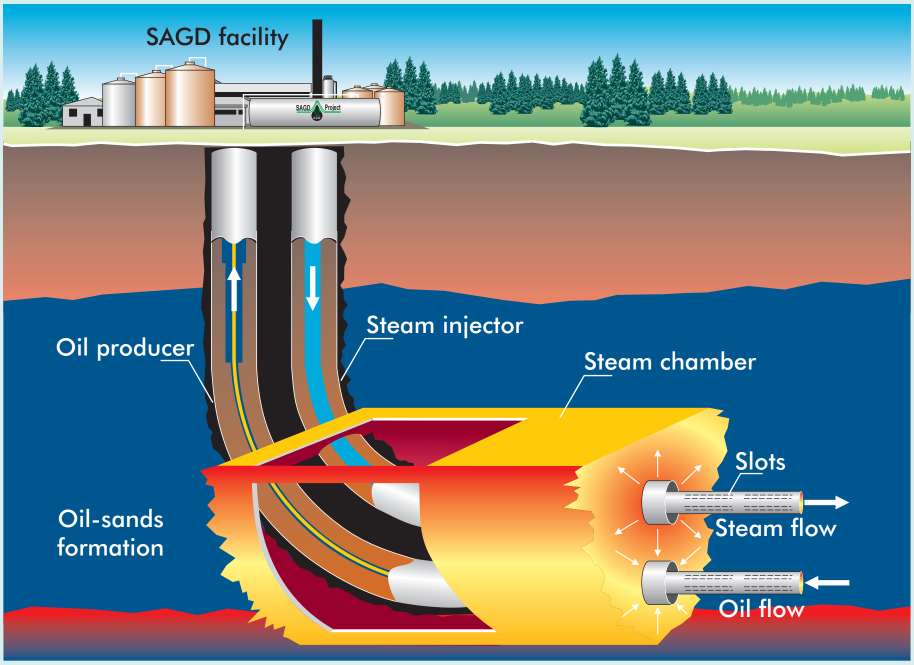
In CSS, the heavy oil is heated by injecting steam into the well for a period of several weeks, before production of the heated oil. This process is repeated several times until it becomes too difficult to reach the oil far from the well. The overall field recovery rate for such a process is low at between 20% and 35%. However, CSS is an effective stimulation technique for producers and is applied in combination with other methods that can drive oil towards the well.

The SAGD method is the most important technological development in viscous oil extraction since the advent of CSS (Box 5.2). SAGD concepts evolved in 1970 to 1985. Theoretical recovery factors of 50% to 70% are predicted for SAGD in thick and homogeneous reservoirs, using a similar amount of steam per barrel produced as is the case for CSS.

Box 5.2 • Steam-assisted gravity drainage

In highly viscous oils, i.e. those with viscosities higher than 100 000 centipoise, SAGD is based on parallel horizontal well pairs, 800 metres (m) to 1 000 m-long, located at the base of the oil zone (Figure 5.3); well pairs are spaced laterally at about four times the zone thickness. Steam is introduced through the upper wells, where it rises because of its low density, subsequently condenses and gives up latent and sensible heat to the viscous oil. The hot oil and condensed water flow downward to the production well below the injector.

Figure 5.3 • The SAGD process



Courtesy of Encana Corporation.

The advantages of SAGD are the improved recovery factors achieved (by over 70%) and the somewhat lower steam-to-oil ratios compared to other steam methods. High recovery factors can be attributed to the stability of a gravity-dominated drainage regime based on gas-liquid phase segregation. Wells are operated at the same pressure to avoid short-circuiting or generation of pressure-induced flow instabilities. The injection rate is controlled so that pressure in the steam chamber remains constant over time.

An ideal SAGD reservoir will have more than 20 m of oil-saturated sand with good vertical permeability (>1 000 millidarcy) and no basal water. Shales of 2 m to 3 m thick can be breached, though they slow down the process. However, fine-grained siltstones without clay are more serious flow barriers because of capillary blockage of gravity flow (such riverbeds severely hampered SAGD in the Shell Peace River Project). If operated carefully, SAGD can be carried out in the presence of active basal water or a gas cap, but not both.

Another reason why SAGD is effective is the extensive, thermally induced shearing that breaks down thin flow barriers and leads to dilation, improving reservoir porosity and permeability. The 30 centimetres (cm) to 50 cm of surface uplift above SAGD operations is proof of benefit achieved from the shear-dilation effect.

Various improvements to basic SAGD concepts are being pursued, for example:

- *where the viscosity of oil may be slightly lower, different injection well configurations (vertical or offset horizontal wells) may be used;*
- *before SAGD, several cycles of high-pressure steam injection may help break down barriers to vertical gravitational flow, which would otherwise significantly reduce production;*
- *viscosity may be reduced further by injecting condensing solvents, possibly alternating with steam injection, to raise oil production rates;*
- *post-SAGD, injecting inert gas can potentially distribute the heat already in the reservoir more effectively;*
- *improved monitoring of pressures, deformations and temperatures can result in better process control and enhanced thermal efficiency;*
- *as generating steam is a costly process, different heat sources for steam are being pursued.*

In the 1980s, the government of Alberta was the first to field test SAGD and was followed by several private companies in the 1990s. It was not until 2001 that it was used by the Encana Corporation in the first SAGD commercial project to exceed 10 000 b/d – the Foster Creek project in eastern Alberta, north of Cold Lake. In March 2012, there were 18 commercial projects in various deposits in Alberta (Government of Alberta, 2012) and a smaller number in Saskatchewan, while there are further SAGD projects in China, Venezuela and Russia. Total SAGD production in Canada passed 1.05 mb/d in 2011 with projections of 1.9 mb/d by 2016 (Rystad, 2012).

Non-thermal methods are currently being pursued, especially in thinner deposits in which there can be high energy costs and a high fraction of heat lost to the surrounding rocks. A commonly applied non-thermal technique is polymer injection. In this method, water is made more viscous by adding polymers that enable the heavy oil to be displaced more efficiently. The disadvantage of polymer injection is the low injectivity[7] and the consequent increase in the number of wells required.

7. Injectivity is the volume per day that can be injected as a function of the injection pressure. As water with dissolved polymers is more viscous than steam, it is more difficult to inject into the reservoir. Furthermore, this difficulty is compounded when injecting into very heavy oil, where the oil itself inhibits the injectivity.

Currently, the industry is investigating the application of "hybrid processes", where more than one of these techniques can be applied in sequence to further improve recovery and production efficiency.

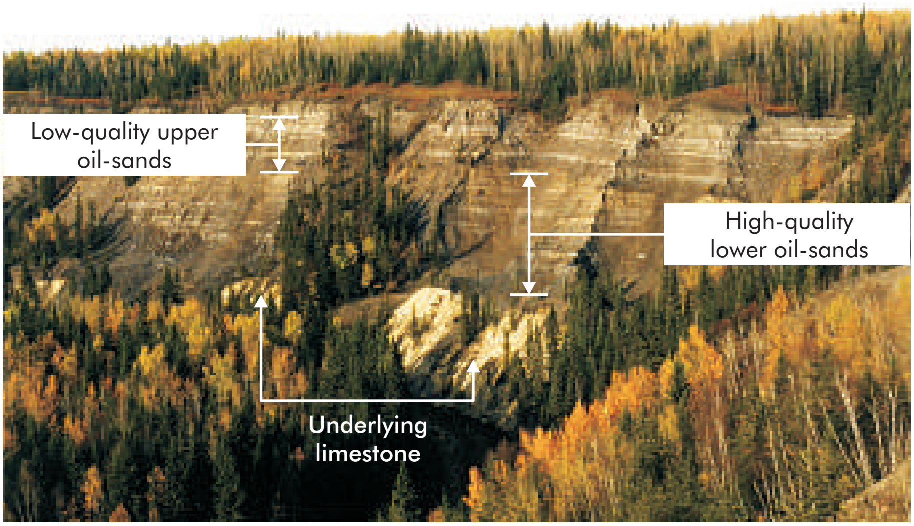
Environmental issues associated with heavy oil and oil-sands production

Both mining and *in situ* viscous oil production generally require greater attention to environmental management than conventional production. Large volumes of gaseous, aqueous and solid wastes are generated, including emulsions and oily mixtures, such as tank bottoms.[8] In addition, large volumes of coke and sulphur must be stockpiled when demand for these by-products is low.

Impact on the landscape

In situ viscous oil production and, in particular, mining change the landscape and affect the existing forest ecosystem (Figure 5.4). Remediation of the land may be necessary. For example, the government of Alberta requires companies to restore the land.

Figure 5.4* • *Oil-sand mining region north of Fort McMurray, Alberta



Note: figure shows 55 m to 65 m high oil-sands slope in a mining region north of Fort McMurray, Alberta, Canada.

Source: Dusseault, 2009.

Water usage

Large volumes of water are required to extract bitumen from oil-sands. For example, between 3 and 4 b of water are required to produce 1 b of synthetic crude oil (NRCAN, 2011). Although 95% of water used to generate steam is

8. Tank bottoms are residues that accumulate in the bottom of storage tanks. They usually comprise sediment, dirt, oil emulsified with water and free water, and may also be referred to as tank settlings or tank sludge. Tank bottoms are generally either disposed of or treated by chemicals to recover additional hydrocarbons.

recycled, that still leaves 0.2 barrels of water consumed for each barrel of bitumen produced. The availability of water, for example from Canada's Athabasca River, presents a potential bottleneck for some projects under development in that region, especially during winter. To reduce the use of potable water for some *in situ* operations, some producers are using brackish water (with salinity between that of fresh water and seawater) instead.

Bitumen slurry

Water-based extraction generates large volumes of bitumen slurries (wastewater or fluid tailings) and a wet, oily, clay-like sludge. In 2009, the Energy Resources Conservation Board of Alberta approved a directive to ensure that operators reduce fluid tailings and dispose of them responsibly in dedicated disposal areas or face penalties for non-compliance (ERCB, 2009). Beginning in July 2010, the directive was phased into practice, with a 20% reduction in fluid tailings required by July 2011, 30% by July 2012 and rising to a 50% reduction by June 2013, with further reductions to be imposed annually thereafter. The directive aims to stop the accumulation of tailings from oil-sands in Alberta.

Sulphur

Sulphur is a by-product of oil-sands production; it can either be exported for use or consigned to a long-term storage/disposal strategy that is socially and environmentally acceptable. In the last 20 years, new waste disposal technologies have emerged. The most common disposal technique is deep slurry injection, in which solid wastes, such as sulphur, are mixed with liquid and pumped into a sealed reservoir. This method of disposal is now used in several locations in the world. For example, since 2002 a large injection facility in Duri, Indonesia has disposed of over 2 million cubic metres (Mm^3) of waste products, including produced water, drill cuttings, waste emulsions, sulphur and other solids. These materials are injected into a shale-sealed sandstone reservoir at 400 m depth.

Greenhouse gases (GHGs)

Given growing concerns about climate change, emissions of atmospheric pollutants and GHGs associated with the exploitation of oil-sands must be addressed. Emissions include substantial volumes of CO_2, small amounts of sulphurous gases and fine particulate matter. During the mining, production and upgrading processes, between 95 kilograms (kg) and 125 kg CO_2/b of upgraded crude oil are generated. If SAGD is applied, this rises to between 125 kg and 150 kg CO_2/b. For cyclic steam injection technologies, CO_2 emissions will be higher than for SAGD by about 40 kg to 60 kg of CO_2/b as more steam is required. Transportation and additional refining add a further 80 kg to 90 kg of CO_2/b. In total, for all processes, CO_2 emissions can vary from 175 kg to 300 kg CO_2/b.

Methods of mitigating emissions from fossil fuels include carbon capture and storage (CCS), in which CO_2 is captured at source and injected into suitable aquifers or oil reservoirs for storage (see also Chapter 2 and Chapter 9). In Alberta, all new fossil fuel plants must be designed and constructed for possible future mandated CCS.

Steam and hydrogen sources

The oil-sands industry uses about 4% of the natural gas produced from the Western Canada Sedimentary Basin. However, though the cost of the natural gas used to generate steam, electricity and hydrogen for the production of heavy oil and oil-sands is high, there is a net benefit. According to Canada's National Energy Board, around 34 m^3 of natural gas are required to produce 1 b of bitumen; and 1 b of bitumen has an energy-equivalent of 170 m^3 natural gas. Nonetheless, as natural gas reserves are diminishing, operators need to look more closely at other sources for energy requirements. One project that has sought to put such a process into practice is the Nexen-CNOOC Long Lake Project.

The Nexen-CNOOC Long Lake Project began production in the Athabasca oil-sands region of Alberta in 2009. All steam and electricity required to operate the project is generated from combustion of the asphaltene fraction of the SAGD-produced bitumen. Though this reduced the need for natural gas, it has led to higher net CO_2 emissions. To address this, the possibility of retrofitting CCS in the future has been considered, though it would involve a number of modifications to the process.

Potential for the clean combustion of coal, coke or residuals (asphaltenes) using pure oxygen to generate heat (steam), electricity and hydrogen also heralds potential for reducing consumption of natural gas. This process would generate nearly pure CO_2, which could be either transported for direct geological storage or used for enhanced recovery of conventional oil.

The possibility of reduced access to sufficient levels of natural gas in Alberta in the future, coupled with increasing environmental pressures to reduce CO_2 emissions, present strong incentives to develop and implement other means of fuelling mining, production and upgrading processes. Reducing the environmental impact of heavy oil development is important, but the means to achieve it still remain to be implemented at full scale.

The future of heavy oil and oil-sands

Non-thermal production methods such as cold production and CHOPS have lower capital and operating costs than mining and thermal steam methods. They are not suitable for high-viscosity reservoirs and suffer from other deficiencies, such as sand management requirements, low recovery factors and low production rates. However, their lower costs make them attractive and they could still be deployed as the first technology in a sequence of primary, non-thermal and thermal methods designed to increase recovery factors.

In Canada, for a mining project that includes upgrading, an investment of about USD 73 000 is needed to generate 1 b of oil per day. The capital investment is somewhat less for SAGD projects, but the need for heat means that operating costs, including upgrading, would be similar to or greater than for mining. The costs for SAGD and upgrading in Venezuela would be lower than in Canada because of the milder climate and lower transportation costs.

Depending on how oil demand and prices develop, global heavy oil and bitumen production could increase from 2.2 mb/d in 2010 to 6.7 mb/d in 2035 (IEA, 2012). Canadian oil-sands alone could increase rapidly from 1.6 mb/d to 4.3 mb/d over the same period. The other large contributor is heavy oil production from the Orinoco belt (Venezuela) that is expected to reach 2.1 mb/d in 2035, from 0.6 mb/d today. In Canada, *in situ* production will overtake mining production over the next decade with SAGD production expected to increase markedly over the same period.

Major issues in viscous oil development include CO_2 emissions; waste management; energy sources for steam; water use; hydrogen sources for hydrogenation; and transportation issues, including the transport of diluent and new pipeline routes. Recent technical advances suggest that significant improvements could take place in each of these areas, reducing the barriers to large-scale heavy oil production while also mitigating the environmental impact.

Kerogen oil

Kerogen shale, often referred to as oil shale, is found at shallow depths, from surface outcrops to 1 000 m deep. It is a very low-permeability sedimentary rock that contains a large proportion of kerogen, a mixture of solid organic compounds. In kerogen shale reservoirs, conversion of the kerogen into liquid oil (or kerogen oil) has not taken place because the high temperatures required have not been experienced.

Historically, kerogen shale has been mined not only for conversion into oil, but also for power generation, cement production and for use in the chemicals industry. Mining of kerogen shale dates back to the 1830s and peaked in 1980 at 46 million tonnes per year (Mt/yr), falling to 16 Mt/yr in 2004. Around 80% of commercial kerogen shale is mined in Estonia, where it is used predominantly for power generation.

By heating kerogen at temperatures up to 500 degrees Celsius for an extended period of time, it is possible to produce kerogen oil and other hydrocarbons, including methane. Currently, global production of kerogen oil lies at around 20 000 barrels per day (b/d). While much exploratory work remains to be done, resources in place are estimated at around 4.8 trillion barrels of oil (WEC, 2010) and remaining recoverable resources at around 1.1 trillion barrels (IEA, 2012). The United States has the world's largest share of resources in place, with more than 77%, followed by China and Russia. Kerogen shale is currently being exploited in Brazil, China, Estonia, Germany, Israel and Jordan.

Kerogen shale that outcrops the surface can be mined; the mined rock is heated in a process called "retorting", which pyrolyses (or thermochemically decomposes) the kerogen into oil. Deeper deposits require the use of techniques to enhance productivity from the formation (such as hydraulic fracturing) and an *in situ* mobility enhancement technology. The processes required are very energy-intensive. Retorting alone requires almost 30% of the energy value of the oil produced. The process also generates CO_2 emissions, ranging from 180 kg to 250 kg CO_2-equivalent per barrel of oil produced. In the absence of a carbon pricing regime, production costs have been estimated to make commercial exploitation (in the United States) possible at an oil price of around USD 60 per barrel (IEA, 2010).

The main kerogen shale reserves in the United States can be found in the Green River Formation. Early experiments in the 1980s were halted because of the costs involved and poor operational performance. Shell has assessed the technical and financial viability of an *in situ* conversion process, using down-hole heaters, at the Mahogany Ridge project. The oil produced has an API gravity of between 30° and 40°, which is significantly less viscous than oil produced by surface retort. The process has the advantage of reducing the environmental impact on the surrounding land compared to mining, assuming that wells can be drilled as little as 12 m apart. However, the process requires the use of both water and a sufficient amount of energy to heat and cool the relevant areas. A 100 000 b/d unit would require 1.2 gigawatts (GW) of power. Shell expects gas output from the produced fluid to yield most of this energy. Preliminary energy balances indicate, on a lifecycle assessment basis, a ratio of between three and four to one of energy generated to energy used. Further technical developments to protect groundwater are required before moving to a larger-scale demonstration phase. Shell is not expected to decide on whether or not to commercialise its technology for another five years at least. Other large companies involved today in kerogen shale projects in the United States are Exxon, Petrobras and Total.

Light tight oil

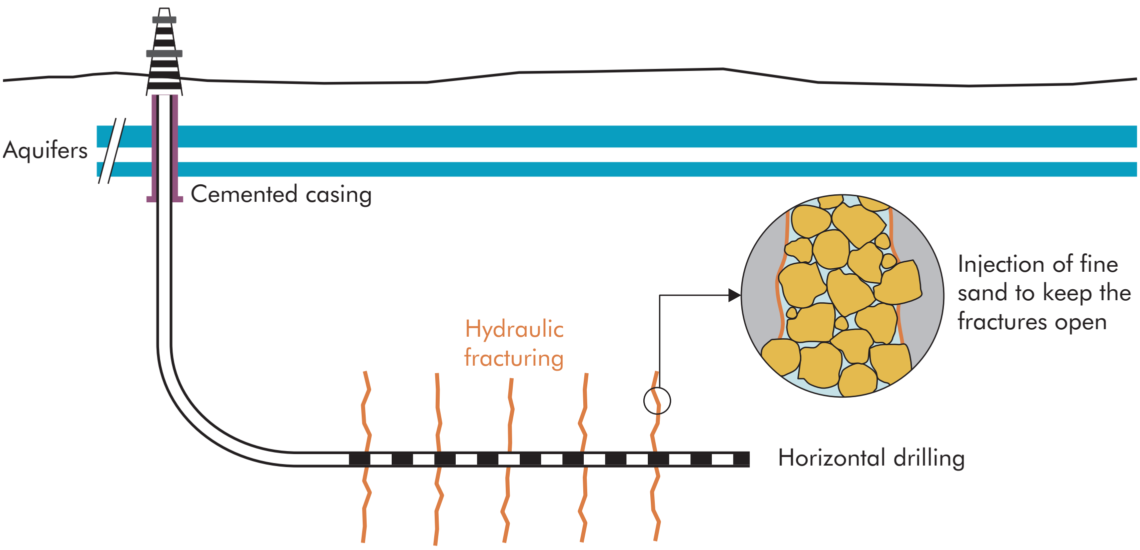
Shales are often found to be source rocks for oil and gas fields. As shales are buried deeper over geological timescales, the organic matter they contain matures, under high pressure and high temperatures, into oil or gas. Subsequently, a fraction of the hydrocarbons formed escapes from the shale and migrates upwards where it is trapped in oil and gas fields. However, a potentially large fraction of the oil or gas may have had no chance to escape from the shale or may have migrated into a neighbouring low-permeability rock formation. Shale, therefore, or neighbouring low-permeability formations, may still contain large volumes of hydrocarbons. These are known as LTO in the case of oil, or shale gas in the case of gas. As fluids cannot move easily through low-permeability rock formations, the production of commercial volumes of hydrocarbons requires the use of advanced technologies. Innovations in well technology have meant that shale gas development has increased significantly over the last ten years. Application of these developments to a new resource category has now led to the unlocking of previously uneconomic resources of LTO.

Geologically, LTO is an analogue of shale gas. This is why LTO is often referred to as shale oil. Unfortunately, the term shale oil is also often used to refer to oil produced by industrial heat treatment of shale, which is rich in certain types of kerogen. To avoid confusion, the latter is referred to as kerogen oil.

Extraction of LTO

Oil has a much higher viscosity and a much lower compressibility than gas, which makes extraction of LTO from low-permeability rock formations a greater challenge. Conventional techniques, involving the drilling of vertical wells, produces insufficient flows and would not be economic. Extracting LTO requires drilling more wells, making extensive use of horizontal drilling and multi-stage hydraulic fracturing to improve the flow of oil from the reservoir to the well bore (Figure 5.5). These are the same principal technologies that have enabled large-scale, unconventional tight gas and shale gas production (see Chapter 6).

Figure 5.5 • *Horizontal drilling and hydraulic fracturing*



Note: unless otherwise indicated, all material in figures and tables derives from IEA data and analysis.

While horizontal drilling increases reservoir contact, hydraulic fracturing creates fractures in the rock that further maximises reservoir contact, particularly with naturally occurring pre-existing fractures in the shale, and allows the oil to flow more easily into the well bores. Fracturing is achieved by pumping large quantities of water-based fluids under high pressure, mixed with specific chemical additives and proppants. Proppants are small solid particles, usually fine sand or ceramic beads, injected to prevent the cracks from closing after the pressure is released. Together with advanced seismic techniques to detect sweet spots and to indicate the best drilling locations, horizontal drilling and hydraulic fracturing have enhanced yields of LTO to commercially attractive levels. Oil production in the United States has been on a steep upward trend since 2005, in large part thanks to the deployment of these technologies.

In targeting more difficult resources, such as LTO, higher investment and technology development is necessary. LTO requires many more wells per unit of production volume than conventional resources as output per well is significantly lower. Like shale gas, production from LTO wells declines rapidly. However, initial production rates vary widely, depending on geology, well lengths and the number of hydraulic fracturing stages carried out. Averaged over the first month, Bakken wells (see next subsection) produce between 300 b/d and more than 1 000 b/d, but within five years the great majority of wells produce less than 50 b/d. Over their lifetime they typically recover between 300 thousand barrels (kb) and 700 kb. Given the steep declines in production, new wells are constantly needed to maintain output; hence, constant drilling activity is essential to production growth. During 2010, 700 new wells were drilled in Bakken with a rig fleet averaging 126 units while, during 2012, twice the number of wells were drilled with just 60% more rigs (NDSG, 2010 and 2012).

Trends are towards drilling more wells and to drilling greater lengths (or "footage") per rig per year. Better design of drilling rigs contributes by reducing operational cycle times and costs. For example, rigs must be capable of operating more effectively in winter.

Better fracturing and completion techniques will allow operators to drill longer horizontally and reduce the number of wells required. However, operation of the drilling rig is no guarantee of a successful outcome. Reducing the number of underperforming wells drilled is important. Exploration using knowledge gained from advanced seismic and other smart field techniques (Chapter 2) adds more certainty to drilling in tight formations. Such techniques also aid the detection of sweet spots, where permeability and porosity are significantly higher than the average values in the reservoir (Chapter 6). Drilling into such areas can greatly enhance production.

As primary recovery of LTO is often low, producing only 5% to 10% of original oil in place, the potential to apply secondary recovery is being investigated and tertiary recovery is gaining interest.

LTO production

Interest in LTO started with the Bakken shale, a large formation underlying North Dakota and extending into Saskatchewan, Manitoba and Montana. Though production from the Bakken formation began on a small scale in the early 1950s; it increased significantly in the early 2000s, after operators began drilling and fracturing horizontal wells. After 2005, production increased more rapidly, reaching a high of 669 thousand barrels per day (kb/d) in November 2012 (NDSG, 2012).

The combination of success in the Bakken shale and the widening of the differential between oil and gas prices prompted interest in developing LTO throughout North America (IEA, 2011). Shale gas producers trying to improve investment returns began targeting plays with a higher liquid content, increasing their production of NGLs, while some progressed further to oil-containing low-permeability formations, like the Bakken. Drilling activity is also shifting from gas to oil in the Eagle Ford play in Texas, in the Niobrara play in Colorado, Utah and Wyoming, in various plays in California (including the Monterey play) and in the Cardium and Exshaw plays in Canada. Other recently identified plays are also likely to be developed.

High oil prices have clearly been a key driver of this growth, given that the break-even oil price for a typical LTO development is around USD 60/b (including royalty payments). The consequent surge in production in the United States has outpaced infrastructure developments, with oil pipelines becoming congested. Estimated production could exceed 3.0 mb/d by 2020 (IEA, 2012), contributing to a significant reduction in US imports. Resources outside North America have not been quantified but, as with shale gas, it is likely that LTO is present in many locations worldwide. Examples include the Paris basin in France, which could hold several billion barrels of recoverable resources, and the Neuquen basin in Argentina, where testing is currently under way.

The Bakken formation provides the most prominent example of the rapid growth in LTO production. In 2008, the US Geological Survey estimated the amount of technically recoverable LTO from the Bakken formation by using technology readily available at the end of 2007 at around 3.5 bb (USGS, 2008a). This is 25 times more than an assessment made in 1995 (USGS, 2008b), while recent unconfirmed industry estimates place the figure as high as 18 bb, and the North Dakota Department of Mineral Resources evaluates it at 10 bb in North Dakota alone. This considerable increase is due largely to technological developments and successes achieved with actual demonstration in the field. By November 2012, LTO production from Bakken had exceeded 660 kb/d. With the recognised potential for LTO to improve energy security and reduce oil imports, many such opportunities in the United States are being pursued. LTO production in the United States increased from 11 000 b/d in 2005 to 840 000 b/d in 2011 (IEA, 2012).

The size of LTO resources and the quantities that can be technically and economically extracted are still poorly known. Unconventional resource estimates are less reliable than those of conventional resources. They have generally been less thoroughly explored and studied, and there is less experience of exploiting them. In many cases, the technical, environmental, political and cost challenges that will have to be overcome for them to be produced commercially should not be underestimated. Appraisal and production is most advanced in North America, which largely explains why that region is currently assessed to hold the largest estimated unconventional resources. Other regions that have received less attention because of their large conventional resources, including the Middle East and Africa, may also hold large volumes of unconventional oil.

Environmental impact

As is the case for shale gas, environmental concerns or regulatory constraints could hinder developments, but the potential economic and energy security benefits could result in significantly higher growth of LTO production.

Rapid expansion of LTO production is projected to continue. However, the implications for water resources, land use and disruption to local communities must be addressed. Estimates of water consumption during hydraulic fracturing vary from 0.2 b to 4 b of water for each barrel of oil recovered (with consumption at Bakken towards the low side of these estimates). Up to 20 000 m^3 water per well may be used for drilling and fracturing. Once the fracturing process is complete, 30% to 70% of the water injected flows out of the well, depending on the characteristics of the reservoirs. The return water must be treated for disposal or reuse. Such a level of water consumption can put a heavy strain on local water sources and, if projections of LTO production are to be met, technology development to reduce consumption will be necessary. The proportion of water reused must be increased. Techniques that require less or no water must be developed.

Other environmental concerns include potential contamination of water courses. Apart from water, which makes up 99.5% of the volume, the fluids used in hydraulic fracturing contain chemical additives to improve the fluid's performance; the additives can include acid, friction reducer, surfactant, gelling agent and scale inhibitor (API, 2010). The composition of the fracturing fluid is tailored to differing geologies and reservoir characteristics in order to address particular challenges, including scale build-up, bacteria growth and proppant transport. The application of modern, best-practice techniques for drilling and hydraulic fracturing should minimise contamination of water courses, and it is essential that these are employed.

An important challenge for the industry is the treatment, recycling, reuse and ultimate disposal of the flowback and produced water, which often contains residual fracturing fluid and may also contain substances found in the reservoir formations, such as trace elements of heavy metals and naturally occurring radioactive elements.

Impacts on land and air must also be minimised. Production wells require roads to connect drilling pads; pipelines or trucks to transport oil or waste water; storage sites; and water treatment facilities. With many hundreds of truck trips per well site, accidents due to the intensive truck traffic must be considered and, indeed, can be a major source of surface spills of chemicals. Pipeline use can minimise surface disturbance and reduce these risks. Infrastructure needs add to the surface impact and must also be evaluated beforehand from a large-scale, regionally cumulative perspective. Local air emissions also arise from on-site power sources.

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Chapter 6 • The unconventional gas revolution

Unconventional gas is generally defined as natural gas that cannot be produced economically by using conventional technology.

The three common types of unconventional gas are tight gas, shale gas and coal-bed methane (CBM), though methane hydrates are often included. Tight gas refers to natural gas trapped in sandstone or limestone formations that exhibit very low permeability and low porosity; such formations may also contain condensate. Shale gas refers to natural gas trapped in organic-rich rocks, dominated by shale. CBM refers to natural gas adsorbed onto the matrix of the coal in coal seams.

Although there are no commercial developments as yet, methane hydrates remain of interest because of their potential as a source of natural gas in the future. Methane hydrates comprise methane molecules trapped in a solid lattice of water molecules under specific conditions of temperature and pressure.

The lifecycle for the extraction of unconventional gas is similar to that for conventional gas (as described in Chapter 2), *i.e.* exploration, appraisal, production and abandonment. Challenges relating to the production of unconventional gas are often related to the difficulty of extraction (*e.g.* tight gas, shale gas) and/or of the source of the gas (*e.g.* CBM, methane hydrates). Though the location of unconventional gas formations is largely well known, there is often a lack of information on the local geology, which is required if the potential of these formations is to be accurately evaluated and the best locations for early development identified. Where source rocks exhibit low permeability, artificial stimulation is required to enhance gas flow rates, which raises the costs of production. Production of unconventional gas is thus quite dependent on the extant (or future) price of natural gas.

The United States has invested heavily in activities aimed at understanding and developing its unconventional gas reserves, and particularly its considerable shale gas reserves, in order to reduce its dependence on conventional natural gas imports. In many parts of the world, growing concerns about energy security are providing incentives to explore potential shale gas resources. This is to a very large extent a result of the success of shale gas developments in the United States.

The potential of unconventional gas resources

Determining the amount of gas in place in unconventional reservoirs is complex because of the heterogeneous structure of the reservoirs. Moreover, assessing productivity is dependent on a detailed investigation of the characteristics of the reservoir, which can vary horizontally and vertically in any given reservoir. Ultimately recoverable unconventional gas resources, excluding methane hydrates, are estimated close to 340 trillion cubic metres (tcm) (Table 6.1). Of this amount, 24% can be found in Organisation for Economic Co-operation and Development (OECD) Americas; 28% in Asia Pacific; 14% in Latin America and 13% in Eastern Europe and Eurasia; with smaller shares in Africa, OECD Europe and the Middle East (IEA, 2012). With remaining recoverable resources of conventional natural gas at 462 tcm and unconventional gas at 328 tcm, together they can sustain more than 230 years of production at current rates. The global distribution of unconventional gas differs markedly from that of conventional gas.

Table 6.1* • *Ultimately recoverable resources of natural gas in 2011

	Total gas, tcm		Unconventional by type, tcm		
Region	Conventional	Unconventional	Tight gas	Shale gas	CBM
Eastern Europe and Eurasia	160	43	10	12	20
Middle East	132	12	8	4	0
Asia Pacific	44	93	20	57	16
OECD Americas	81	82	16	57	10
Latin America (non-OECD)	27	48	15	34	0
Africa	41	38	8	30	0.1
OECD Europe	35	22	4	17	2
World	**519**	**337**	**78**	**210**	**48**

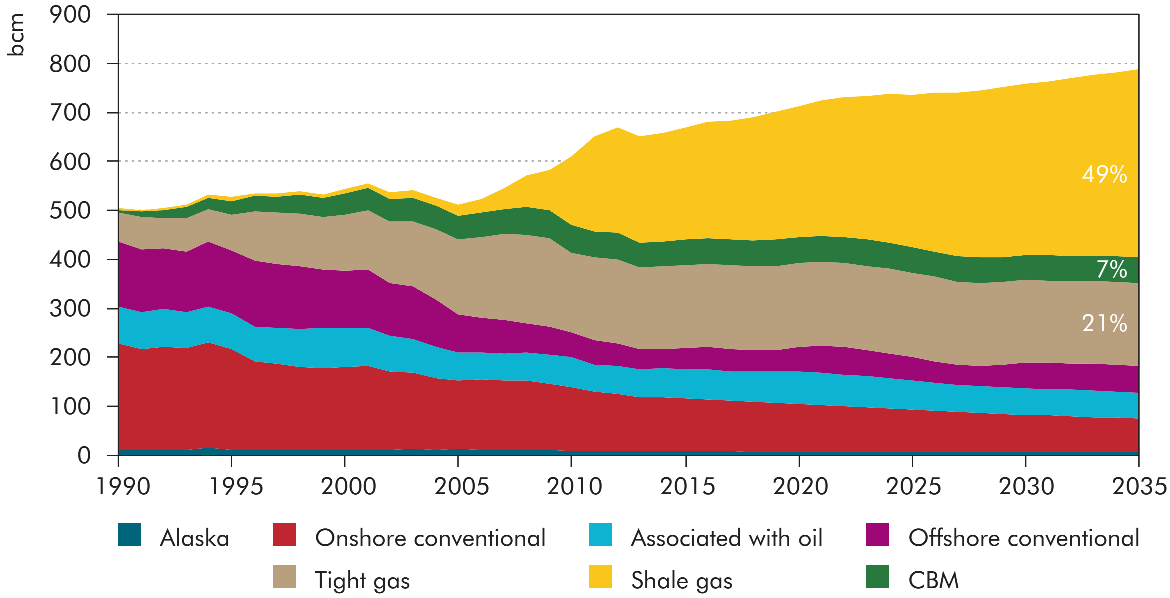
Note: totals may be subject to rounding errors.

Source: IEA, 2012.

Unconventional gas production made up almost 13% of global gas supply in 2009, which could rise to over 20% by 2035. Advances in technology have brought a tripling of unconventional gas production in the United States over the past decade, reaching over 350 billion cubic metres (bcm) in 2010, and providing 58% of the United States' natural gas supply (because of this percentage in the United States, it could be argued that reference to the source as "unconventional gas" is now a misnomer) (Figure 6.1). Canada was the second-largest contributor with almost 60 bcm in 2008. Exploitation of unconventional sources is expected to increase elsewhere as the experience gained in North America is transferred to other regions.

Unconventional gas will significantly expand the global supply of gas. From 34% in 2011, shale gas could account for as much as 49% of natural gas production in the United States by 2035 (US EIA, 2012). Tight gas, shale gas and CBM resources are even more important for the future of domestic natural gas supplies in Canada and China, where they could account for more than 65% (Canada) and more than 80% (China) of total domestic production by 2035 (IEA, 2012).

Figure 6.1* • *Annual actual and projected production of unconventional gas in the United States



Source: EIA, 2012.

For tight gas, shale gas and CBM, economies of scale have enabled their production to be achieved at costs broadly similar to those for production of conventional gas.

Tight gas

Tight gas is natural gas, mainly methane, trapped in geological sandstone or limestone formations. Though there is no formal definition to differentiate between conventional gas and tight gas, if the permeability of the reservoir is below 0.1 millidarcy,[1] the gas is often referred to as tight gas. A working definition of tight gas could be natural gas from a reservoir that cannot be developed profitably with conventional vertical wells, because of low flow rates.

As much as 15% of Canada's current gas production is from readily accessed tight gas resources, which may be referred to by some as conventional gas reservoirs. They include, for example, shallow gas in Alberta and Saskatchewan, some deep-basin plays in the tight sandstones of Alberta and British Columbia, and limestones in north-eastern British Columbia. Estimates for the United States put tight gas reserves at more than 20% of remaining recoverable natural gas.

1. The millidarcy (md) is the customary unit of measurement of permeability, where 1 m = 9.87×10^{-16} m².

Extraction of tight gas

Tight gas has been produced for decades, especially, for example, in the southern part of the North Sea. Success in producing gas from these reservoirs relies on wells that are in contact with a large volume of reservoir, reducing the distance the gas flows through the extremely low-permeability rock. The best way to do this is by hydraulic fracturing, which involves creating cracks in the rock through which the gas can flow to the wells. Significant reservoir contact can be created by combining a dense pattern of deviated or horizontal drilling with placement of multiple fractures along the hole. This approach makes it possible to tap a very thick stack of many thinner reservoirs. Such wells have been instrumental in the surge of tight gas developments in the United States.

The key technologies for tight gas production enable:

- numerous long horizontal wells to be drilled efficiently from a single surface location;
- large surface areas of rock to be opened by hydraulic fracturing along horizontal, lateral sections;
- “sweet spots” to be found in a large reservoir.

The rock is fractured hydraulically by injecting specially engineered, water-based fluids at high rates and pressures. Proppant, often fine sand or ceramic beads, is added to the fracture fluid to stop the fractures from closing when the well is in production. While water and proppant make up 99.5% of the volume of the fracturing fluid, the remainder comprises chemical additives, such as acid, friction reducer, surfactant, gelling agent and scale inhibitor (API, 2010). Technological developments are focused on finding techniques to improve the fracturing process, as well as techniques to clean the well and fracture system of the fracturing fluids, which could otherwise block the inflow of gas into the fracture.

Sweet spots are areas where permeability and porosity are significantly higher than the average values in the reservoir. Higher permeability may often result from open natural fractures, formed in the reservoir by natural stresses, creating a dense pattern of fractures. Such fractures may have reclosed, filled in with other materials or may still be open. A well that can be connected through hydraulic fracturing to open natural fracture systems can have a significant flow potential. Sweet spots are often located empirically in combination with geomechanical assessments by using, for example, advanced seismic techniques. Drilling wells and hydraulic fracturing are costly processes, but improvements in procedures have brought significant cost reductions.

Shale gas

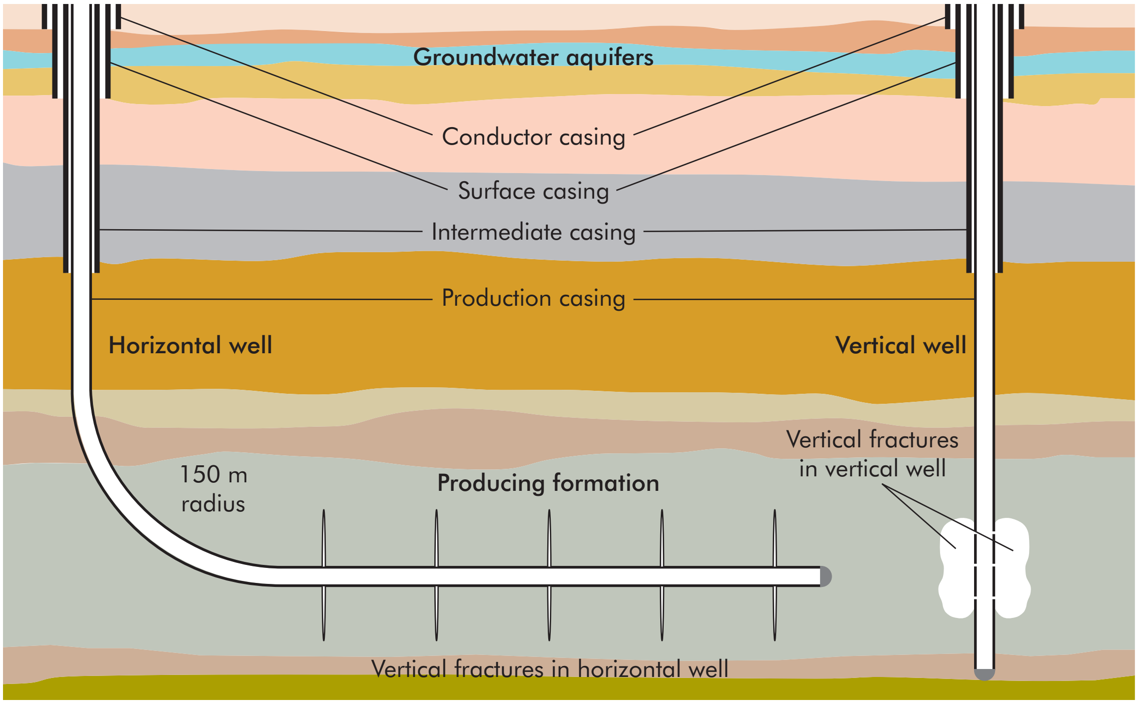
Shale gas is a natural gas contained within predominantly organic-rich, fine-grained rocks and silts dominated by shale. Shale itself is a very fine-grained sedimentary rock that can easily be broken into thin, parallel layers. However, it is the organic material that is important; when buried sufficiently deep underground, and the conditions of pressure and temperature are appropriate, gas is formed. Where the gas has not been able to escape the source rock and remains trapped within its structure, it is referred to as shale gas. Significant volumes of natural gas may be contained in layers of shale rock, often hundreds of metres thick. Shale gas is often considered a sub-category of tight gas.

Extraction of shale gas

In the past, shale gas was usually discovered when drilling for oil and gas at deeper levels. Until recently, however, producing the gas from shale formations was not profitable because of the low permeability of the rock and the low yields. While often found in regions with conventional oil and gas resources, shale gas can also occur in areas with no conventional oil and gas resources. As exploration in those areas has been minimal, resources of shale gas may be significantly higher than previously predicted.

Key technologies for shale gas production are the same as those required for tight gas. Adapting these basic techniques to meet the characteristics of a specific resource area or play is a vital step towards optimising project costs. In most cases, the longer, more complex and more expensive wells, which are fractured at multiple stages along their length, tend to be more cost-effective by reducing the unit production costs (Figure 6.2).

Figure 6.2* • *Horizontal well with multiple hydraulic fractures



Notes: m = metres. Unless otherwise indicated, all material in figures and tables derives from IEA data and analysis.

As for tight gas, connecting a large surface area of rock with the well-bore is achieved by hydraulic fracturing. Tens of thousands of cubic metres of water, mixed with sand and chemicals, are pumped into the wells at high pressure. In shallow reservoirs, highly viscous fluids mixed with nitrogen are often used. In deeper formations, slick water fracturing, involving low-viscosity fracturing fluids containing mainly water with some chemical additives, has replaced more expensive treatments. Both the fluid volumes and the pressures are higher than those used in previous tight gas fracturing processes that used the more viscous fracturing fluids. Technologies, particularly those employed in the fracturing processes, are tested and adapted in each play.

Technology proven to date has been applied only to onshore shale gas fields, since it relies on intense drilling and fracturing of closely spaced surface wells across the reservoir. Except in North America, shale gas exploitation is still largely in the experimental or exploratory phase.

Commercial development of shale gas depends on the availability of sufficient quantities of water for drilling and completing wells, as well as on the cost and environmental impact of treating and disposing of the water that is produced with the gas. Box 6.1 lists some success factors common to the development of shale gas plays.

Box 6.1* • *Success factors in shale gas development

The following factors contribute to the successful development of shale gas plays:

- *early identification of the location and potential of the best producing areas;*
- *efficient leasing of large prospective areas;*
- *experimentation and adaptation of drilling, completion techniques, and development processes similar to those used in industrial manufacturing;*
- *adequate local infrastructure (particularly transportation), since most equipment and supplies (especially the vast quantities of water used and then disposed of) have to be trucked to and from the wells;*
- *awareness and acceptance by local communities;*
- *resolution of environmental issues related to water use and disposal.*

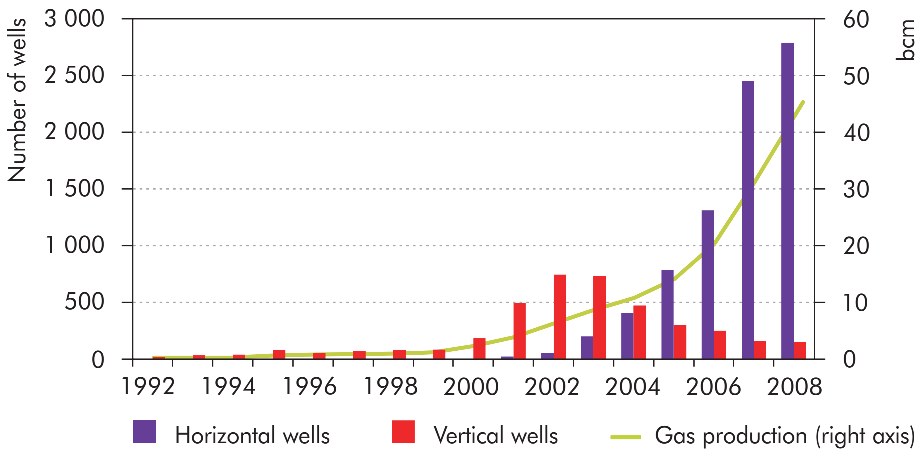
While many of these factors have been successfully addressed in the United States, some require yet further effort.

Barnett Shales gas development

The Barnett Shales in North Texas was the first field to attract significant development after experimentation with newer technologies, and well designs resulted in consistently higher productivity. Drilling increased more than tenfold between 2000 and 2007 as more operators joined the development. Approximately 44 bcm were produced from more than 12 000 wells in 2008 and almost 3 000 more wells were drilled during that year. When activity peaked in 2008, there were more than 180 drilling rigs, which represented nearly 10% of active rigs in the country and 5% of all rigs worldwide.[2]

The number of wells completed in the Barnett Shales grew rapidly between 1992 and 2008 (Figure 6.3); the significance of horizontal wells and their relation to gas production were clearly recognised during the course of the last decade.

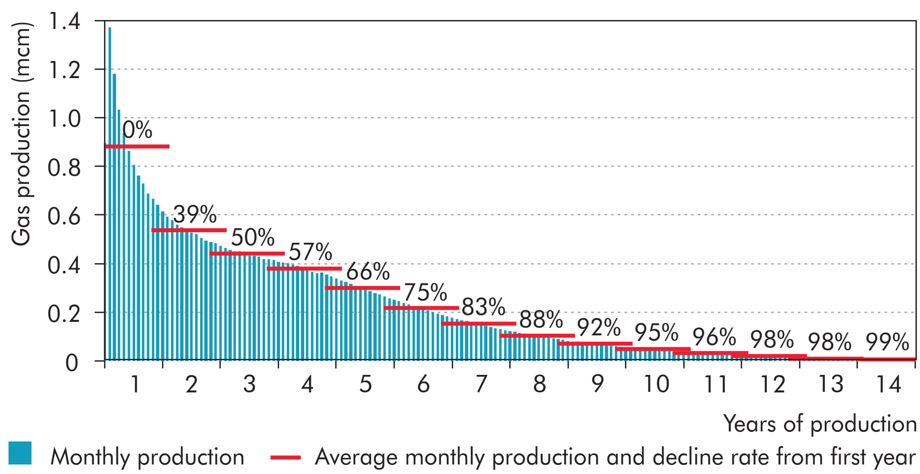
Figure 6.3 • Barnett Shales' gas wells completed and production



Source: IEA, 2009.

Barnett wells (both horizontal and vertical) have tended to exhibit an early production peak followed by a rapid decline. On average, weighted by production, horizontal Barnett wells have declined by 39% from the first to second year of production and by 50% from the first to third year (Figure 6.4).

Figure 6.4 • Production decline rates for Barnett Shales' horizontal gas wells



Note: mcm = million cubic metres.

Source: IEA, 2009.

2. According to the Baker Hughes rig count, a leading measure of drilling activity: www.bakerhughesdirect.com.

Average production and estimated recovery rates per well in Barnett Shales have not improved significantly since the widespread adoption of horizontal wells in 2005. The reason for this is mainly because the play includes many less productive areas and involves a large number of companies attracted by initially high gas demand and prices. The key to improving financial viability lies in reducing production costs by experimenting with different well designs and completion processes in a given area. Particular focus should be given to the length of the horizontal section drilled per well and the number of fracture stages, together with their size, spacing and execution. By quickly identifying the designs and techniques that improve results in a specific area, by applying them in subsequent wells and by continually updating standard practices used in trials, operators have been able to improve their production and recovery rates.

Although the Barnett Shales is the best known and currently the most developed of shale gas plays in the United States, it is neither the most productive nor the most financially viable to develop.

Distinctive features of shale gas plays

The Barnett Shales has been a prime mover, but the focus of shale gas development has shifted to other plays in the United States such as the Haynesville (on the Texas-Louisiana border), Fayetteville (in Arkansas) and Marcellus shale (in the north-eastern United States), and the Horn River Basin shale (in British Columbia, Canada). The physical and geophysical properties vary significantly both among and within shale gas plays. A common characteristic is the relatively low concentration of resources, with gas in place ranging from 0.2 bcm to 3.2 bcm per square kilometre (bcm/km^2). Add this to the low recovery factors (up to 20% estimated to date) and the yield of recoverable resources amounts to between 0.04 bcm and 0.6 bcm/km^2. This compares to recoverable resources from the world's largest conventional gas fields, which produce on average 2 bcm/km^2 and in some cases exceed 5 bcm/km^2.

Not only do shale plays cover much larger areas, but they also require that more wells are drilled more closely together than those of conventional resources. This means that a much larger surface area is affected by drilling and production operations. Some areas have been drilled with wells every 6 hectares (ha) to 8 ha equivalent to some 16 wells/km^2. At present, 20 to 30 wells are often drilled from a single surface location and long-reach horizontal well-bores of up to 2 kilometres (km) to 3 km reduce the impact on the surface. Future technological breakthroughs that further reduce the surface environmental impact would facilitate the development of more plays, especially in the more densely populated or environmentally sensitive areas. This will be a key factor in Western European developments.

The economics of shale gas production

The cost of developing and producing shale gas varies according to the particular reservoir or play. The IEA estimates that the threshold gas development and production costs at the well-head for the main plays being developed in the

United States and Canada ranges between USD 3 and USD 7 per million British thermal units (MBtu).

Current estimates of gas recovery factors vary from less than 8% to 30% of gas in place, which is significantly lower than the 60% to 80% recovery factor for conventional gas reserves. The use of horizontal wells, fractured at multiple intervals, has brought an improvement in recovery factors. Operators are actively engaged in identifying measures that can further improve matters by, for example, experimenting with horizontal wells of different lengths, varying the spacing and number of fractures, as well as altering the spacing between wells. Testing several well designs has enabled companies to improve the ratio of cost to initial production rate, sometimes by up to 40%. Encana Corporation more than doubled well production by increasing the well length and the number of intervals fractured, while reducing the cost per interval (IEA, 2009). Making full use of experience gained is important. It took more than 20 years for the annual production capacity of Barnett Shales to reach 5 bcm, but this was accomplished in just four years at the Fayetteville shale gas play.

The relationship between investment, production and cash flow is quite different for a shale gas play from that for a conventional gas field development. To reach and sustain a production plateau for shale gas usually takes several years and requires continuous drilling. When drilling is discontinued, production falls by half in something like three years. Another feature of shale plays is that most of the capital costs are recovered within the first few years. This means that greenfield developments tend to be less influenced by medium-term instability in terms of both cost and price. As a result, shale gas could play a role as a swing producer, with production moving up and down rapidly in response to market signals.

Over the last decade, shale gas production has expanded throughout the United States (Figure 6.5). It reached nearly 141 bcm or over 23% of total natural gas output in 2010 and technically recoverable reserves increased to about 14 tcm in 2011. Until now, shale gas production has only put downward pressure on domestic gas prices in the United States because of segregated global gas markets. This could change as companies are looking to export some of the gas as liquefied natural gas (LNG). Questions remain as to what extent gas produced domestically will be exported and to what extent this phenomenon will impact on global gas prices, supply and demand.

Outside North America, shale gas production is still negligible. However, the North American experience is stimulating interest elsewhere and shale gas formations are known to be widespread. The first phase of a European assessment, due for completion in 2012-2013, will provide a database of European black shale formations, volumes of gas in place and feasibility of producing it economically (Schultz *et al.*, 2010). Several companies throughout Europe are investigating shale gas prospects, for example in Austria, Poland, Sweden and the United Kingdom. In South America, prospects in Chile and Argentina are being reviewed and provisional assessments have been made in India and China.

Figure 6.5* • *Shale gas plays in the United States

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

Source: IEA, 2009.

CBM

CBM is a generic term for the methane found in most coal seams. As the coal forms, large quantities of methane-rich gas are produced and subsequently adsorbed onto the coal matrix. Because of its many natural cracks and fissures, as well as its porous nature, coal has a large internal surface area and can store much more gas than a conventional natural gas reservoir of similar rock volume.

If a seam is disturbed, either during mining or by drilling into it before mining, methane is released from the surface of the coal. This methane, known as coal-mine methane (CMM), then leaks into any open spaces, such as fractures in the seam (known as cleats). In these cleats, the CMM mixes with nitrogen and carbon dioxide (CO_2). Boreholes or wells can be drilled into the seams to recover the CMM. Large amounts of coal are found at shallow depths, where wells to recover the gas are easy to drill at a relatively low cost. At greater depths, increased pressure may have closed the cleats, or minerals may have filled them over time, lowering permeability and making it more difficult for the gas to move through the coal seam. CMM has been a hazard since mining began. To reduce any danger to coal miners, most effort is addressed at minimising the presence of CMM in the mine, predominantly by venting it to the atmosphere. Only during the past two decades has significant effort been devoted to recovering the methane as an energy resource. Another source of methane from a working mine is the methane mixed with ventilation air, the so-called ventilation air methane (VAM). In the mine, ventilation air is circulated in sufficient quantity to dilute the methane to low concentrations for safety reasons. VAM is often too low in concentration to be of commercial value.

Although, strictly speaking, CMM is the fraction of CBM that is released during the mining operation, in practice, the terms CBM and CMM usually refer to different sources of gas. Whereas CMM is used to refer to gas released from working coal mines, CBM is most often used to refer to the gas held in coal seams that are considered uneconomic to mine. Reasons why a seam may be uneconomic to mine may be related to its depth, its thickness or, perhaps, the poor quality of its coal. The gas from these seams can be extracted by using technologies that are similar to those used to produce conventional gas, *i.e.* using well-bores. Complexity arises from the fact that the formations are generally of low permeability; hence, technologies such as horizontal and multilateral drilling with hydraulic fracturing are sometimes used to create longer, more open channels that enhance well productivity. Water present in the seam, either naturally occurring or introduced during the fracturing operation, is usually removed to reduce the pressure sufficiently to allow the gas to be released, which leads to additional operational requirements, increased investment and environmental concerns.

Production of CBM

CBM is a potential source of energy and is recovered as a natural gas resource. Commercial production from CBM began in the United States in the late 1980s, spurred by tax incentives and accelerated by new technologies and expansions to new basins.

Advances in basin modelling, seismic techniques, horizontal-well drilling and hydraulic fracturing have helped reduce uncertainties related to reserves assessment, and have improved both recovery rates and the potential for commercial exploitation of CBM fields. Production is now advanced in the United States, Canada and Australia, with activities also under way in China (Box 6.2), India, Russia and Indonesia.

Box 6.2* • *China: a major opportunity for CBM

China has extensive coal deposits and is heavily dependent on coal as a primary energy source. Its mining activities release large quantities of methane gas, which contribute significantly to atmospheric GHG emissions. The naturally gaseous nature of coal mines in China mean that much of the mined coal comes from gassy underground workings. It is a major factor leading to the loss of many lives in Chinese coal mines each year, resulting predominantly from gas explosions.

Estimates of methane emissions by venting from Chinese coal mines are in the order of 12 bcm annually, representing around half of all global CMM released. In 2000, 0.92 bcm/yr of methane-equivalent was captured from 185 coal mines, and only 0.4 bcm/yr from 60 coal mines was actually used (mainly for domestic cooking), with the remainder released to the atmosphere (Weitang, 2003). In 2010, about 7.4 bcm CMM was captured by various means, with only around 2.5 bcm utilised as a source of energy (Huang, 2010).

Although drilling for CBM began in the early 1980s, there was little success until 1996 when the North China Bureau of Petroleum developed a field in Shanxi Province. The lack of pipeline infrastructure has limited new CBM projects. Several players are now active, resulting in a cumulative production of 8.6 bcm by 2010. In 2010, output was 3.1 bcm, rising to 5.3 bcm in 2011 and was set to reach 8 bcm in 2012. There is a policy to divert new natural gas pipelines through areas where CBM potential has been identified. Most projects are funded by international organisations, with the Clean Development Mechanism (CDM) under the Kyoto Protocol providing an important incentive for exploring investment opportunities. The West-East gas pipeline between Tarim and Shanghai increased the supply of natural gas to the population and industry around the Shanghai region. The gas in this pipeline is supplemented with CBM. Although there is a long-term plan to pipe natural gas to north-eastern China from eastern Siberia, the immediate need for gas in the area has necessitated the development of local CBM projects. Even if additional natural gas becomes available from Siberia, once established, CBM will still be competitive given projected gas demand. China's 12th Five-Year Plan aims to reach between 20 bcm and 30 bcm annual production by 2015. Implementing best practices and using new technologies in Chinese projects will be essential to achieving this target.

The urgent need to reduce urban air pollution is an important stimulus to natural gas development in China. Urban areas, in particular, require access to gas to displace demand for coal. This will also serve to further encourage CBM development.

Existing CBM schemes primarily serve the domestic sector and suffer from seasonal variability in demand. There would be environmental advantages in increasing the use of CBM in cities for district heating, cogeneration schemes and as a clean fuel for industry. Industrial users could provide a more consistent consumer base than domestic users. Increased local use by industrial plants with a steady gas requirement or conversion to electricity could increase gas use, reduce the volumes of CBM vented and reduce the need to construct costly pipelines.

In the United States, aside from the original San Juan Basin, expansion has included several new basins in Colorado, New Mexico and Wyoming, bringing current US production to around 56 bcm per year (bcm/yr), or 7% of domestic gas production, in 2010 (EIA, 2012). Technically recoverable CBM in the United States is currently estimated at around 5% of the total natural gas resource base.

The major CBM resources in Canada are located in the Mannville, Ardley and Horseshoe Canyon basins. Following the drilling of over 10 500 CBM wells by early 2007, Canada's production exceeded 9 bcm in 2010 (8% of Canada's total gas production).

Commercial production in Queensland, Australia began in 1998 and in 2008 CBM supplied 3.5 bcm, or 14% of the country's total domestic gas production. Since then, through continued growth, unconventional gas, which is mainly CBM, now represents 21% of Australian domestic gas. CBM reserves doubled between 2005 and 2007 and almost doubled again during 2008, reaching 9% of the country's total reserves and over 40% of the onshore gas reserves. International oil companies, including Shell, Petronas and the BG Group, have acquired CBM assets in Australia. The BG Group and Santos are investing in two CBM-to-LNG projects targeting LNG export from 2014 onwards. Both production and reserves of CBM are projected to continue their rapid growth in the short term. This growth can compensate for a decline in conventional onshore production, export of LNG and, if prices are competitive, could meet the increasing demand for gas in eastern Australia.

India is encouraging CBM production with new areas being licensed to operators. Appraisal and testing of appropriate development techniques are under way in 33 blocks already awarded. With commercial production at 0.23 million cubic metres per day (mcm/d) in 2011 to 2012, this is expected to rise to 4 mcm/d by 2016.

The Indonesian government also hopes to develop the country's CBM resources and is offering more favourable terms for production-sharing agreements than for conventional natural gas projects.

CBM production has been slower to develop in China, even though it has the world's third-largest reserves with a resource base of around 37 tcm at depths under 2 000 m (Zhou, Zhang and Gong, 2011). This is despite the large amounts of methane released through venting from coal mines, estimated at over 12 bcm/yr, and the associated safety and environmental risks. Increased CBM production was a priority in China's 11th Five-Year National Plan (2006-10), which started from virtually zero in 2006. By 2010, however, actual production in China stood at 8.6 bcm CBM (Natural Gas Asia, 2011). According to its 12th Five-Year National Plan, China aims to more than double this (to between 20 bcm and 30 bcm) by 2015.

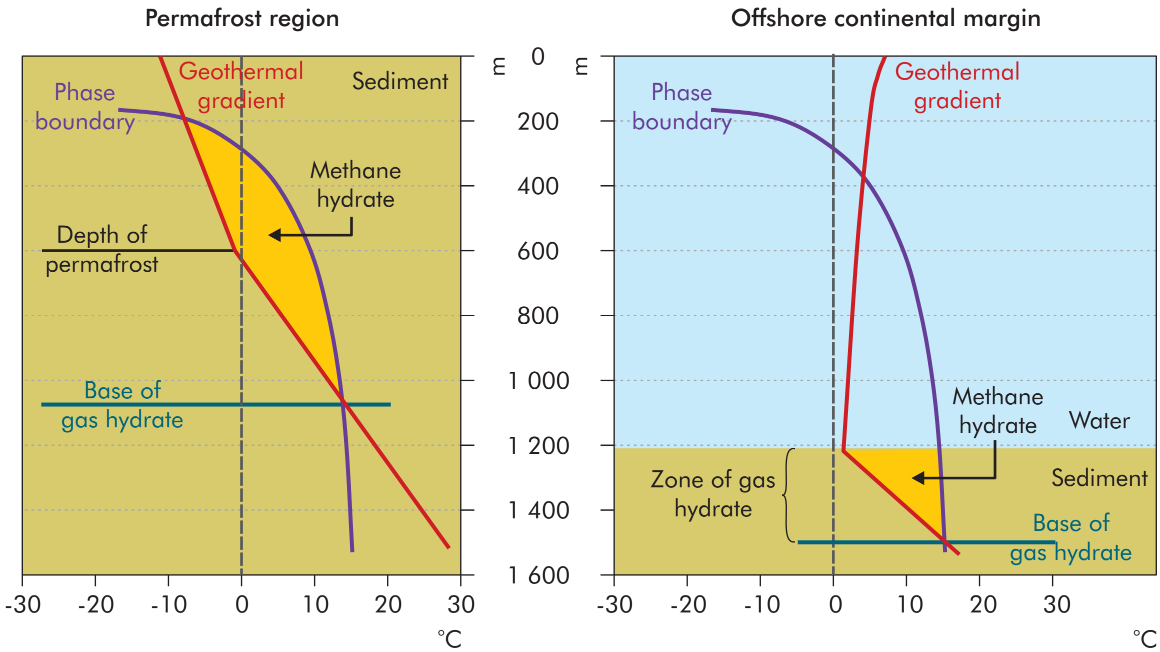
Total CBM production in Australia, China, India and Indonesia is expected to increase from 14.9 mcm (2009) to 64.9 mcm in 2015.

With an estimated 80 tcm of resources in place, Russia has 17 tcm of recoverable CBM reserves, including more than 10 tcm in the Kuzbass basin located at a depth of less than 1 200 m. Promgaz (a Gazprom subsidiary) has started a few pilot projects but there is little incentive to develop this resource given Russia's vast natural gas reserves; production therefore remains insignificant by comparison. Other countries developing an interest in CBM include Ukraine and Romania.

The potential for methane hydrates

Methane (or gas) hydrates are thought to be the most abundant sources of hydrocarbon gas on earth. They are solids composed of natural gas molecules surrounded by a cage of water molecules, *i.e.* methane molecules held within a clathrate or lattice structure. Methane hydrates require very specific conditions of pressure and temperature to form and be stable (Figure 6.6); if removed from those conditions, it will quickly dissociate into water and methane gas. One cubic metre of hydrates contains about 164 cubic metres of methane gas at standard conditions, with an energy content that is comparable to that of bitumen and oil-sands. It exists both as a void-filling material within shallow sediments (onshore in the Arctic and within deepwater continental shelves) and as massive deep-sea floor mounds (Figure 6.7). Methane hydrates can be found in permafrost Arctic regions at 200 m to 1 000 m depth or on the seabed between 500 m and 1 500 m water depth.

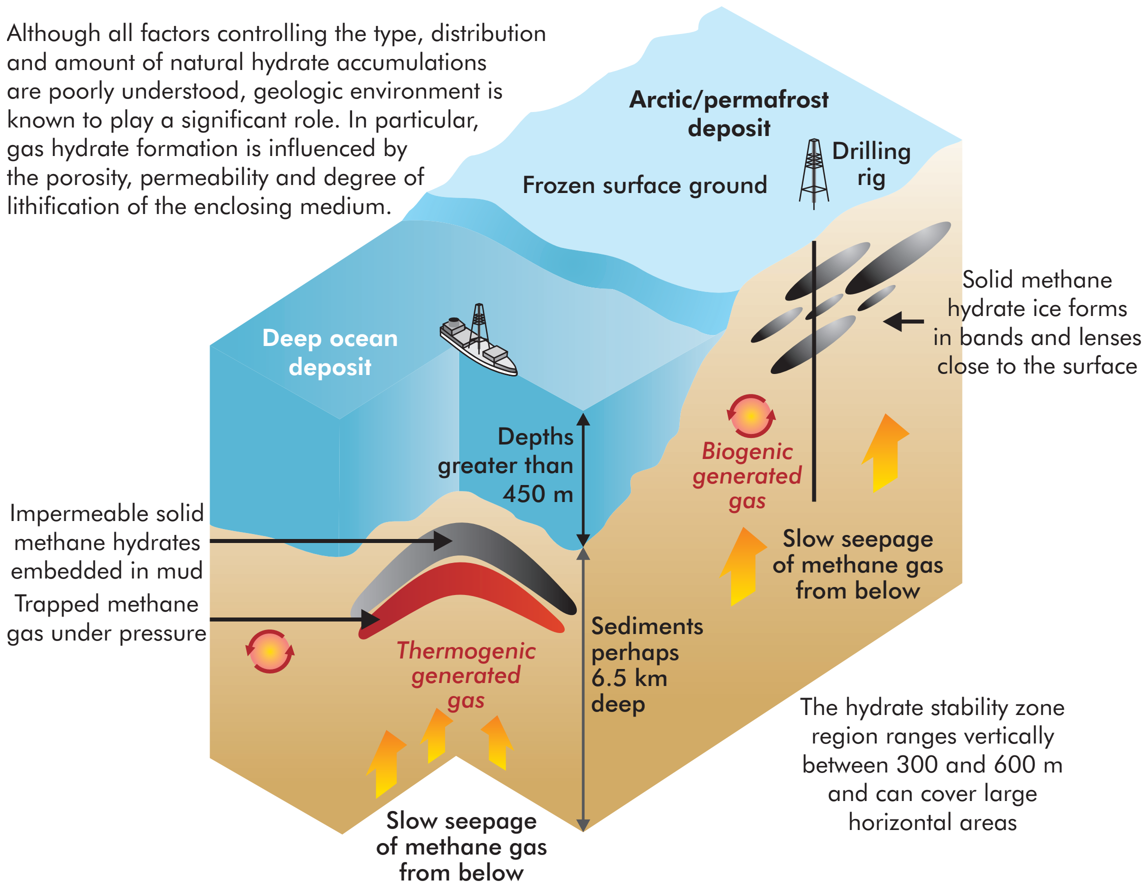
Figure 6.6 **•** *Existence of methane hydrate as a function of geothermal gradient and phase boundary*



Sources: Osadetz *et al.*, 2006. Courtesy of S. Dallimore, National Resources Canada.

The amount of natural gas in hydrate accumulations may be in the range of 1 000 tcm to 5 000 tcm (IEA, 2009), but there is great uncertainty and some estimates are much higher. Some experts estimate the volume of gas trapped as hydrate to be much greater than that of any other gas resource. While volumes of hydrate contained in marine environments are orders of magnitude larger than in Arctic permafrost regions, most concentrated deposits found to date have been in the Arctic. The potentially massive amount of natural gas trapped in the deposits has stimulated international interest. Much research focuses on finding out more about this resource in terms of both its real potential as an addition to future natural gas supply and the potential environmental and climate risks.

Figure 6.7* • *Methane hydrates in Arctic and marine environments



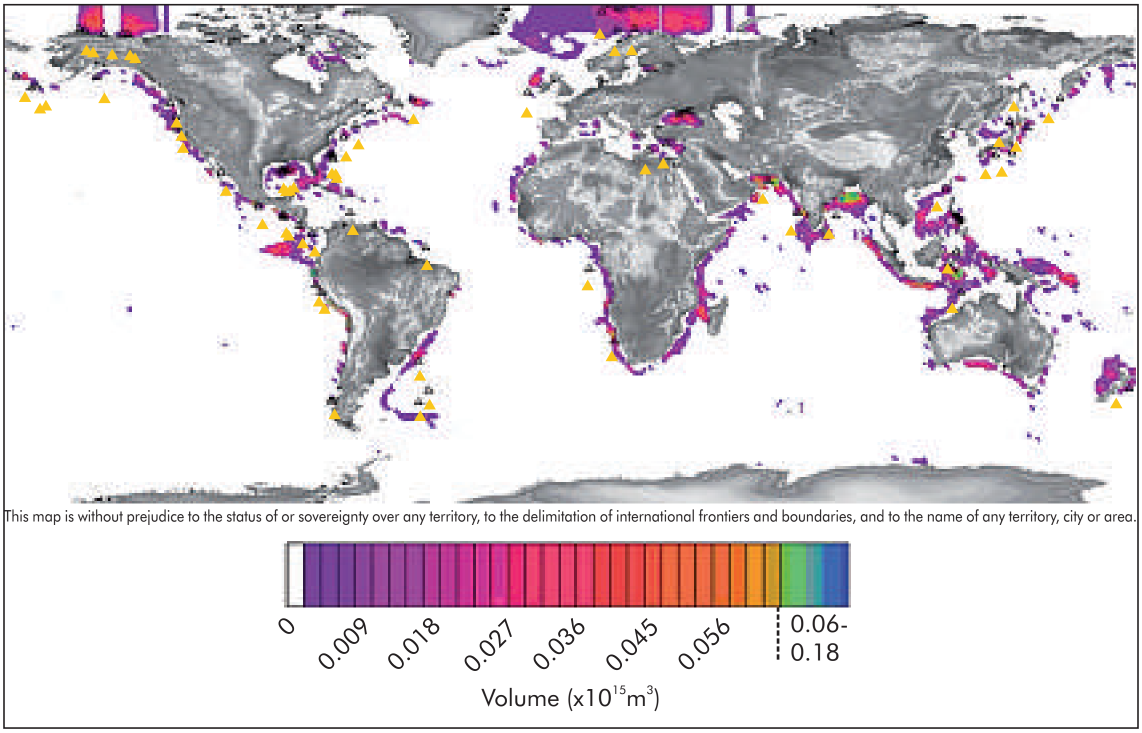
Source: USDOE/NETL, 2008.

Using an equilibrium thermodynamic model (Klauda and Sandler, 2005) to predict the maximum depth in the seabed at which hydrate is stable, a global volume distribution of methane hydrates at seabed depths of less than 3 000 m was constructed (Figure 6.8). Out of 71 direct and indirect observations of marine gas hydrates, the model correctly predicted the presence of hydrates in 68 of them.

It has been estimated that ocean hydrates may contain up to 120 000 tcm of methane gas in place, more than two orders of magnitude greater than worldwide conventional natural gas reserves. Considering only seabed depths of less than 3 000 m (as an approximation for the continental margins), a total of 44 000 tcm of methane was estimated. The greatest amounts of methane in hydrate form are predicted to be in the Arabian Sea, the western coast of Africa and near Peru, Chile and Bangladesh (Klauda and Sandler, 2005).

Previously reported estimates, of the order of 1 000 tcm of methane, relate to the continental margins only and ignore the existence of hydrates at greater depths and in inland seas. However, total volumes of methane hydrates remain a subject of debate. Other estimates give a volume of gas trapped in the range of 2 500 tcm to 20 000 tcm (Klauda and Sandler, 2005; NPC, 2007).

Figure 6.8 *• Global volume distribution of methane hydrates*



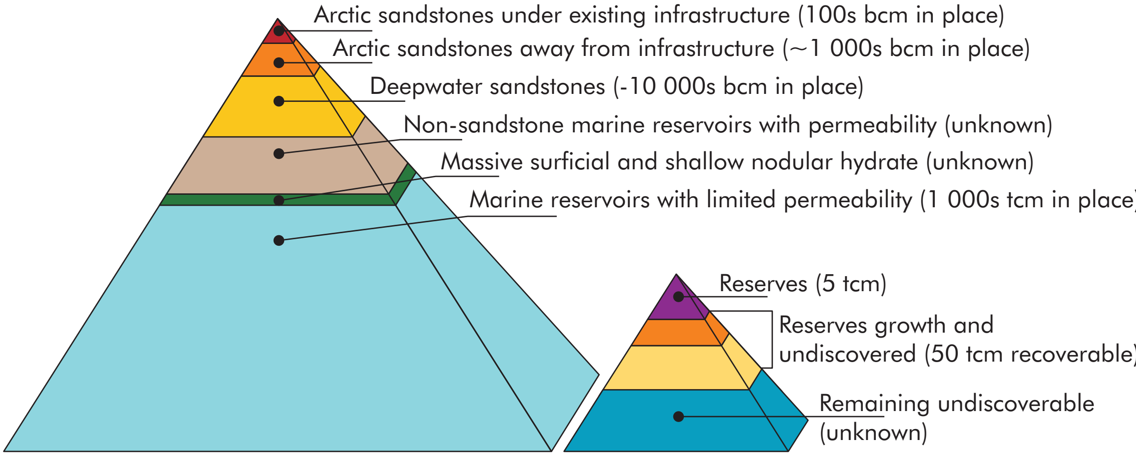
Note: triangles denote observed hydrates at seabed depths of less than 3 000 m.

Source: Klauda and Sandler, 2005.

The possible magnitudes of the resource and types of deposit are illustrated in Figure 6.9 (Boswell and Collett, 2006), where volumes of hydrates are compared with the natural gas resource. The peak of the pyramid includes hydrates known to exist with high pore space saturations within reservoirs under existing Arctic infrastructure, such as the Eileen trend of Alaska's North Slope (ANS) or the Mallik gas hydrate field in the Mackenzie Delta. Next come less well-defined accumulations that exist in similar geological settings (discretely trapped, high-saturation occurrences within high-quality sandstone reservoirs) on the North Slope, but away from existing infrastructure. A recent US Geological Survey assessment estimated that there are 2.4 tcm of technically recoverable natural gas from hydrate deposits on the Alaskan North Slope (Collett *et al.*, 2008).

Below the Artic resources are methane hydrates of a moderate-to-high concentration within quality sandstone reservoirs in the marine environment. As the cost of extracting these resources from very deep water would be high, the most favourable accumulations are found in the Gulf of Mexico in the vicinity of oil and gas production infrastructure. The scale of this resource is not well known, but is the subject of an ongoing assessment by the US Minerals Management Service.

Figure 6.9 *• Methane hydrate resource pyramid*



Source: adapted from Boswell and Collett, 2006.

At the base of the resource pyramid are finely disseminated accumulations, typified by the Blake Ridge accumulation offshore the Carolinas, in which large volumes of methane hydrates are relatively evenly distributed through vast volumes of fine-grained and relatively undeformed sediment at low saturation (about 10% or less). The prospects for economic recovery of natural gas from this highly disseminated resource are very poor with current technologies.

Seabed stability in areas prone to natural deposits of methane hydrates is an issue when it comes to the safe exploration and production of deepwater hydrocarbons. Methane hydrate reservoirs can cause problems if wells have to be drilled through them to reach deeper deposits of conventional oil and gas.

Environmental impact

Environmental concerns have an important role in steering technological advances for unconventional gas (NPC, 2003; IEA, 2012). Though they cannot reduce them to zero, the application of best-practice or state-of-the-art techniques to production of unconventional gas can address effectively many widely held environmental concerns.

If wells are of sound construction and are located effectively, then fewer of them are required and, consequently, the environmental impact is reduced. Moreover, smaller, modular rigs will reduce the footprint while reducing down-time for rig moves.

Water is often co-produced with the gas and needs to be treated and disposed of effectively. Improving the efficiency and cost-effectiveness of water treatment technologies is an important challenge for ensuring that the exploitation of unconventional gas resources is environmentally acceptable.

Fluid discharge requirements in sensitive areas stimulate the development and use of environmentally compatible drilling and completion fluids.

A key concern that has received significant attention by operators is the danger of contaminating groundwater resources. Fluids used in well fracturing may have leaked into shallower potable aquifers. Best-practice selection and execution of drilling technologies can mitigate such concerns.

With significant opposition to the development of unconventional gas projects in many countries, constructive engagement with all stakeholders during all phases of a development is crucial. Operators must be able to explain openly and honestly their production practices, the environmental, safety and health risks and how they are addressed. The public needs to gain a clear understanding of the challenges, risks and benefits associated with the development.

Tight gas and shale gas

Given the important role that unconventional gas is projected to play in the future provision of energy, and particularly following the impact that shale gas has had in the United States, many countries are now beginning to look closely at their own gas prospects. However, while the impact of shale gas production in the United States has had many positive results, increasing its energy security for example, concerns have been raised about the environmental issues that have arisen from its exploration and production.

Addressing environmental concerns relating to the provision of unconventional gas in a thorough and responsible manner will play a major part in determining the extent to which projections on future production will be met. In the United States, some of the greatest concerns have touched on land use before, during and after the shale gas production phase; on the high volumes of water used; and on pollution of water and air. It will be crucial that the management of environmental impacts is factored in when planning and evaluating programmes for exploration and production.

In the case of both tight gas and shale gas, concerns over landscape relate to the very dense patterns of surface wells drilled; it is likely that such concerns will limit applications in densely populated areas, such as the Netherlands. Disposal of the fracturing fluids is also a concern as there is a risk that hydraulic fracturing could open up routes to connect with potable aquifers. Indeed, just such concerns have led France and Bulgaria to ban hydraulic fracturing techniques on their territories. Poland, in its early exploratory stage for shale gas, ranks attention to environmental risk assessment, monitoring, management and mitigation as high priority tasks.

In 2012, the International Energy Agency released its *Golden Rules for a Golden Age of Gas* (IEA, 2012). The “Golden Rules” address legitimate concerns on the environmental and social hazards relating to exploration and extraction of unconventional gas. They provide guiding principles for policy-makers, regulators, operators and other stakeholders to manage their concerns in an effective and responsible manner. In the United States, the Shale Gas Subcommittee of the

US Secretary of Energy Advisory Board has published two reports and offered a series of recommendations for immediate steps to reduce the environmental impacts of shale gas production.

Coal-bed methane

Accessing and producing both CMM and CBM has environmental implications. Removing CMM from the coal seam, for example, reduces the risk of gas release in the mine. In turn, this can reduce the potential for methane explosions, which are a constant threat in many coal mining operations. Furthermore, instead of venting the methane to the atmosphere, which is the normal procedure to reduce the risk of explosion, CMM may be utilised, *e.g.* for power generation. In this case, CO_2 would subsequently be emitted, which has a lower global warming potential than methane. If the CMM displaced coal or oil as fuel to generate power, it would lead to lower specific emissions of CO_2: CMM has a higher heat content per unit mass than both oil and coal, and gas-fired power generation is more efficient.

There are notable differences between production of CBM and production from oil or gas reservoirs. In the latter, as gas is normally found above oil, which in turn is found above water, the hydrocarbons can be extracted without producing much water. In coal seams, however, water penetrates the permeable matrix and traps the methane. To produce CBM from coal seams, a series of wells are drilled to pump groundwater to the surface, in order to reduce pressure and permit CBM to flow towards the production well. This water, which is commonly saline but in some areas can be potable, must be either put to beneficial use or disposed of in an environmentally acceptable manner (USDOE, 2003; ALL Consulting, 2003; WGA, 2006). In the early stages of development of a CBM project, the volume of produced water is high, but reduces substantially as gas production increases later in the life of the well.

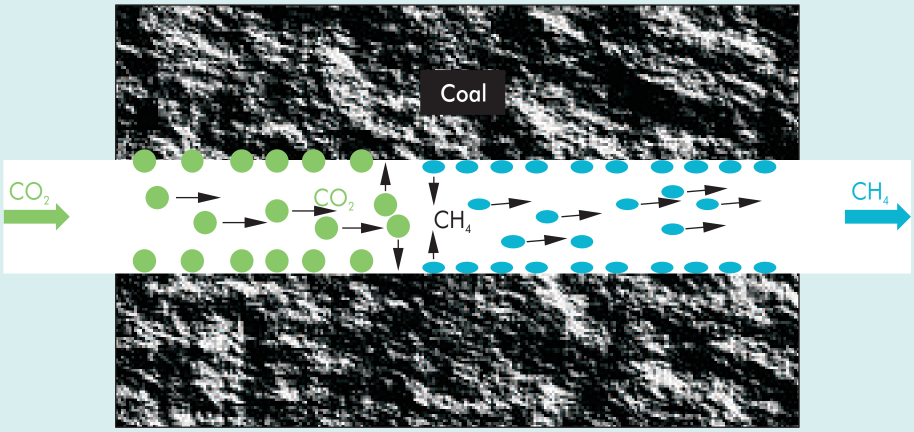
There are various options for the beneficial use of CBM-produced water, depending on its quality and on the effectiveness of the treatment options that can be applied to improve its quality. Even with treatment, however, it is unlikely that all of the water produced could be used, and disposal of some of it would still be necessary. Disposal methods for CBM-produced water, other than deep-well injection, include discharging it directly onto the land surface or in reservoirs for evaporation.

Injecting CO_2 to displace CBM may offer advantages for the environment (Box 6.3).

Box 6.3* • *CO_2-enhanced CBM production

Coal contains significant volumes of adsorbed methane. When CO_2 is injected into the coal seam, the methane molecules released are replaced by CO_2 molecules (Figure 6.10). The process by which CO_2 is injected into a coal seam and is preferentially adsorbed onto the coal, displacing methane, is termed CO_2-enhanced coal-bed methane recovery. As a rule of thumb, two molecules of injected CO_2 are trapped in the coal seam for every molecule of methane released.

Figure 6.10 • *Schematic of methane displacement by CO_2*



Note: CH_4 = methane.

In contrast to normal CBM operations, replacing methane with CO_2 molecules can be achieved without reducing the pressure. The main advantages of this technique over reduced-pressure desorption are:

- *much less water is drawn into the well;*
- *production operations are simpler;*
- *CO_2 is stored with reduced environmental concerns about leakage.*

The CO_2 adsorbed onto coal occupies a larger volume than does the methane it displaces, which could hamper the flow of CO_2 as injection progresses. This could present a problem, particularly if, for example, the coal exhibits low permeability.

The characteristics of a coal seam allow it to serve as a source of CBM and as a CO_2 storage reservoir, while providing the seal to prevent the CO_2 from escaping. As such, geological storage of CO_2 in deep, un-minable coal seams holds promise for the long term, secure storage of CO_2, while also providing incremental methane recovery.

Various projects have been undertaken in Canada, China, Japan, Poland and the United States. Such projects have provided opportunities to test and develop the technology, to assess the viability of particular coal seams to produce commercial rates of gas and, in some cases, to test the viability of the process as a means to permanently store CO_2.

Methane hydrates: impact on the environment and climate change

Although Arctic hydrates contain less gas than marine hydrate accumulations, they are more accessible and can have higher concentrations, prompting concern with regard to global climate change. With a global warming potential of 25, methane will trap 25 times more heat over a 100-year period than would be trapped by a similar mass of CO_2.

At present, if the increase in atmospheric methane continues, methane would be the dominant greenhouse gas by the second half of this century. The degassing of natural gas hydrates may contribute to the increase in emissions. The release of large amounts of methane into the atmosphere from natural hydrate dissociation has been linked to the extreme climate changes of the late Paleocene thermal maximum period over 55.8 million years ago (Dickens *et al.*, 1995). Natural hydrate dissociation could also be related to the end of glacial periods. These arguments are persuasive but have only circumstantial evidence to support them. It is not yet known how such quantities of methane were released nor whether the methane came mainly from the Arctic land and shallow sea hydrate, which is most susceptible to atmospheric temperature change, or from the larger deep-sea hydrate at lower latitudes, which is probably less susceptible to atmospheric temperature change (Hyndman and Dallimore, 2001). The possibility of such phenomena occurring provides some justification for research into the effects of gas hydrate on global climate change and vice versa.

The potential existence of huge volumes of methane in hydrate form close to the sea floor not only raises important questions about the influence of hydrates on global climate change but also on the stability of the sea floor, under deep shelves and upon slopes. More needs to be known about the properties of hydrates before they can be reliably factored into the modelling of carbon balance in the equilibrium between oceans and atmosphere.

To address these questions, the United States Department of Energy's (US DOE's) Inter-agency programme (Box 6.4) suggests that data should be collected in both the marine and Arctic environments, and aimed towards:

- developing predictive models of methane generation, oxidation and migration, as well as natural hydrate formation and dissociation;
- measuring and interpreting the timing, magnitude, distribution and ultimate fate of past methane releases;
- determining background fluxes of gases between sediments on the sea floor, hydrate, the water column and the atmosphere;
- numerical modelling of the impact among hydrate-related phenomena, global carbon cycling and climate change;
- an improved understanding of the exploration and production-related impact to ecosystems associated with gas hydrate and identification of methods that minimise the impact;
- studying the role of hydrates in the development and stability of continental shelves and slopes.

Technology development

Technologies to improve exploration and production of tight gas, shale gas and CBM are discussed together, while those for methane hydrates are addressed separately. Compared with other unconventional gases, commercial extraction of methane hydrates is considered unlikely for some years, and development is at a relatively early stage.

Tight gas, shale gas and CBM

Exploration

The goal for exploring unconventional gas resources is to find out where the most promising reservoir rock areas are likely to be located. Much of the characterisation and modelling techniques for conventional gas reservoirs can be used, adapted and extended to unconventional resources. The large amount of existing data (*e.g.* existing seismic data, rock cuttings, core samples, mud and geophysical logs) provide a basis for re-evaluating opportunities in unconventional gas zones. But it is necessary to obtain a better understanding of the mechanical and chemical properties of the reservoir rock, and refine reservoir modelling for the tighter rock structures associated with unconventional gas. Development of seismic techniques and the analysis of well cores and cuttings contribute to improved detection and visualisation of fractures. Increased use of techniques such as microseismic monitoring of fracturing operations (breaking rock to create small seismic signals) help to understand the geometry and effectiveness of the fracture systems created. This information allows better reservoir models to be constructed, which can be used to define development strategies.

Drilling and stimulation

Directional drilling with real-time imaging plays an increasingly important role in confirming the model validity and locating the natural fractures that promise good well productivity, while reducing the environmental footprint of drilling. Real-time sensors installed near the drill bit can send information to the geologists who can integrate these data with mud-logging (examining the rock samples that are brought to the surface by the drilling fluid) and seismic information of the area being drilled. Based on such information, a decision to alter the drilling direction may be taken to maximise the quality and quantity of gas produced from the reservoir. Higher well productivity will also reduce the number of wells needed to develop a reservoir.

Stimulation methods are used to exploit and expand natural fractures. Substantial efforts are in progress to adapt and refine stimulation technology for unconventional gas. Creating high-performance proppant has proven to be a key development for shale gas.

Gas compression

Unconventional gas reservoirs, because the economics of drilling often favours relatively shallow reservoirs, generally have lower well-head pressures than conventional reservoirs, necessitating above-ground compression and down-hole lifting devices for gas recovery. These are important components for reducing the cost of producing unconventional gas.

Research goals for the future include investigating the possibility of compression at the bottom of the well, as well as devices to separate out production fluids (such as water) within the well (downhole) and reinject these fluids immediately in lower, appropriate disposal zones.

Methane hydrates: the need for technological innovation

The development of methane hydrates still remains in the research phase with the focus on characterising hydrates to learn more about their natural properties, to measure and monitor their production behaviour and to assess techniques for their production. Dedicated wells for such studies have been drilled in ANS, the Andaman Sea, offshore Japan and in the Gulf of Mexico (USGS, 2010). In 2008, Canadian and Japanese researchers produced a constant stream of natural gas from a pilot project at the Mallik gas hydrate field by lowering the hydrate pressure (Yamamoto and Dallimore, 2008; Thomas, 2008).

Technological innovation will be required for hydrates to be commercially exploited with minimum environmental impact. A good understanding of the process of hydrate deposition, technologies to identify accumulations and an analysis of the interaction between their production and the rock structure are all necessary. The local distribution of hydrates is more difficult to predict than the distribution of gas in conventional gas reservoirs, where migrating gas is collected in permeable formations. It is a challenge to develop remote-sensing tools that can map well the concentrations within a hydrate accumulation and thus locate the sweet spots most suitable for early development.

Furthermore, gas hydrates are mostly not overlain by impermeable layers as are conventional gas or oil reservoirs. After dissociation into gas and water, the gas is often able to escape into the atmosphere. A key challenge is to capture the gas rather than allow it to escape. Drilling and well design for hydrate production will need to take into account these particular characteristics of hydrate development.

To date, there has been no commercial production of methane hydrates directly. Some gas reservoirs in the Arctic produce conventional gas from rocks directly underlying hydrate deposits. In some cases, it is possible that the overlying hydrates dissociate and recharge the conventional reservoirs, as gas production leads to a pressure drop in the reservoir. This is believed to be the case in both the Barrow Gas Fields in Alaska and the Messoyakha Field in Siberia (Grover, 2008).

Conventional methods to release methane from the hydrate structure include pressure reduction and thermal stimulation. While these methods are well demonstrated in the laboratory, application would need to consider the larger scale and the standard reservoir engineering aspects of well designs, development strategies, recovery factors, energy balance, and safety and environmental aspects.

More innovative methods are under investigation. Chemicals may be added to destabilise the hydrate. CO_2 may be injected to displace the methane molecules in the structure, liberating the methane while keeping the hydrate intact. This latter concept has certain similarities with the injection of CO_2 to release CBM.

Research to date indicates that methane hydrates could eventually be produced commercially. The magnitude of the potential resource has stimulated co-operation in global research; Canada, India, Japan and the United States have joint research programmes addressing methane hydrates as both a bio-hazard and a potential energy source. Pilot projects in the Arctic and in deepwater offshore areas will provide a better understanding of what is involved in developing commercial projects. In 2006, the US Inter-agency programme (described in Box 6.4) suggested a roadmap for methane hydrate research and development.

Box 6.4 • Inter-agency activity on gas hydrate research and development in the United States

In 2006, the USDOE published An Inter-agency Roadmap for Methane Hydrate Research and Development *(USDOE, 2006; NRC, 2004). This roadmap was the result of joint efforts involving: the Department of the Interior; the US Geological Survey; the US Mineral Management Service; the Bureau of Land Management; the Department of Defense Naval Research Laboratory; the Department of Commerce; the National Oceanic and Atmospheric Administration; and the National Science Foundation. This roadmap is essentially an action plan to determine the potential of methane hydrates as a source of energy supply. It sets out to clarify important questions in hydrate research, such as seabed stability, drilling safety and the environmental issues associated with naturally occurring methane hydrates.*

According to the roadmap, significant challenges for research are to:

- *assess the scale of the potentially recoverable share of the resource in place, particularly in the marine environment;*
- *identify a proven means of remotely detecting and appraising marine accumulations;*
- *conduct a long-term test of a proposed hydrate production technology;*
- *understand the role that methane hydrates play in the global carbon cycle, in the evolution of the sea floor or in global climate more generally.*

The inter-agency publication outlines a programme designed to develop a comprehensive knowledge base and suite of tools/technologies that will, by 2015:

- *demonstrate viable technologies to assess and mitigate the environmental impact related to hydrate destabilisation that results from ongoing conventional oil and gas exploration and production activities;*
- *document the risks and demonstrate viable mitigation strategies related to safe drilling in hydrate-bearing areas;*
- *demonstrate the technical and financial viability of methane recovery from Arctic hydrate formations.*

By 2025, the objectives of the programme are to:

- *demonstrate the technical and financial viability of methane recovery from domestic marine hydrate;*
- *document the potential for, and impact of, natural hydrate degassing (dissociation into gas and water by natural changes in pressure/temperature) on the environment;*
- *assess the potential to further extend marine hydrate recoverability beyond the initial producible areas.*

The United States National Academy of Sciences administers an academic research programme to support efforts to meet the challenges set out in the roadmap.

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Chapter 7 • Coal in the 21st century

Coal has long been an essential source of energy worldwide. Though its use declined in the developed world over the previous century, in large part because of the emergence of oil, coal still provided 27% of total primary energy supply in 2010, behind the contribution from oil (32%), but ahead of gas (22%).

Coals are solid, combustible, fossil sediments. They originate predominantly from dead organic plant material that was deposited in a layer of water, protected from biodegradation and oxidation and covered by other sediments. While buried deeper and deeper, organic material is converted to coal by an enrichment of carbon (Pohl, 1992). Though the many shallow seas of the Carboniferous period provided excellent conditions to form thick and extended coal layers, coal was formed over nearly all time periods. Essentially, coals are fossil residues of dead biomass.

Types of coal

The various types of coal are usually classified by their rank, volatile matter, energy content, and the composition of their solids and moisture content. Coal rank varies according to the degree of transformation from the original plant source and may loosely be considered a measure of a coal's age.

In increasing order of transformation, from low to high rank, there is lignite (or brown coal), sub-bituminous coal, bituminous coal and anthracite. Coal starts off as peat, often considered to be a precursor of coal. After being subjected for an extensive period of time to temperature and pressure, it is transformed from peat to lignite. As time passes, lignite increases in maturity, becomes darker and harder, and is classified as sub-bituminous coal. As this process of transformation continues, more chemical and physical changes occur until the coal is classified as bituminous coal. Anthracite, a very hard and glossy black coal, is the final stage in this transformation.

The properties of a coal vary with its rank. As its rank increases, so do its reflectivity, hardness, carbon content and heating value. On the other hand, its oxygen content, moisture content and volatile matter content fall with increasing rank. Its sulphur, nitrogen and ash content are independent of rank.

Coal rank and content

Among geoscientists, the classification of coals in terms of vitrinite reflectance[1] is standard practice. Vitrinites, along with exinites and inertinites, are the three main organic components of coals, which, taken together, are referred to as macerals. Macerals are the organic counterpart to minerals and vary in their

1. The reflectance of individual grains of vitrinite, as measured under a microscope, remains the most definitive measure of coal rank.

optical properties (under the microscope), in hardness and in shape. The vitrinite group is glossy, and is the purest and most consistent component of coal, which is why vitrinite reflectance – or, more precisely, random vitrinite reflectance – is used as a measure of coal rank.

Carbon content

The carbon content, on a water- and ash-free basis, is between 60% and 70% in soft brown coals. That of anthracite can be as high as 97%. If the carbon content is higher, it becomes non-combustible graphite, which may be used as crucible material or lubricant.

Calorific value (or heat content)

The calorific value of coals is a measure of the amount of heat released when a unit mass of the solid fuel is burnt completely. Depending on the country-specific classification, this measurement is made by using coal that is ash-free, or water- and ash-free. Volatile matter is the gaseous decomposition product of the water- and ash-free substance escaping when heated. It typically includes methane, ethane and carbon dioxide (CO_2), and, more rarely, hydrogen (H_2) and helium.

Moisture content

The moisture content of coals plays a role mainly in the classification of lignites. In coals, a distinction is made between surface water, water held by capillary action, water held within decomposed organic compounds, and water bound within the crystal structure of clays and other minerals.

Ash content

The ash content is a measure of the mineral content of the coal. The composition mainly depends on the associated rock,[2] which mostly consists of sandstones, claystones or carbonates. The ash may also stem from mineral substances (clays and sands) synergetically washed into the peat bogs or from a very low biogenic mineral share in some plants (Pohl, 1992; Ruhrkohlen-Handbuch, 1984; and Taylor *et al*., 1998).

In addition to the parameters discussed above, there is a further subdivision of coals that relates to their coking properties. Investigations into the coking properties are undertaken to provide information about the potential of coals to produce coke.

Coal classifications

Lignites are generally distinguished by their moisture content and associated firmness, as well as by their colour. By contrast, hard coals are classified mainly by the amount of volatile matter, vitrinite reflectance and energy content, and by their coking properties (Pohl, 1992).

2. Associated rock is the non-combustible main component of the fuel that is referred to in its totality as ash. It occurs both above, below and within the coal seams.

An overview of common terminologies used for coal classifications and coal rank is presented in Table 7.1. Often the English designations are used at the international level, yet small differences in terminology and classification can be found. For example in Germany, brown coals, which are almost entirely soft brown coals, may be referred to as "lignite" and domestic hard coals and anthracites as "hard coal". However, there are no precise international limit values to define the demarcation of these two coal groups. This is why, in surveys of coal deposits, problems are often encountered on the classification of hard coals and soft brown coals.

Table 7.1* • *Comparison of standard subdivisions and classifications of coal by coal rank

<table>
<tr><th>Subdivisions and classifications</th><th colspan="11">Increasing coal rank →</th></tr>
<tr><td>International conventional classification</td><td>lignite</td><td colspan="10">hard coal</td></tr>
<tr><td>Germany and countries to the east</td><td colspan="3">brown coal</td><td colspan="7">hard coal</td><td>anthracite</td></tr>
<tr><td>English-speaking areas</td><td>lignite</td><td colspan="3">sub-bituminous coal</td><td colspan="6">bituminous coal</td><td>anthracite</td></tr>
<tr><td>International Classification of In-Seam Coals (UNECE, 1998)</td><td colspan="2">lignite</td><td colspan="2">sub-bituminous coal</td><td colspan="5">bituminous coal</td><td colspan="2">anthracite</td></tr>
<tr><td rowspan="3">Commercial classification according to intended use</td><td colspan="2"></td><td colspan="4">steam coal</td><td></td><td colspan="4">steam coal</td></tr>
<tr><td colspan="5"></td><td colspan="3">coking coal</td><td colspan="2"></td><td>anthracite</td></tr>
<tr><td colspan="4"></td><td colspan="2">PCI coal</td><td colspan="4"></td><td>PCI coal</td></tr>
</table>

Note: PCI = pulverised coal injection. PCI coal is used in steel production.

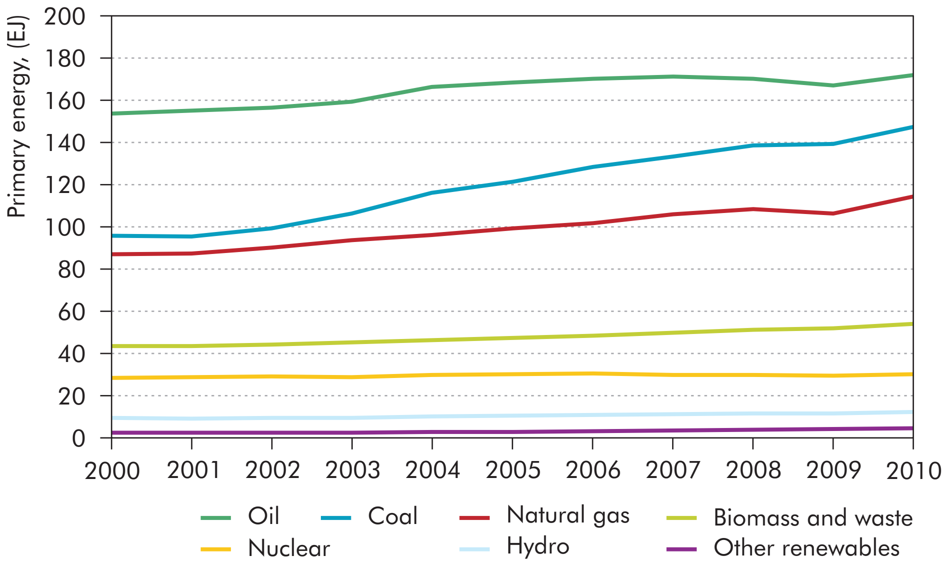
Source: BGR, 2009.

Demand for coal

Coal is by far the most abundant fossil fuel resource worldwide. Recoverable reserves may be found in an estimated 70 countries, with the largest reserves in a small number of them, notably the United States, Russia, China, India and Australia. In 2010, coal satisfied more than one-quarter of the world's primary energy supply, second only to oil. In the same year, the world was dependent on coal for more than 40% of its electricity.

Over the past decade, the contribution of coal to total primary energy supply has risen faster than any other fuel to meet increasing energy requirements (Figure 7.1).

Figure 7.1 • *Growth rate in primary energy supply, 2000-10*



Notes: unless otherwise indicated, all material in figures and tables derives from IEA data and analysis. EJ = exajoule.

The rising demand for coal has been set against a background of rising costs of coal over the last decade. The costs of materials, equipment, labour and fuel have all increased. Environmental regulations and safety requirements have become more stringent and, consequently, more costly to address. As demand for coal has grown, the cost of transportation has also increased. In the case of deep-mined coal, for example in China, coal is being extracted from deeper seams, reserves are located further from points of demand and coal quality is becoming poorer. Conversely, coal mining is a much less capital-intensive business than oil and gas extraction, particularly in countries where opencast mining dominates, such as in Australia, Colombia and Indonesia. However, as long as the demand for coal maintains prices higher than the costs of supply, the outlook for coal will remain strong.

Global seaborne trade[3] in steam coal[4] almost doubled between 1999 and 2009, illustrating its strong role in economic growth over that period (IEA, 2010). In 2009, China became a net importer of coal, with 104 million tonnes (Mt) net, and this is a major reason why demand for coal remained fairly solid in 2009, despite the global economic crisis (oil and gas demand, by contrast, fell substantially). In 2010, net imports of coal to China were even higher (146 Mt) climbing to 183 Mt in 2011 (VDKI, 2012). In the near future, a continued increase in the use of coal is foreseen (IEA, 2012a).

3. The marine industry is an essential link in the international trade of coal, with ocean-going vessels representing the most efficient method of transporting large volumes. As the demand for new coal-fired power plants has increased in a number of developing countries, it has resulted in significant growth in the steam coal trade. The most dramatic growth has occurred in China and Indonesia, both of which have increased their export capacity. In the global market for steam coal, China is a major importer and Australia is the largest exporter.

4. Steam coal is generally defined as all other hard coal not classified as coking coal. Steam coal is also commonly known as thermal coal and is principally used for power generation or in industry to produce steam and process heat. Coking (metallurgical) coal refers to coal with a quality that allows the production of coke to feed blast furnaces in the production of steel.

However, the scenarios addressed in the IEA *Energy Technology Perspectives 2012* demonstrate the critical influence of government policies, especially those related to climate change, on coal demand to 2050 (IEA, 2012b). Demand could more than double in a "business as usual" scenario or be reduced by 40% if sustainable energy solutions were pursued with increased vigour.

Classification of traded hard coals

Trade in hard coals usually distinguishes between steam coals, coking coals and PCI coals. Anthracites are only rarely listed separately and are mostly contained in the statistics for steam coals.

Steam coals

The dominant quality parameter for steam coals is calorific value. Imported coals that are used in power plants must, depending on their provenance, meet various minimum requirements for calorific value, usually at least 5 750 kilocalories per kilogram or 24.07 megajoules per kilogram. Their volatile matter mostly ranges between 10% and 40%, while maximum ash and total moisture contents must not exceed 15%. A further very important parameter is sulphur content, especially for power plants without flue-gas desulphurisation systems. Here, the requirement is a maximum of 1% sulphur.

Coking coals

Unlike steam coals, coking coals must meet much higher-quality requirements. The hard-coking coals used in coke ovens must be both low-ash and low-sulphur. For the production of metallurgical coke, coal mixtures with an ash content of maximum 8%, and of maximum 1% sulphur, are used (Ritschel and Schiffer, 2005). The share of volatile matter is usually 20% to 30%. In addition, the coals must have strong caking properties.

PCI coals

PCI coals are increasingly being used as a substitute for heavy oil and metallurgical coke for pig-iron production in blast furnaces. Suitable PCI coals include all low-sulphur and low-ash anthracites, but also highly volatile steam and semi-soft coking coals. An ash content usually below 7% air-dried (ad) is required, together with a total moisture content of less than 10% ad, and a low alkali and phosphorus content (Ritschel and Schiffer, 2005).

Anthracite

Anthracite is employed mainly as a high-quality fuel in power generation, but also in the cement industry, in metallurgy (as sintering coal) and as a PCI coal. Very low-ash anthracites are used in the manufacture of electrodes.

Calculating coal deposits

Compared with other raw materials, coal deposits (resources and reserves) can be calculated with relative ease thanks to the simple structure of seam deposits or stratum of coal to be mined. To make the calculation, it is necessary to know the area across which coal seams extend, seam thickness and coal density.

The two most important parameters for establishing the quantity of coal in a deposit are the seam thicknesses and the specific maximum depths of the seams. Most countries and most companies have different minimum requirements[5] according to particular mining technology and economic requirements. Mining technology requirements change much more slowly than economic requirements. In many European countries, seam thicknesses upwards of 30 centimetres (cm) were included in deposit calculations well into the middle of the 20th century and beyond. This is largely because such thin seams were mineable manually in underground operations. With growing mechanisation underground, seam thickness requirements were extended to 60 cm or more and this is reflected in most current deposit calculations. The maximum depths included in the deposit calculations of coal-rich countries such as Russia, Ukraine and the United States are 1 800 m, with most other countries including only coals at shallower depths in their calculations.

Global surveys of coal deposits and associated difficulties

In practice, global evaluations of coal reserves and resources often contain gaps or are outdated. The view that coal reserves are sufficient to meet demand for many years, the discovery of large unconventional gas sources and a focus on natural gas as a substitute for coal in European industrialised countries, have reduced interest in new surveys of coal resources and reserves in the last 10 to 15 years.

Data on resources and reserves are usually collated from submissions made by various associations, geological services, ministries or coal producers. Since virtually every country has its own historically developed classifications of resources, reserves and coal itself, direct cross-border comparability of resource and reserve quantities is rarely possible. Country- or basin-specific exploration requirements and differences in valuation parameters with differing limit values (for example as regards the included minimum seam/coal thicknesses and maximum depths) play a key role in the assessment of resources and reserves. Institutions also tend to use data from other sources without sufficiently questioning the basis on which they were prepared.

As far back as 1976 (Fettweis, 1976), it was noted that "There is no internationally recognised and uniform procedure for recording, classifying and designating coal deposits. Instead, we have a plethora of different definitions and methods

5. Ukraine, for example, includes seams of bituminous coals upward of a thickness of 0.5 metres (m) to 0.6 m and down to a depth of 1 800 m. In Poland, hard-coal seams must be a minimum of 1 m thick and may not be deeper than 1 000 m.

varying not only from country to country but often even within a national setting and there is confusion to match." At present, there are more than 150 different classifications worldwide, making any correlation of data on resources and reserves complicated, if not impossible (Ersoy, 2003). It is important to note these factors when comparing different estimates of global coal reserves.

Coal extraction

After centuries of mineral exploration, the location, size and characteristics of the coal resources of most countries are quite well known. What tends to vary much more than the assessed level of coal resources, however, is the proven recoverable reserves that are economically extractable with today's technology.

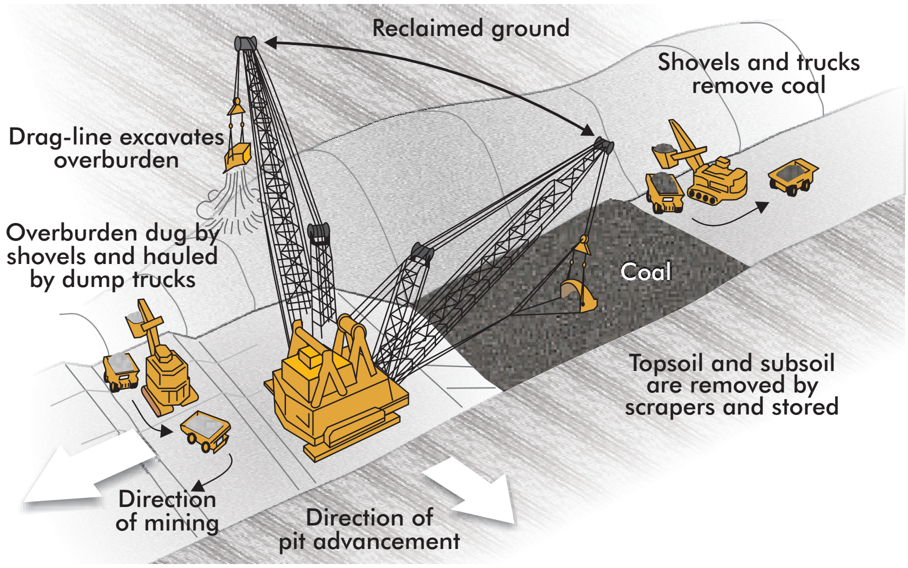
As for oil and gas, coal reserves are discovered through exploration activities. To develop an accurate picture of the area, processes are undertaken that, again, broadly mirror those undertaken for oil and gas. A geological map of the area is created, geochemical and geophysical surveys are carried out, and exploratory boreholes are drilled. The coal will be mined if there is enough of it and of sufficient quality to make it economically recoverable.

The geological characteristics of coal reserves largely determine whether they are to be extracted by mining. The two primary methods of mining coal are surface mining and underground mining.

Surface mining

Surface mining involves removing overburden (earth and rock covering the coal) with heavy earth-moving equipment, such as drag-lines, power shovels, excavators and loaders. Once exposed, the coal is drilled, fractured and systematically transported, using haul trucks or conveyors, to a preparation plant or load-out facility. Disturbed areas are reclaimed as part of normal mining activities. After final coal removal, the remaining pits are back-filled with overburden removed at the beginning of the process. When good practice is observed, topsoil is replaced, vegetation replanted and other improvements made that bring local community and environmental benefits. Figure 7.2 illustrates a typical drag-line surface mining operation.

Figure 7.2* • *Typical drag-line surface mining operation



Source: Arch Coal, 2008.

Underground mining

Underground mining methods are used when coal is located deep beneath the surface. Mines are typically operated by using one or both of two different techniques: longwall mining and room-and-pillar mining.

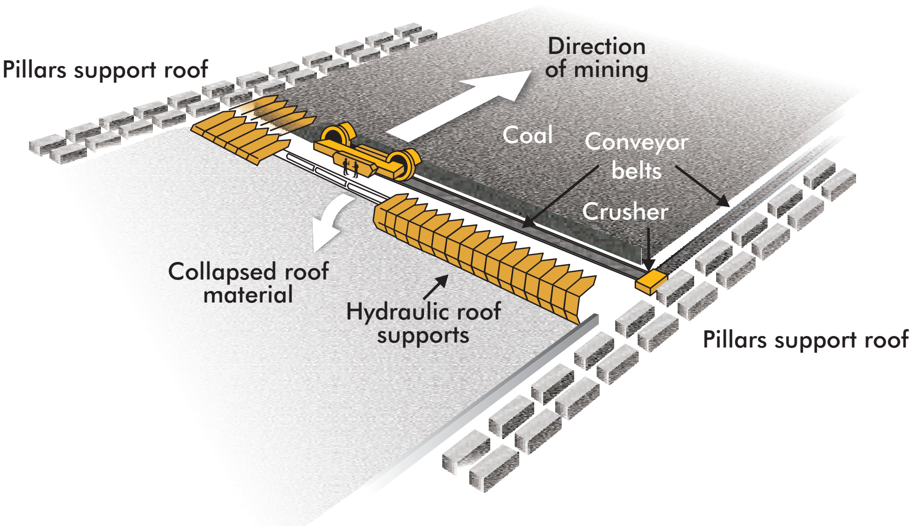
Longwall mining

Longwall mining involves using mechanical shearers to extract coal from long rectangular blocks of medium to thick seams. Ultimate seam recovery using longwall mining techniques can exceed 75%. In longwall mining, continuous mining machines are used to open the access to these long rectangular coal blocks. Hydraulically powered supports temporarily hold up the roof of the mine while a rotating drum mechanically advances across the face of the coal seam, cutting coal from the coalface. Chain conveyors then move the loosened coal to an underground mine conveyor system that delivers the coal to the surface. Once coal is extracted from an area, the roof is allowed to collapse in a controlled fashion. Figure 7.3 illustrates a typical underground mining operation with longwall mining techniques.

Room-and-pillar mining

Room-and-pillar mining is effective for small blocks of thin coal seams. The approach uses a network of rooms cut into the coal seam, leaving a series of pillars of coal to support the roof of the mine. Continuous mining machines cut the coal and shuttle cars transport it to a conveyor belt for further transportation to the surface. The pillars generated as part of this mining method can constitute up to 40% of the total coal in a seam, in which case more than 40% of the coal remains *in situ*.

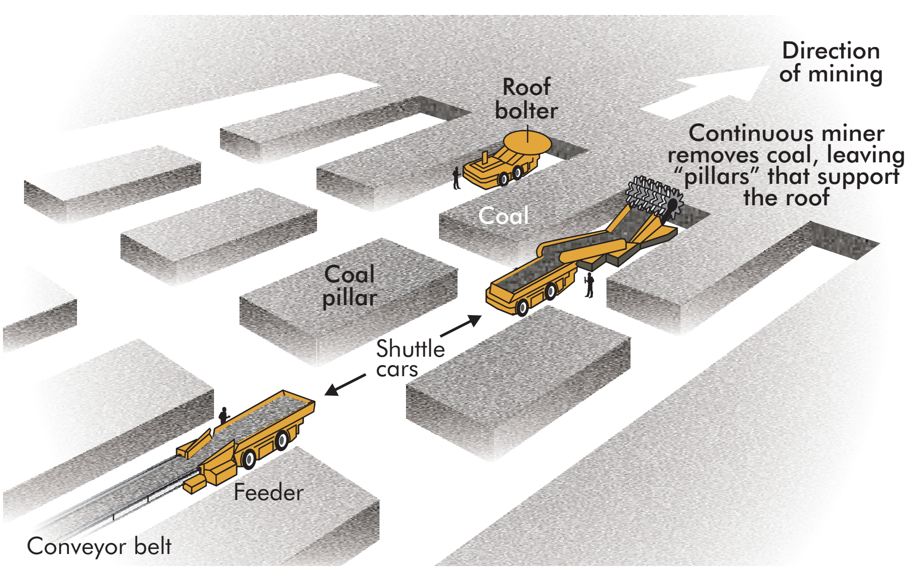
Figure 7.3* • *Typical underground longwall mining operation



Source: Arch Coal, 2008.

Higher seam recovery rates can be achieved by using retreat mining, where coal is mined from the pillars as workers retreat. As retreat mining occurs, the roof is allowed to collapse in a controlled fashion. Once mining in an area is finished, the area is abandoned and sealed from the rest of the mine. Figure 7.4 illustrates a typical underground mining operation with room-and-pillar mining techniques.

Figure 7.4* • *Typical underground room-and-pillar mining operation



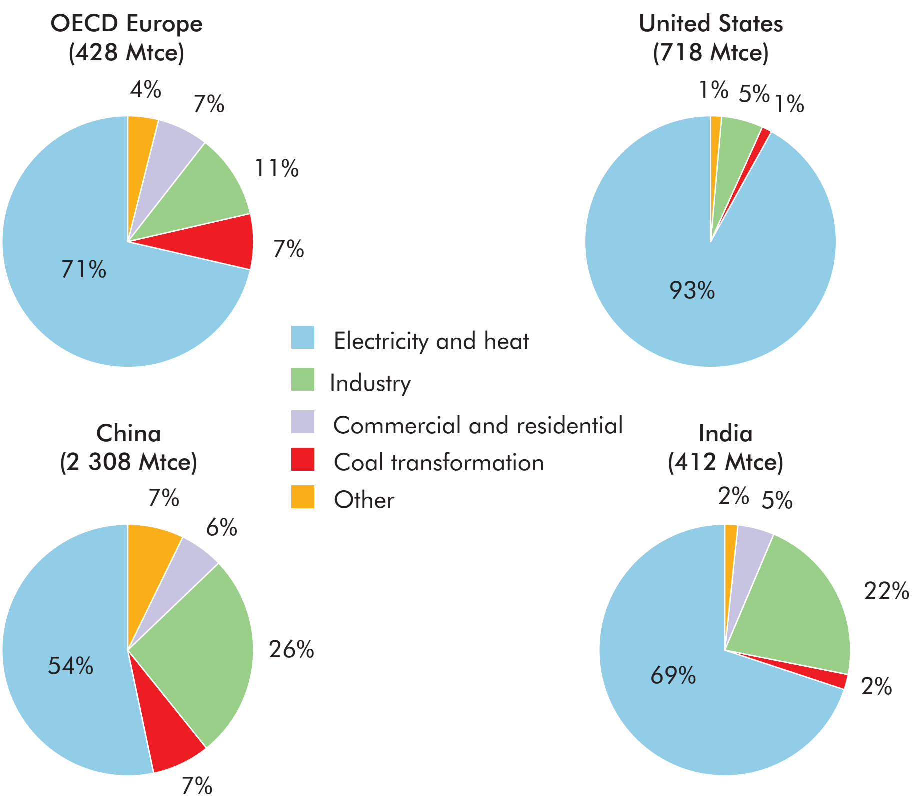
Source: Arch Coal, 2008.

The reserves most conducive to large-scale and highly efficient mining equipment have, in many regions, already been exploited. As a result, some mature mining regions could in the future see a transition towards smaller and less productive equipment with its greater flexibility and lower capital costs, often more appropriate for the smaller and less uniform blocks of contiguous resources that remain. For example, large drag-lines or electric shovels may give way to smaller equipment such as excavators and loaders. In such instances, the combination of reduced reserve quality and less efficient mining equipment may well push production costs higher.

Coal use

Coal has many important uses worldwide. Most coal produced goes to the energy sector, to generate electricity and heat, or to the industry sector, where it is used in manufacturing. Heavy industry uses it in iron and steel production, and in the manufacture of cement. Other important users include alumina refineries, paper manufacturers, and the chemical and pharmaceutical industries. Many thousands of different products have coal or coal by-products as components, including soap, aspirins, solvents, dyes, and plastics and fibres, such as rayon and nylon. Particularly in developing countries, it is still used for heating and cooking.

Figure 7.5 • *Coal use in different regions in 2010*



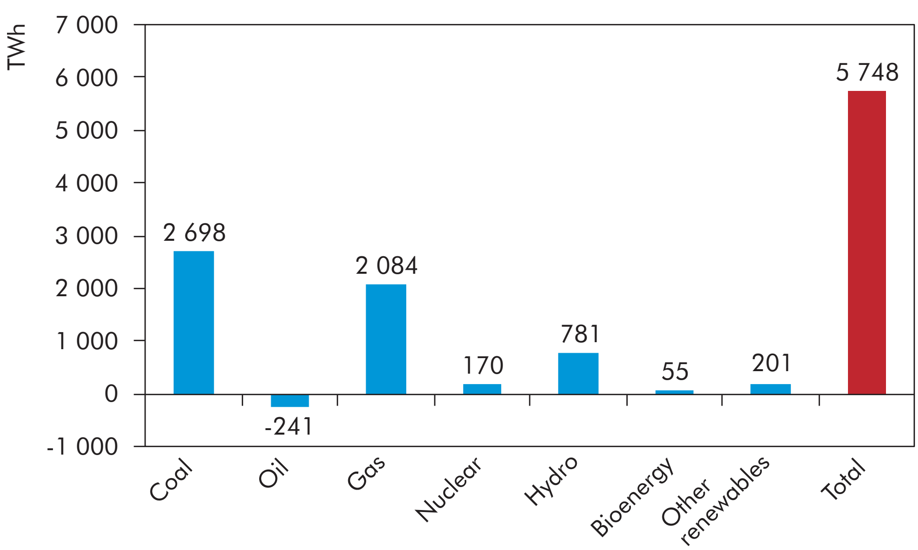
Note: Mtce = million tonnes of coal-equivalent.

Consumption patterns vary for different regions and countries (Figure 7.5). In developed countries, coal is used predominantly to generate electricity and heat. In these countries, coal may have been replaced, perhaps by electricity or gas, in the industry and buildings sectors. In others, perhaps the application is no longer practised, for example much heavy manufacturing has moved to China over the past decade.

Coal for electricity generation

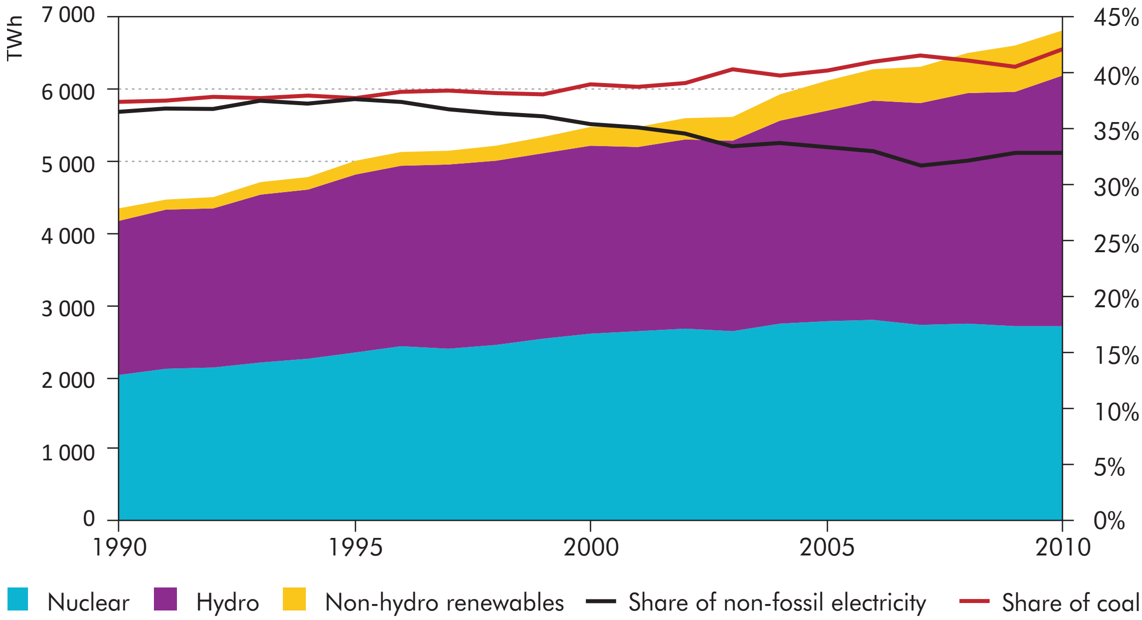
Global electricity generation has increased by 70% since 1990 and by 37% since 2000 (Figure 7.6), reaching 21 408 terawatt hours (TWh) in 2010. Coal dominates electricity production, and between 2000 and 2010 its share of total generation increased from 38% to 41%. The use of gas has grown rapidly over the same period, increasing its share from 17% to 22%. In contrast, electricity generation from oil has fallen; its share of total electricity generation in 2010 was just 5%.

Figure 7.6 **•** *Global incremental growth in power generation between 2000 and 2010*



Total electricity generation from non-fossil fuels has increased in absolute terms since 1990, but not fast enough to keep pace with rising electricity demand (Figure 7.7). Consequently, the overall share of non-fossil fuels in the electricity production mix has fallen from 37% to 32%. The share of nuclear power has fallen from 17% in 1990 to 13% in 2010, while the share of hydropower has fallen from 18% to 16% over the same period. Electricity production from other renewable energy sources has increased markedly, albeit from a low base (IEA, 2012b).

Figure 7.7* • *Electricity generation from non-fossil fuels, 1990 to 2010



The share of coal in a country's electricity generation mix varies considerably and is one of the most important factors determining the level of CO_2 emissions from the sector. The share depends on a country's indigenous resources, on its energy and environmental policies, and on domestic fuel prices. On average, the share of electricity production from coal in Organisation for Economic Co-operation and Development (OECD) countries was 35% in 2009. In contrast, the share in non-OECD countries was 47%. These shares are average values and, for a number of countries, electricity generation from coal is significantly higher. Countries that generated more than 70% of their electricity from coal in 2010 included South Africa (94%), Poland (88%), China (78%) and Australia (75%).

Efficiency of electricity generation

In addition to the generation mix, the efficiency of plants is another important factor influencing CO_2 emissions. Though there were fluctuations in 1990, the global average efficiency of coal-fired power plants rose from 34% for lower heating value (LHV)[6] to around 35% to 2009. In recent years, largely as a result of the growing energy needs of the major emerging economies and developing countries, particularly in China and India, there has been a substantial increase in the global capacity of coal-fired plants. In 2009, global coal-fired installed capacity totalled 1 514 gigawatts (GW), with a further 216 GW under construction (Platts,

6. LHV measures a fuel's heat of combustion assuming all water in the flue gas remains as vapour, *i.e.* it is not condensed. The LHV assumes that the latent heat of vaporisation of water in the fuel and the reaction products is not recovered.

2010). Increasingly, newly constructed plants will be based on the latest, most efficient technology, with more than 80% located in non-OECD countries and over half of them in China. However, construction of small, less efficient units of 300 megawatts-electrical (MWe) or less continues; generation from these less efficient units must reduce dramatically over the next two or three decades if CO_2 emissions are to be effectively addressed (IEA, 2012c).

Coal-fired plants in China

In the last decade there was a move towards more efficient and cleaner coal plants worldwide. New plants consist largely of supercritical (SC) and ultra-supercritical (USC) pulverised coal (PC) technology. The oldest, least efficient plants are being phased out of operation, and remaining inefficient plants are being systematically upgraded, with ageing components replaced and more effective operational practices introduced. The majority of coal-fired power generation capacity in China is less than ten years old, while in the United States and Europe, most of the fleet is between 30 and 40 years old. China has been systematically closing down old, inefficient coal-fired plants (with less than 200 GW-electrical capacity) and replacing them with modern, efficient technology. In 2010, for example, more than 16.7 GW small plants were taken out of operation (Ding, 2011). The introduction of SC and USC units in the last decade has brought about a rapid modernisation of the Chinese coal-fired fleet. In 2010, CO_2 emissions from coal-fired generation plants in China (1 076 grams per kilowatt hour [g/kWh]) were higher than those in the United States (913 g/kWh) and OECD Europe (1 009 g/kWh). With continued deployment of high-efficiency units, however, the average efficiency of Chinese coal-fired plants is now likely to outstrip the current average efficiency of plants in many OECD countries.

Coal-fired plants in India

With average CO_2 emissions of 1 188 g/kWh, coal-fired power generation plants in India are not particularly efficient. Coal provides almost 70% of India's power. And, like China, India also has plans to reduce the carbon intensity of its coal-fired power plants. India has a total coal-fired capacity of 92 GW (2009), over half of which is more than 20 years old. Poor efficiency is blamed on a variety of technical and institutional factors, including: poor quality of coal; poor grid conditions; low plant load factor; degradation due to age; lack of proper operation and maintenance at plants; ineffective regulations; and lack of incentives to improve efficiency (Chikkatur, 2008). According to Chikkatur, there is ample scope to improve the efficiency of existing power plants by at least 1 to 2 percentage points. The retrofit of plants built during the last 30 years is considered a cost-effective measure to improve operational efficiency and provide additional capacity (Remme *et al.,* 2011). In its 11th Five-Year Plan (2007-12), India planned to renovate and modernise 26 GW of coal plants and a further 17 GW in its 12th Five-Year Plan (2012-17). In addition, 1.1 GW of old, inefficient plants has already been retired, with closure of a further 8 GW anticipated over the next ten years (Mathur, 2010).

Coal-fired capacity in OECD countries

It is expected that, because of ageing plants and higher costs, significant coal-fired capacity will be retired over the next few years in OECD countries. The relatively stable population and modest economic growth projected for these countries suggest a modest growth in demand for electricity. The shortfall resulting from the consequent decrease in coal consumption will be replaced by gas-fired generation, renewable energy and nuclear (IEA, 2012b).

Technologies to improve efficiency of coal-fired plants

The efficiency of coal-fired plants depends on a range of factors, including the technology employed, the type and quality of coal used, and the operating conditions and practices. Denmark, for example, has some of the most efficient coal-fired power plants in the world, averaging almost 43% LHV, including a new generation of PC combustion SC plants that were introduced in the 1990s.

PC combustion

PC combustion is currently the predominant technology used to generate electricity from coal. It accounts for more than 97% of the world's coal-fired capacity. Most existing plants operate under subcritical[7] steam conditions, with the best examples reaching 39% efficiency. In recent years, a substantial number of plants employing SC steam conditions have been constructed, which are capable of reaching significantly higher efficiencies. This has been made possible largely through progress in materials development. Sufficient confidence in mechanical performance means that plants can now accommodate the higher pressures and temperatures characteristic of SC steam conditions. SC plants operate with steam pressures of over 22.1 megapascals (MPa). They are often subdivided into two categories, SC and USC depending on the temperature regime. Though there is no agreed definition, manufacturers usually refer to plants operating with steam temperatures in excess of 600°C (degrees Celsius) as USC. The efficiencies of SC and USC plants installed in recent years range from 42% to 47%, depending on the actual steam values, the quality of the coal and the ambient conditions.

Further developments in materials are under way, such as in the European power industry's COMPTES700 development programme, also supported by the European Commission. The ambition of the development programme is to raise the main steam temperature and pressure to 700°C and up to 37.5 MPa, with a reheat temperature of 720°C. Another programme, the United States Department of Energy (US DOE)-led "Advanced Materials for Ultra-Supercritical Boiler Systems", aims to raise the main steam temperature to 760°C and pressure up to 37.5 MPa. This requires the use of nickel-based super alloys that would offer the potential to raise net efficiencies to 50% and beyond. These developments have paved the way for increasing unit capacities, with single

7. The efficiency of a steam cycle is influenced by, among other factors, the pressure and superheat and reheat temperatures of the steam. SC is a thermodynamic expression where there is no distinction between the liquid and gaseous phases. Water/steam reaches this state at about 22.1 MPa (221 bar) pressure. Above this operating pressure of the steam, the cycle is SC and below it, the cycle is sub-critical.

units of 1 000 megawatts (MW) now in commercial operation. However, the potential cost savings arising from the simpler design and reduced fuel usage of supercritical plants are offset by the greater expense of materials, the more complex boiler fabrication and the more precise control systems required.

Technologies have been developed to reduce emissions of particulates, sulphur dioxide (SO_2) and nitrogen oxides (NO_x) from PC combustion plants below the most stringent levels demanded anywhere in the world. These technologies are mature, with a competitive market. The levels of emissions in countries are more often a function of the extant legislation and compliance with regulation rather than the capabilities of modern pollution control technology.

Fluidised bed combustion

Fluidised bed combustion (FBC) offers an alternative combustion technology for generating electricity from coal, albeit more often employed for particular or niche applications. It is a flexible technology that uses effectively low-grade coals, biomass and general waste. Several hundred FBC plants are in operation worldwide. With the burning coal suspended in an upward flow of combustion air, there are two main technology variants: bubbling fluidised bed combustion (BFBC) and circulating fluidised bed combustion (CFBC), with the latter distinctly more common for power generation. Both BFBC and CFBC offer the potential for integrated in-bed sulphur reduction and, as a result of the lower operating temperatures, lower NO_x emissions.

Plant sizes are more restricted compared with PC combustion, though developments have meant that there are many plants with capacities ranging from 250 MW_e to 300 MW_e in existence. For FBC, plants with a greater unit size and with supercritical steam cycles are natural developments. In late 2009, a 460-MW_e CFBC plant at Lagisza (southern Poland) began commercial operation. In the future, manufacturers hope to scale up designs to offer units within the range 500 MW_e to 800 MW_e. China is in the process of building a 600-MW_e CFBC boiler as a demonstration project at its Baima power plant in Sichuan Province.

Integrated gasification combined cycle

Integrated gasification combined cycle (IGCC) has inherently lower emissions of some pollutants than PC combustion, with the potential for high efficiency mirroring that of PC combustion plants. A fuel gas (mainly comprising carbon monoxide and hydrogen) is generated by partially combusting coal in air or oxygen at elevated pressure. Following cooling, the fuel gas is treated to reduce the concentration of particulates, sulphur and nitrogen compounds to extremely low levels before it is burnt in the combustion chamber of a gas turbine. Electricity is produced via the combined cycle of gas and steam turbines. Designs offering efficiencies in excess of 50% are achievable.

The 1970s and 1980s saw a surge of interest in the development of IGCC plants for power generation, particularly in Europe, Japan and the United States. Of the large-scale, coal-based plants that were commissioned in the 1990s, only a handful continue to operate on a commercial basis, two in Europe two in the

United States and one in Japan. The net capacity of each is between 250 MW_e and 350 MW_e, with net efficiencies between 40% and 43%. The lack of uptake of this technology in the last 15 to 20 years is mostly attributed to its higher generation costs. Apart from cost, the "cultural" difference between the two technologies is also regarded as a factor in its failure to compete with PC combustion, with IGCC more closely resembling a chemical plant.

More recently, however, there has been a resurgence of interest in the technology. Significant developments are currently under way, notably in China, but also in the United States, Japan and Europe. This is a positive trend given the potential for the power generation efficiency of an IGCC plant to exceed 50%, its low emissions of some pollutants, the prospect for capture of CO_2 emissions and its flexibility to be used to synthesise substitute transport fuels or a range of other chemicals. The small number of reference plants, however, underlines the progress that will need to be made if IGCC is to become more widely deployed.

Co-generation

Co-generation, also often referred to as combined heat and power, is the combined production of heat and power from a single fuel source. Almost any fuel is suitable, although natural gas and coal currently predominate. By making use of both heat and power, co-generation plants generally convert 75% to 80% of the fuel source into useful energy, while the most modern plants have efficiencies of 90% or more. Co-generation is often carried out at an industrial site, where the heat output may be used for space heating or as process heat. Power requirements are less dependent on grid connection and distribution.

The amount of electricity produced globally from co-generation has been gradually increasing and is now around 2 000 TWh per year or 10% of total global electricity production. The amount of heat co-generated is not exactly known, but it is in the range of 5 EJ to 15 EJ per year, which represents an important share of industrial, commercial and residential heat supply.

Coal-to-liquids

Converting coal to a liquid fuel in a process referred to as coal liquefaction allows coal to be used as an alternative to oil. The extent of the activity on coal conversion technologies is closely linked to the price of oil. For example, the dramatic increase in the price of crude oil in 2007 and 2008 spurred renewed interest in coal-to-liquids (CTL) technologies. Depending on the geographical location of CTL projects, estimates suggest that CTL plants can operate profitably when oil prices lie in the range of USD 60 to USD 100 per barrel (IEA, 2010). China and the United States both express interest in converting CTL as a means of reducing their dependence on imported oil and thereby increasing their energy security. China, in particular, has been active in constructing large-scale CTL plants.

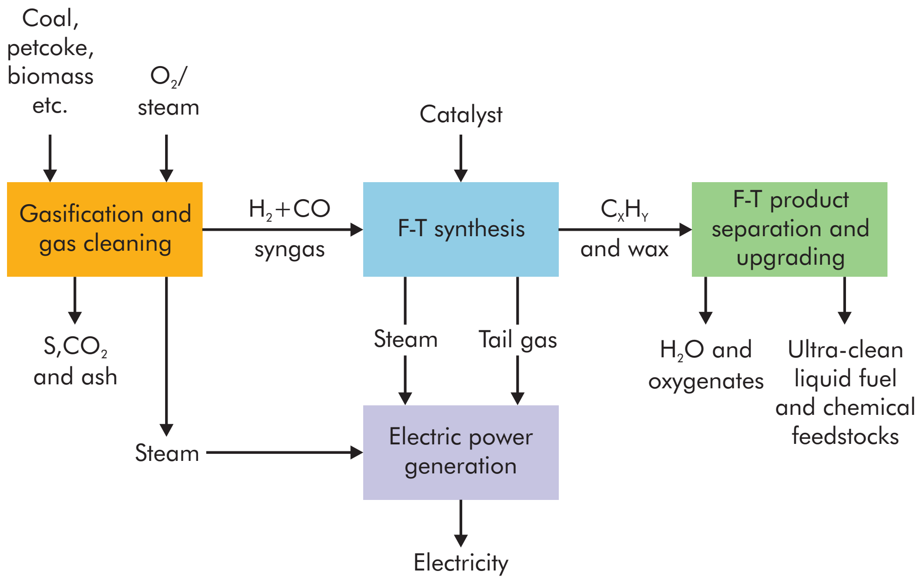
Plants are commercially operating in South Africa and China (World CTL Association, 2012). Further projects are planned in Australia, Botswana, China, India, Mongolia, Russia and the United States.

There has been extensive development work by the Japanese in the use of Fischer-Tropsch synthesis as part of their effort to stabilise the cost and security of energy supplies, as well as technical advances in South Africa. To convert coal to a liquid fuel, there are two different processes: indirect liquefaction and direct liquefaction.

Indirect liquefaction

Indirect liquefaction involves a two-step process. First, the coal is gasified to produce synthetic gas or "syngas", a mix of H_2 and CO. The synthetic gas, once cleaned of pollutants, is then converted by Fischer-Tropsch synthesis, using an iron or cobalt catalyst, to produce liquid hydrocarbon fuels. This two-step process, which was first developed on an industrial scale by Germany during World War II, is used by South Africa's Sasol to convert domestic coal into more than 150 000 barrels of oil-equivalent per day of saleable products (Figure 7.8). The current Sasol plants were built with government support in the 1970s and 1980s. Besides conversion to liquid and gaseous fuels, Sasol also produces higher-value products that include fertilisers, detergents, waxes and plastics.

Figure 7.8 • *Indirect coal liquefaction*



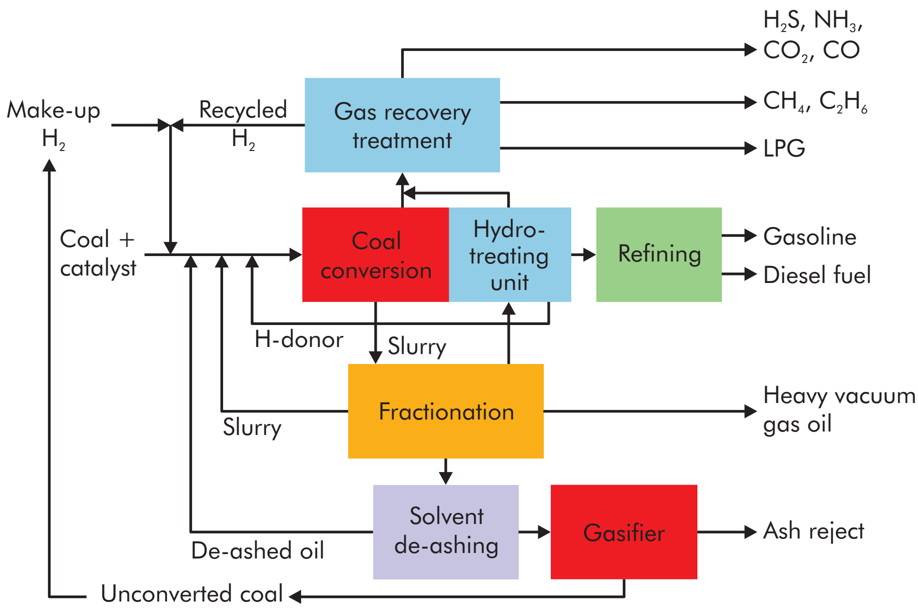
Note: F-T = Fischer-Tropsch; C_XH_Y = hydrocarbon products; O_2 = oxygen; S = sulphur; H_2O = water.

Source: IEA CIAB, 2006.

Direct liquefaction

Liquid fuels may also be produced by direct liquefaction (Figure 7.9), in which coal reacts directly with H_2 in the presence of a catalyst. China is one of a few countries pursuing direct liquefaction. The process was adopted by China's Shenhua Group for its CTL plant in the Ordos Basin, located at Erdos (Inner Mongolia). Trial operations commenced in 2008 (Shenhua, 2013). The plant was designed to produce one Mt of fuel annually. Early in 2009, the company announced that, subject to approval from China's highest economic planning body, the National Development and Reform Commission (NDRC), it would triple the capacity of its direct CTL project by 2015, once its technology had tested sound in trial operations.

Figure 7.9 • *Direct coal liquefaction*



Note: H_2S = hydrogen sulphide; NH_3 = ammonia; CH_4 = methane; C_2H_6 = ethane; LPG = liquefied petroleum gas.

Source: IEA CIAB, 2006.

At the end of 2008, the NDRC decided to suspend approvals for new CTL projects with few exceptions until the technology and business procedures were more mature. In March 2011, having passed the environmental impact assessment, approval was received from the Chinese Ministry of Environmental Protection for Shenhua to build a second plant, operating at 94 000 barrels per day, together with Sasol in the Ningxia Hui autonomous region, which would convert coal into motor fuel. Construction of the plant, however, will be subject to NDRC approval.

New technologies for CTL

Carbon capture and storage (CCS) is considered important to the future of CTL. The Shenhua Group is developing China's first CCS project at its Erdos plant. The company has completed a storage trial, having injected 100 tonnes (t) of CO_2 into a saline aquifer 2 000 m below the ground. Significant scaling-up of its storage operations has been under way (MIT, 2012). With a relatively short distance of 17 km between plant and storage location, transport of the CO_2 is undertaken by truck.

Additional energy and environmental benefits will be obtained if the CO_2 captured were to be used for enhanced oil recovery (EOR) (see Chapter 2). Using EOR to store CO_2 is considered an attractive CO_2 mitigation strategy for use by China, the United States and other countries in future CTL facilities.

Environmental impact

Reasons for replacing coal as a fuel or for moving manufacturing to a new place are complex, but one of the major drivers is environmental regulation. The major challenges facing coal relate to its environmental impact. Coal contains many elements bound up within its complex structure, which are released in one form or another, *e.g.* during coal combustion. Over many years, highly effective technologies have been developed to tackle the release of pollutants such as SO_2, NO_X, particulates and trace elements, such as mercury. Many of these technologies are mature, with a competitive market. The levels of emissions of these pollutants are more often a function of existing legislation and compliance with regulation rather than the capabilities of modern pollution control technology.

Given that its carbon content varies between 60% in lignites to more than 97% in anthracite, coal is a major source of CO_2. More than 40% of anthropogenic CO_2 emissions result from coal and these emissions are rising. Coal produces almost three-quarters of the 30% of CO_2 that comes from the generation of electricity. The reduction of CO_2 emissions from electricity generating plants would have a significant impact on global emissions and, therefore, on climate change. As large point sources of CO_2, coal-fired units are considered to offer high potential for CO_2 reduction.

From 1990 to 2009, CO_2 emissions from global electricity production increased by 57%. Most of this rise was driven by the increasing use of coal for electricity generation. In 2009, coal-fired power plants accounted for 73% of total emissions from the power generation sector, up from a share of 66% in 1990. There are various means to reduce emissions of CO_2 from coal-fired power plants. Apart from improved demand-side energy efficiency, which reduces the amount of electricity needed, the main options are to:

- switch to renewable energy technologies or to lower-carbon fuels, such as natural gas and biomass;
- use more efficient technology, modernise existing plants, close the most inefficient ones and continue to develop higher-efficiency conversion processes;
- use CCS.

CCS from power production has been demonstrated to be technically viable. However, as yet, none of the fully integrated, commercial-scale CCS projects in operation (described in Chapter 9, Box 9.1) involve captured CO_2 from power generation.

CTL processes and projects pose significant environmental challenges. The fuel products are virtually sulphur-free and emit substantially lower amounts of NO_X, particulates and CO_2. However, when the energy needs for the conversion and refining processes of CTL are taken into account, CO_2 emissions of the CTL fuel cycle are at least double those of conventional petroleum-based fuels (Farrell and Brandt, 2006). The plant-level CO_2, which accounts for almost half the emissions, can be offset by using CCS. The Shenhua Group has proven this is technologically feasible in a 100 000 t per year CCS demonstration project (Yi, 2012).

Water consumption is another factor of major environmental importance. From coal extraction to coal conversion, in power generation and emissions reduction, water is an essential component. Ensuring application of good practice and recycling water where possible is important in all cases.

For coal extraction, depending on whether underground or surface mining is being practised, water is used for coal cutting, coal washing and for dust suppression. The amount of water consumed in these operations depends on a range of factors, including the mine location, the geology, and the type and composition of the coal. As these factors can vary markedly, estimates in the literature for water consumption in mining operations and coal washing can also vary greatly.

The primary issue in coal extraction, however, is water contamination rather than consumption. Drainage from mines and mining waste can become acidic and dissolve heavy metals that may be present in the rock and soil. As these compounds are carried in the water, in the absence of operational best practice they can subsequently be absorbed and enter the food chain.

The process of electricity generation from coal is also water-intensive. Between 40% and 50% of all water abstracted and used in developed countries is used in the generation of electricity. Thus, a reliable, abundant and predictable source of raw water supply to a fossil-fired power plant is a critical factor in site selection. Water is required for various operations, including:

- boiler make-up water to the water/steam circuit;
- cooling water for steam turbine condensers;
- auxiliary plant cooling water;
- make-up water to flue-gas desulphurisation plant;
- ash handling and disposal.

As a guide, one megawatt hour (MWh) of electricity generated from coal uses 20 litres (l) to 270 l of water at the coal mining stage and an additional 1 200 l to 2 000 l when the energy in the coal is converted to electricity (WEF, 2009). Substantially reducing water consumption in power generation usually leads to an energy penalty, significantly reducing the net efficiency of the plant.

If CCS is applied to the power generation plant, water consumption increases substantially. Depending on the technology and the mode of CO_2 capture, water consumption can double.

The amount of water required to operate a coal liquefaction plant is a function of a number of variables, including the design of the unit, the type of gasifier, the coal properties and the local ambient conditions. For indirect liquefaction, between 5 l and 7 l of water are consumed for each litre of liquid fuel produced (USDOE, 2006). For direct liquefaction, consumption is of the same order. Water used for cooling that is lost through evaporation tends to be the largest source of consumption; use of air cooling instead of water cooling can potentially reduce water requirements to less than 1 barrel of water per barrel of Fischer-Tropsch product. Management of water supplies, reuse of effluent, technologies for reuse of water and water-loss prevention all play an important part in reducing water demand.

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Chapter 8 • Production costs of fossil fuels

Converting resources to reserves is closely linked to the cost of production relative to the market price. Increases in market price while production costs remain constant will lead to proposals for new projects (greenfield projects) or to new developments, and expansions at sites of existing production (brownfield projects) and, therefore, to an increase in reserves. If margins are supportive, then novel methodologies of extraction will be tested and implemented. As a result of increasing oil prices over the last eight years, enhanced oil recovery (EOR) projects are being pursued. However, some new projects have been difficult to implement because of the sharp increase in material costs that have followed growing demand. Then, in 2008 and 2009, as a result of the global economic crisis, many of these projects were delayed, postponed or cancelled as oil prices dropped. In 2010, economic activity improved, leading once again to a rise in the price of oil. The investment cycle for coal mines followed a similar pattern. Investments in new projects and expansions boomed as global coal prices rose, only for investment to fall as equipment costs and other capital costs increased and global coal prices fell, as in late-2011 and 2012.

Fossil fuel prices are difficult to predict and depend on the particular energy scenario adopted. To gain insight into which resource categories may be produced in the future, this chapter will focus on the cost factor. Examples of resource categories include coal, conventional oil, light tight oil, conventional gas and shale gas, among others. The cost factor provides an insight into which resource categories need technological advances for production to be viable under various price scenarios. The three energy scenarios used in the International Energy Agency (IEA) *World Energy Outlook* project different futures for extraction and use of oil, gas and coal. For example, in the 450 Scenario (Chapter 1), projections for a low-carbon future mean a reduced demand for fossil fuels, which leads to a lower price and, hence, less investment in new technologies and methods for extraction.

The cost of production will have a direct influence on the amount of oil, gas and coal that may be accessed at any particular time. The impact of carbon pricing will be greater for coal than for oil and gas, and greater for oil than for gas. Depending on the carbon price, the relative energy mix in the future may be influenced; this is further discussed in Chapter 9.

Factors influencing production costs

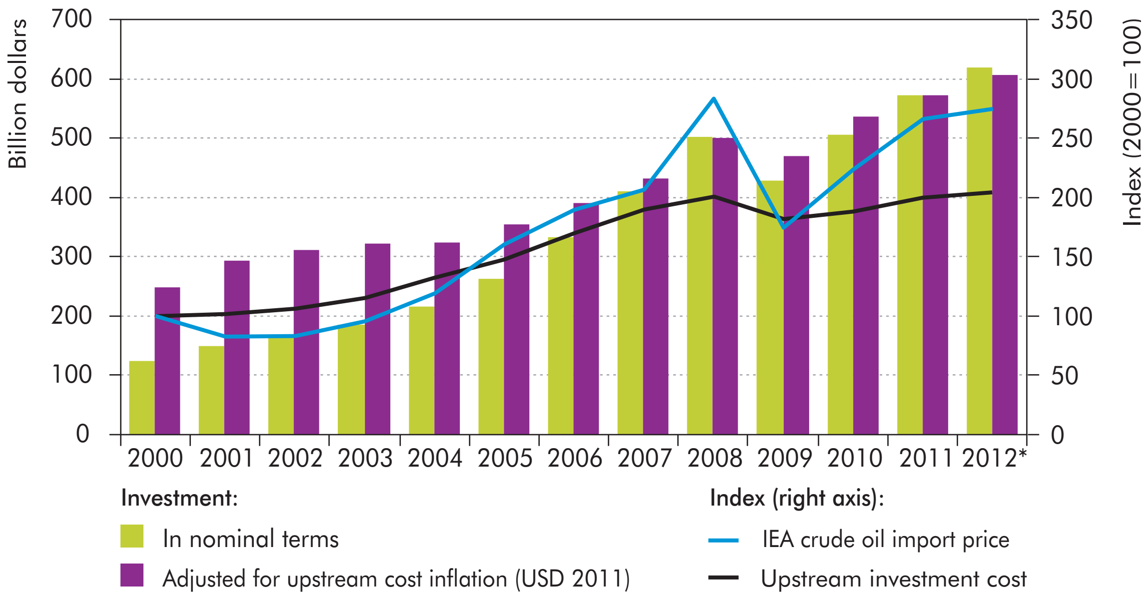
The different factors influencing production costs are:

- the resource category to be exploited, which defines the necessary infrastructure and production processes, *e.g.* large conventional oilfields (Chapter 2), deepwater developments (Chapter 4), energy-intensive steam-assisted gravity drainage processes for *in situ* oil-sands production (Chapter 5), the high well costs for tight gas (Chapter 6), the depth and thickness of coal seams or coal-to-liquids (CTL) conversion (Chapter 7);

- location of the reservoir, *e.g.* onshore or near-shore reservoirs versus ultra-deepwater offshore or Arctic fields (Chapter 4) and distance of coal reserves to the power station or the export terminal (Chapter 7);
- the evolution of capital costs for upstream and downstream production stages.

To monitor trends in oil prices and costs, the IEA has published annually, since 2000, its crude oil import price index and its upstream investment cost index (UICI). Furthermore, a comprehensive assessment of how the capital cost for oil production has evolved in recent years is provided by the IHS CERA cost indices (IHS CERA, 2012). The costs for all areas of production, including aggregated upstream and downstream capital costs, as well as upstream operating costs, almost doubled between 2000 and 2008 because of the high demand for steel, factory space and manpower (Figure 8.1).

Figure 8.1* • *UICI and annual inflation rate



* Budgeted spend

Note: the IEA UICI, set at 100 in 2000, measures the change in underlying capital costs for exploration and production. It uses weighted averages to remove the effects of spending on different types and locations of upstream projects.

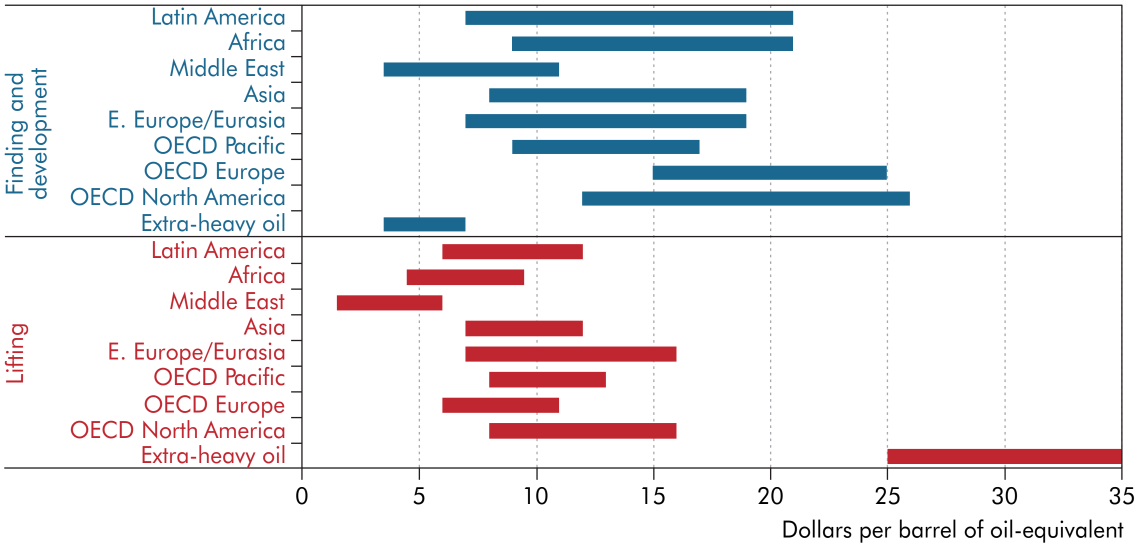
Source: IEA, 2012.

Exploration (finding), development and operating (lifting) costs depend on the specific challenges of a particular resource category, and the region and reserves to be developed (Figure 8.2). The future trajectory of these costs will be affected by two opposing factors:

- the development and use of new technologies to facilitate access to more resources and help reduce unit costs;
- the depletion of basins that increases the effort and expense needed to extract additional resources.

Cyclical cost variations will also occur as short-term fluctuations in activity and price affect the availability of services and other resources.

Figure 8.2* • *Upstream oil and gas investment and operating costs, by region



Note: OECD = Organisation for Economic Co-operation and Development.

Source: IEA, 2010.

Production cost curve for oil

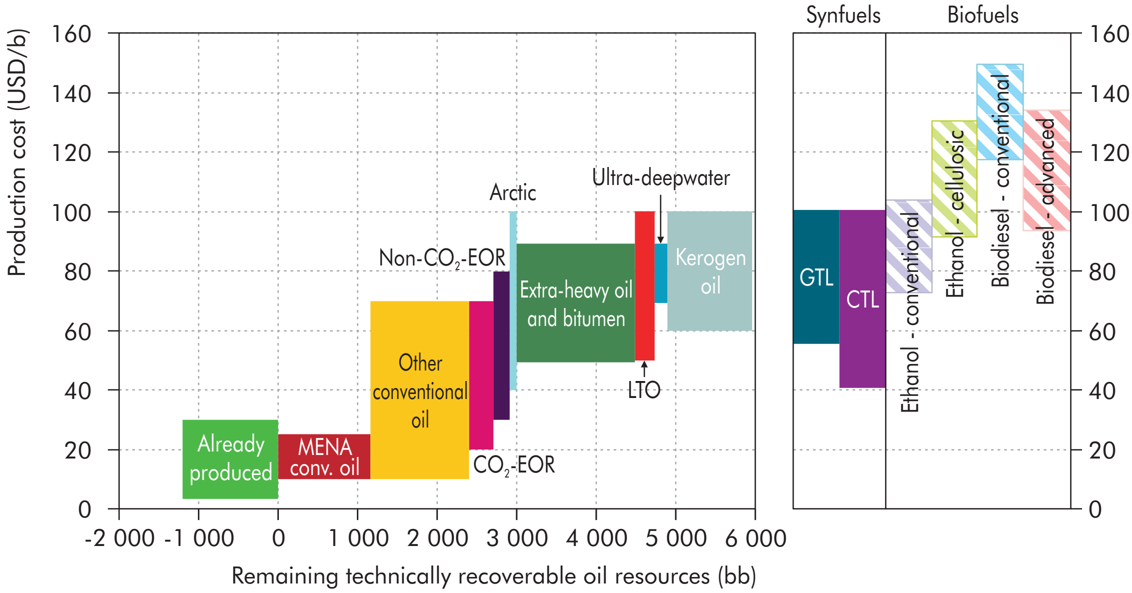
The highest costs for crude oil are incurred during the extraction (plus upgrading) and refining operations. Transportation costs represent only a fraction of overall production costs. Potential substitutes for crude oil are "synfuels" derived from Fischer-Tropsch synthesis or from other conversion processes. Liquid hydrocarbon fuels may be synthesised from gas in gas-to-liquids (GTL) processes, and from coal in CTL processes. Biofuels, such as ethanol and biodiesel, may also be produced from thermochemical or biochemical processes, including biomass-to-liquids (BTL). Liquid hydrocarbon fuels derived from gas, coal and biomass are all fuels that may compete with traditional crude oil resources.

The inflation in upstream and downstream investment costs in recent years, as well as new developments for unconventional oil sources and competing fuels have all been factored into the production cost estimates provided below. The estimates for resources and reserves were calculated by using review data from a number of sources (BGR, 2011; O&GJ, 2011; USGS, 2000, 2012a and 2012b; IEA, 2012; IEA databases and analysis).

The total worldwide potential oil resource base, from conventional and unconventional oil resources, is roughly 5.9 trillion barrels. Synfuel production from CTL and GTL conversion processes and biofuel production from thermochemical and biochemical conversion processes could considerably increase the potential depending on feedstock availability.

Some 1.2 trillion barrels of conventional oil have already been produced, mostly at a cost of up to USD 30 per barrel (/b). For the remaining technically recoverable resource categories, a number of assumptions were made to estimate the quantity of the resource and the production costs. The resulting estimates for resource quantities and potential production costs are given in Figure 8.3.

Figure 8.3 • Oil production costs for various resource categories



Notes: unless otherwise indicated, all material in figures and tables derives from IEA data and analysis. CO_2 = carbon dioxide; MENA = Middle East and North Africa. "Other conventional oil" includes deepwater. No carbon pricing included. Synfuel resources are difficult to assess due to competition with other natural gas and coal uses. Biofuels are renewable and, in theory, not resource constrained. Biofuels production costs have been credited with a "refiner's margin", using the ratio of gasoline and diesel spot prices in the United States compared to the West Texas Intermediate crude oil price. The ratio was, on average, 1.3 for gasoline and 1.35 for diesel between 2007 and 2012.

The horizontal axis shows the cumulative resource quantity of the given resource category for the production of liquid hydrocarbon final fuel. Note that for the competing fuel sources, such cumulative quantities cannot be evaluated; coal and natural gas resources are in plentiful supply and in significant demand, therefore only a fraction will likely ever be used for CTL, GTL or similar conversion processes. Estimates for ethanol and biodiesel are also provided. These last two resources are replenished after every harvest season and, therefore, the question is rather how much synfuel can be produced annually without affecting food production and the environment.

The vertical axis shows the range of the potential cost in US dollars per barrel of oil (USD/b) of producing liquid hydrocarbon final fuel from each resource category. At this stage, no additional costs for carbon emissions are considered.

The assumptions for each category that were used to calculate the costs in Figure 8.3 are as follows:

- All conventional oil resources, proven and yet to be proven or discovered, from the MENA region can be produced relatively cheaply in comparison to other regions. Nevertheless, considerably higher upstream investment costs for new developments and upgrades in mature fields have made production more expensive than in the past. Oil resources amount to 1 120 bb. Production costs of USD 10/b to USD 25/b are assumed.
- Production costs for conventional oil resources from other regions vary. From a technical point of view, some Russian oilfields are as easy to exploit as MENA oilfields. They constitute the lower end of the production cost range. The higher end includes onshore and offshore fields that are technically more challenging, excluding ultra-deepwater. Oil resources amount to 1 220 bb. Production costs of USD 10/b to USD 70/b are assumed.
- All EOR methods together may deliver up to 500 bb of oil (IEA, 2008), of which 300 bb possibly come from CO_2-EOR techniques and the rest from thermal EOR (*e.g.* steam injection) or chemical EOR. Estimated costs vary for EOR techniques as they are highly dependent on specific field parameters. The cost ranges from USD 30/barrel to USD 80/barrel, with CO_2-EOR techniques being somewhat cheaper (USD 20/barrel to USD 70/barrel). If carbon pricing were incorporated, CO_2-EOR would be considerably cheaper because of the carbon credits obtained for net CO_2 storage underground. An international CO_2 emissions trading system would have a similar impact.
- Oil from ultra-deepwater developments (more than 1 500 m deep) is estimated to deliver 160 bb at production costs in the range of USD 70/b to USD 90/b (IEA, 2008).
- According to the most recent US Geological Survey estimates, Arctic areas north of the Arctic Circle may deliver 90 bb of crude oil and another 44 bb in natural gas liquids at production costs in the range of USD 40 to USD 100/b (Chapter 4). This is a relatively small contribution for oil. The estimates for natural gas resources in these areas are much higher (47 trillion cubic metres or about 290 bb of oil-equivalent).
- There is a large resource base of unconventional extra-heavy oil and bitumen, around 1.47 trillion boe, mostly in deposits situated mainly in Canada and Venezuela, but also in other countries such as Russia and Kazakhstan. The production costs for new installations, including crude upgrading and environmental mitigation costs, but excluding CO_2 emissions mitigation, are in the range of USD 50/b to USD 90/b.
- Production of kerogen oil and LTO is still in a developmental stage, but progressing rapidly. Estimating costs for a future commercial-scale production is therefore difficult. For kerogen oil, commercial-scale production costs are likely to be in the range of USD 40 to USD 100 and technically recoverable resources may amount to 1 070 bb. LTO production costs are estimated between USD 60/b and USD 100/b, and technically proven resources amount to 240 bb.
- Synfuel production technologies (such as GTL, CTL and BTL) are mostly based on Fischer-Tropsch conversion. Here, the two main cost drivers are the initial plant installation costs per unit of synfuel production capacity, which is dependent on the size of the plant (economies of scale) and the costs of the conversion process feedstock. The influence that feedstock prices have on total production cost is

determined by the plant efficiency, *i.e.* how much feedstock mass is needed for a unit of synfuel output. Note that synfuel products coming from the Fischer-Tropsch conversion processes are already high-quality final fuels, whereas crude oil still needs to undergo refining, which incurs further costs. As such, the analysis should be considered as well on a source-to-energy basis. The availability of the resource for liquid fuel production is constrained not only by the amount of proven resources but especially by the competition with other energy sectors, especially the power sector, that may use the gaseous or solid fuel directly. The resources represented in the supply curve are therefore only representative, even though resource estimates are discussed in the following paragraphs.

- GTL plant installation costs have increased in line with a general increase in upstream investment from around USD 30 000 per barrel per day (/b/d) of production capacity in 2005 to an estimated USD 80 000/b/d by 2010. In addition, there has been a sharp increase in the prices of natural gas over the past few years. These trends have been responsible for a significant increase in the cost of GTL production. The total production cost for GTL can vary widely. The feedstock may be stranded gas for which there are no financially viable options for transportation to markets, and the gas value is roughly equal to its production cost. Or the feedstock has to be bought on the regular gas market for a much higher price. For new plants, GTL costs range from USD 60/boe of synfuel for stranded gas to USD 105/boe for natural gas at market price. Up to 1 700 billion boe of final fuel could come from GTL if about 20% of the global natural gas resources were used as feedstock.

- CTL plant installation costs have also increased, and are now USD 85 000/b/d for a 50 000 b/d CTL plant. Coal prices increased sharply during 2007 and early 2008. Again, these trends were responsible for a sharp increase in CTL production costs. The total CTL production cost can vary widely as the feedstock could be cheap stranded coal (*e.g.* where there is no other market for the coal and hence its value is the same as the extraction cost) or, conversely, the coal could be purchased at a much higher global market price. It is estimated that CTL costs are in the range of USD 45/boe of synfuel for stranded coal to USD 105/boe for coal at a market price of USD 135 per tonne (/t) of hard coal. Up to 4.5 trillion boe of final fuel could come from CTL if about 10% of global hard coal and lignite resources were used as feedstock.

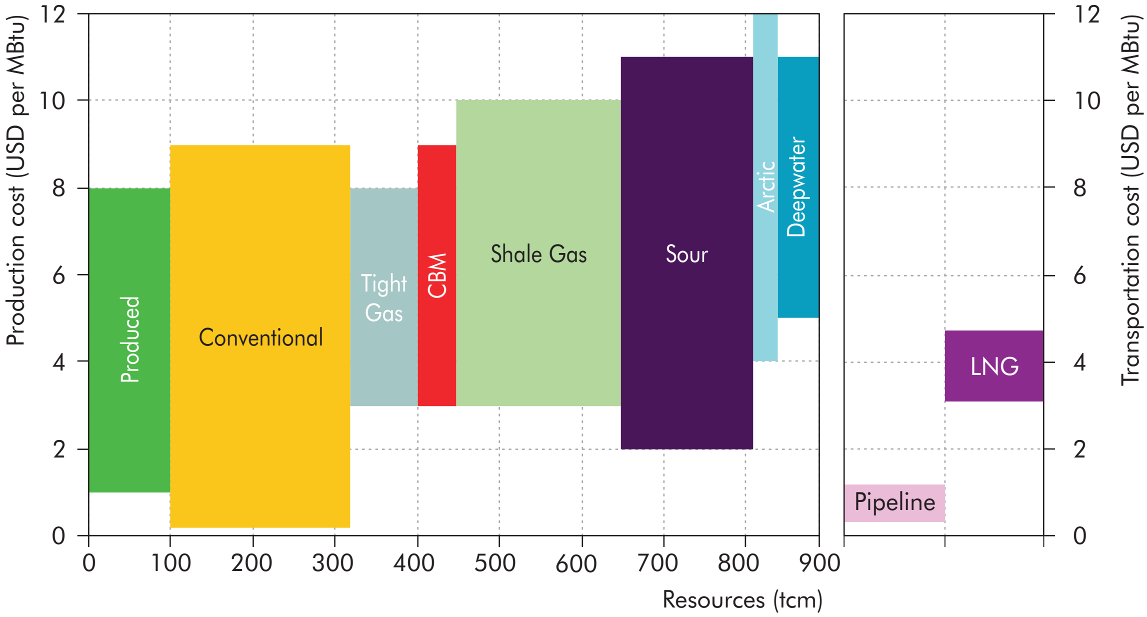
- The other categories, *i.e.* biofuels, ethanol and biodiesel, are included for comparison. These renewable and, therefore, "infinite" resources are technically only limited by land availability and climate conditions. Unlike oil-based fuels, biofuels are final fuels that do not need further refining. To aid comparison with production from oil resources, these costs were credited with a "refiner's margin", based on the average ratio of gasoline and diesel spot prices to the West Texas Intermediate crude oil price in the United States between 2007 and 2012.

The lower value of the cost range for many of the more complex sources is quite similar. This suggests that, at an oil price that would allow a production cost of about USD 50/b to USD 60/b, the most profitable projects of almost all the unconventional resources become feasible. This is important because such developments help to identify areas where costs can be reduced, which is currently the case.

Production cost curve for gas

The potential long-term contributions that each of the various types of conventional and unconventional natural gas categories currently in commercial production make to the global gas supply can been seen in Figure 8.4. This figure also outlines the range of production and transportation costs in 2008 (IEA, 2009). The volumes shown are based on the latest estimates of resource potential. Gas hydrates are not included as commercial production has not yet been proven, and they are not expected to contribute significantly to supply in the immediate future.

Figure 8.4* • *Long-term gas supply cost curve



Notes: CBM = coal-bed methane; LNG = liquefied natural gas; Pipeline costs refer to costs per 1 000 km; MBtu = million British thermal units; tcm = trillion cubic metres.

The total long-term potential gas resource base from these sources is estimated at approximately 790 tcm. Of this total, some 105 tcm have already been produced (and flared and vented to the atmosphere) at costs of up to USD 8/MBtu.[1] To compare this with the cost of oil for the same energy content, USD 8/MBtu equates to USD 46.4/boe.[2]

Production costs for associated gas (gas produced in an oil operation) would generally be lower than for non-associated gas (gas produced from a natural gas field). This is particularly true for fields in which infrastructure for producing oil had already been installed before exploitation of the gas resource had been planned. Significant quantities of associated gas are still flared because it is not

1. USD 1/MBtu (1 million Btu) is approximately equivalent to USD 0.035 per cubic metre.
2. USD 1/MBtu is equal to USD 5.8/boe.

currently worth treating and transporting the gas to market. More than 1.5 tcm has been flared worldwide in the last decade alone, equal to more than 5% of marketed production.

The most easily accessible part of the remaining conventional resources amounts to about 220 tcm, with typical production costs between USD 0.20/MBtu and USD 9/MBtu. Other conventional resources include sour gas and gas produced from the Arctic or from deep water. Sour gas resources, with high concentrations of hydrogen sulphide (H_2S) or CO_2 total some 160 tcm and could be produced at costs between USD 2/MBtu and USD 11/MBtu. Resources in the Arctic Circle could amount to 30 tcm, at costs between USD 4/MBtu and USD 12/MBtu, while deepwater resources of 50 tcm could be produced at costs ranging from USD 5/MBtu to USD 11/MBtu. Unconventional resources totalling 330 tcm (including 80 tcm tight gas, 200 tcm shale gas and 50 tcm CBM) could be produced at costs between USD 3/MBtu and USD 10/MBtu.

An essential cost factor for gas is transportation. For pipelines, the transportation costs are USD 0.30/MBtu to USD 1.20/MBtu per 1 000 kilometres of pipeline, varying for onshore and offshore segments and according to pipe capacity and age of installation. For LNG, total costs for liquefaction, transportation and regasification vary from USD 3.10/MBtu to USD 4.70/MBtu, depending on the installation size and the transportation distances involved. So the production and transportation costs should be added to the total cost at the market location (Figure 8.4).

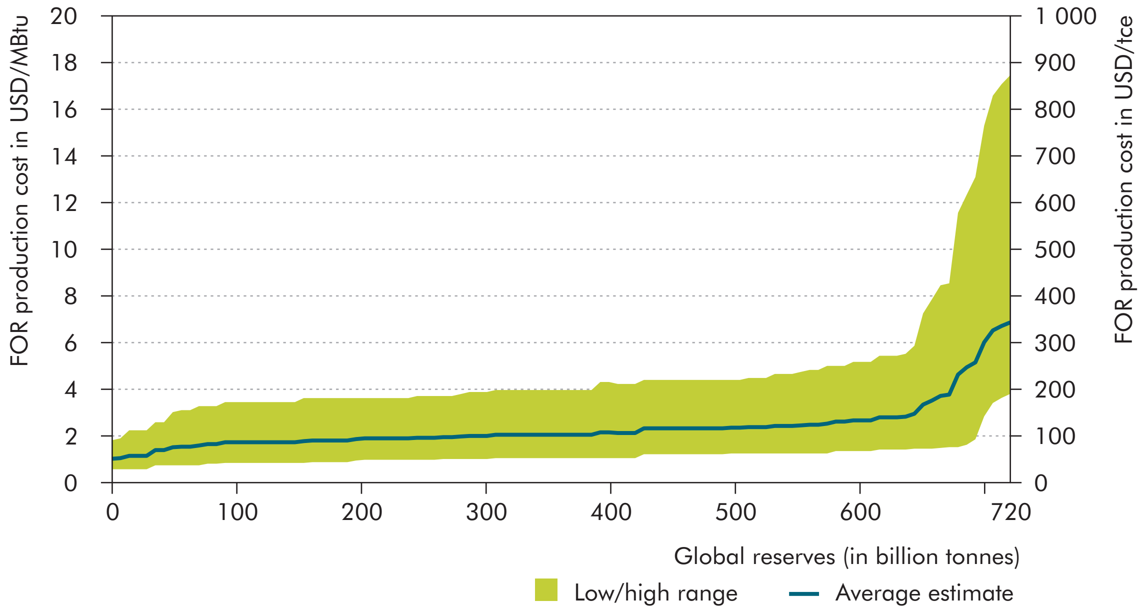
Production cost curve for coal

The quality and frequency of collecting data on coal reserves vary widely from country to country. Estimated costs for coal reserves where extraction is financially viable are often not tracked or researched, or are unavailable, partly as a consequence of commercial confidentiality.

There is currently no complete study that includes a supply-based cost curve of production costs for global hard coal reserves. Extensive research for Australian and South African reserves was carried out by Schulz and published in two articles almost 30 years ago (Schulz, 1984). This author examined the production cost curve for export-oriented thermal coal on an FOB (free-on-board) basis. This source is one of the few estimates and still most appropriate basis for estimating a supply cost curve for all hard coal reserves and includes estimates for production costs as well as capital costs.

The shape and slope of the supply cost curve shows a large volume range for global reserves with a relatively flat slope for global average estimated supply costs and a sharp increase in costs of the last 10% of reserves (Figure 8.5). The curve in Figure 8.5 is extrapolated from Schulz's supply curve up to the 2011 estimate of 728 gigatonnes (Gt) of global hard coal reserves (BGR, 2011). The intercept and scaling of costs are based on the estimated average country level of production costs and reported project-based investment costs when available as observed from 2009 to 2011. This cost information is also used as an estimate for excavation and capital costs for the remaining coal reserves where more detailed country-level information is either not available or not published. It is not possible to create the supply cost curve for global hard coal resources as there is a lack of reliable country-level data for both volume and cost.

Figure 8.5 • Estimated supply cost curve for global hard coal reserves



Notes: tce = tonne of coal-equivalent. The free-on-rail (FOR) production cost includes the cost of mining and delivering the coal from the mine plus surface handling, coal preparation or beneficiation, storage and loading costs.

Source: Rademacher, 2012 (Ranges extrapolated from Schulz [1984], BGR [2011], and public mining records)

Average country-level mining production costs for export-based hard coal were collected (in USD/t, FOB, cash costs) from external public mining and coal services covering major exporting mines across the globe, including Australia, Canada, China, Colombia, Indonesia, Russia, South Africa and the United States. Data came from countries that accounted for nearly 85% of total global hard coal production in 2009 (6 100 million tonnes). The average FOB cash costs (USD/tonne) were then transformed into FOR (free-on-rail or free-mine) costs by subtracting the estimated port and transportation costs. These latter costs made up the largest proportion of costs in China and Russia and the lowest in Australia. Estimates of country-level FOR costs include initial investment costs for new mining projects as well as the capital costs with a 10% hurdle rate.

Estimates of capital costs (depreciation and interest) are available at a country level and based on historical project investment information collected and adjusted to 2010 US dollars. Country-level production costs range widely between low-cost producers such as China and high-cost producers like Canada. The average per unit cost in 2010 US dollars in the data sample is estimated at approximately USD 43/t (USD 50/tce) for the entire global sample. The estimated global cost-adjusted supply curve for hard coal reserves results, with the range determined by low-/high-cost producers, are represented in Figure 8.5.

The cost to develop and produce coal from the first 100 Gt of global coal reserves is low and estimated in the range of USD 42 to USD 170/tce FOR, equivalent to USD 0.84/MBtu to USD 3.45/MBtu. Given a current global hard coal production of 6.0 Gt, this low-cost reserve basis is adequate to cover global demand for almost 17 years. The expected production costs for the next 500 Gt of reserves, sufficient to cover an additional 83 years at current coal mining levels, rise marginally from USD 71/tce to USD 272/tce FOR (USD 1.42 to USD 5.44/MBtu). Production cost estimates for the last 128 Gt of known hard coal reserves, the most difficult to assess and most uncertain, rise sharply to a range of USD 71 tce to USD 800+/tce (USD 1.41/MBtu to USD 15+/MBtu). Given the current global hard coal production, this section of reserves would first be needed in 120+ years. The mining and investment cost estimates would be highly subjective and dependent on developments in technology, global demand and further geological assessments of reserves.

The cost of inland infrastructure for many new undeveloped coal basins and projects is not included, and this can easily more than double production costs in terms of USD/t FOB depending on location. For example, transportation costs currently make up over 50% of total cost for some export coal in China and Russia.

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Chapter 9 • Meeting the environmental challenges

Though they may bring economic benefits, the production, transportation and use of oil, gas and coal can have negative impacts on the environment at both the local and global levels. At the local or regional level, the challenge to the environment comes from pollution and potential hazards at the production site. For oil and gas, these may manifest themselves, for example, as crude oil spills or from accidents with local or regional transportation. Another example is the damage that can result from coal mining operations, including sometimes the despoiling of the countryside or the pollution of local water courses due to the leaching of heavy metals from coal spoil heaps.

On a global scale, the challenge to the environment comes from direct and indirect damage caused by the production, transportation and use of fossil fuels. The main concern in virtually all cases comes in the form of emissions of greenhouse gases (GHGs), predominantly methane and carbon dioxide (CO_2). During the extraction of oil, gas and coal, for example, methane is released, and CO_2 emissions occur at oil and natural gas well-heads. Methane leaks from long-distance, natural gas pipelines and CO_2 is emitted wherever electricity is generated from the combustion of coal, gas and oil.

Global increases in the concentrations of CO_2 and other GHGs are due primarily to fossil fuel use, with land-use change (LUC) providing another significant but smaller contribution. This chapter focuses on the emissions produced by the oil, gas and coal industries, and the cost implications that arise.

Production-related GHG emissions from oil resources

A fraction of total emissions from the use of fossil fuels arises directly from crude oil production and the subsequent refining processes needed to turn crude into final fuel products.

An industry survey from the International Association of Oil & Gas Producers (OGP, 2012)[1] indicates that around 1.1 gigatonnes (Gt) of CO_2 emissions per year (3.5% of total energy-related CO_2 emissions worldwide) come from oil and gas production and fugitive emissions at the well-head. As the majority of crude oil is still produced from conventional resources, emissions from upgrading crude, which is necessary for unconventional resources such as oil-sands and extra-heavy oil production, currently represent only a small fraction of total emissions. However, if more unconventional resources requiring upgrading were extracted, the average production of GHG emissions per barrel of oil-equivalent (boe) of final fuel would increase.

Oil-refining processes accounted for around 728 million tonnes (Mt) of CO_2 in 2010, which equated to around 2.4% of total energy-related CO_2 emissions.

1. The survey includes 32% of world oil and gas production (2 221 Mt of hydrocarbon production) and was expanded to a global level by assuming that the CO_2-equivalent (CO_2-eq) emissions from all countries globally were similar.

Factors influencing GHG emissions from oil production

The amount of GHG emissions released during upstream and downstream oil production depends primarily on the following factors:

- energy input from fossil fuels used for oil extraction at the production site;
- flaring and venting of fugitive GHG emissions at the well-head, where the amount of the well-head fugitive emissions depends on individual reservoir characteristics;
- flaring of associated gas at the well-head;
- emissions from crude oil upgrading (if necessary) and refining, which are dependent on the quality of the recovered crude oil or crude oil substitute, expressed as American Petroleum Institute (API[2]) gravity.

Conventional crude oil can usually be extracted without substantial energy input. The technological challenges can nevertheless be high. This is the case for ultra-deepwater and Arctic oil resources for which more capital- and energy-intensive infrastructure is needed (Chapter 4).

For high-quality crude oil, additional upgrading before the refinery stage is not necessary. However, significant emissions of CO_2 and methane may stem directly from the multiphase flow at the well-head. The methane may either be: vented (released as methane to the atmosphere) with the CO_2; or flared (burnt at the top of flare stack); or, preferably, it may be used to power the energy requirements of the oil extraction operation.

Comparatively low-quality oil shale and viscous extra-heavy oil and bitumen resources are either mined and processed or heated underground (in situ) to create a liquid crude product that can then be extracted from the reservoir. In addition, energy-intensive upgrading of extra-heavy oil and bitumen to produce a so-called “syncrude” is required. The syncrude is used as a substitute for conventional crude oil in refineries.

The energy intensity of the refining process depends directly on the crude oil quality. Deep conversion processes that are needed for heavy oil (with an API gravity less than 22.3°) are, for example, considerably more energy-intensive than conventional distillation processes for light oil (with an API gravity greater than 31.1°).

The combined amount of GHG emissions from upstream stages varies widely, depending on the reservoir characteristics, the extraction methods used, *i.e.* the energy input needed for crude oil extraction, and the treatment of fugitive emissions at the well-head. Downstream emissions will hinge on the energy intensity of the subsequent refining processes and on the need for a possible additional upgrading stage, depending directly on the quality of the crude oil.

2. API (American Petroleum Institute) gravity is a measure of the density of oil. The API gravity scale is calibrated such that most crude oils, as well as distillate fuels, will have API gravities between 10° and 70° API. The lower the number, the heavier and the more viscous is the oil.

Competing fuels

In recent years, crude oil substitutes from various types of feedstock sources have received growing attention. Such fuels, referred to here as competing fuels, can be split into two subgroups: synfuels and biofuels.

Synfuels are derived from Fischer-Tropsch synthesis (see Chapter 3, Box 3.1) or other conversion processes. Feedstocks for the process may be coal, natural gas, biomass or a mixture of these. Such conversion processes are very energy-intensive and the consequent CO_2 emissions are high. The GHG emissions per barrel of oil-equivalent depend on the process, the process feedstock and the conversion efficiency.

In the most commonly used coal-to-liquids (CTL) technology, coal is first gasified to produce synthesis gas (or syngas), which is then catalytically treated in a Fischer-Tropsch process to produce liquid fuels (or synfuels). CTL synfuels, therefore, have the highest CO_2 emissions because of the higher carbon intensity of coal compared with the other feedstocks and the need to gasify the coal before Fischer-Tropsch conversion; the overall energy conversion efficiency is around 50%. Gas-to-liquids (GTL) synfuel production has lower CO_2 emissions owing to a more favourable carbon/hydrogen ratio of natural gas and has a significantly better conversion efficiency of around 58%.

Biofuels, such as ethanol and biodiesel, are derived from a variety of possible feedstocks. It would be expected that, in theory, biofuels are carbon-neutral. However, the fossil fuels needed for crop harvest, transportation, natural gas-based fertilisers for crop growing and conversion processes can be significant. In some cases, almost as much energy may be needed in the form of fossil fuels during the production chain as energy eventually delivered in the form of biofuels.

Nevertheless, there are promising examples of biofuels, such as ethanol produced from sugar cane and biodiesel produced from palm oil. Both have a high energy-output to energy-input ratio, or energy return on energy investment. However, it is crucial that environmentally sustainable growing methods be used for all types of biomass plantations. In terms of the lifecycle GHG balance of biofuels, it is important to avoid emissions stemming from the conversion of land with high-carbon stocks (*e.g.* tropical peat forest) into biofuel production. Such LUC can result in initial CO_2 emissions that would take decades to be compensated by the use of biofuels.

Options for mitigation

Important mitigation measures to reduce GHG emissions are increasing energy efficiency in the supply and demand sectors, and preferential use of, or switching to, lower-carbon footprint sources such as natural gas, renewable energy and nuclear. Such measures would make a major contribution to cost-effective CO_2 emissions reductions as illustrated in *Energy Technology Perspectives 2012* (IEA, 2012a), where the low-carbon scenario based on stabilising CO_2 atmospheric concentrations at 450 parts per million (ppm) offers an 80% probability of limiting the rise in atmospheric temperature to 2°C. Projections show that carbon capture and storage (CCS) will also bring an essential contribution to a low-carbon future, contributing around one-fifth of total reductions in energy-related CO_2 emissions by 2050 compared to the business-as-usual case.

Carbon capture from gas streams with high concentrations of CO_2 and at high pressures, typical of a number of industrial applications, could be achieved at comparatively low cost. CCS from industrial applications, for example liquefied natural gas (LNG) production facilities, is expected to cost on average between USD 10 per tonne (/t) to USD 20/t (UNIDO, 2010). In some instances, costs could be even less than USD 10/t or even result in net cost benefits. If CCS is combined with enhanced oil recovery (EOR), the value of the additional oil extracted may partially offset the additional costs of CCS.

CCS remains an emerging technology in the power sector, where it has not yet been demonstrated at commercial scale. As a consequence, information on current costs and performance of CCS from power generation is still uncertain and limited to estimates from engineering studies or pilot projects. The cost of carbon capture from power generation is estimated to be around USD 60/t in recent studies (Folger, 2010; Finkenrath, 2011). Additional costs for the transportation and storage of CO_2 are more difficult to model, as they depend on site-specific considerations and on the availability of storage space. Typically, however, costs related to the carbon capture step, which includes compression of the CO_2 for transport (if required), are expected to account for the majority of CCS costs. Technology for capturing CO_2 is still evolving and novel solutions are being tested such as improved membrane or cryogenic cyclone technologies. Membranes are being developed such that, when a gas stream is passed over them, only CO_2 molecules will pass through, thus separating the CO_2 from other contaminating gases present in the stream. In cryogenic cyclones, the gas is cooled down by rapid expansion, after which contaminants condense into small droplets that are then separated by centrifugal action.

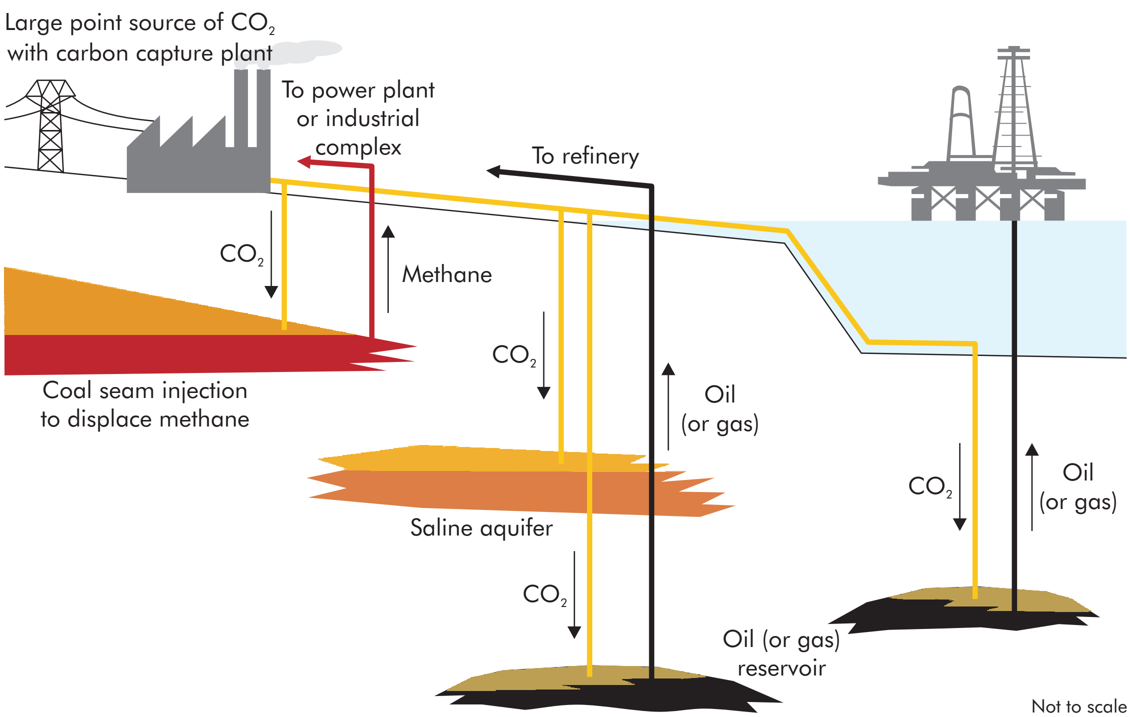
In the oil industry, energy efficiency measures are part of current project design. Choices include using solar energy for steam generation, applying co-generation for steam and power, and using wind energy on offshore platform installations. In the future, projects with a large carbon footprint will need to consider CCS. Such projects will likely include underground storage as the preferred option. Within oil companies, there is already significant expertise in many aspects of underground CO_2 storage, but there are also unresolved issues, such as long-term storage security. This expertise is also being applied to the capture of CO_2 from fossil-fuelled power generation plants.

There are four main options (Figure 9.1) considered for storing CO_2 underground for long periods of time:

- injection and eventual dissolution and precipitation as carbonate in saline aquifers;
- injection into depleted oil and gas reservoirs;
- enhanced recovery techniques to displace oil or gas from reservoirs;
- injection into coal seams for enhanced coal-bed methane recovery.

In addition, there are a number of other possibilities that are less likely to offer significant potential for storage in the short to medium term.

Figure 9.1 • Underground storage options



Note: unless otherwise indicated, all material in figures and tables derives from IEA data and analysis.

The main options listed above are already viable, proven or being demonstrated. For example, large volumes of CO_2 separated from natural gas extracted from the Norwegian offshore fields of Sleipner and Snøhvit are being injected and stored in deep saline aquifers every year. Until recently, this was also the case for CO_2 separated at the Algerian In Salah field. Similarly, large volumes have been injected to enhance oil recovery from the Canadian Weyburn-Midale oilfields while, at the same time, providing a means of storage. For all these options, long-term containment of CO_2 is still a key issue and will require appropriate site selection and resolution of the monitoring strategies supported by an appropriate legal framework. Four fully integrated, commercial-scale CCS projects that are or were recently in operation are described in Box 9.1.

Box 9.1 • Commercial CCS projects

Three of the four fully integrated, large-scale CCS projects described below are in commercial operation today. All four projects contribute to the knowledge base needed for widespread CCS use.

Sleipner

The Sleipner project began in 1996 when Norway's Statoil started to inject more than 1 Mt per year of CO_2 under the North Sea. This CO_2 was extracted with natural gas from the offshore Sleipner gas field. In order to avoid a government-imposed carbon tax equivalent to about USD 55/t, Statoil built a special offshore platform to separate CO_2 from other gases. The CO_2 is reinjected about 1 000 metres (m) below the sea floor into the Utsira saline formation located near the natural gas field. The formation is estimated to have a capacity of about 600 Gt of CO_2 and is expected to continue receiving CO_2 long after natural gas extraction at Sleipner has ended.

Snøhvit

Europe's first LNG plant also captures CO_2 for injection and storage. Statoil extracts natural gas and CO_2 from the offshore Snøhvit gas field in the Barents Sea. It pipes the mixture 160 kilometres (km) to shore for processing at its LNG plant near Hammerfest, Europe's northernmost town. Separating the CO_2 is necessary to produce LNG and the Snøhvit project captures about 700 000 t of CO_2 per year. Starting in 2008, the captured CO_2 is piped back to the offshore platform and injected in the Tubåsen sandstone formation 2 600 m under the seabed and below the geologic formation from which natural gas is produced.

Weyburn-Midale

About 2.8 Mt CO_2 per year is captured at the Great Plains Synfuels Plant in North Dakota, United States, which is a coal-gasification plant that produces synthetic gas and various chemicals. The CO_2 is transported by pipeline 320 km (200 miles) across the international border into Saskatchewan, Canada and is injected into depleting oilfields where it is used for EOR. Although it is a commercial project, researchers from around the world have been monitoring the injected CO_2 to ensure its long-term containment. The Weyburn-Midale CO_2 monitoring and storage project, which is part of the IEA Greenhouse Gas Research and Development Programme, has been the first project to scientifically study and monitor the underground behaviour of CO_2. Canada's Petroleum Technologies Research Centre has managed the monitoring effort. A manual of best practices for carbon injection and storage has been published (IEA GHG, 2012).

In Salah

In August 2004, Sonatrach, the Algerian national oil and gas company, with its partners BP and Statoil, began injecting about 1 Mt CO_2 per year into the Krechba geologic formation near their natural gas extraction site in the Sahara desert. The Krechba formation is adjacent to the gas-producing reservoir and lies 1 800 m below ground. It has an estimated 17 Mt CO_2 total storage lifetime. Injection of CO_2 was suspended in June 2011, though monitoring of the site continues.

Source: IEA, 2010 (adapted).

For these four projects, the sources of the CO_2 are from contaminated gas sources and an industrial plant but, as yet, there are no large-scale, integrated CCS projects on a coal- or gas-fired power generation plant.

Upstream GHG emissions

Results from an extensive survey of upstream and downstream GHG emissions in the oil sector (Brandt and Farrell, 2007; Brandt, 2008; Brandt, 2009; IFEU, 2008; NETL, 2008; Charpentier, Bergerson and MacLean, 2009; Mui, Tonachel and Shope, 2010; NRCan, 2012; ANL, 2012; Jacobs Consultancy, 2012) and the biofuels sector (IEA, 2011a) are summarised below. Metrics used in the survey are defined in Box 9.2.

Box 9.2* • *Definitions used for the lifecycle assessment of oil production

Well-to-refinery (WTR): *the phase in which crude oil (or oil-sands) is extracted from the well and brought to a refinery. For oil-sands and heavy oil, it usually includes upgrading the low-quality crude to syncrude. This phase incorporates all emissions of the following stages:*

- *recovery/extraction;*
- *upgrading;*
- *transport to refinery and supply-chain emissions;*
- *venting and flaring, as well as fugitive emissions from leaks and tailing ponds.*

Refinery-to-tank (RTT): *the phase in which the crude oil or syncrude is refined to final fuel (in this case gasoline). This phase incorporates all emissions from the following stages:*

- *refining;*
- *distribution/storage/dispensing;*
- *supply chain emissions.*

Well-to-tank (WTT): *the phase includes production-related GHG emissions from all upstream and downstream stages. It is the sum of the previous two phases, WTR and RTT: WTT = WTR + RTT. For gasoline, this is around 120 kilograms of CO_2 per boe (kg CO_2/boe).*

Tank-to-wheel (TTW): *this phase includes all GHG emissions from the combustion of the final fuel. For gasoline, this is around 425 kg CO_2/boe (using the lower heating value for gasoline, which equals 44.4 megajoules per kilogram [MJ/kg]).*

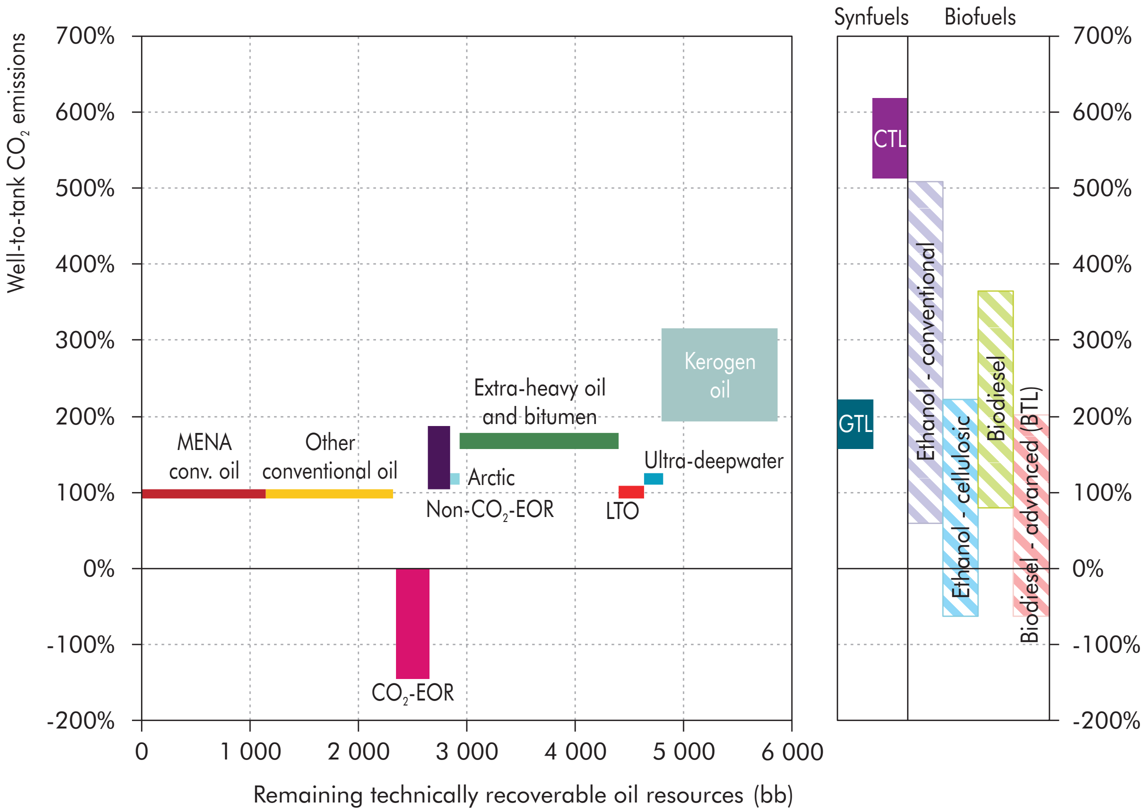
Well-to-wheel (WTW): *this measure represents total GHG emissions. All production-related GHG emissions and GHG emissions from final fuel combustion are accounted for (from oil well to car wheel). It is the sum of the previous phases: WTW = WTT + TTW.*

Comparison of fuel cycle GHG emissions from different liquid fuels

In the analysis, the GHG emissions that occur during oil extraction, from upgrading heavy oils and bitumen, and from refineries during processing to the final fuel gasoline are addressed. The combustion of regular gasoline alone creates around 425 kg CO_2/boe of final fuel and is used here as a comparison with upstream GHG emissions.

The results of the analysis are shown in Figures 9.2 (WTT GHG emissions balance, normalised against conventional oil) and Figure 9.3 (WTW GHG emissions balance).

Figure 9.2 • Total WTT GHG emissions from various oil resource categories

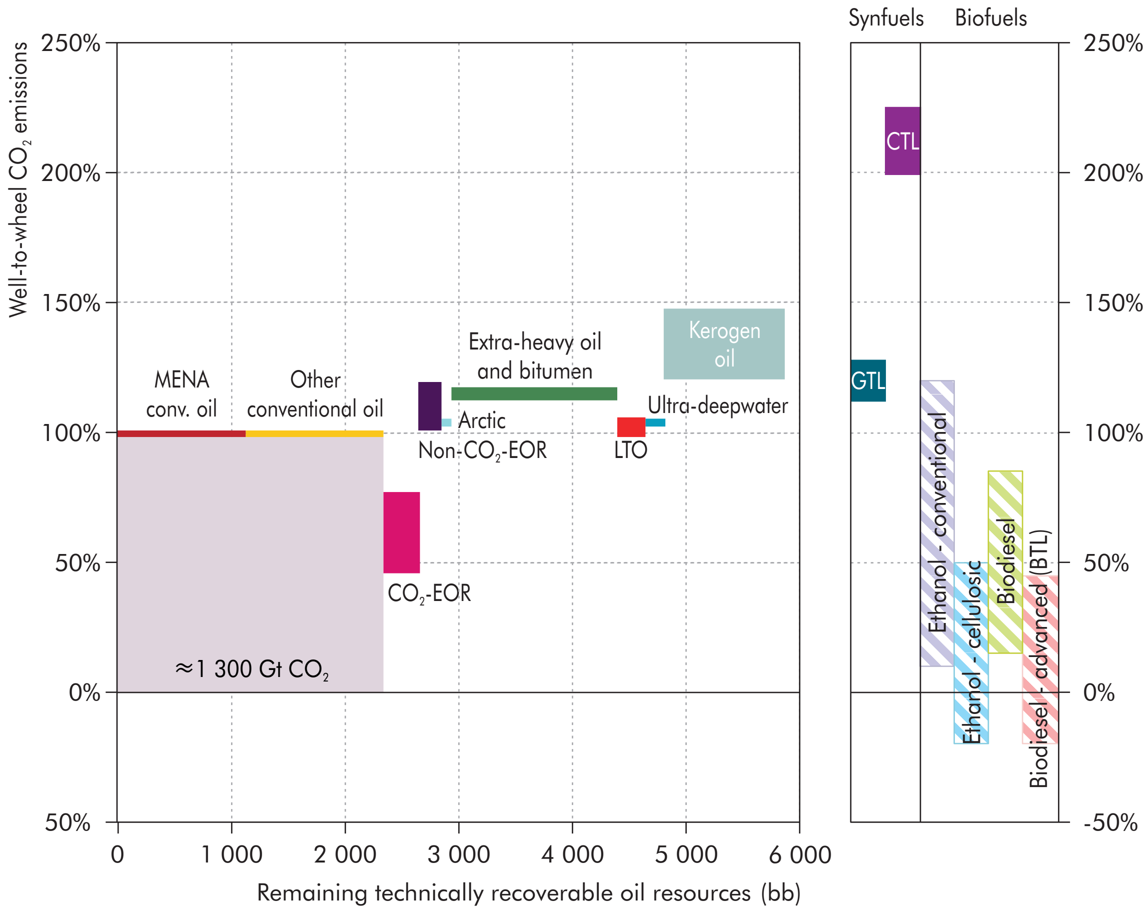


Notes: MENA = Middle East and North Africa; LTO = light tight oil; BTL = biomass-to-liquids. Values normalised, with conventional oil as the benchmark (120 kg CO_2/boe).

In Figure 9.3, the area of one grid rectangle is equivalent to 270 Gt of CO_2 emissions. This is roughly a factor of nine higher than the current global energy-related CO_2 emissions per year. The area underneath the box of each resource category is roughly equivalent to the corresponding total GHG emissions (from production, refining and final fuel combustion) in the best case. As an example, using up all crude oil from conventional resources (2.35 trillion barrels, excluding EOR) would emit around 1 300 Gt of additional GHG emissions. This would be equivalent to more than 40 years of current energy-related CO_2 emissions.

A comparison of production-related GHG emissions, such as WTT emissions from upstream activities and downstream processing, using GHG emissions from conventional oil as the benchmark, is presented in Table 9.1. Furthermore, total GHG emissions, such as WTW emissions from upstream and downstream production and final fuel combustion are compared again using the GHG emissions from conventional oil as the benchmark.

Figure 9.3* • *Total WTW GHG emissions from various oil resource categories



Note: values normalised, with conventional oil as the benchmark (545 kg CO_2/boe).

Greenhouse gas emissions of biofuel and BTL synfuel combustion are assumed here to be carbon-neutral. All GHG emissions actually occurring are already accounted for in the fuel production and conversion stages.

From Table 9.1, and Figures 9.2 and 9.3, it can be seen that:

- Biofuels have the best WTW GHG emissions balance. In fact, the lowest emissions are from cellulosic ethanol and BTL biodiesel (-20% to 50% of GHG emissions when compared to the conventional oil benchmark). Conventional biofuels have higher emissions (10% to 120%). WTT GHG emissions are not necessarily lower than the benchmark (-91% to 545%), but the fuel combustion afterwards is by definition carbon-neutral. Hence, total biofuel WTW GHG emissions are in many cases lower than those of the gasoline reference. However, emissions from direct and indirect LUC can in some cases significantly reduce the WTW GHG emissions balance of biofuels, and should therefore be avoided.

Table 9.1 • *Production-related WTT GHG emissions, and comparison with total WTW GHG emissions*

Resource type	Production WTT GHG emissions kg/boe	Production WTT GHG emissions (normalised to conventional oil: 120 kg CO_2-eq/boe)	Total WTW GHG emissions (normalised to gasoline: 545 kg CO_2-eq/boe)
Conventional oil (average)	110 to 125	91 % to 104%	98 % to 101%
Non-CO_2-EOR	125 to 225	104 % to 188%	101% to 119%
CO_2-EOR	-175 to -5	-146 % to -4%	46 % to 77%
Ultra-deepwater and Arctic	132 to 150	110 % to 125%	102 % to 105%
Extra-heavy oil an bitumen	189 to 214	157 % to 178%	113 % to 117%
Kerogen	232 to 379	193 % to 315%	121 % to 147%
LTO	110 to 131	91 % to 109%	98 % to 106%
GTL	184 to 272	153 % to 227%	112 % to 128%
CTL	660 to 801	550 % to 668%	199 % to 225%
Ethanol – conventional (wheat, corn, sugar beet)	55 to 654	45 % to 545%	10 % to 120%
Ethanol – cellulosic	-109 to 273	-91 % to 227%	-20 % to 50%
Biodiesel – conventional (rapeseed, palm oil)	82 to 463	68 % to 386%	15 % to 85%
Biodiesel – advanced (BTL) diesel	-109 to 245	-91 % to 204%	-20 % to 45%

Notes: kg/boe = kilogram per barrel of oil-equivalent; kg CO_2-eq/boe = kilogram of carbon dioxide-equivalent per barrel of oil equivalent).

- Using CO_2-EOR production substantially decreases the GHG emissions of oil production on a per-barrel basis, where there is a net CO_2 storage underground. Production-related WTT GHG emissions would then be negative (down to -146%) with total GHG emissions being considerably lower than the benchmark (46% to 77%).
- The amount of GHG emissions from non-CO_2-EOR production measures ranges from slightly higher to significantly higher when compared to the production-related GHG emissions of the benchmark (104% to 188%). Total GHG emissions are up to a fifth higher than benchmark emissions (100% to 120%).
- Final fuel produced from extra-heavy oilfields and oil-sands performs considerably worse in terms of GHG emissions than final fuel produced from conventional oil (157% to 178%). When total WTW GHG emissions are compared, emissions are still 13% to 17% higher than for the benchmark conventional oil.
- Final fuel from GTL plants is in the same range of WTW GHG emissions as fuel produced from extra-heavy oil, oil-sands and non-CO_2-EOR (112% to 128%).
- Fuel production from kerogen creates more GHG emissions than oil-sands production and GTL plants (193% to 315%), because of the extremely high

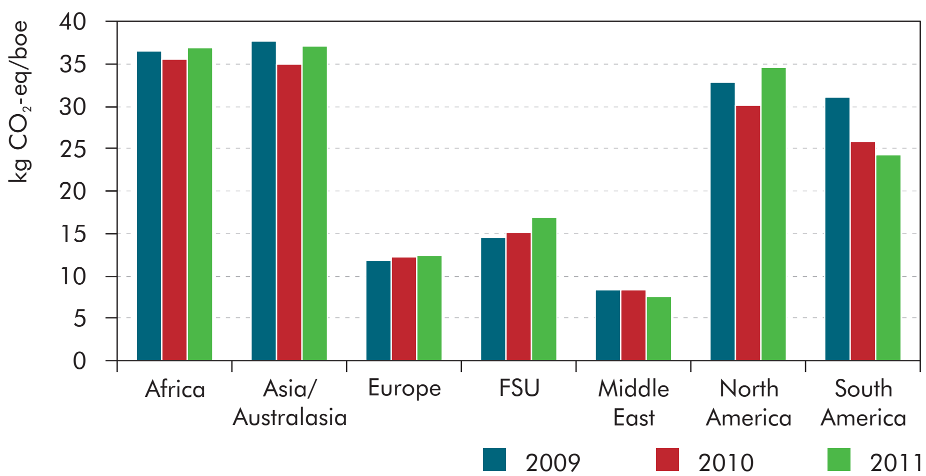
energy input needed for crude oil extraction and the lower quality of the crude produced. In terms of total WTW GHG emissions, these fuels have 21% to 47% higher emission levels.

- A complete study on GHG emissions for LTO was not available. Higher production-related emissions for landing and take-off are roughly compensated by lower refinery emissions. GHG emissions are assumed to be identical to conventional oil, with the higher boundary set to be 5% higher.
- A coal liquefaction plant has by far the highest production-related GHG emissions (550% to 668%), because of its carbon-intensive feedstock (coal) and the lower conversion efficiency compared to GTL processes. Its total WTW GHG emissions can be double the benchmark GHG emissions (199% to 225%).

Figures for GHG emissions related to oil production are the average GHG emissions from production for the respective oil resource category. In reality, there are wide variations in GHG emissions for every type of oil resources. Oilfield characteristics are not identical and crude quality varies considerably even within the same resource category. Production technology also plays an important role. Application of more efficient production technologies can significantly reduce the energy input needed for production, as well as the amount of fugitive GHG emissions at a well-head.

The upstream (WTR) GHG emissions from production and the necessary energy input averaged for all oilfields in a given region are shown in Figures 9.4 and 9.5 (OGP, 2012). The regional spread in GHG emissions and energy-input intensity cannot only be explained by varying crude oil quality and oilfield characteristics, but also by environmental regulations (*e.g.* for flaring) and higher taxes on transportation fuels (as in Europe). These have been effective drivers in reducing GHG emissions through the widespread use of more efficient technology.

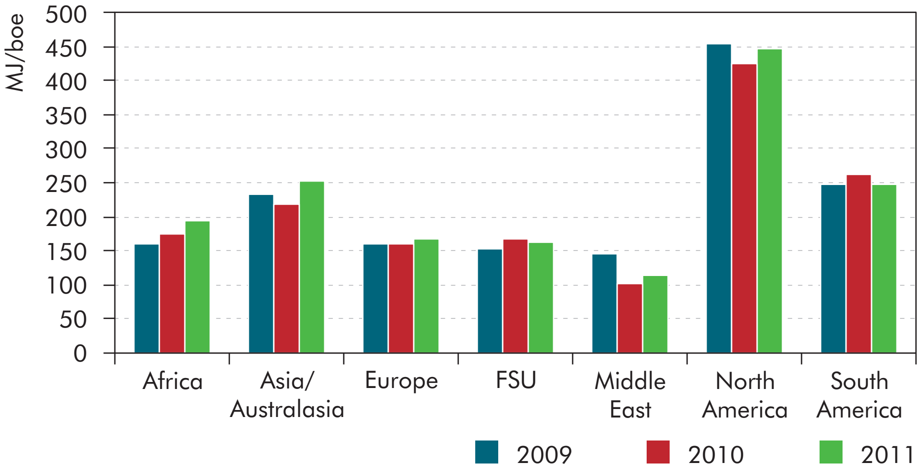
Figure 9.4* • *Upstream (WTR) GHG emissions per unit of production from industry survey



Notes: MJ = megajoule; FSU = former Soviet Union. Survey data include 32% of 2011 world production; assumes 1 t of crude oil = 6.84 boe.

Sources: OGP, 2010, 2011 and 2012.

Figure 9.5 • *Energy input in upstream production from industry survey*



Note: Survey data include 32% of 2011 world production; assumes 1 tonne crude oil = 6.84 boe; FSU = former Soviet Union.

Sources: OGP, 2010, 2011 and 2012.

Trends for the future

A shift away from the production of conventional towards unconventional oil would increase GHG emissions in both the upstream and downstream stages. The reason for this is largely because unconventional sources such as oil-sands, heavy oil, CTLs and GTLs, are generally more energy-intensive to produce and refine. On the other hand, improvements in vehicle efficiency could potentially reduce emissions. Recently, there has been a trend towards replacing gasoline and diesel with biofuels in the transport sector. However, future trends in this direction are uncertain, especially for biofuels from agricultural crops and from crops grown in cleared tropical forest areas.

A continuing shift from conventional crude oil production to petroleum substitutes could increase global GHG emissions up to 2030 and hence become an additional driver for climate change (Brandt and Farrell, 2007).

For oil-sands and heavy oil, the higher average upstream GHG emissions from unconventional oil are expected to be accompanied by a decrease in the quality of crude oil. These two effects would raise GHG emissions from oil production by several million tonnes to 1 Gt per year in the long term unless effective mitigation measures are put in place. The mitigation of GHG emissions from oil production is crucial for both the conventional and unconventional oil sectors.

There are multiple ways to reduce GHG emissions by using technology. For example:

- Improving the highly energy- and emissions-intensive in situ extraction methods used for heavy oil and bitumen as well as oil shale would have a positive effect on the GHG emissions balance of these oil resource types.
- There are good opportunities for implementing CCS in CTL and GTL plants, because the CO_2 stream, unlike that from pulverised coal-fired power plants,

is already sufficiently pure for direct sequestration. CCS would, of course, add to the cost. However, further costly processing steps that reduce overall plant efficiency, as in the case for power plants, would not be necessary. Increasing the efficiency of CTL and GTL plants would obviously reduce additional CCS costs by reducing CO_2 emissions per barrel of final synfuels.

- Putting associated natural gas from oil production into better use in a gas turbine at the well site, instead of venting or flaring it, would save energy and probably also costs, especially if carbon pricing were introduced. Also, fugitive CO_2 emissions at the well-head could be used for CO_2-EOR in favourable oilfield settings, which would in turn considerably increase the oil recovery factor there and, if the oilfield characteristics permit, provide a net storage of CO_2 underground.

As regards the future role of biofuels and BTL synfuel, it is crucial to shift towards high energy-yield biomass feedstocks such as sugar cane for ethanol production, so as to better exploit the potential of waste biomass such as bagasse and waste wood for BTL processes and to make BTL plants more energy-efficient. Moreover, for the long-term credibility and environmental sustainability of biofuels, it is essential to ensure internationally aligned standards for sustainable biomass cultivation to avoid negative environmental, economic and social impacts.

Impact of carbon pricing

This section provides an in-depth quantitative assessment of the additional production costs for one barrel of crude oil or 1 barrel of oil-equivalent (boe) if a carbon tax (or price per emissions) were to be introduced in the oil sector. The assessment takes into account WTT emissions but excludes TTW emissions. The objective of a carbon tax would be to internalise the external costs occurring as a consequence of climate change. Depending on its magnitude, this would provide an economic incentive to reduce GHG emissions. However, this analysis cannot be used to judge the impact of different hydrocarbons and biofuels on climate change.

The assessment mainly focuses on the assumption that the price of carbon emissions would be USD 50 per tonne of CO_2-equivalent (/t CO_2-eq) or USD 150/t CO_2-eq emissions, depending on the commitment to mitigate climate change.

The negative impact of a carbon price on liquid fuel production costs would be substantial for some resource types and less for others, depending on the specific GHG emissions from the production of fuel in each resource category.

Table 9.2 provides an overview of the average specific WTT GHG emissions from upstream and downstream oil production and the related cost increases for liquid fuels if various levels of carbon price were put in place.

The quantitative effects on the oil production cost curve are shown in Figure 9.6 (USD 50/t CO_2-eq) and Figure 9.7 (USD 150/t CO_2-eq). These graphs should be compared to Figure 8.3 (Chapter 8) where carbon pricing was not included.

Table 9.2 • *Impact of GHG emissions on production costs (for various carbon prices)*

Resource type	Production GHG emissions (WTT) (kg/boe final fuel)	Additional costs (USD) at carbon price: USD 50/t CO_2-eq GHG emissions	Additional costs (USD) at carbon price: USD 150/t CO_2-eq GHG emissions
Conventional oil (average)	110 to 125	5 to 6	16 to 19
Non-CO_2-EOR	125 to 225	6 to 11	19 to 34
CO_2-EOR	-175 to -5	-9 to 0	-26 to -1
Ultra-deepwater and Arctic	132 to 150	6 to 7	20 to 22
Extra-heavy oil and bitumen	189 to 214	6 to 17	17 to 30
Kerogen	232 to 379	12 to 19	35 to 57
LTO	110 to 131	5 to 7	16 to 20
GTL	184 to 272	9 to 14	28 to 41
CTL	660 to 801	33 to 40	99 to 120
Ethanol - conventional	55 to 654	3 to 33	8 to 98
Ethanol - cellulosic	-109 to 273	-5 to 14	-16 to 41
Biodiesel - conventional	82 to 463	4 to 23	12 to 69
Biodiesel - advanced	-109 to 245	-5 to 12	-16 to 37

Figure 9.6 • *Oil production costs for a carbon price of USD 50/tCO_2-eq*

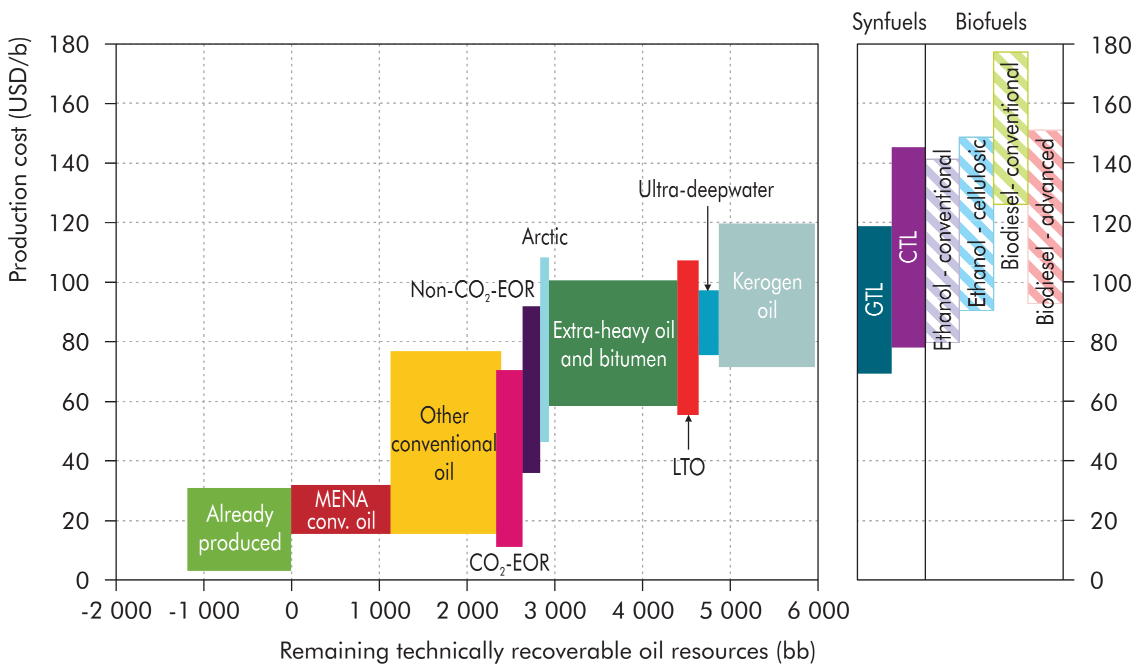
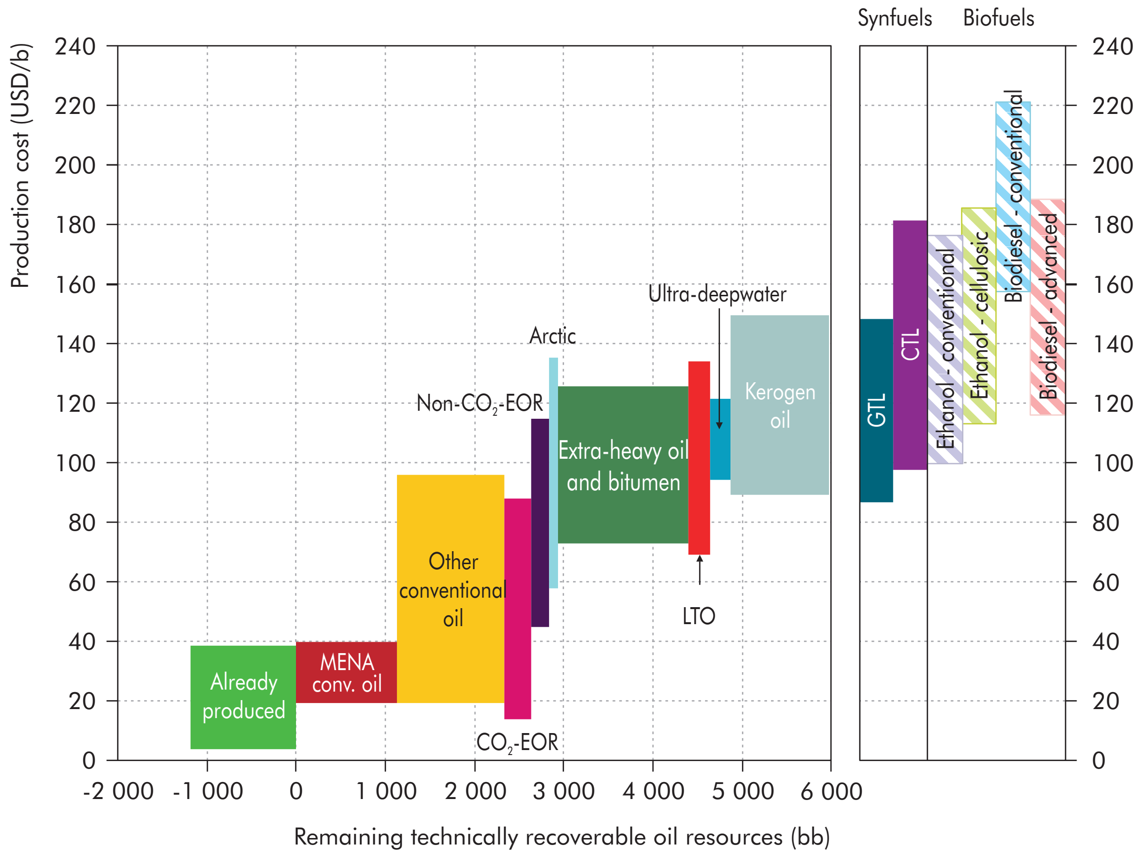


Figure 9.7 • *Oil production costs for a carbon price of USD 150/tCO$_2$-eq*



A carbon price of USD 50/t CO$_2$-eq would drive up the costs for conventional oil and LTO by around USD 6 per barrel (/b). The costs of syncrude production, extra-heavy oil, bitumen and kerogen resources as well as synfuel production from CTL processes would increase significantly (higher than USD 10/boe) at USD 50/t CO$_2$-eq. The costs of kerogen would increase by USD 12/b to USD 19/b and those of extra-heavy oil and bitumen by USD 6/b to USD 17/b. The costs of CTL synfuel would increase very substantially by USD 33/boe to USD 40/boe. GTL synfuel would be less affected (plus USD 9/boe to USD 14/boe) because of the more favourable carbon/hydrogen ratio of natural gas and a more efficient process. Given this prospect, investments in these oil resource categories would be discouraged from a pure financial viewpoint. If, however, supply security were to play a stronger role in the future, resources such as Canadian oil-sands in Alberta could still be exploited despite the increased production costs.

EOR, deepwater and ultra-deepwater oil resources improve their cost-competiveness compared to unconventional oil resources (Table 9.2). These resources experience cost increases of less than USD 10/boe or even cost reductions in the case of EOR.

EOR technologies by CO$_2$ injection are an interesting exception to the general cost increase under carbon pricing. This production technique could in effect help to convert conventional oilfields into significant carbon sinks. Oil production from CO_2-EOR would become significantly less expensive, with the cost being reduced by between USD 9 (for a carbon price of USD 50/t CO_2-eq) and USD 26 (for a carbon price of USD 150/t CO_2-eq) per barrel of additional oil produced, if a lasting net carbon storage effect could be achieved. This estimated reduction in costs is derived when looking at the net balance of sequestered CO_2 and emissions from upstream production and downstream refining. Such a reduction would make production more financially viable. A carbon price could incentivise additional use of EOR and increase the CO_2-EOR resource estimates.

Such a strong financial incentive would dramatically change the outlook for oil production capacity. It could effectively alter business-as-usual projections for 2035, the year by which higher CO_2-emitting unconventional oil resources are projected to amount to more than 12% of total oil production (Table 9.3), from less than 5% in 2011.

Table 9.3 • *Oil production, overview by resource type (million barrels per day)*

Resource	2011	2035		
		New Policies Scenario	Current Policies Scenario	450 Scenario
Crude oil	68.5	65.4	70.8	51.5
Natural gas liquids	12.0	18.2	19.5	14.4
Unconventional oil	3.9	13.2	15.0	10.8
Biofuels	1.3	4.5	3.7	8.2
Processing gains	2.1	2.9	3.2	2.3
World total liquids supply	87.9	104.2	112.2	87.2

Note: biofuels are expressed as energy-equivalent volumes of gasoline and diesel.

Source: IEA, 2012b.

In favouring low-carbon oil resources over more polluting, high-carbon resources that are environment-unfriendly in terms of GHG emissions, carbon pricing clearly offers benefits. Nevertheless oil production from almost all resource categories remains economically feasible. For oil prices around USD 80/b, even a carbon price of USD 50/t CO_2-eq brings most resource categories into play.

To eliminate high CO_2-emitting oil resources and oil substitutes, a much stronger economic incentive would be needed; for example, raising the carbon tax even higher. At a carbon price of USD 150/t, oil prices would need to be USD 100/boe to make the exploitation of most unconventional oil resources financially feasible (Figure 9.7).

The introduction of carbon pricing would also penalise most biofuels with respect to conventional oil, if considered on a WTT basis. However, this does not reflect the beneficial impact that biofuels can have on climate change. Combustion of biofuels is in fact carbon neutral, since the feedstock absorbed carbon from the atmosphere during its creation phase. The combustion emissions of oil-based fuels could monetise into an additional cost of USD 20/boe and USD 60/boe at a carbon price of USD 50/t CO_2-eq and USD 150/t CO_2-eq, and thus favour the use of biofuels.

Political willingness and governmental actions will strongly influence the extent of CO_2 emissions reductions, such as those promised in the Copenhagen Accords or those based on limiting atmospheric CO_2 concentrations to a maximum of 450 ppm. Carbon pricing, energy efficiency, stimulus packages for sustainable energy sources and switching to natural gas may curb the demand for coal or oil. If this happens, it will slow down the further development of high CO_2-emitting resources on a WTW basis.

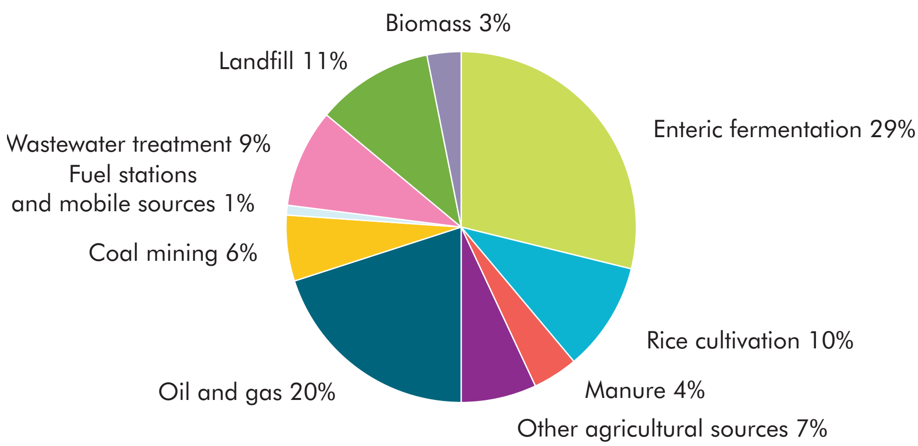
Energy sector methane releases

Methane emissions have both a global and a local impact on the environment. However, analysis has shown that the potential to reduce methane emissions from the energy sector is high (IEA, 2008). This is, in part, due to the fact that while methane is a GHG, it also has significant value as a commodity. With rising fuel prices, even in the absence of a GHG emissions price signal, the value of capturing methane as a fuel could make it financially attractive.

Methane is 25 times more potent as a GHG than CO_2 and, as such, its influence on global warming is significant. Total global GHG emissions (all gases) have risen substantially over recent decades – from 38.0 gigatonnes of CO_2-equivalent (Gt CO_2-eq) in 1990, to 40.0 Gt CO_2-eq in 2000 and 49.5 Gt CO_2-eq in 2010. With its high global warming potential and its relatively short lifetime in the atmosphere (approximately 12 years), methane is an important candidate for mitigating global warming. The importance of mitigating methane emissions early because of the immediate climate impacts is widely recognised.

Slightly over half of total methane emissions results from human activity. Key anthropogenic sources include: fossil fuel production; agriculture (enteric fermentation in livestock, manure management and rice cultivation); biomass burning; and waste management. Energy- and waste-related activities comprised half of global anthropogenic methane emissions in 2010, while emissions from natural gas systems, coal mines and oil exploration alone made up 26% (Figure 9.8).

Figure 9.8 • Global anthropogenic methane emissions in 2010



Source: GMI, 2011a.

From around 700 parts per billion (ppb) at the start of the industrial revolution in the mid-1700s, global average atmospheric concentrations of methane have risen by more than 150%. Though the overall growth rate has slowed more recently thanks to mitigation efforts, the concentration currently lies between 1 750 ppb and 1 871 ppb, depending on the measurement location (Blasing, 2012).

Anthropogenic hydrocarbon sources of methane emissions

Natural gas and oil operations accounted for around 20% of the estimated 6.9 Gt CO_2-eq global anthropogenic methane emissions in 2010, with Russia, the United States and Ukraine the largest emitters. Natural gas operations include the production, processing, transportation and storage, as well as the distribution of natural gas. Methane emissions mainly occur as the result of equipment/pipeline leaks and routine process or maintenance venting activities. As the gas moves through components under high pressure, methane can escape to the atmosphere through worn valves, flanges, pump seals, compressor seals and joints or connections in pipelines. At production sites, emissions occur at the well-head, during dehydration and when the gas is compressed to be transported from the well-head site to a processing plant.

In oil operations, methane may escape during production, transportation and refining operations. The main source of methane emissions is during production, with methane released as fugitive emissions, emissions arising from operational difficulties and emissions from the incomplete flaring of methane. During production, methane may be released into the atmosphere via venting, accidental leaks and incomplete fuel combustion (flaring). Equipment leaks and vessel blow-downs during routine maintenance can also be large contributors to emissions.

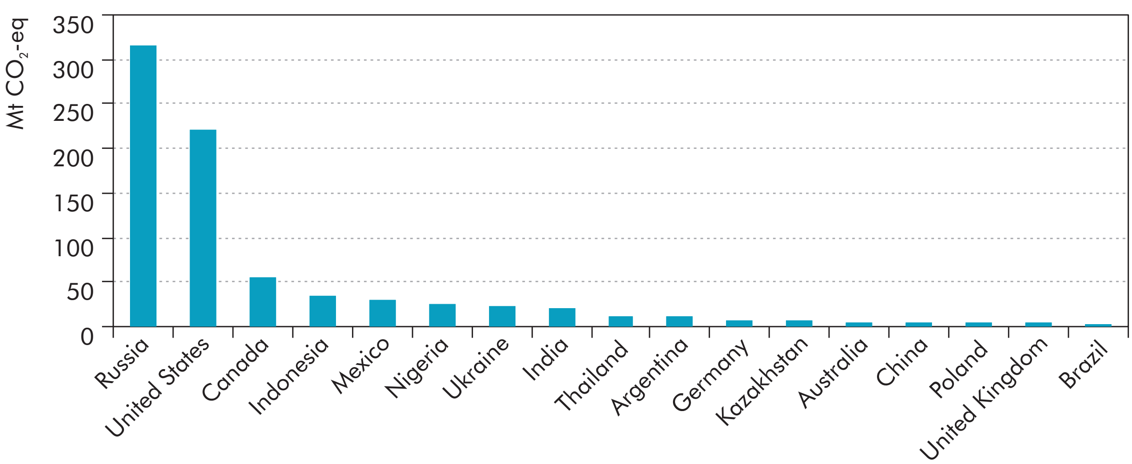
Over the two decades to 2010, methane emissions from oil and natural gas operations increased by 37% to 1.6 Gt CO_2-eq (GMI, 2011b). With the growth in production of oil and gas projected to continue over the next two decades, methane emissions are expected to rise by a further 23% by 2030 (US EPA, 2011).

While conventional gas production will provide the bulk of global gas production to 2030, the share of unconventional gas will continue to rise. Gas production in Organisation for Economic Co-Operation and Development (OECD) countries is projected to rise by around 10% to 2030, with highest production in the United States, followed by Canada, Australia and Norway; highest growth will come from Australia. In contrast, production in non-OECD countries is projected to rise by close to 70% over the next two decades (IEA, 2011b), with high growth in many countries, including Azerbaijan, Brazil, China, India, Iraq, Libya, Nigeria, Qatar, Turkmenistan and Venezuela. Within the OECD, the share of unconventional gas production will increase, though in Europe its rise will be insufficient to offset the decline in total gas production.

Global oil production is projected to rise by around 14% over the period to 2030, with increases coming chiefly from the Organization of the Petroleum Exporting Countries (OPEC) economies of Iraq, Saudi Arabia and Venezuela. Non-OPEC countries projected to increase their production are Brazil, Canada (unconventional oil) and Kazakhstan. In addition to the increased production, significant new production capacity will be required simply to offset the decline in production from currently producing fields.

Though increases in oil and gas production are projected, this does not necessarily translate into a similarly increased share in the magnitude of methane emissions. Estimated emissions from oil and natural gas are shown for selected countries in Figure 9.9. In recent years, increased attention has been drawn to the concern over emissions of GHGs. This has led to increased awareness and stricter legislation to mitigate the rise in emissions, both of which have led to developments and improvements in technology for exploration, production and use. The rise in shale gas production in the United States over the past five to ten years has been made possible through technology development, mainly horizontal drilling and hydraulic fracturing. The successful deployment of these technologies has led to a surge of interest from other countries, many of them now characterising their own shale gas potential. The level of specific emissions from this nascent source of gas has reduced extensively as technologies and practices have been improved, and are likely to improve still further as many interested countries are placing an important emphasis on environmental protection.

Figure 9.9* • *Global methane emissions from oil and natural gas in selected countries

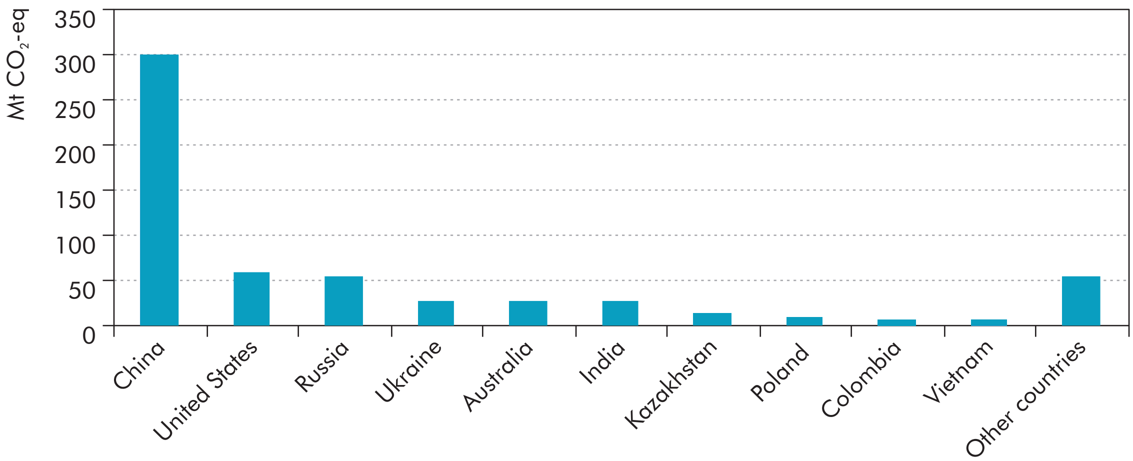


Source: GMI, 2011b.

Coal mines contributed about 6% of total global anthropogenic methane emissions in 2010 (GMI, 2011c), with the largest emissions by far emanating from China, the United States, Russia, Ukraine, Australia and India (Figure 9.10). More than 90% of fugitive methane emissions from the coal sector come from underground coal mining. Abandoned (closed) underground coal mines also emit methane, depending on the extent to which the mine has been sealed or the extent to which it has been flooded.

Methane emissions from coal mines have grown over many years, with this growth projected to continue as greater volumes of coal are extracted and as improvements to technology enable extraction from increasingly greater depths. China is projected to have the largest increase in coal methane emissions as a result of its continued economic growth and the expansion in its coal production. Issues related to coal-mine methane and coal-bed methane (CBM) emissions and their recuperation are discussed in Chapters 6 and 7.

Figure 9.10 • Methane emissions from coal mines in selected countries



Source: GMI, 2011c.

Another important source of anthropogenic methane emissions is municipal solid waste management, which contributes 11% of total global methane emissions. Methane is produced through the natural process of bacterial decomposition of organic waste under anaerobic conditions in sanitary landfills and open dumps. Methane makes up approximately 50% of landfill gas (LFG), the remainder being mostly CO_2 mixed with small quantities of other gases. If LFG is not actively collected, it escapes into the atmosphere.

Reducing methane emissions in the oil and gas sectors

In oil and natural gas systems, opportunities to reduce methane emissions generally fall into one of three categories:

- upgrading the technology or equipment, *e.g.* installing low-emission regulator valves, which can reduce or eliminate equipment venting or fugitive emissions;
- improving management practices and operational procedures to reduce venting;
- enhancing leak detection and measurement programmes that take advantage of improved measurement or emissions reduction technologies.

Cost-effective opportunities for reducing methane emissions in the oil and gas sectors vary greatly from country to country according to the levels of physical and institutional infrastructure. Many abatement options and technologies, however, can be applied universally throughout the oil and gas industries. For example, directed inspection and maintenance (DI&M) programmes use a variety of leak detection and measurement technologies to identify and quantify leaks. This enables operators to discover the largest sources of methane leaks, leading to more accurate, efficient and cost-effective leak repairs. Such DI&M programmes can be applied to gas production, processing, transmission and distribution operations wherever they take place. In countries with large oil and gas infrastructures, such as Russia and the United States, the wider application of these programmes has the potential to yield both substantial reductions in methane emissions and gas savings.

Although flaring of natural gas during oil production contributes less to global warming than if the gas were vented, and while increasing amounts of previously flared gas are being captured for later use, the amount of flaring worldwide remains substantial. Any international agreement on mitigating global climate change would be needed to address this issue.

Dealing with methane emissions: opportunities and constraints

There is substantial potential for reducing anthropogenic methane emissions, in particular from the oil and gas sectors, from coal mining and from waste. Much progress has been made. Technology to reduce emissions is improving continually across each of these sectors. Unless further measures are taken, however, methane emissions will continue to grow as a result of the increased need for energy, mainly from the natural gas and coal mining sectors.

There are a number of challenges hindering the use of methane mitigation technologies. One of them is knowledge – the widespread lack of understanding of existing methane emissions, the impact of those emissions on global temperatures and the value of the lost fuel. This is particularly the case in countries such as China, India, Russia and Ukraine, with rapidly growing energy and waste sectors. Legal and regulatory barriers also exist relating to: ascertaining methane ownership at coal mines and landfills; reducing gas flaring and promoting the use of associated gas; and obtaining access to the electricity grid to sell back power that is generated at landfills or coal mines. There are efforts under way that attempt to address these barriers.

Shale gas and tight gas have higher production-related methane emissions than conventional gas. With the rapid rise in unconventional gas production in recent years, there has been a strong emphasis on technology development to improve matters, with remaining emissions largely associated with more venting or flaring during well completion. In the case of flaring, total well-to-burner emissions are estimated to be 3.5% higher than for conventional gas, which rises to 12% in the case of venting. Eliminating venting, minimising flaring and recovering and selling the methane produced during flow-back would reduce emissions below 3.5% (IEA, 2011b). Though technology improvements have led to significant reductions in methane emissions per unit of gas produced, absolute emissions continue to rise as the volumes of gas produced continue to increase.

Many countries have started to regulate gas flaring in the oil and gas sectors, with some success. Initiatives such as the World Bank's Global Gas Flaring Reduction (GGFR) public-private partnership play an important role. Launched in

2002, the GGFR brings together representatives of governments of oil-producing countries, state-owned companies and major international oil companies so that, together, they can overcome the barriers to reducing gas flaring by sharing global best practices and implementing country-specific programmes. It facilitates and supports national efforts to use flared gas by promoting effective regulatory frameworks and tackling constraints on gas utilisation.

Several methane projects relating to coal mines in China have been negotiated under the auspices of the United Nations Framework Convention on Climate Change (UNFCCC) and its Clean Development Mechanism (CDM). Furthermore, China also has a number of projects that address LFG and, as regulations stipulate that LFG cannot simply be flared to qualify for CDM project certification, these projects must deploy energy recovery. As a result of China's success in attracting investors in GHG mitigation, other developing countries have also begun to explore possibilities to reduce methane emissions.

In 2010, 38 governments, the European Commission, the Asian Development Bank and the Inter-American Development Bank launched the Global Methane Initiative (GMI). The GMI builds on the achievements of the Methane to Markets Partnership, while expanding its scope and pursuing co-ordinated action plans to encourage new financial commitments from developing countries. The GMI urges stronger international action to mitigate climate change from methane emissions. Its goal is to help reduce global methane emissions by partnering with the private sector to identify and finance projects around the world, as well as to suggest appropriate public policies to address key barriers. In the past, the Methane to Markets Partnership was an effective international instrument in reducing GHG emissions. The 38 member countries of the GMI generate approximately 70% of global methane emissions. More than 1 000 public- and private-sector organisations are members of the project network and have helped the programme leverage substantial investment from private companies and financial institutions.

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List of abbreviations, acronyms and units of measure

Abbreviations and acronyms

3-D	three-dimensional
4-D	four-dimensional
ad	air-dried
ANS	Alaska's North Slope
API	American Petroleum Institute
ASP	alkaline-surfactant polymer
BFBC	bubbling fluidised bed combustion
BGR	Federal Institute for Geosciences and Natural Resources (Germany)
BTL	biomass-to-liquids
CAPEX	capital expenditure
$CaSO_4$	calcium sulphate
CBM	coal-bed methane
CCS	carbon capture and storage
CDM	Clean Development Mechanism (under the Kyoto Protocol)
CERA	Cambridge Energy Research Associates
CFBC	circulating fluidised bed combustion
CGR	condensate-to-gas ratio
CH_4	methane
CHOPS	cold heavy oil production with sand
CIS	Commonwealth of Independent States
CMM	coal-mine methane
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CO_2-EOR	carbon dioxide-enhanced oil recovery
CO_2-eq	carbon dioxide-equivalent

CP	cold production
CSS	cyclic steam stimulations
CTL	coal-to-liquids
C_XH_Y	hydrocarbon products
DBMS	database management systems
DEA	diethanolamine
DI&M	directed inspection and maintenance
DOE	United States Department of Energy
DVA	direct vertical access
E&P	exploration and production
EBRD	European Bank for Reconstruction and Development
EGR	enhanced gas recovery
EIA	environmental impact assessment
EIA	United States Energy Information Administration
EOR	enhanced oil recovery
EPS	electric submersible pump
ERC	extreme reservoir contact
ERCB	Energy Resources Conservation Board (Alberta, Canada)
ESHIA	environmental, social and health impact assessments
EUB	Energy and Utilities Board (Alberta, Canada)
FBC	fluidised bed combustion
FDP	field development plan
FDPSO	floating drilling, production, storage and offloading (vessels)
FID	final investment decision
FLNG	floating LNG systems
FOB	free-on-board
FOR	free-on-rail
FPSO	floating production, storage and offloading
FPU	floating production unit

FSRU	floating storage and regasification unit
FSU	former Soviet Union
F-T	Fischer-Tropsch
GDP	gross domestic product
GGFR	Global Gas Flaring Reduction public-private partnership (World Bank)
GHG	greenhouse gas
GMI	Global Methane Initiative
GTL	gas-to-liquids
H_2	hydrogen
H_2S	hydrogen sulphide
HCS	horizontal-well cyclic stimulation
HPU	hydraulic power unit
IEA GHG	IEA Greenhouse Gas Research and Development Programme
IEA	International Energy Agency
IFC	International Finance Corporation
IGCC	integrated gasification combined cycle
IHS CERA	Information Handling Services – Cambridge Energy Research Associates
IOR	improved oil recovery
IRM	integrated reservoir modelling
KOC	Kuwait Oil Company
LFG	landfill gas
LHV	lower heating value
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LTO	light tight oil
LUC	land-use change
MCS	master control station

MEA	monoethanolamine
MENA	Middle East and North Africa
MinDOC	minimum deepwater operating concept
MMS	Minerals Management Service (United States)
MRC	maximum reservoir contact
N_2	nitrogen gas
NCS	Norwegian Continental Shelf
NCS-INT	Norwegian Continental Shelf-International
NDRC	National Development and Reform Commission (China)
NGL	natural gas liquid
NH_3	ammonia
NO_x	nitrogen oxides
NRCan	Natural Resources Canada
OECD	Organisation for Economic Co-operation and Development
OG21	Oil and Gas in the 21st Century (Norway)
OPEC	Organization of the Petroleum Exporting Countries
OWC	oil-water contact
PC	pulverised coal
PCC	pulverised coal combustion
PCI	pulverised coal injection
PDO	plan for development and operation
PIIP	petroleum initially in place
PRMS	Petroleum Resources Management System
PSSG	Provincial Advisory Committee on Public Safety and Sour Gas (Canada)
R&D	research and development
R/P	reserves-to-production ratio
RD&D	research, development and deployment
RF	radio frequency

RTT	refinery-to-tank
SAGD	steam-assisted gravity drainage
SC	supercritical
SEC	Securities and Exchange Commission (United States)
SO_2	sulphur dioxide
SPE	Society of Petroleum Engineers
SPU	subsea production umbilical
TAPS	Trans-Alaska Pipeline System
THAI™	Toe-to-Heel Air Injection
TLP	tension-leg platform
TTW	tank-to-wheel
UAE	United Arab Emirates
UDW	ultra-deepwater
UICI	upstream investment cost index
UN	United Nations
UNEP IE	United Nations Environment Programme Industry and Environment
UNEP	United Nations Environment Programme
UNFC	United Nations Framework Classification for Fossil Energy and Mineral Resources
UNFCCC	United Nations Framework Convention on Climate Change
USC	ultra-supercritical
USGS	United States Geological Survey
UTA	umbilical termination assembly
VAM	ventilation air methane
VAPEX	vapour-assisted petroleum extraction
VIV	vortex-induced vibration
WAG	water alternating gas injection
WEC	World Energy Council
WRM	well and reservoir management

WTO	World Trade Organization
WTR	well-to-refinery
WTT	well-to-tank
WTW	well-to-wheel
WWF	World Wildlife Fund

Units of measure

°C	degree Celsius
b	barrel
b/b	barrels of oil from a barrel of raw bitumen
b/d	barrels per day
b/Mscf	barrel per million standard cubic feet
bb	billion barrels
bb/yr	billion barrels per year
bcm	billion cubic metres
bcm/km²	billion cubic metres per square kilometre
bcm/yr	billion cubic metres per year
boe	barrel of oil-equivalent
boe/d	barrels of oil-equivalent per day
cm	centimetres
EJ	exajoule
g CO_2/kWh	grams of carbon dioxide per kilowatt hour
g/cm³	grams per cubic centimetre
g/kWh	grams per kilowatt hour
GJ	gigajoule
Gt	gigatonne

Gtce	gigatonne of coal-equivalent
GW	gigawatt
ha	hectare
kb	thousand barrels
kb/d	thousand barrels per day
kg CO_2/boe	kilograms of carbon dioxide per barrel of oil-equivalent
kg CO_2-eq/boe	kilograms of carbon dioxide-equivalent per barrel of oil-equivalent
kg	kilogram
kg/m^3	kilogram per cubic metre
kj/kg	kilojoules per kilogram
km	kilometre
km^2	square kilometre
l	litre
m	metre
m^3	cubic metre
m^3/d	cubic metre per day
mb	million barrels
mb/d	million barrels per day
MBtu	million British thermal units
mcm	million cubic metres
mcm/d	million cubic metres per day
md	millidarcy (unit of permeability)
MJ	megajoule
MJ/kg	megajoules per kilogram
MPa	megapascal (unit of pressure)
Msm^3	million standard cubic metres
Mt	million tonnes
Mt/yr	million tonnes per year

Mtce	million tonnes of coal-equivalent
Mtoe	million tonnes of oil-equivalent
MW	megawatt
MWe	megawatt-electrical
ppb	parts-per-billion
ppm CO_2-eq	parts-per-million carbon dioxide-equivalent
ppm	parts-per-million
sm^3/yr	standard cubic metres per year
t CO_2-eq	tonne of carbon dioxide-equivalent
t	tonne
t/b	tonne per barrel
t/d	tonnes per day
t/yr	tonnes per year
tce	tonne of coal-equivalent
tcm	trillion cubic metres
toe	tonne of oil-equivalent
TWh	terawatt hour
USD/boe	US dollars per barrels of oil-equivalent
USD/t	US dollars per tonne

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