INTERNATIONAL
ENERGY AGENCY

Resources to Reserves

Oil & Gas Technologies for the Energy Markets of the Future

OECD

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INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an international energy programme.

It carries out a comprehensive programme of energy co-operation among twenty-six of the OECD's thirty member countries. The basic aims of the IEA are:

- to maintain and improve systems for coping with oil supply disruptions;
- to promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations;
- to operate a permanent information system on the international oil market;
- to improve the world's energy supply and demand structure by developing alternative energy sources and increasing the efficiency of energy use;
- to assist in the integration of environmental and energy policies.

The IEA member countries are: Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, the Republic of Korea, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States. The European Commission takes part in the work of the IEA.

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The OECD is a unique forum where the governments of thirty democracies work together to address the economic, social and environmental challenges of globalisation. The OECD is also at the forefront of efforts to understand and to help governments respond to new developments and concerns, such as corporate governance, the information economy and the challenges of an ageing population. The Organisation provides a setting where governments can compare policy experiences, seek answers to common problems, identify good practice and work to co-ordinate domestic and international policies.

The OECD member countries are: Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Korea, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, the Slovak Republic, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States. The European Commission takes part in the work of the OECD.

FOREWORD

Soaring oil prices have again spotlighted the old question. Are we running out of oil? The doomsayers are again conveying grim messages through the front pages of major newspapers. "Peak oil" is now part of the general public's vocabulary, along with the notion that oil production may have peaked already, heralding a period of inevitable decline.

The IEA has long maintained that none of this is a cause for concern. Hydrocarbon resources around the world are abundant and will easily fuel the world through its transition to a sustainable energy future. What is badly needed, however, is capital investment in projects to unlock new hydrocarbon resources, be they non-conventional, or in deepwater offshore locations, or in countries where geopolitical factors have restricted investment. While today's high oil prices have now started to mobilise capital, the entire supply chain in the upstream oil and gas industry is nevertheless stretched after years of low investment. Since new projects take several years to materialise, high oil prices may be with us for several years to come.

Technological progress has always been the key factor to prove the doomsayers wrong. We expect that technology will once again drive costs down, providing more attractive returns for investors. Technology will enable new resources to be developed cost-effectively and it will accelerate implementation of new projects.

This book reviews current and future technology trends in the upstream oil and gas industry. It confirms that exciting innovations are on the horizon, with the potential to fulfill expectations of secure energy supplies in an expanding world economy, but also to mitigate fossil fuels' impact on the global climate. It highlights how governments can help create the conditions for technology to deliver its promises.

It is our hope that this publication will make a significant contribution to broadening knowledge of the scene behind the petrol pumps and pipelines and inform the ongoing debate on the future of worldwide energy supply.

Claude Mandil

Executive Director

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The lead author of this book was Christian Besson, working within a broad, collective effort drawing on extensive input from many colleagues at the IEA and experts around the globe.

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EXECUTIVE SUMMARY

Over the coming decades, the world will continue to rely heavily on large-scale supplies of oil and gas. According to demand projections from the IEA *World Energy Outlook* (WEO) Reference Scenario, the share of these two fuels in the world energy fuel mix will actually increase from around 57% in 2002 to some 60% in 2030, if energy policies worldwide do not change.

As a result, demand for oil and gas will expand by nearly 70% over these three decades. Even if governments took more vigorous steps to address environmental and energy-security concerns, as modelled in the IEA *World Energy Outlook*'s Alternative Scenario, worldwide demand for oil would be only 11% lower than under the IEA Reference Scenario's projections, and demand for gas only 10% lower. In addition, as output from the world's existing production sources inevitably declines, probably at a rate around 5% per year, this decline will need to be compensated with new supplies.

The hydrocarbon resources in place around the world are sufficiently abundant to sustain likely growth in the global energy system for the foreseeable future. But keeping pace with today's demand growth projections will oblige the hydrocarbon industry to take on a new, diverse set of business and technological challenges. This is largely because it will be more technically demanding to develop remaining world oil and gas resources and bring them to markets than was the case for previous output.

Ensuring the right conditions for sustained and accelerated technological progress in the oil and gas upstream sector will be a key factor for success in securing global security of supply for all countries.

The purpose of this book is to:

- Review future needs for technological advances to meet the challenges facing the hydrocarbon industry in the 21st century.
- Discuss embedded policy implications.
- Measure the impact that technological progress can be expected to have on tomorrow's hydrocarbon resources availability.

The big challenges for the future

Measured in units of oil equivalent, roughly 10 trillion barrels of conventional oil and gas are in place, and at least as much non-conventional oil and gas. Out of these 20 trillion barrels of oil equivalent (boe), 5 to 10 trillion can be considered technically, but not necessarily economically, recoverable, depending on recovery rates, technological progress and long-term price assumptions.

Proven reserves amount to about 2.2 trillion boe, which is not so far from the 1.5 trillion boe produced so far, over more than 100 years of exploitation. Indeed, 1.5 trillion boe is also a rough estimate of what needs to be produced over the next 25 years.

But the intensifying need to obtain supplies from more challenging conventional and non-conventional resources will impose very considerable demands on the sector's human, financial and intellectual capabilities. Conventional oil and gas resources will continue to dominate global oil and gas supply throughout the period to 2030. The existing base of either exploited or known reservoirs will provide the lion's share of future supply from conventional hydrocarbon. Steepening output decline curves, however, and the need to sustain economic field life through cost reductions and enhanced recovery methods, present major challenges in this context. Current worldwide average recovery rates for oil are roughly 35% and technological progress could substantially raise that percentage. In particular, increased use of CO_2 for enhanced oil recovery could simultaneously increase recovery factors and curb greenhouse gas emissions into the atmosphere. Gas recovery rates, on the other hand, average around 70% worldwide. As a consequence, enhancing recovery rates does not have the same significance for gas as it does for oil.

If future supplies of conventional oil and gas are to expand, it will also become necessary to obtain access to resources in more technologically demanding areas, such as:

- Deep and ultra-deep water.
- Deeply buried and more complex reservoirs.
- Arctic regions, where governments consider this desirable.
- The few remaining, remote, unexplored basins.
- Remaining prospects with smaller accumulations in known areas.

In terms of investment, projected requirements for natural gas supply will be close to those for oil over the next 30 years. Indeed, growth in demand for gas will outpace that for oil. Also, moving gas to frequently more distant markets is more costly than shipping oil. While the major calls for capital to mobilise oil stem essentially from exploration, production and refining, investment in gas supply will focus chiefly on transportation infrastructure to feed a fast growing market. New technology is needed to provide more cost-effective solutions; liquefied natural gas is one option that will play a large role if global markets are to be created and served.

Meanwhile, enhanced exploitation of substantial known resources of non-conventional oil and gas promises to produce much larger supplies of both fuels. Significant declines in the cost of extracting and producing these resources over the past two decades have already won them a sizeable share of the market. Boosting the relative fuel-mix shares of non-conventional oil and gas resources in future world energy supply will call for major investments in production and distribution capacity and for development and deployment of more cost-effective technologies. Government policies to encourage such investment can play an important role.

Given the broad span of challenges, expanding the global supply from both conventional and non-conventional resources will thus demand important advances in key technologies and the related science base to foster:

- Industry's technical capability to expand and meet projected needs.
- Further reductions in recovery costs.
- Successful handling of more challenging economics and greater investment risk.

Focus of the study

This study takes a detailed look at what kind of technological progress is required to underpin future oil and gas supply. The question is examined in terms of core technology, but also in terms of the role to be played by industry, scientific research, academia and governments in furthering technological progress in the industry.

The following technology areas are highlighted as central to ensuring future supplies.

- Improved ability to characterise reservoir heterogeneities and to image fluid movements, particularly in large carbonate reservoirs.
- Low-cost wells.
- A range of information technology-based, intelligent "e-field" systems allowing real-time management of reservoirs.
- A more streamlined, standardised, "assembly-line" approach to all operations in oil and gas fields.
- Renewed emphasis on better-performing enhanced oil recovery techniques, including the use of CO_2 to combine oil recovery with climate-change mitigation.
- Improving deepwater technologies to secure viability at a water depth of up to some 4 000 metres.
- Technologies for safe and environmentally sound operations in Arctic regions.
- Technologies for economical production of non-conventional resources, in particular heavy oils, bitumen, oil shales and non-conventional gas.
- Technologies to minimise the environmental footprint of all oil and gas operations.
- Technologies and actions to ease shipping bottlenecks.
- Technologies that reinforce the safety of installations.

Major ongoing industrial developments in each of these areas are explored and summarised.

Key conclusions and recommendations

The key problem is not the limit of geological resources. The overriding questions today revolve around the technologies, prices and policies that will make the world's vast resources economically recoverable and turn them into proven reserves.

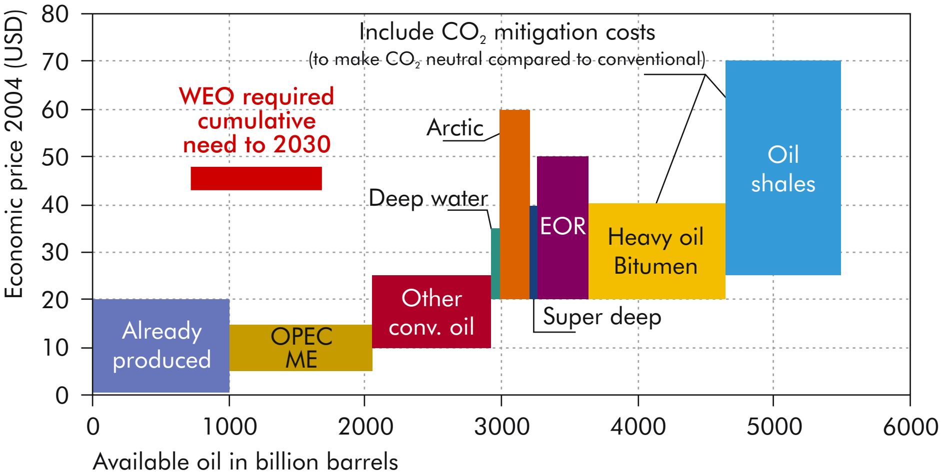
First, it will be necessary to mobilise some very large-scale investments, estimated at some USD 5 trillion over the coming three decades[1]. Then a widespread and determined R&D effort will be needed to bring in the technologies required. Industry clearly has the means, capabilities and incentives to perform the required R&D. Measures encouraging that effort would be beneficial. Public policy can play a key role in numerous ways, notably by focusing on the following:

- Providing a framework favourable to investment in new resources, including appropriate licensing, taxation, royalties and support for demonstration projects. Experience has shown that these can be instrumental in catalysing the technology learning required to make non-conventional resources competitive.
- Providing a policy climate that ensures continued active co-operation between technology developers in IEA countries and hydrocarbon resources holders in OPEC countries.
- Taking the lead in promoting technology development and facilitating investments that can reduce shipping bottlenecks.
- Actively participating in developing and facilitating the implementation of technologies that improve the safety of installations.
- Ensuring that CO_2 emissions reduction is given sufficient value to foster more widespread CO_2 enhanced oil recovery (EOR) and thus higher recovery rates.
- Supporting basic science in the biology and ecology of subsurface bacterial systems, since this can trigger breakthroughs in use of biotechnologies to enhance recovery or to transform heavy hydrocarbons.
- Vigilantly supporting industry's efforts to reduce its environmental footprint and thus to access resources in new areas.
- Continuing to spearhead science and technology advances linked to future exploitation of methane hydrate deposits, while ensuring strong industry participation. These resources are potentially very important to long-term supply but currently too far off for sole reliance on industry contributions.

From discussions with industry experts on the impact of future technologies, a shared perspective has emerged on the future availability of various types of resource, as a function of oil prices, but also taking into account likely technological progress. This perspective is expressed graphically in Figure ES.1. It shows the various oil prices (Brent) at which the exploitation of various volumes of different resources becomes an economical option. The cost of capture and storage of CO_2 produced during the extraction of non-conventional oils is taken into account.

1. Projected oil and gas investment requirements are not discussed at any length in this study. This figure of USD 5 trillion for worldwide upstream operations and transportation comes from analyses in the IEA World Energy Outlook 2004.

Figure ES.1* • *Oil cost curve, including technological progress: availability of oil resources as a function of economic price



The x axis represents cumulative accessible oil. The y axis represents the price at which each type of resource becomes economical.

Source: IEA.

Currently, most companies base their investment decisions on a long-term price of USD 20 to USD 25 per barrel. The graph suggests that accepting a long-term price of, for example, USD 30/barrel would make an appreciable difference to the economic recoverability of large amounts of oil.

The analysis here focuses only on oil, for which extraction represents the dominant cost. Where gas is concerned, reserves are plentiful and the economics are dominated by the cost of transportation. Development of liquefied natural gas and other transportation technologies will determine the future supply equation.

INTRODUCTION

Oil and gas will continue to play a key role in energy supply for IEA countries and the world at large throughout the first half of this century. This is the consensus view held by numerous studies on prospective energy markets, including the IEA *World Energy Outlook* (*WEO*). Their predictions assume the oil and gas industry's continuing ability to deliver hydrocarbons in the quantities required under the various price scenarios used in each study. Although different models use different methodologies, their common assumption is essentially based, in turn, on extrapolation of the industry's track-record in expanding reserves, recovery and production.

Sustaining such production trends, however, depends on three key factors.

- **Sufficient capital investment** in exploration, wells, production facilities, transportation, processing plants, refineries. The importance of such capital investment has been stressed in various IEA publications over recent years, as illustrated in Figures 0.1 and 0.2 (next page).

- **Sufficient skilled human resources**. This is a major challenge for the industry in general. Various downsizing exercises carried out by major oil companies over the past 20 years have distorted the industry's age pyramid and many professionals will reach retirement age in the next 10 years. The industry's image tends to make it less attractive for young, educated people than other “greener” industries, particularly in IEA countries. At the same time, due to shifts of production from industrialised to developing countries and the legitimate wish to favour the local work force in such countries, it is now becoming urgent to train large numbers of young professionals from many different nations. Providing adequate skilled staff is a well known challenge in industry management circles and one that is being addressed, in part, by various players.

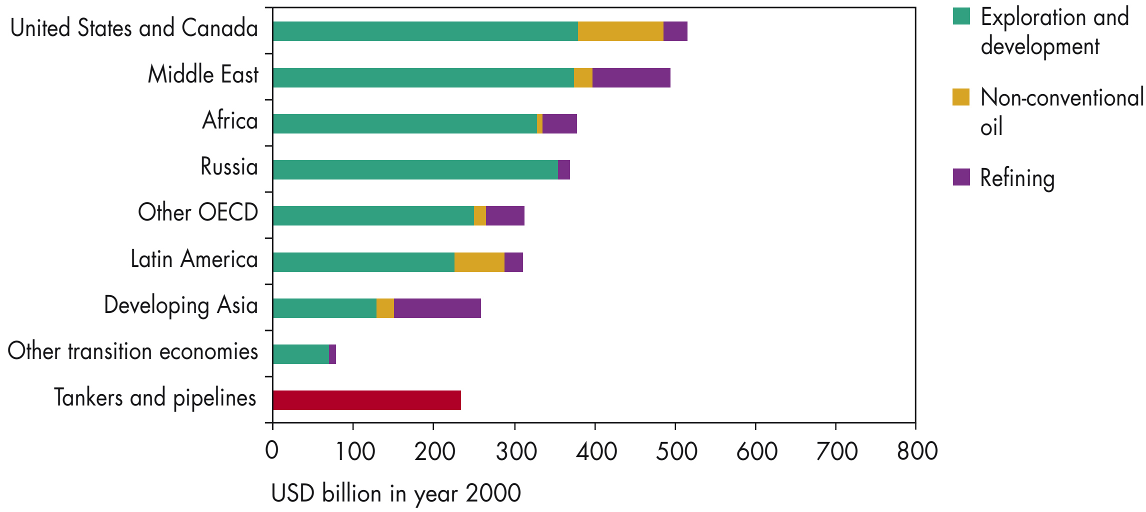
  While this topic is not discussed in this study, it is nevertheless worth stressing that attracting and training enough skilled professionals are going to be crucial to security of supply in a scenario where oil and gas remain a large component in energy use in IEA countries.

- **Continuing technological progress**. Most projections assume various levels of sustained improvement in technologies to expand recoverable reserves in known fields or to develop new, more challenging fields. Projections are based heavily on extrapolating past industry trends. There are three reasons, however, why such assumptions may need to be re-examined.

  - As the industry moves on to more and more “difficult” oil and gas deposits, the pace of technological progress will need to accelerate significantly if past production trends are to be maintained.

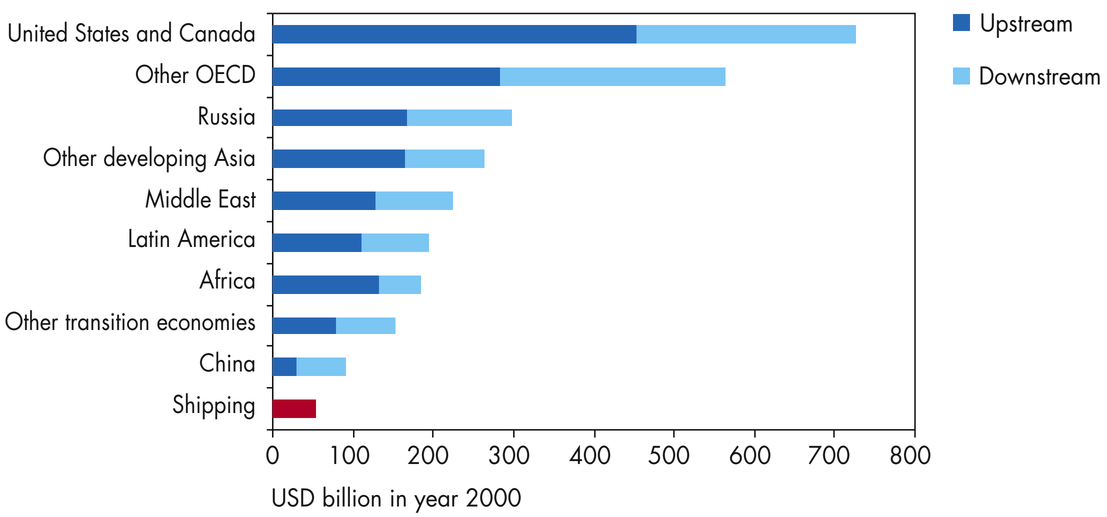
  - Although technological advances appear to be continuous when averaged over time, such advances actually come in discrete steps as successive new techniques are deployed. There is no guarantee that the required key technologies will actually emerge in time to make new supplies available in the way that the models project.

Figure 0.1 • *Cumulative global oil investment needs, 2003-2030*



Source: WEO-2004, IEA.

Figure 0.2 • *Cumulative natural gas investment needs, 2003-2030*



Source: WEO-2004, IEA.

- Technological progress also needs investment; and long lead times are often involved. Wide price fluctuations over the past 25 years have led to relatively modest investments in research and development (R&D) in the oil and gas industry. These investments tend to be postponed in the absence of a stable planning horizon, thus undermining the industry's ability to assure sustained production in the required timescales. Indeed, it can be argued that some of the impressive technical progress seen in the oil and gas industry during the 1990s was the result of high R&D spending at the end of the 1970s and early 1980s, and that reduced R&D expenditures in the 1990s may have already "locked-in" a period of slower progress.

Ensuring the conditions for continuing rapid technological progress in the oil and gas industry is therefore a key requirement for security of supply in IEA countries.

The oil and gas "upstream" industry (exploration, production and transport) involves a vast number of technologies, each of them constantly evolving. It is of course far beyond the scope of this book to attempt any discussion of the future evolution of each of the very numerous technologies involved. Large numbers of existing specialised publications take up this subject in relation to the various branches of the industry. Our focus here is rather on the impact of key areas of technology on future security of supply.

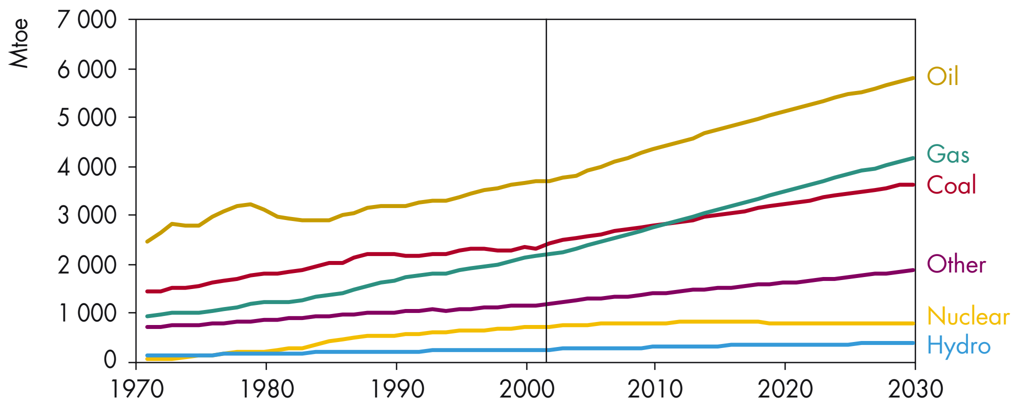
Picking those areas, of course, means making choices in the face of much uncertainty. Past history has shown that the oil and gas industry is very active in pushing the technology envelope but also relatively risk adverse. As a result, changes take time. The R&D teams of the key industry players are already working on the technologies that are likely to bring major change to the industry before 2030. There are few surprises in store. Nevertheless, picking the technologies most likely to succeed offers plenty of scope for error. If they were asked to identify the key technologies that have brought change to the oil and gas industry over the past 25 years, most observers would point to 3D seismic and horizontal wells. But a glance through technical journals from 25 years ago (1980) reveals that, while 3D seismic and horizontal wells were indeed on the horizon, much R&D investment was going to chemical enhanced oil recovery techniques, or to exploitation of oil shales, from which essentially no commercial impact has resulted to this day. Readers may wish to keep uncertainties such as this in mind.

Chapter 1 • SETTING THE SCENE

Demand for oil and gas

The past century has seen a steadily growing role for oil and gas in fuelling development around the globe. All the studies on energy's future tell us that oil and gas will remain dominant in world energy supply well into this century. The IEA *World Energy Outlook* (IEA *WEO-2004*) projects that, without new energy and environmental policies, demand for oil will continue to grow at 1.6% per year (Figure 1.1). Indeed, oil is expected to continue providing more than 90% of transport vehicles' energy requirements up till at least 2030 (Figure 1.2). Natural gas demand will grow even faster, at 2.3% per year. Since it provides "cleaner" energy than other fossil fuels, gas is claiming a rapidly growing share of the electricity generation market. Even in scenarios like the IEA Alternative Scenario (IEA *WEO-2004*) which factor in strong policies to curb CO_2 emissions, projected growth in oil and gas consumption remains significant.

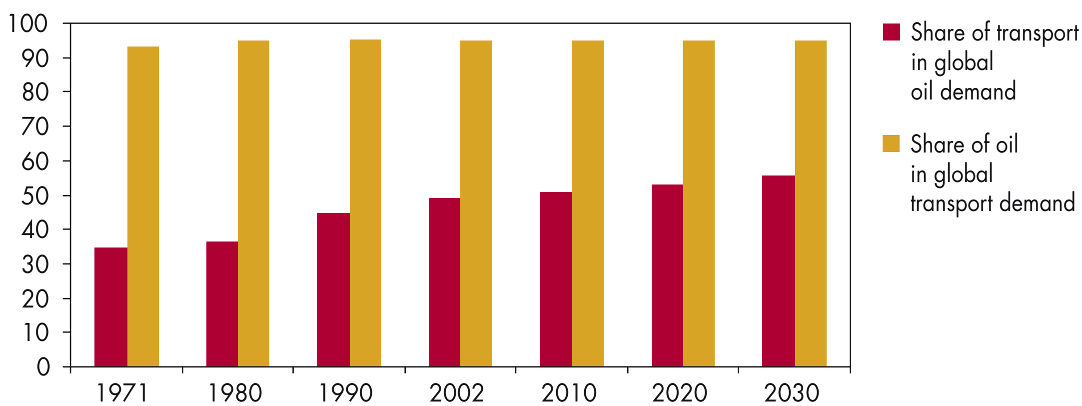
Figure 1.1* • *World primary energy demand over time in IEA Reference Scenario



"Other" encompasses both traditional and modern renewables (biomass, wind, solar, etc.)

Source: WEO-2004, IEA.

Figure 1.2* • *Percentage share of transport in global oil demand, percentage share of oil in transport energy demand



Source: WEO-2004, IEA.

Resources and reserves

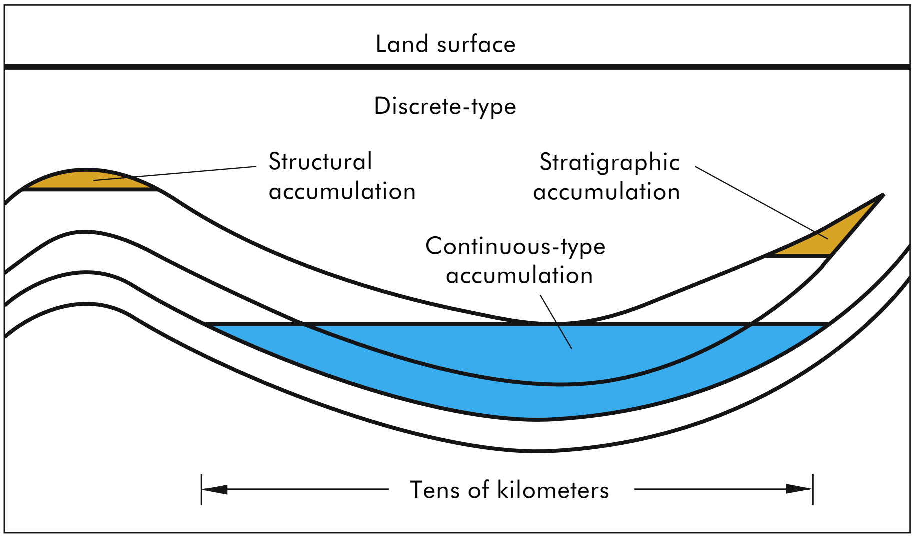
Where do oil and gas actually come from? They are produced from underground deposits. The oil and gas are found in the small pores of sedimentary rocks layers (Figure 1.3) buried in the earth's crust (Figure 1.4).

While theories vary regarding the origin of these hydrocarbons, the general consensus is that most of the deposits result from burial and transformation of biomass over geological periods during the last 200 million years or so. In terms of quantities, therefore, the total amount of oil and gas residing in the earth's subsurface is certainly finite. Since some of these resources have yet to be found, however, there is considerable uncertainty about the magnitude of the "undiscovered resources". The most widely used estimates of total amounts of hydrocarbons to be found in the earth's subsurface are those of the United States Geological Survey (USGS 2000). These deal primarily with conventional oil and gas. Data on other types of resource can be located from other sources[2]. The following statistics summarise collected findings, shown in graphic form in Figure 1.5. (Box 1 explains the terms "conventional" and "non-conventional". More details can be found in Chapters 3 and 4).

Figure 1.3 • *Example of cores of oil-bearing rock*

Photo courtesy of Neil O'Donell, Keyano College, Ft. McMurray, Alberta (Canada), with thanks to Maurice Dusseault, University of Waterloo (Canada).

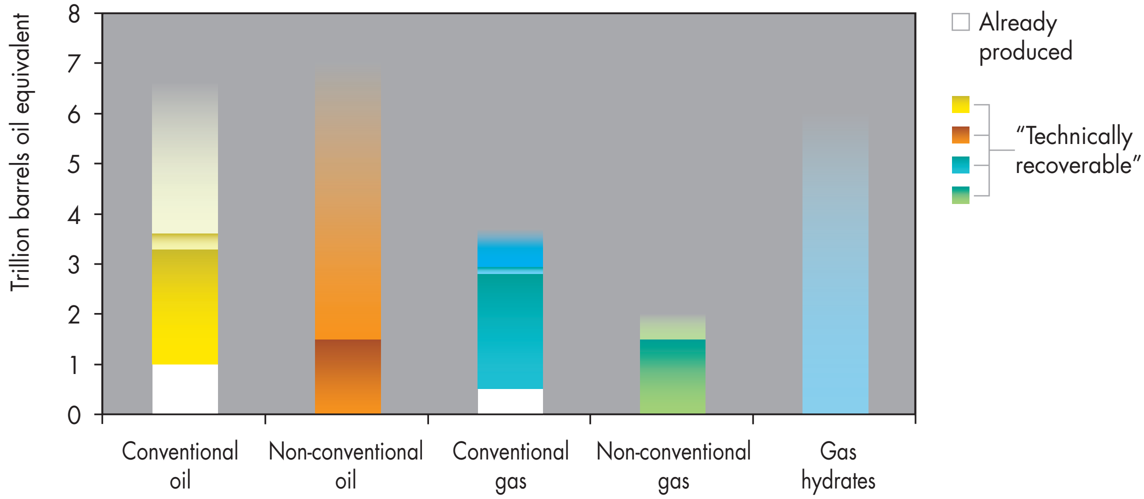
Figure 1.4 • *Typical oil- or gas-bearing sedimentary layers*



After United States Geological Survey.

2. Rogner 1997; Rogner 2000; SAUNER 2000; Greene 2003; Milkov 2004; IEA WEO-2001; IEA WEO-2004.

Figure 1.5 • *World hydrocarbon resources*



The thin lighter yellow band in the conventional oil bar and the lighter blue band in the conventional gas bar represent the contribution of future enhanced oil recovery techniques beyond that assumed in the USGS analysis (see Box 1 1 for more details).

Based on USGS and IEA data.

- **Oil**
  - **Some 7 to 8 trillion barrels of conventional oil**. Of these, 3.3 trillion barrels are considered technically (or ultimately) recoverable; 1.0 trillion have already been produced[3].
  - **Seven trillion barrels of non-conventional oil** (heavy oil, bitumen, oil sands, and oil shales). Estimated technically recoverable quantities vary from 1 trillion to 3 trillion barrels; roughly 0.01 trillion barrels have been produced to date.
- **Gas**
  - **450 trillion cubic metres of technically recoverable conventional gas**, or 2.8 trillion barrels of oil equivalent (boe), of which about 80 trillion cubic metres have already been produced (0.5 trillion boe). There are few estimates of "non-technically recoverable" conventional gas, but recovery factors for conventional gas tend to be high, typically around 70%.
  - **At least 250 trillion cubic metres of non-conventional gas**, or 1.5 trillion boe (coal bed methane, tight gas, gas shales), although there is no reliable estimate world wide and there could be two or three times more. About 0.01 trillion boe of non-conventional gas have already been produced.
  - **Between 1 000 and 10 000 000 trillion cubic metres of gas locked in the form of hydrates** at seabed level or in permafrost (between 6 trillion and 60 000 trillion boe). Estimates vary widely, but it is generally agreed that resources here are significantly larger than those of conventional gas. The recoverability status is unknown.

3. These numbers include natural gas liquids (NGL), the small amount of oil that condenses out when gas is produced from many gas fields. Similarly, the gas numbers include "associated gas", which is gas dissolved in oil reservoirs.

Box 1 • "Conventional" and "non-conventional"

There is no universally agreed definition of what is meant by conventional oil or gas, as opposed to non-conventional hydrocarbons. Roughly speaking, any source of hydrocarbons that requires production technologies significantly different from the mainstream in currently exploited reservoirs is described as non-conventional. However, this is clearly an imprecise and time-dependant definition. In the long-term future, in fact, non-conventional, heavy oils may well become the norm rather than the exception.

Oil

Some experts use a definition based on oil density, or API gravity (American Petroleum Institute gravity). For example, all oils with API gravity below 20 (i.e. density greater than 0.934 g/cm^3) are considered to be non-conventional. This includes "heavy oils", bitumen and tar deposits. While this classification has the merit of precision, it does not always reflect which technologies are used for production. For example, some oils with 20 API gravity located in deep offshore reservoirs in Brazil are extracted using entirely conventional techniques. Other experts focus on the viscosity of the oil. They regard as conventional any oil which 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.

Oil shales are generally regarded as non-conventional, although they do not fit into the above definitions. More details on this can be found in Chapter 3. Also classified as non-conventional are both oil derived from processing coal with coal-to-liquids (CTL) technologies and oil derived from gas through gas-to-liquids (GTL) technologies. The raw materials are nevertheless perfectly conventional fossil fuels. These will be discussed briefly in Chapters 5 and 7.

Another approach, used notably by the United States Geological Survey, is to denominate non-conventional (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 non-conventional. This type of definition has a sound geological basis, but does not always connect with the technologies required for production, which are the main concern in this study.

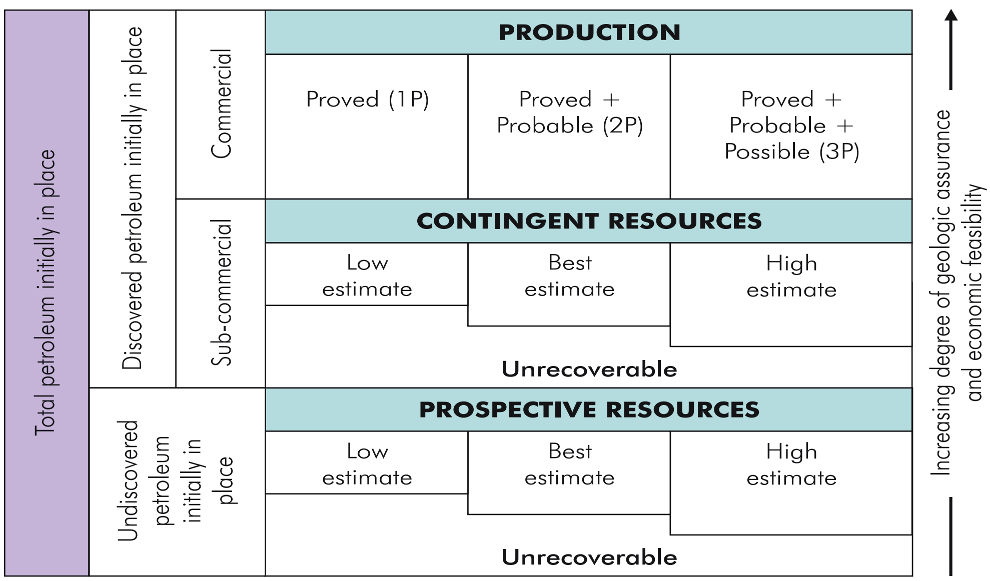
Gas

The definitions are just as hazy for gas. Generally, the industry classifies as non-conventional the gas that is found in unusual types of reservoir. The main types are coal bed methane (CBM), which is gas associated with deeply buried coal seams, and "tight gas", gas from reservoirs with very low permeability that can only be produced at economic rates through special production technologies (systematic use of stimulation techniques). While CBM has an unambiguous definition, there is a continuum between conventional and tight reservoirs, without any sharp transition. Stimulation techniques are also frequently used for conventional reservoirs. This question is discussed further in Chapter 4.

One can also list "lean gas" and "sour gas", gas contained in conventional gas reservoirs, but with a high concentration of impurities (nitrogen and carbon dioxide for lean gas, hydrogen sulphide for sour gas) that negatively impacts the economics.

These numbers indicate that only a small fraction of the hydrocarbon resources in place have been produced. However, not all of these resources can be extracted. Some resources are "unrecoverable" using currently known technologies. Others, although technically recoverable, are not "economically recoverable" at current or expected prices. Extracting them would be simply too costly using present technologies. "Proven" and "probable" reserves are thus hydrocarbons that can reasonably be considered economically recoverable at current prices. Obviously, quantities here can only be estimated, since the exact amount of oil that will be produced cannot be determined before it has been extracted and the reservoir abandoned. To introduce some uniformity and coherence in the figures used by different companies, various organisations have standardised estimating methodologies (Figure 1.6). A degree of uncertainty remains, however, and judgement is called for[4].

Figure 1.6 • *Classification of hydrocarbon resources*



Source: SPE/WPC/AAPG (2000).

Clearly, estimates of proven or probable reserves are simply today's snapshot. Over time, the picture will change as prices evolve and, more particularly, as new technologies reduce the cost of production from some resources. Technology may even unlock access to previously unrecoverable hydrocarbons. In fact, the level of "remaining reserves" of oil has been remarkably constant historically, in spite of the volumes extracted each successive year (Figure 1.8). The addition of new reserves has therefore roughly compensated for consumption.

The current "best estimates" for (proven) reserves of oil and natural gas liquids are shown in Figure 1.7. Proven oil reserves as a function of time can be seen in Figure 1.8. Proven reserves of gas are mapped in Figure 1.9.

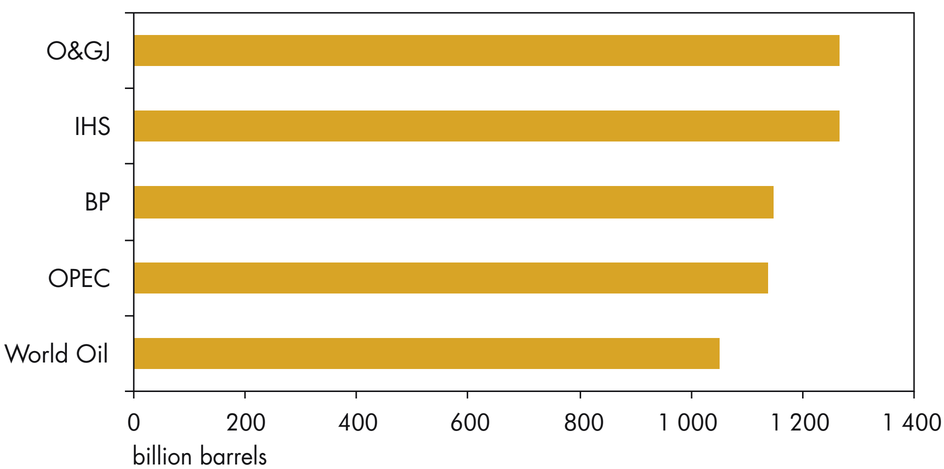
4. *For a recent discussion, see, for example:* ***http://www.otcnet.org/2005/presentations/index.html*** *.*

These numbers should be seen in the light of figures both for oil and gas already produced to date and for annual production rates (30 billion barrels of oil and 3 trillion cubic metres of gas in 2004). The ratio of proven reserves to current yearly production gives a very rough feel of how many more years of output remain, on the basis of reserves as they stand today. That is, roughly 40 years for oil and 60 years for gas.

The fairly constant level of remaining reserves has led some stakeholders to consider that such levels will continue indefinitely, and that evolving technology will mobilise whatever volumes of hydrocarbons are needed. Others, however, stress that hydrocarbons are unquestionably finite, and that close to one-half of the earth's proven reserves of conventional oil has already been consumed. Because of the uncertainties over the respective amounts of resources and reserves, it is difficult to predict the moment of "peak oil[5]", when production might be expected to start to decline. Estimates range from today to 2050 or beyond. In fact, many experts agree that conventional oil outside OPEC Middle East has either peaked already, or will do so over the next ten years. Optimists retort that, even if this were so, non-conventional hydrocarbons are abundant and technology will make it possible to tap them at reasonable cost.

The key questions, however, are not about when conventional oil production will peak, but about the cost involved (not forgetting the cost of CO_2 emissions) in making non-conventional hydrocarbons available or increasing the recovery rates of conventional hydrocarbons, as well as about the impact of energy efficiency gains. It is the answers to these questions that will determine how far, and when, other primary sources of energy like coal, nuclear or renewable energies will supersede hydrocarbons in the role they play today.

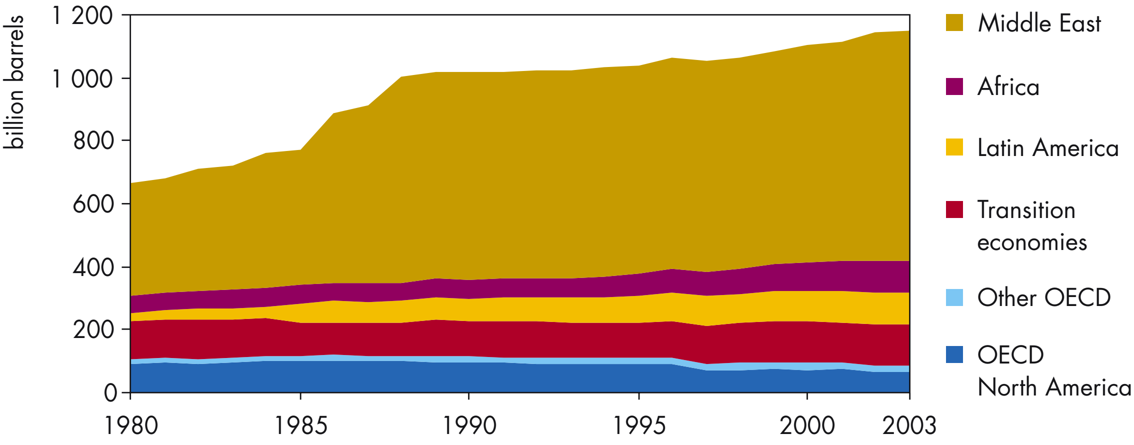
Figure 1.7 • *Crude oil and NGL reserves at end-2003, according to various sources*



Source: WEO-2004, IEA.

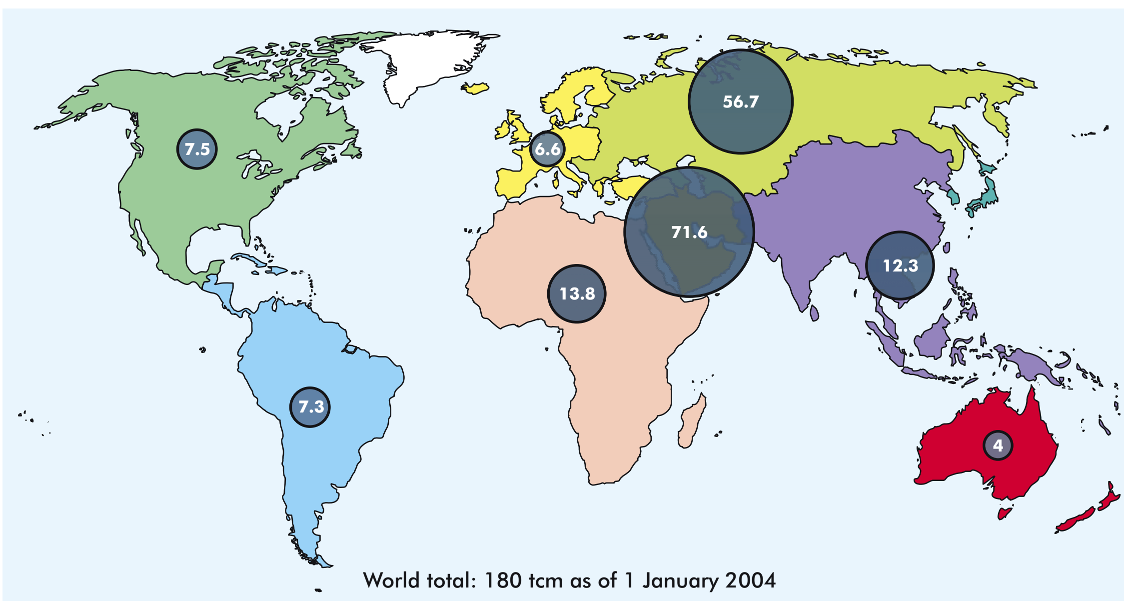
5. The term "peak oil" is commonly used to denote the point of maximum production worldwide; see Box 2 for a short discussion.

Figure 1.8* • *Evolution of proven oil reserves as a function of time



Source: WEO-2004, IEA.

Figure 1.9* • *World proven reserves of natural gas in trillion cubic metres



Source: WEO-2004, IEA.

Geographical distribution

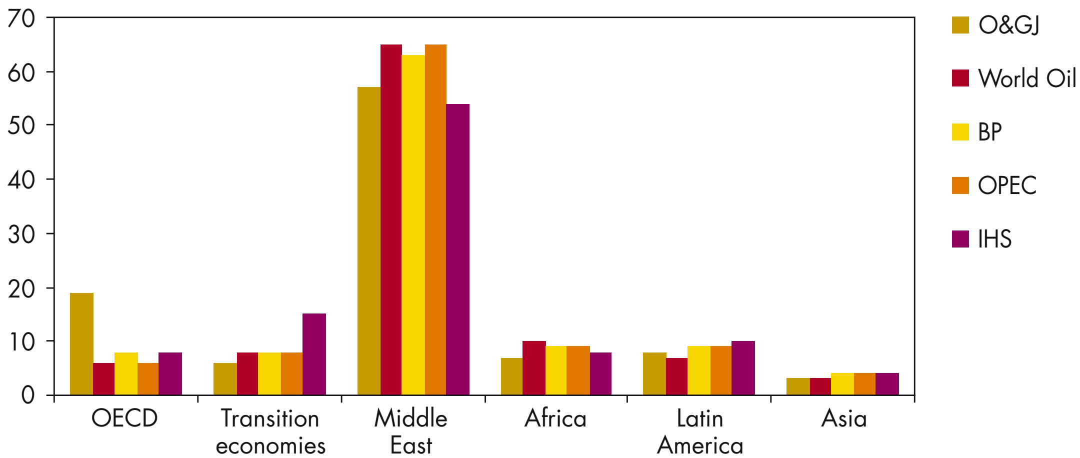
Hydrocarbons are not, of course, distributed uniformly around the globe. Some regions and countries are well endowed, others have none (Figure 1.10).

As Figure 1.10 shows, most of the proven reserves of conventional oil are to be found in the Middle East OPEC countries: Iran, Iraq, Kuwait, Saudi Arabia and the United Arab Emirates (UAE).

Similarly, conventional gas is located primarily in Russia and the Former Soviet Union (FSU) countries, and in Iran, Qatar and Saudi Arabia, as shown in Figure 1.9.

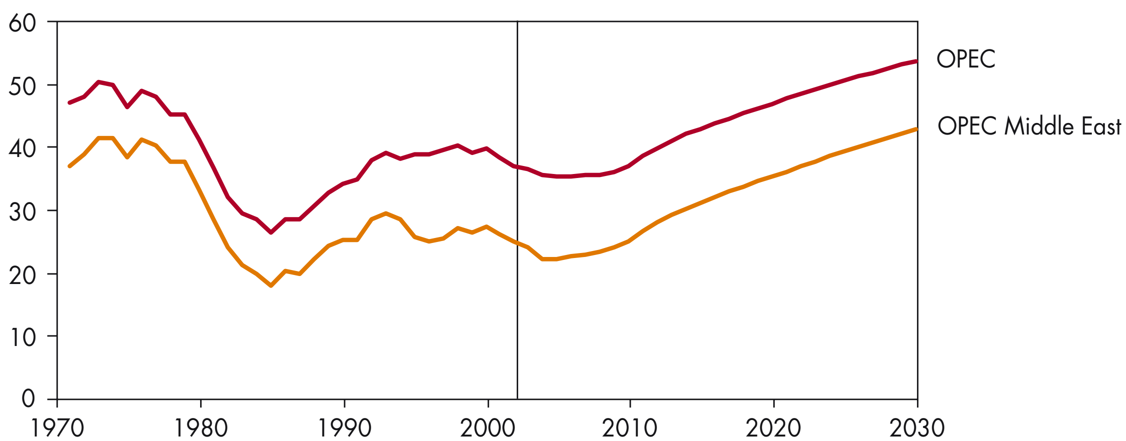
Since these reserves are often not in the same regions as the markets they serve, considerations of security and diversity of supply are among the important factors to be placed in the balance in decisions over squeezing more hydrocarbons from deposits in other regions closer to home or over developing non-conventional hydrocarbons. Underlining this point, the IEA *World Energy Outlook* 2004 Reference Scenario predicts that 43% of the world's oil supply will be coming from the OPEC Middle East countries by 2030, compared with 25% in 2004 (Figure 1.11).

Figure 1.10 • *Distribution of proven reserves of conventional oil, according to various sources, in percentages*



Source: WEO-2004, IEA.

Figure 1.11 • *OPEC and OPEC Middle East percentage shares of world oil supply*

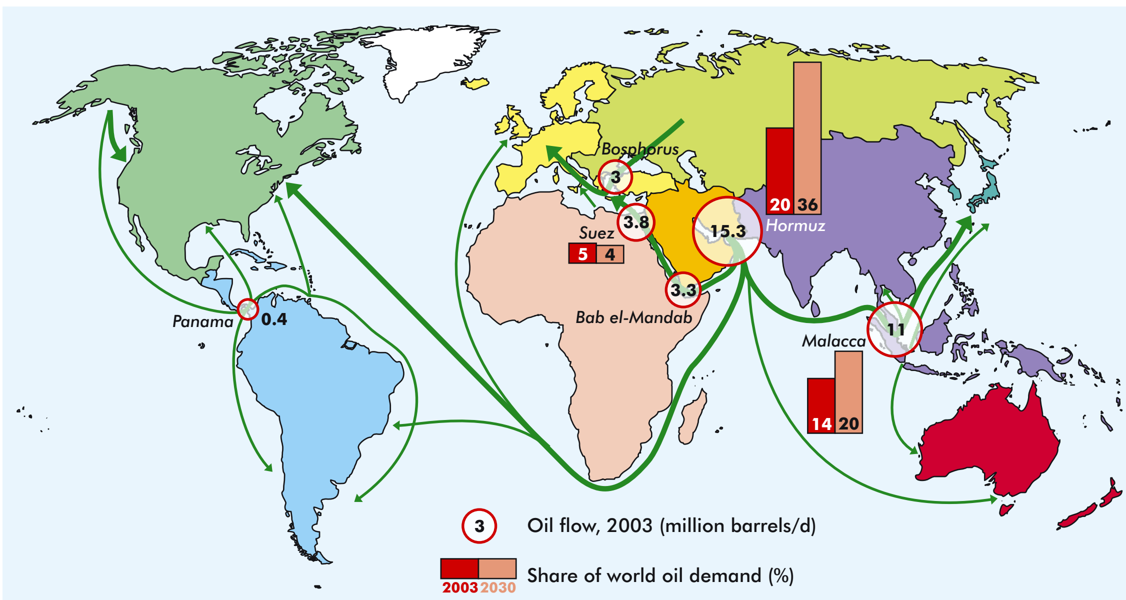


Source: WEO-2004, IEA.

Oil and gas transport

Because of its uneven geographical distribution, oil has long been traded and transported all around the world. But gas is much more difficult to transport economically and gas trading has traditionally been much more regional than truly worldwide. Currently, however, a worldwide trade for gas is developing and could assume a scale similar to that for oil. The catalysts are, first, declining production from conventional gas fields in the United States and Europe and, second, the advent of technological capability for longer pipelines and long-distance sea transport in the form of liquefied natural gas (LNG). A concern here is the future capacity of current, already busy maritime channels (Figure 1.12). Chapter 5 is devoted to transportation of oil and gas.

***Figure 1.12 •** Oil flows and major chokepoints, 2003*



Source: WEO-2004, IEA.

Structure of the oil and gas industry

Many players are involved in the oil and gas production chain, from the owners of the subsurface resources to financing organisations, and on to operators, drillers, equipment manufacturers, facility constructors, service providers and engineering companies.

The producing companies are generally classified within three main groups.

- **The international "majors"** like ExxonMobil, Shell, BP and Total, to name just a few. Typically, they hold portfolios of very big projects all over the world, wielding extensive skills sets and easy access to capital. They assume significant investment risks, of a technical, market or political nature, and they seek corresponding return premiums. These majors promote technology development very actively.

- **The "independents"**, which are smaller, private companies specialising in smaller-scale projects focusing on specific geographical areas or types of reservoir. Working with a smaller cost base, they are usually adept at managing older reservoirs or reacting quickly to swings in oil and gas prices and taking on projects offering rapid returns. These companies are often innovative in developing new types of resource and in leveraging their local knowledge.
- **The "major resources holders"**, national companies which own and often operate the fields in their home countries. Some of the many examples are Saudi-Aramco, PDVSA (Venezuela) and PEMEX (Mexico). The major resource holders tend to practice longer-term resource management (in contrast with the net-present-value approach and significant discount rates seen among private companies). With some notable exceptions, they tend to be followers of new technologies rather than developers. Together, these companies produce about 70% of worldwide oil and gas consumption. They control more than 90% of proven reserves.

Of course, all the companies co-exist within a continuum. Some national companies are active internationally, for example, and some independent companies compete with majors for the same types of project. A particularly strong trend among national companies is towards participation in projects outside their own countries, be it to diversify investment risks, as with Norway's Statoil or Malaysia's Petronas, or to target supply security, as with companies in net-importer countries like China's CNPC and Sinopec, or ONGC, the Indian national oil company. The latter are prime examples of companies with a rapidly growing international presence and a readiness to take on more risky or less economically attractive projects because corporate policy is driven by security of supply more than by economics on a project-by-project basis.

Subsequent chapters of this study will examine the dynamics of developing new resources. A key to understanding these dynamics is a grasp of the huge initial capital investment required to develop a field: exploration surveys, well drilling and construction, production and treatment facilities, transport (pipelines, tankers, LNG plants). Capital depreciation represents a large portion of hydrocarbon production cost. While this varies widely around the world, 60% is probably a typical value. Marginal production costs, on the other hand, are relatively low, ranging from less than USD 1 per barrel in Saudi Arabia to up to USD 10 per barrel in difficult offshore, Arctic regions. The pay-back period for large capital investments is often ten years or more. This is why many of the major companies plan projects on the basis of an oil price of around USD 20, even if the current price is much higher.

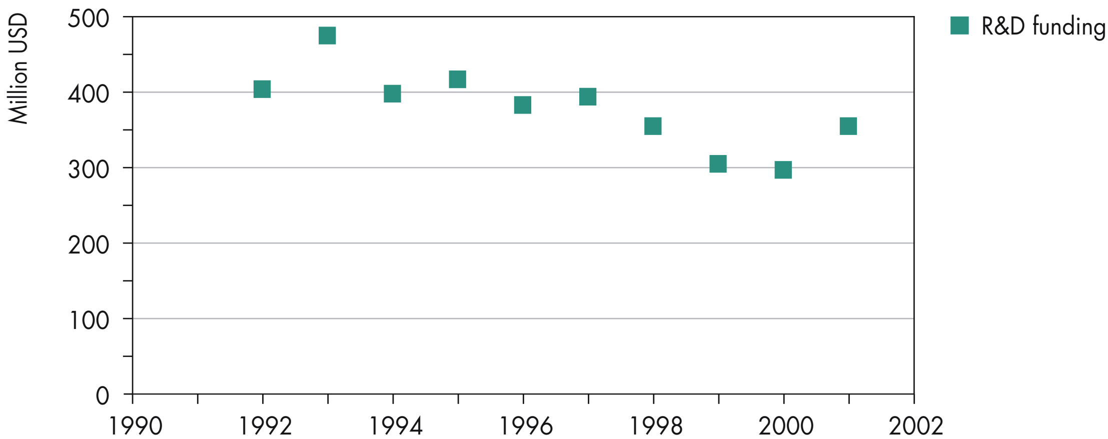
The producing companies act as planners, architects and project managers for most of the exploration and production projects. They rely heavily on service and supply companies for the actual implementation. Drilling contractors own and operate drilling rigs. Engineering companies design and build production facilities. Service companies perform seismic surveys and most of the operations required in wells. The service and supply sector thus plays a key role in technology development, alongside the producing companies themselves.

Research and development

In their role as prime developers of new technology, the service providers and equipment manufacturers work closely with the major oil and gas companies. The leading international oil and gas groups are the most active in taking up innovative concepts, but some national oil companies are also key players, as illustrated in the deepwater oil technology activities of Brazil's Petrobras. The major service companies and equipment manufacturers ensure that new technology is available rapidly worldwide for all customers. In addition, smaller, local companies also frequently contribute greatly to advancing technology by leveraging their local knowledge to try more risky ideas, often in partnership with local independents.

While some figures can be cited for industry-funded and national R&D respectively, statistics on total R&D spending on upstream oil and gas technology are difficult to come by (IFP 2005). A plausible ball park figure for the industry as a whole might be between USD 5 billion and USD 10 billion per year. This represents less than 1% of the industry's turnover.

Figure 1.13 • *Public oil and gas upstream R&D spending*

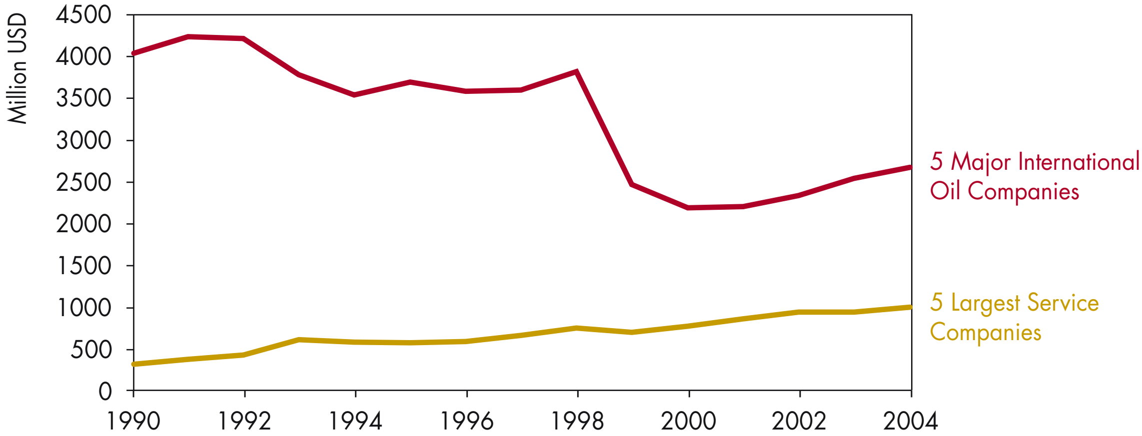


From IEA database, using figures reported by IEA member countries and extrapolations by the IEA.

Public R&D spending, as reported by IEA member countries, is shown in Figure 1.13. From a high level after the oil shocks of the 1970s, this upstream oil and gas R&D spending declined steadily during the period of relatively low oil prices of the 1990s. A handful of countries account for the bulk of this funding (Australia, Canada, France, Japan, Norway, United States). Some see such outlay as crucial in order to support their national oil and gas production. France and Japan are the only non-producing countries investing significantly in oil and gas R&D.

The R&D investments of large, publicly listed companies can be traced through their annual reports. Figure 1.14 shows the trends and volumes of spending for a group of the foremost producing and service companies. Large oil companies, too, cut back on R&D investment during the 1990s as they adapted to lower oil prices by outsourcing more activities, focusing on core businesses and consolidating.

Figure 1.14* • *R&D spending of major companies



From public sources, courtesy of Schlumberger.

Their R&D efforts have often been refocused on a limited number of areas seen to offer the possibility of a competitive advantage, for instance in exploration in some specific types of reservoir. For their part, service companies have maintained substantial and growing levels of R&D investment. A comparison between Figures 1.13 and 1.14 shows clearly that R&D spending among private companies far exceeds public expenditures, as to be expected within a mature industry.

The R&D contributions of small and medium-sized companies (SMEs) are more difficult to gauge. In Europe, the European Oil and Gas Innovation Forum (EUROGIF) groups more than 2 500 European supply and service companies in the oil and gas industry. They account for more than 250 000 jobs and an annual turnover exceeding USD 50 billion. Their reported R&D spending amounts to roughly USD 2 billion per year (Marquette 2004). A reasonable guess is that about 25% of that comes from SMEs.

While public information is scarce on R&D investment among national oil companies, anecdotal evidence suggests this has been growing. For example, R&D centres have been launched by Saudi Aramco, Petrobras and Petronas. Overall, however, it is likely that 90% of the R&D in the oil and gas upstream sector is undertaken in IEA countries.

Even if partly offset by increases in R&D investment in the service and supply sector, the decline in R&D investment among large oil companies and governments could be a worrying sign that technological progress might be slower over coming years than in the past.

The role of technology

Before exploring technology's future impact on the oil and gas industry, it is worth glancing back over advances to date. Some 150 years ago, methods in the upstream oil and gas industry were akin to those in traditional mining or construction. But steadily improving technology has propelled the industry towards techniques that would seem at home today in missions to explore outer space.

Once a hit-and-miss affair guided by surface topography, exploration is now a highly computer-intensive operation. Modelling traces the evolution of sediments throughout the history of the earth's crust ("basin modelling") in order to compute the stage of maturity and the movement of hydrocarbon deposits. Promising areas are mapped extensively through satellite and airborne surveys. Precise images of sediments 5 000 metres below the ground are created through seismic surveys that generate as much as 10 gigabytes of data per square kilometre.

Drilling, originally featuring shovels and buckets at the end of a rope, is now done with sophisticated rotary drills. A drill-bit coated with diamond powder grinds a hole 20 centimetres in diameter through rocks thousands of metres below the drilling control rig. It is possible to control the trajectory and enable it to deviate from a vertical to a horizontal bore of up to 10 km, and to turn, twist or drill upwards. All this underground activity is conducted out of the operator's physical sight through remote-control equipment not unlike that used in a mission to Mars.

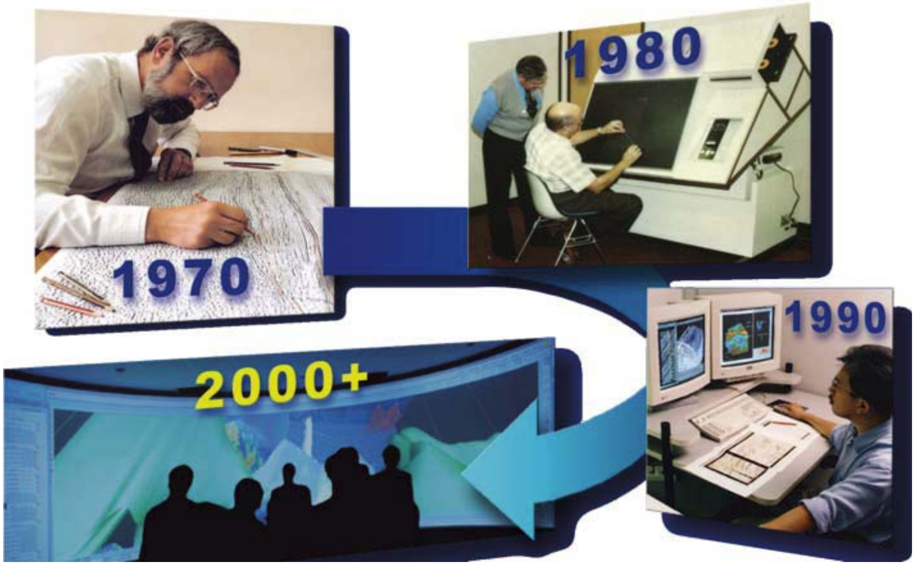
Figure 1.15 • *From a wooden shack …*

Courtesy of the Pennsylvania Historical & Museum Commission, Drake Well Museum, Titusville, PA., United States: ***www.drakewell.org****.*

Figure 1.16 • *… to a North Sea offshore platform*

Courtesy of Shell.

Figure 1.17 • From paper to immersive 3D



Courtesy of Shell.

Offshore drilling, which started with platforms resting on the seabed in a few metres of water, now involves dynamically positioned vessels able to control their positions in deep sea to within fractions of metres. Today's enormous floating structures carry vast arrays of facilities and stand above depths of 3 000 metres.

In the old days, reservoir management was largely a question of adjusting a valve to control the natural flow of the hydrocarbons. It now involves a closed loop of sophisticated computer simulations ("reservoir simulators"), which drive the positions of new wells and the injection of water, gas or more complex fluids to maximise the amount of hydrocarbons produced. Field development is optimised using massive amounts of data from measurements taken within the wells or at surface level and visualised in three dimensions in "virtual reality" rooms.

Figure 1.18 • From wooden pipeline …

Photo courtesy of S.T. Peas, Meadville, PA, USA, with thanks to Syracuse University and Onondaga Historical Society, Syracuse, NY, USA.

Figure 1.19 • … to liquefied natural gas carriers

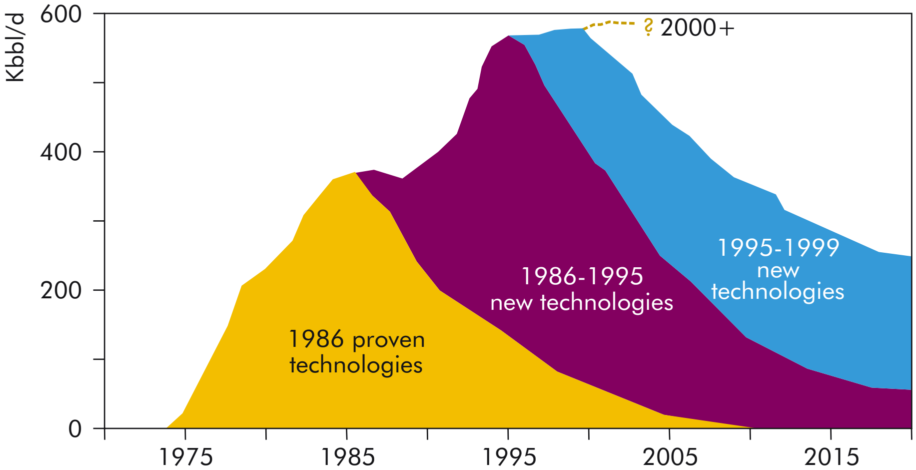
Courtesy of Statoil.

Regular technological advances are pushing back the frontiers of operating capability at extreme depths, under extreme reservoir pressure, or in difficult temperatures or geographical situations.

Ever more sophisticated pipelines, tankers and LNG carriers now enable hydrocarbons to travel all around the world.

These regular, spectacular forward leaps in technology have enabled hydrocarbons to fuel the world's economies for more than 100 years. Over this period, specialists have repeatedly predicted the end of the oil era, only to be proved wrong by new advances in technology. We conclude this chapter with an illustration of the impact of technology on the volumes of oil extracted from the North Sea, as of year 2000 (Figure 1.20): technology played a key role in extending the life of this oil province. We shall look at further examples in subsequent chapters.

Figure 1.20 • Impact of technology on production from the North Sea, in thousand barrels per day



Source: European Network for Research in Geo-Energy - ENeRG - courtesy of Shell.

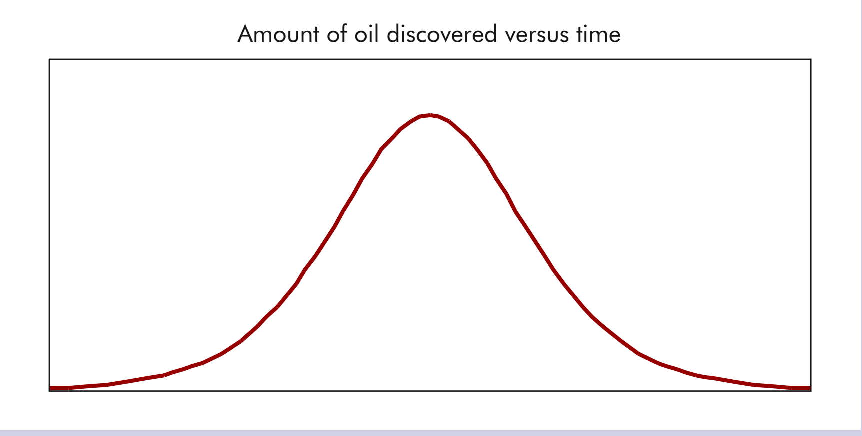
Box 2 • Peak oil

The issue of "peak oil", the time when worldwide oil production will begin to decrease, has generated a large amount of literature and controversy. The purpose of this box is to give an elementary introduction to this issue.

The idea of peak oil originates in the work of M.K. Hubbert, a geologist at Shell and the USGS who successfully predicted the peak in oil production in the USA. There are various ways to "derive" the Hubbert curve; here we use one that focuses on the exploration process.

In the initial stage of exploration for a resource such as oil, the success rate for discoveries is small because geologists do not know where it is best to explore. But as more oil is found, we learn more about places where it is likely to be found, and the success rate increases. However, because the amount of oil in the ground is finite, there eventually comes a time when most of it has been found, and it becomes more and more difficult to find additional reservoirs: the exploration success rate decreases again. Based on this argument, one expects the amount of oil discovered as a function of time to look like the curve in Figure 1.21.

***Figure 1.21 •** Theoretical shape of amount of oil discovered as a function of time*



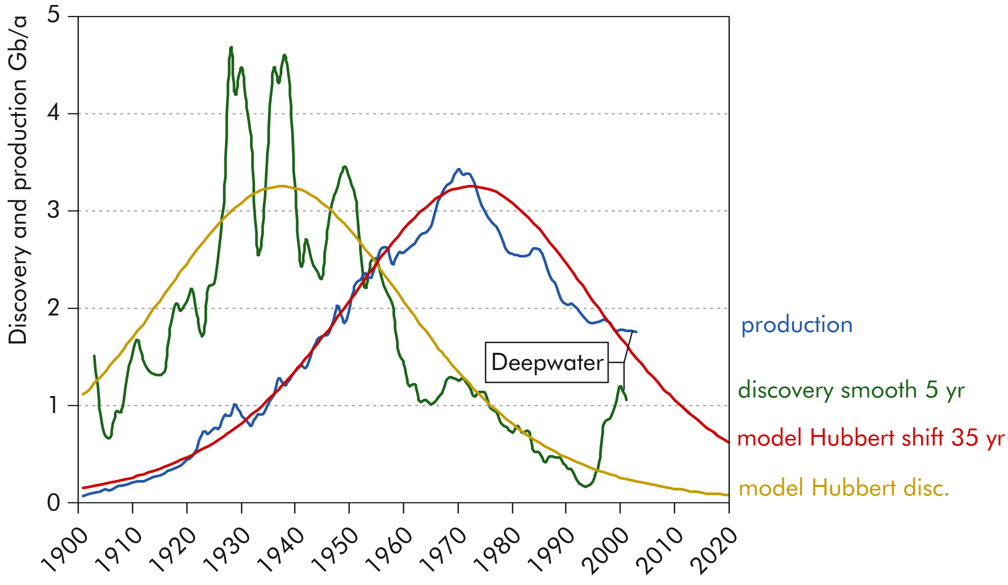
It is common, after Hubbert, to describe this curve by a "logistic" function:

$$Q(t) = \frac{Q_{tot}\, b \exp(-b(t-t_0))}{(1+\exp(-b(t-t_0)))^2}$$

where Q(t) is the amount of oil discovered in year t, Q_{tot} is the total amount of oil in the ground, b is a parameter, and t_0 is the time of peak oil.

There is nothing rigorous in this mathematical form, it is only a simple representation with the right shape. What Hubbert discovered is that this mathematical equation is a good representation of actual data for discoveries and for production in the USA (Figure 1.22).

Figure 1.22 *• Annual oil discoveries and production for USA Lower 48*



Reproduced with permission from Laherrere 2003.

The fact that production data can be described by a curve similar to discovery data, simply shifted by a time lag (35 years in Figure 1.22), is quite remarkable. It can be expected to happen for almost ideally functioning markets in which fields are put into full production regularly following discovery. The striking success of Hubbert in predicting the peak of USA production suggests that such conditions were more or less met in the USA during that time period.

The controversies surrounding peak oil in the literature revolve around four main points.

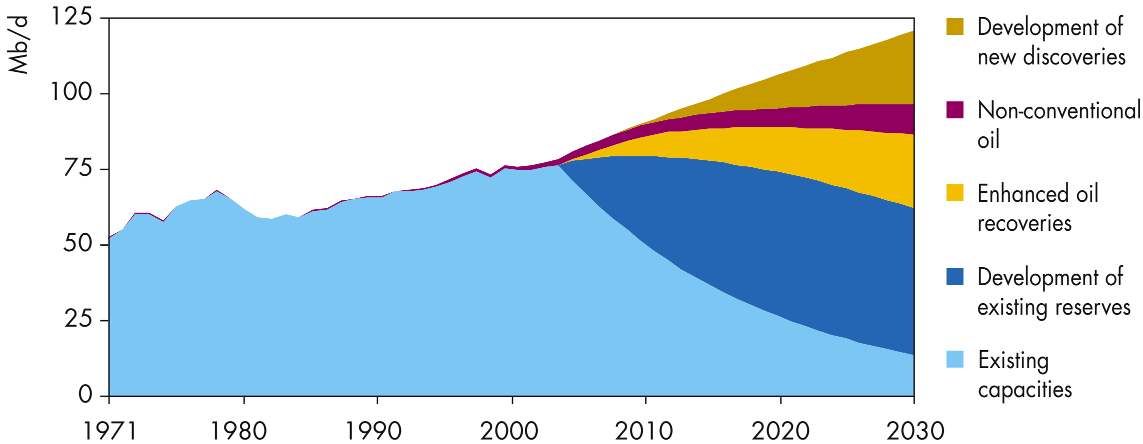
- *Does the Hubbert model apply to oil production worldwide?*
- *If the Hubbert model does apply, when will the peak in worldwide oil production be?*
- *What happens after the peak? How fast will the decrease of production be?*
- *What role does technology play in such models? Technology can change the amount of recoverable oil (Q_{tot}) as a function of time, and can affect the post-peak decline rate. This is illustrated for example in Figure 1.20 for the North Sea. Some analysts in fact prefer to use "multi-cycle Hubbert curves", i.e. the superposition of several Hubbert curves for different technology cycles, in order to capture the effects of technological progress.*

*Discussion of these questions is outside the scope of this book. Some pointers to the relevant literature can be found on the ASPO web site (**http://www.peakoil.net**), or in recent editions of* Oil and Gas Journal *(6 June 2005 and 13 June 2005).*

Chapter 2 • "CONVENTIONAL" OIL AND GAS

Projections made in the IEA *World Energy Outlook 2004* show that conventional oil and gas will continue to dominate supply during the three decades to 2030, even though use of non-conventional sources is likely to grow significantly (Figure 2.1). This is why a large part of this study is devoted to conventional resources.

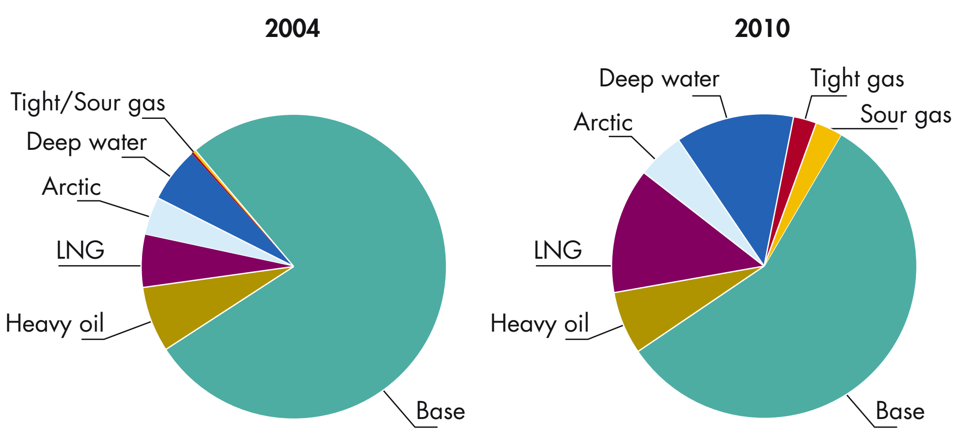
Figure 2.1* • *World oil production by source in million barrels per day



Source: WEO-2004, IEA.

A comparable perspective is reflected in the projections of one of the companies in the field (ExxonMobil), which show how production is expected to shift between different types of resource by 2010 (Figure 2.2). Most major oil companies are working on similar development paths. The continuing key role of conventional resources is clear, but so is the shift to more challenging areas (deepwater, Arctic) and the growing role of gas.

Figure 2.2* • *ExxonMobil's production projections



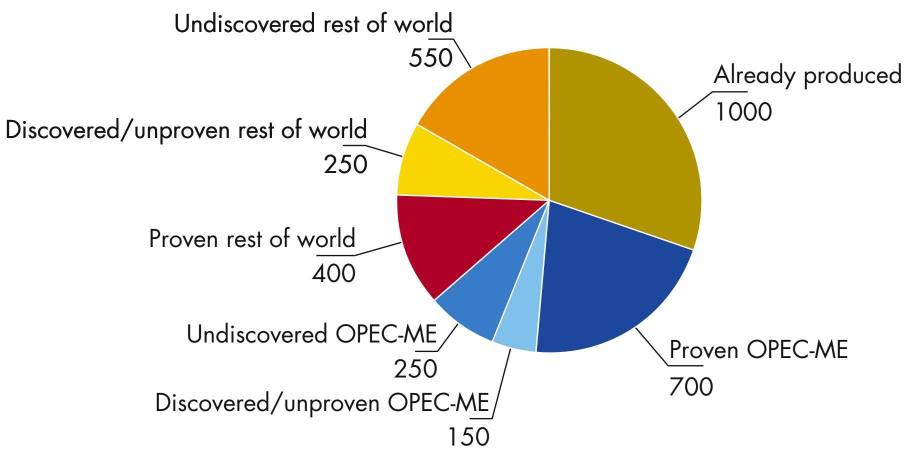
Sour gas is gas with high H_2S content.

Courtesy of ExxonMobil.

In this chapter, we shall look, first, at the geographical locations of both present and future major conventional oil and gas resources, then at the issues affecting extraction and the technology solutions currently used to maximise output.

Figure 2.3 shows the breakdown of technically recoverable conventional oil, according to the 2000 United States Geological Survey assessment. It is useful to remember that, according to the projections of the IEA *WEO-2004*, the cumulative need for oil between 2003 and 2030 amounts to roughly 1 000 billion barrels, i.e. about as much as has been "already produced". The figure illustrates clearly the importance of OPEC Middle East proven reserves in the supply equation for the coming 25 years.

Figure 2.3 • *World ultimately recoverable conventional oil in billion barrels*



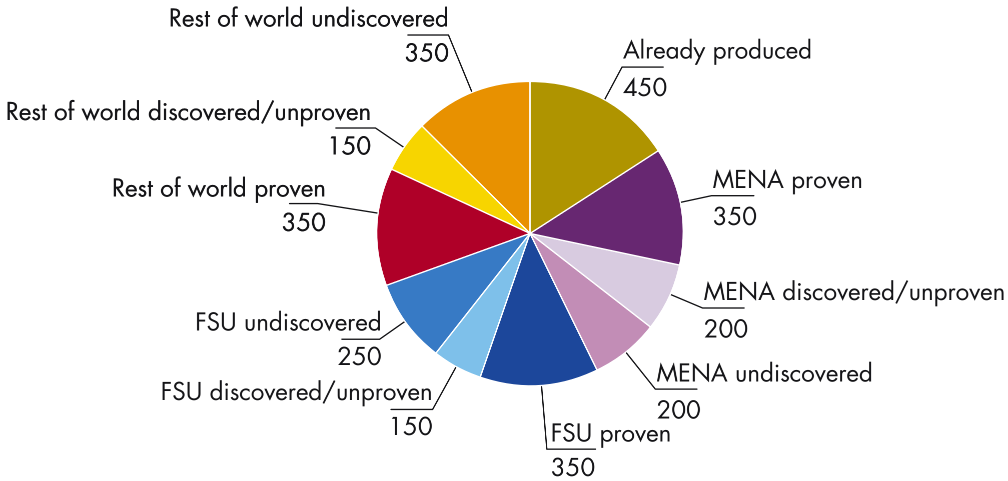
The "Discovered/unproven" category corresponds to the USGS "reserve growth" (see Box 11). Numbers from the USGS 2000 assessment have been updated to take roughly into account production and changes in reserves between 1996 (the reference year of the USGS study) and 2003.

Based on USGS data and IEA analysis.

Figure 2.4 presents a similar breakdown for conventional gas resources, using the same approach as in Figure 2.3. Gas volumes are converted to barrels of oil equivalent (boe), calculating 6.25 boe per thousand cubic metres. Here, we highlight the role of two key regions: the Former Soviet Union (FSU) and the Middle East/North Africa region (MENA). Cumulative worldwide demand between 2003 and 2030 totals something like 600 billion barrels of oil equivalent. Availability of conventional gas reserves to meet this expected demand is much less of a concern than in the case of oil reserves. As we shall see in Chapter 5, transportation of gas is the area where technology will have the greatest impact.

In order to discuss the supply situation a little further and pinpoint the key technology issues involved, conventional oil and gas are addressed in separate sections below, dealing respectively with OPEC Middle East and with other regions.

***Figure 2.4 •** World ultimately recoverable conventional gas in billion barrels oil equivalent*



Based on USGS data, Cedigaz data and IEA analysis.

OPEC Middle East

A number of countries have both vast proven reserves and large ratios of proven reserves to production, combined with low production costs. Typically, these are OPEC Middle East countries (e.g. Saudi Arabia has 80 years reserves to production ratio), but also others like Venezuela. Their main focus is on careful, long-term exploitation of their reservoirs, on maximising recovery rates and on providing for adequate revenues far into the future. They have a partial monopoly and can attempt to improve their short-term returns by exercising their monopoly influence. Their prime technology needs relate to reservoir management and recovery improvements, discussed at length under the "Improved recovery" section later in this chapter. In all probability, these countries also possess significant undiscovered resources. But their incentive to explore and develop them is modest, given their comfortable reserves-to-production ratios at present.

Although they are seldom technology trend-setters, some of these countries - Saudi Arabia and the United Arab Emirates, for instance - are active in following the latest technology developments coming from international companies and leveraging these to optimise costs and reservoir management. Examples include Saudi Aramco's extensive use of horizontal and multilateral wells in what is termed a "maximum reservoir contact approach" (Saleri 2004). Other countries (Iran, Iraq or Libya) are still lagging behind, due to past or ongoing restrictions over access to technology. All countries are likely to benefit significantly from the various developments described in later sections of this chapter.

The Reference Scenario of the IEA *WEO-2004* projects that OPEC Middle East oil production between now and 2030 will more than double. Long-term access among Middle East producers to the latest technologies will therefore be crucial, even in alternative scenarios involving reduced reliance on OPEC Middle East countries.

Partnerships between such producers and the technology developers will remain fundamental to security of supply for IEA countries and the entire world. More details on future supply from the Middle East and North Africa region is due to be presented in the upcoming IEA *World Energy Outlook 2005* (IEA *WEO-2005*).

In this region, improved capability in monitoring fluid movements between wells could be the most significant future technological development. There are important reasons for this. The region is characterised by large-size reservoirs, from which oil is extracted relatively slowly in an attempt to maximise long-term recovery using a relatively limited number of wells. For example, many of the large Middle East reservoirs obtain their output through "peripheral water flooding", a technique in which water is injected from the edges of the reservoir to try to obtain a slow but extensive sweep of the entire reservoir. In contrast, in the traditional "five-spot pattern" used in many other countries, each producing well is surrounded by four injector wells relatively close to each other, thus ensuring a relatively rapid sweep of the oil by the water, rapid oil production and a favourable result in terms of net present value.

Since a well is not only a channel for injecting and producing fluids but also the prime conduit for acquiring information about what is actually happening in the reservoir, there are drawbacks with the peripheral water flooding approach. When there are only a few, widely spaced wells, tracking of fluid movement in the reservoir is limited and fewer opportunities exist to validate reservoir models. This can occasionally lead to unpleasant surprises when production suddenly declines unexpectedly. It is a particular concern with carbonate reservoirs which may contain significant incidence of unrecognised breaks in formation homogeneity (see the "Improved recovery" section further on).

A recent and widely discussed occurrence of this phenomenon involved the Yibal field in Oman (Mijnssen 2003). Although this field had many wells, an insufficient acquisition of well surveillance data led to a failure to spot fault zones creating a high permeability path for water to bypass the remaining oil. The drilling of horizontal wells intersecting these zones contributed to a very abrupt drop in oil production. From 225 000 barrels per day (b/d) in 1997, output declined to 95 000 b/d in 2001. Interestingly, recognition of the problem led to new plans offering a potential increase in the recovery factor from 40% to more than 50%.

Further development of techniques described under the "Improved recovery" section (notably four-dimensional seismic, cross-well surveys), coupled with low-cost drilling of observation wells exclusively to acquire information, can be expected to play a very significant role in the future management of Middle East reservoirs.

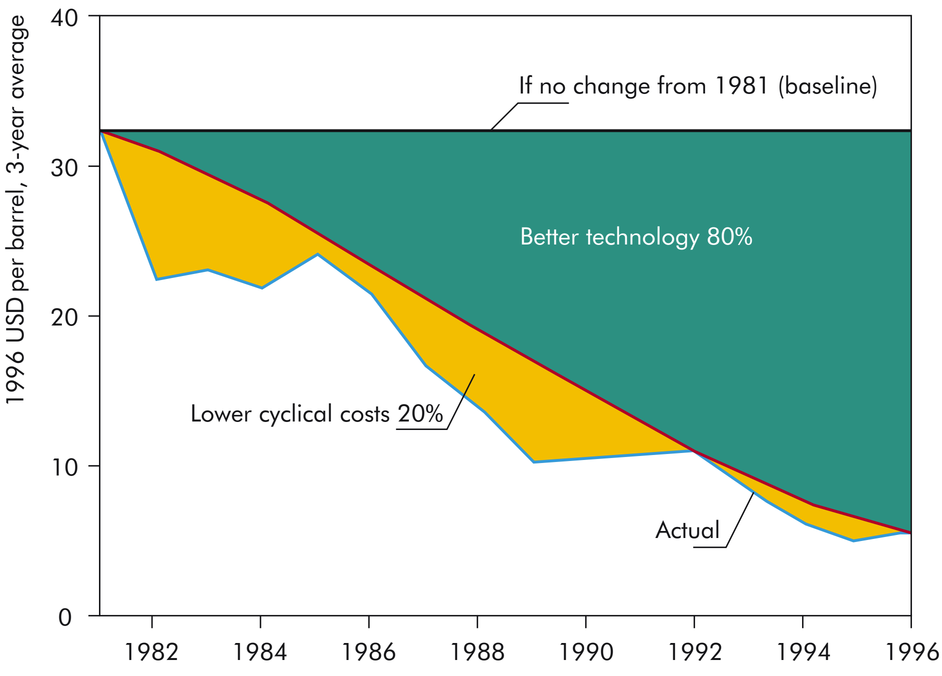
Other regions

Most other countries have passed their peaks in conventional oil production[6], or will do so shortly. Their world is one of maturing oil fields. Their exploration and production costs are typically higher but they limit OPEC's monopoly effect, thus operating with smaller margins. Cost reduction is therefore a constant concern.

Proven reserves/production ratios are small, averaging around 15 years and production in the older fields is declining. The challenges are:

- To make unproven reserves in known reservoirs economically viable by lowering production costs, maintaining production volumes as long as possible and fighting decline curves.
- To discover more new reserves in the remaining undeveloped or undiscovered hydrocarbon deposits, which will be harder to find and to exploit. Some of the frontier areas promising new discoveries (notably deepwater, Arctic) are discussed later under the "New conventional resources" section. One of the challenges is to attract investment for these remaining large, but more costly, resources.

***Figure 2.5** • Technology impact on costs for offshore USA*



Technology improvements account for 80% of the reduction in costs over the 15 years period, while cyclical costs account for only 20%.

Courtesy of Shell. Source: Cambridge Energy Research Associates.

6. Russia and Former Soviet Union countries are special cases, discussed briefly in Box 3.

On the latter point, one of the major issues for the coming 25 years will be how to attract enough capital to ensure adequate supplies of fossil fuels, as underlined in IEA publications (IEA *WEO-2003* and IEA *WEO-2004*). On the other hand, the IEA *WEO-2004* Reference Scenario also assumes a fairly moderate, relatively stable oil market environment, with prices between USD 22 and USD 29 per barrel. Attracting large amounts of capital in a moderate price context will be possible only if the cost of exploring, producing, transporting and transforming hydrocarbons is low enough to ensure adequate return on capital.

As hydrocarbon production shifts to more difficult fields, the onus will be on vigorously advancing technology to curb rising costs. Even with already proven reserves, which are by definition already profitable using current technology and at current prices, substantial capital investment must in any case be mobilised to extract the hydrocarbons. If this capital is to be secured, further cost cuts will be necessary in order to increase return on capital. The degree to which this is absolutely critical is illustrated in Figure 2.1. Current production declines very rapidly if not sustained by new investment.

Over the years, technological progress has been a principal enabling factor in controlling the cost of exploration and production of oil and gas. Major advances in the 1980s and 1990s like three-dimensional seismic and horizontal wells have had a dramatic impact on the industry. Figure 2.5, for example, shows an estimate of the role of technology in reducing costs in offshore production in the United States.

When considering approaches for the future, it should not be forgotten that cost-effectiveness cannot be reduced to a couple of breakthrough technologies. It covers a multitude of small improvements in all aspects of the industry's activities. Three main areas can nevertheless be identified: low-cost wells, i-field technologies, and the economies of scale possible in mature fields. They are discussed in turn below.

Box 3 • Russia and Former Soviet Union (FSU) countries

Russia – and to some extent other FSU countries – deserve special mention as they are not prominent in the above discussion centring on OPEC Middle East and other regions. They nevertheless play a key role in the world supply of oil and gas.

Oil

Russia has very sizeable oil reserves (IEA WEO-2004*), amounting to some 70 billion barrels of proven reserves, as well as what must be the equivalent in discovered but not yet proven resources. In addition, Russia has a potential in excess of 100 billion barrels of undiscovered oil in the vast, poorly explored territories of Eastern Siberia and on the Northern and Eastern seaboards.*

After peaking in the 1980s, production declined rapidly in the early 1990s, before staging an impressive recovery between 1997 and 2004. This recent increase in production is largely associated with the introduction of modern technologies, following an influx of western expertise and practices.

The current structure of the industry is still changing, with both State and private sector playing significant roles. Rather like in the Middle East producing countries, the State brings strong political views to the industry, but the private companies have been leading the introduction of more modern technologies.

Although substantial mileage remains in more widespread use of technologies developed in other countries, much innovation may well be spurred within Russia itself by the characteristics of the country: remote location of reservoirs, large transportation distances, difficult climate, highly educated workforce, relatively low labour and industrial equipment costs. Given the right political and economic environment, Russia will probably play a key role in oil exploration and production innovation over the next 20 years, starting with local, custom-made, cost-effective technologies, which could later be exported and applied in other regions.

Gas

As shown in Figure 1.9 (Chapter 1), Russia and the FSU states have about one-third of the proven gas reserves in the world, and probably a similar fraction of conventional gas resources. They also possess considerable potential for non-conventional gas (especially coal bed methane and methane hydrates; see Chapter 4). Russia is – and is likely to remain – the primary source for meeting the growing gas needs of the European countries. There is also strong interest from China and Japan in gas supplies from eastern Russia, as well as other FSU gas producers like Kazakhstan and Turkmenistan.

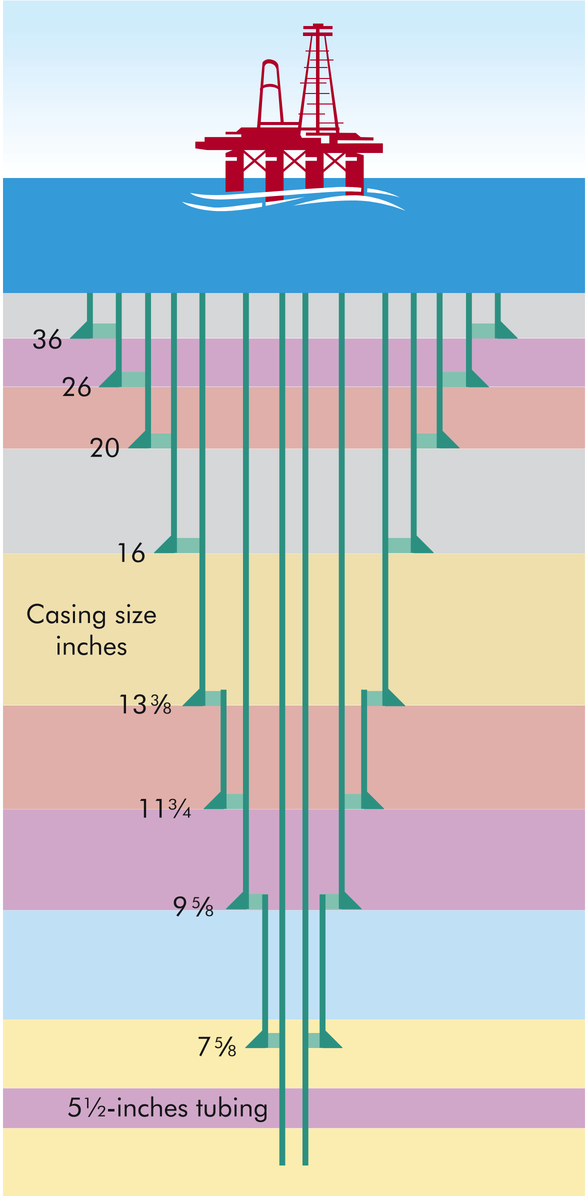
The gas sector is largely dominated by the state company Gazprom. Although a few smaller independent producers like Novatek have now emerged, Gazprom continues to leverage its monopoly on long-distance transport to play a role in all major projects. Currently, most production comes from a few, ageing giant fields (Medvezhye, Urengoy, Yamburg), which are due for replacement by new green-field developments over the coming few years. Gazprom brought on stream the large Zapolyar field in 2003, and the company is holding extensive discussions with possible western partners to develop the super giant Shtokman field in the Barents Sea. It is expected that this field will require capital investment in excess of USD 20 billion. To date, participation of international companies has been limited to the Sakhalin Island fields in the Far East.

As in the case of oil, factors such as remoteness, climate and long distances to markets create a great need for new technologies in the sector. Gazprom has a long tradition of internal investment in technology, with a number of active R&D laboratories. It has been relatively slow (compared with the oil sector) in adopting western technical practices. Many experts believe that, beyond the difficult offshore developments (Sakhalin, Shtokman) for which Russia considers western technology necessary, appropriate use of innovative technologies can provide a key to realising a very large potential for efficiency and recovery improvements in existing fields, as well as in the transportation system. How and when this need for technology and investment is met will depend in large part on how the structure of the gas industry evolves in Russia.

Low-cost wells

Constructing wells and surface facilities claims the largest share of costs. Although the cost of both is likely to fall, drilling wells is probably the most amenable to revolutionary changes. (Offshore surface facilities are also destined for major change, as discussed later under "New conventional resources".) The industry has a long history of drilling innovation. Two recent high-potential innovations can be cited.

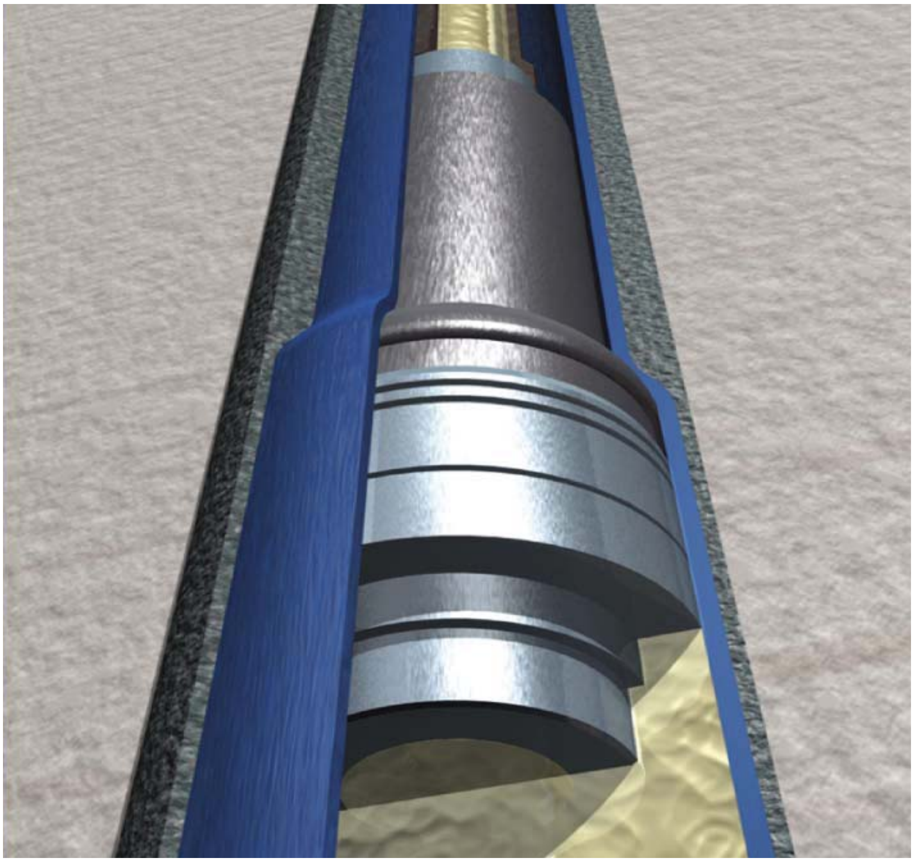
Figure 2.6 • *Example of conventional well construction, showing diameter reduction with depth*



Courtesy of Schlumberger.

- "Casing drilling", which consists in using casing pipes instead of the usual drill pipes during the drilling process. The casing is the set of metal pipes that are cemented to the rock at the end of the drilling process to keep the hole in place. Although this technology presents some challenges in relation to mechanical robustness, and this may confine it to relatively shallow wells, casing drilling is a method that nevertheless saves several steps in the construction of a well.
- Expandable casings, a new technology that could open the way to the long-time holy grail of "monobore" completion (completion being the last stage in well construction). Here, the deep well constructed has the same diameter from top to bottom. In conventional well construction, boring starts with a large diameter hole at the top and the hole diameter is reduced step by step as it goes deeper (Figure 2.6). For example, if a 20 cm. diameter hole is required across the producing zone, the well might start at the surface with an 80 cm. diameter hole. The monobore well offers the advantages of reduced energy for drilling, reduced waste from drilling and reduced size of the drilling rig. The most recent technology developed to target this objective is based on metal piping that can be introduced into the well and expanded *in situ* to match the size of the hole (Figure 2.7). Advanced materials form the cornerstone of this process, and they are likely to continue evolving.

Figure 2.7 • *Sketch of casing (blue) being expanded by an expanding tool pulled from bottom to top*



Courtesy of Shell.

I-field or e-field technologies

These are a broad class of technologies also called real-time processes, smart oil field technologies (SOFT) or digital oil field technologies. Such techniques rely heavily on advances in electronics and information/communication technologies[7]. A number of concepts are involved, in which sensors and actuators placed in wells or at the surface continuously monitor what is happening in the reservoirs. They relay the information in real time to a control room, where the measurements are compared with complex numerical models, and operations are constantly optimised. These technologies have been widely discussed in the industry for the past ten years. Although many of the components exist already, the full capability of these technologies is being implemented relatively slowly because the return on investment is hard to quantify ahead of time. Nevertheless, they can be expected to transform the industry over the coming 20 years and to contribute significantly to driving costs down (as well as easing the current human capital crunch and contributing to increased recovery factors).

7. To highlight the key role of modern information technology in the oil and gas upstream industry, it suffices to note that seismic companies operate the largest parallel processing computers outside the military domain. Several upstream companies are also at the forefront of use of grid computing.

Economies of scale in mature fields.

These will facilitate very much more streamlined operations. As producing fields mature, they usually comprise larger numbers of wells, closer to each other. This opens up potential for streamlining operations in a much more systematic way than in the past. Already a very clear trend in the United States onshore fields, such streamlining is likely to become more widespread in fields around the world. For example, operations in wells like drilling, completing and stimulating have traditionally been sequential, involving different personnel or contractors bringing in specialised equipment with which to conduct each of the various steps in the process. This is entirely appropriate in the case of new, remote fields in which each well is a special case. But in a mature field with many similar wells, there is ample opportunity to develop standard processes that integrate different steps and significantly cut costs. Figure 2.8 illustrates such an approach.

Figure 2.8 • *New equipment for integrated completion services*

One single piece of equipment is now able to conduct multiple operations simultaneously when construction of a well is being completed, replacing a series of tasks formerly carried out successively, often involving multiple contractors.

Courtesy of Schlumberger.

The transition to a world of maturing fields is likely to have a far-reaching impact on technological development. This will be significant, for example, with large installations in mature offshore fields, which may be reaching the end of their technical and economic life. Increasingly important will be the technologies to provide for safe and environmentally friendly abandonment and disposal – or conversely for extension of useful life by tapping remaining smaller pockets of hydrocarbons – or for conversion to new purposes such as geo-sequestration of CO_2.

Improved recovery

What is recovery?

When oil contained in the pores of the sedimentary rocks forming the reservoir is extracted, it needs to be replaced by something else. The replacement can be fluids already contained in the reservoir, such as water located below the oil, or gas located above the oil or in solution. This oil production mechanism is called "primary" recovery. But water or gas can also be injected into the reservoir to replace or "sweep" the oil. This is called "secondary" recovery, even though the process often runs from the very start of production. Finally, more complex materials can be injected (polymer solutions in water, surfactants, steam, microbes) and this is called "tertiary" recovery. Needless to say, the materials injected must carry less value than the oil extracted.

While the figures vary widely, depending on the reservoir characteristics, primary recovery can typically extract 10% to 30% of the oil in place, and secondary recovery an additional 10% to 30% (a total of 30% to 50%). Extracting much more than 40% of the reservoir's oil usually requires additional steps in the way of tertiary recovery, which may or may not be economical.

The above refers to oil. Gas reservoirs typically have much higher recovery factors of 70% to 80%. Improved recovery in gas reservoirs has therefore received little attention. There exist, however, gas reservoirs, like those underlain by strong active aquifers, for which recovery can be low for reasons very similar to those in oil reservoirs. The technologies discussed below are applicable in such cases.

Trends

It is well known that in most reservoirs one-half to two-thirds of the hydrocarbons in place are actually left in the ground at the time the field is abandoned as no longer economical. Average oil recovery rates world wide are currently around 35%[8]. This is illustrated vividly by Figure 2.9 for the United States.

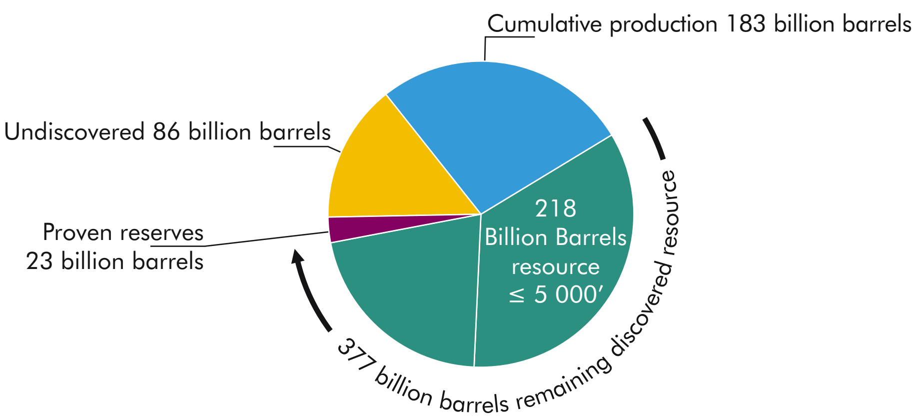
Some fields are now reaching 50% recovery rates. Norway, for example, has been particularly active in bringing up the recovery levels, as shown in Figure 2.10. Increasing the worldwide average recovery rate to 45% in existing fields would usher in "new" oil reserves larger than those of Saudi Arabia. It should be noted that the assumptions on recovery rates made in the USGS estimates of worldwide ultimately recoverable hydrocarbons (Figure 1.5) are not explicit. They include a "reserve growth" factor for known fields, which is based on historical experience in the United States. This takes into account a certain amount of enhanced oil recovery (EOR), since CO_2 injection or thermal recovery are used extensively in the United States, but it does not reflect the potential of techniques not widely used, for instance polymer floods or microbial EOR (MEOR).

8. Numbers of this order are often quoted, but rarely supported by abundant data. In fact, it is in principle necessary to look at abandoned reservoirs, estimate original oil in place (which is always somewhat uncertain) and compare it with actual cumulative production up till abandonment. Also, because such analysis looks at the past, it does not necessarily take into account current, more advanced technology practices. The data available is mainly from the United States.

A substantial increase in recovery rates would therefore expand the amount of ultimately recoverable oil beyond the USGS figures. USGS estimates are discussed in more details in Box 11.

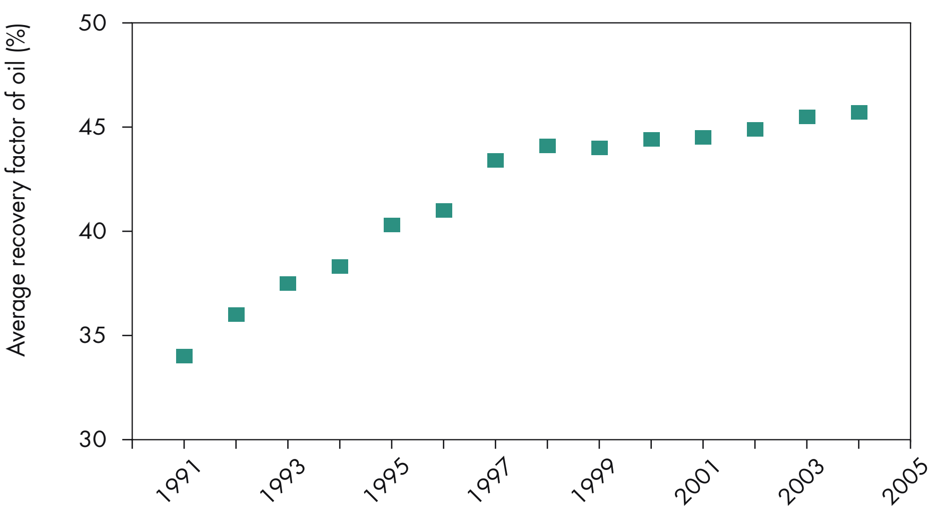
It is customary to think of this left-over oil as having two components: "by-passed oil" and "residual oil". These are discussed, in turn, below.

Figure 2.9 • *Un-recovered oil left over in United States fields*



After United States Department of Energy; DoE 2004.

Figure 2.10 • *Evolution of expected recovery factor in Norway*



The 50% line is the future goal of the Norwegian government.

Courtesy of Norwegian Petroleum Directorate.

By-passed oil

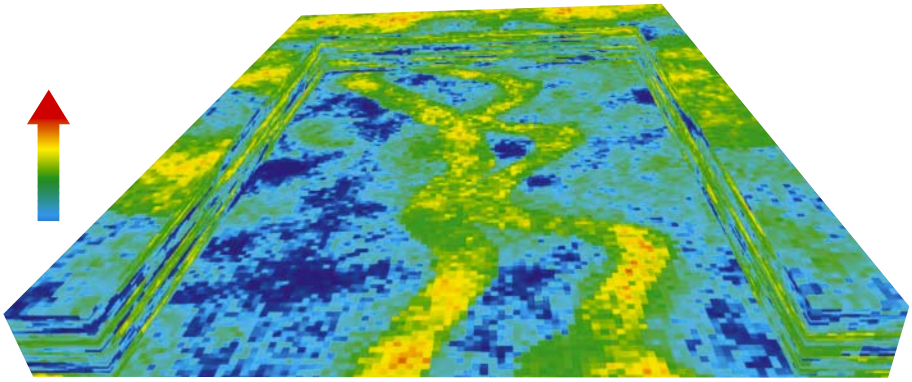
This term refers to large pockets of oil (or gas) which have not been swept out (Figure 2.11). Techniques are being developed continuously to minimise such by-passed oil, to locate places where it remains and to produce it cost-effectively. These techniques are generally termed "improved oil recovery" (IOR)[9]. Recent progress, notably with four-dimensional (4D) seismic imaging or re-entry lateral drain holes, is expected to have a significant impact.

Briefly described in Box 4, four-dimensional (time lapse) seismic surveys are now coming of age and hold considerable potential, particularly offshore where they are cost effective. Another method involves permanently installed geophones, for example on the seabed. This technique has also proved extremely useful, even though current costs preclude dense sampling. On land, the economics are often unfavourable for large 4D surveys. Further reductions will be needed in the cost of high-quality, dense, 4D land surveys if this technique is to become widespread.

Electromagnetic (EM) surveys from the surface (see Box 5) are also a potentially very powerful means of localising by-passed hydrocarbons, although they are limited to relatively shallow reservoirs. ExxonMobil and Statoil are among the companies actively developing new EM survey techniques. Further improvements are needed in this field.

Cross-well surveys, whether seismic or electromagnetic, have the potential to play a key role (Box 6). While they have existed for a couple of decades, they have remained a niche technology. The key limitation has been availability of wells with the appropriate spacing (distance between wells). Will they come of age? Maybe they have a future in the form of permanently installed sensors (resistivity or geophone arrays placed behind casing), although the cost of deploying these is still too high for routine use.

***Figure 2.11* •** *By-passed oil*



Water, in blue, has swept out the oil but left some channels still containing oil (high concentration in yellow and red, lower concentration in green). The oil may have been left behind because, for example, the channels have lower permeability.

This illustration, not based on factual data, is reproduced from Yeten 2002, courtesy of Fikri Kuchuk, Schlumberger.

9. The definitions we use (IOR for recovery of by-passed oil, EOR for reduction of residual oil at the pore level) are not universally accepted, creating some confusion. For some authors, EOR is a subset of IOR; for others, IOR is enlarged to include essentially all modern technologies for good reservoir management.

Box 4 • 4D seismic surveys

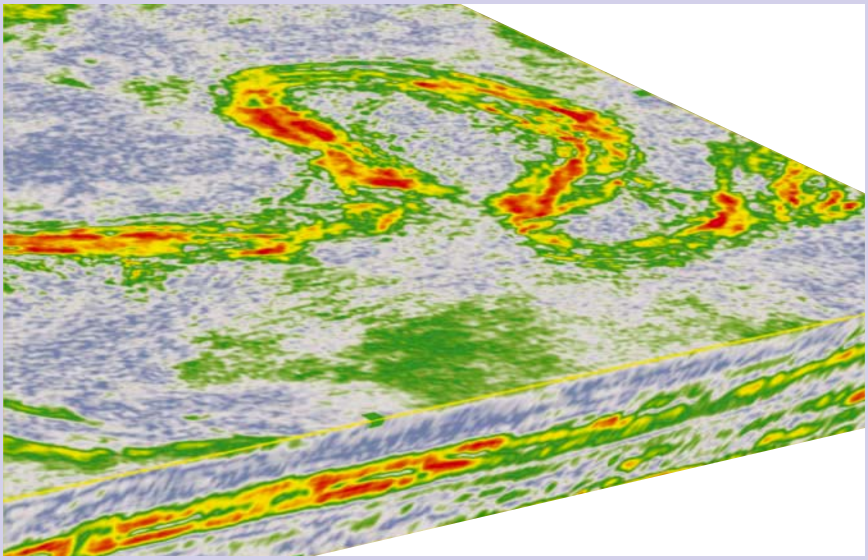
Seismic surveys have long been one of the key tools in oil and gas exploration and production. These surveys consist in moving an acoustic source (emitting sounds) on the earth's surface and recording the acoustic signals reflected from the subsurface using an array of acoustic receivers. As the boundary between successive sedimentary layers typically reflects part of the acoustic waves, seismic surveys make it possible to reconstruct an image of the geometry of the subsurface layers.

Originally, the soundings were taken along a line on the surface, giving a two-dimensional (2D) image of a vertical slice of the earth's subsurface. In the past 20 years, the norm has become 3D surveys, in which a 3-dimensional image of a cube-shaped section of the subsurface is obtained by moving the acoustic source and receivers on a 2D grid at the earth's surface. Continuous improvements in the quality of the recording of acoustic signals and in the processing of the data have led to very striking images of the geometry of reservoirs (Figure 2.12), which have become a fundamental part of the exploration and production process.

4D seismic techniques consist in making repeated 3D surveys at regular time intervals. As the reservoir geometry does not change, in principle, differences between successive surveys can reveal the movement of fluids through the reservoirs, notably oil being produced and replaced by water. This is rapidly becoming a fundamental tool in optimising production and recovery.

There are two major limitations with these techniques. First, their spatial resolution prevents them from imaging small details less than some 50 metres in size. The second limitation is the cost of such surveys. Offshore, where the acoustic sources and receivers are towed by a boat, very large surveys can be carried out cost-effectively. On land, however, the receivers have to be moved manually, making large surveys cumbersome and expensive. Improved resolution and improved deployment techniques are active areas of research in the industry.

Figure 2.12 • *3D seismic picture of fluvial sediments 3 000 metres below ground*



Courtesy of Schlumberger.

Box 5 • Electromagnetic surveys

Unlike seismic (acoustic) surveys, which respond primarily to the geometry of the reservoirs and only to a much smaller extent to the nature of the fluids, electromagnetic measurement techniques are well suited, in principle, to remotely differentiating between oil and water. This is because oil-containing rocks tend to have much lower electrical conductivity than water-containing rocks. This sensitivity is routinely used in well-logging (taking measurements in wells) and is a key part of any assessment of oil in-place. Electromagnetic measurements taken from the surface also have a long history and they have been used extensively in the mineral mining industry[10]. But in the oil and gas industry, where interest is in deeply buried sediments, their handicap is very poor spatial resolution in comparison with seismic surveys, and this has prevented extensive application. Recently, however, interest in this technology has been revived by the convergence of two factors: measurement capability and emergence of the deepwater market. In the deepwater context, the reservoirs of interest are still very deep below the sea's surface, but often not very deep below the seabed. This enables modern electromagnetic measurement techniques, using instruments placed near the seabed, to image oil and water distribution – and their behaviour over time – with acceptable resolution.

10. Note that static magnetic surveys also have a long history of use in geological mapping; here we are concerned with AC surveys.

Box 6 • Cross-well surveys

In cross-well surveys, a source (acoustic or electromagnetic) is typically placed in one well and corresponding receivers in another nearby well. From this an image can be obtained of reservoir geometry and/or fluid distribution in the space between the wells. Because of the proximity to the reservoir, these images can provide much better spatial resolution, showing finer details than images obtained from the surface. The principal limitations are the need to access two wells that are not too far apart, and to do so without disturbing ongoing production. Also, as this technique essentially provides information on a 2D slice of the reservoir only, its use to inform production decisions is more difficult than the 3D images provided by surface seismic imaging. These technologies, initially introduced in the 1980s, have been steadily refined but their capacity to evolve is still considerable.

Another technique, known as "behind-casing logging", is described in Box 7. This is a routine technique nowadays and has a large impact on re-assessment of old fields for un-produced layers of hydrocarbon. Its importance will definitely continue to grow.

Once by-passed oil has been identified, it needs to be accessed. Because each remaining pocket may be small, this can be done economically only if the cost is low enough for drilling and completing new wells, re-entering existing wells or completing lateral well bores. Considerable progress has been made with coiled tubing drilling and re-entry, for example, but more is needed, particularly offshore (see Box 8).

Box 7 • Behind-casing logging

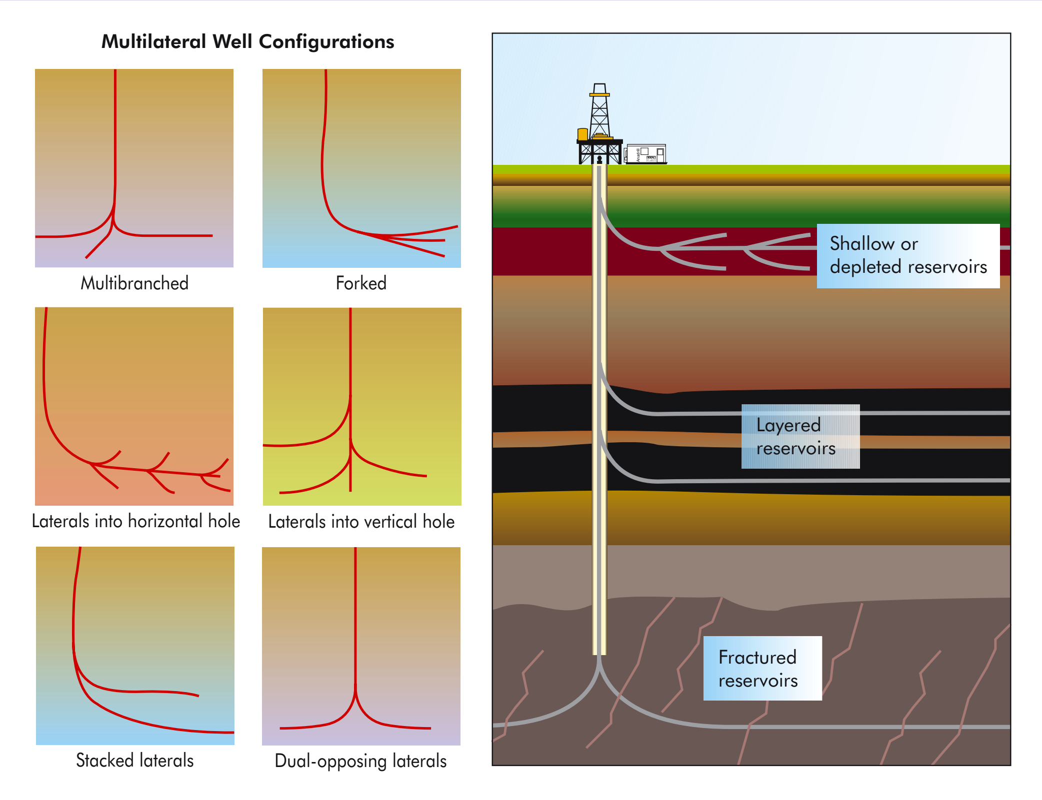
Traditionally, measurements taken in wells to characterise the reservoir and the reserves are performed immediately after a well has been drilled, before a metallic pipe (casing) is installed in the well. Hence the name "open-hole" measurements. Over the past 20 years, techniques have been developed to perform essentially the same measurements after the casing is in place. This "behind-casing logging" offers plentiful opportunities to return to old wells that have been producing for some time, or have even been abandoned, and to re-analyse both the reservoir and the current distribution of fluids (oil, water and gas). This usually reveals potential for improving production, for improving recovery, or for tapping hydrocarbons in layers that have not been produced. For example, the most recent generation of behind-casing electrical resistivity measurement methods exploits the latest progress in electronics to measure small changes in the electrical resistivity of the rock behind what is essentially a perfectly conducting tube.

Progress in all these areas is being pursued actively by the industry and steady, regular advances can be expected over the coming years. Although there is no clear way to quantify increases in the recovery rate, we can look at experience among companies which have adopted challenging recovery targets and have consistently applied recent technologies, for example in the Norwegian sector of the North Sea. This experience suggests that it is realistic to anticipate reaching 45% worldwide recovery, compared with 35% today. To some degree, such projections are usually factored into most scenarios for future oil and gas supply (Rogner 1997, Rogner 2000, Greene 2003, IEA *WEO-2004*).

Box 8 • Re-entry drilling, multilaterals, coiled tubing drilling

Several technologies have been combined recently to provide significantly improved access to by-passed oil pockets. One of the major technological developments of the 1980s and 1990s was generalisation of deviated and horizontal wells, which start as a conventional vertical hole, then turn and continue horizontally for distances up to 10 km. This often involves drilling an initial vertical pilot hole, selecting the point of departure, then re-entering this pilot hole to start boring a deviated hole from a chosen point (a process called "kick-off"). Such technology can also be applied to old wells, that is, by re-entering an old well and kicking off a horizontal side hole (or "drain hole") to access left-over oil without having to drill completely new wells. This application, known as "re-entry drilling", is a growing activity in declining oil fields. The concept can be taken several steps further to re-entry into a deviated or horizontal well, or into an already re-entered well, which then becomes a "multilateral" well. The technology for this purpose has been developed since the mid-1990s. Although the method is not yet widely used, there appear to be no limits to the type of complex geometries that can be achieved (Figure 2.13).

***Figure 2.13 •** Schematics of multilateral wells*



Courtesy of Schlumberger.

While cost savings with re-entry drilling to access by-passed oil are significant because the drilling of entirely new wells is no longer necessary, large, expensive, conventional drilling rigs still need to be mobilised for re-entry drilling. Coiled tubing drilling, although not confined to re-entry drilling, really comes into its own in this context. Instead of using drill pipe coming in lengths of 10 metres or so that need to be lifted and screwed together as drilling progresses, coiled tubing involves a small diameter drill pipe that can be coiled and uncoiled as required (Figure 2.14). This, is turn, has been made possible by advances in materials sciences and permits re-entry drilling with a smaller, more mobile and more cost-effective unit.

***Figure 2.14 •** Coiled tubing unit*

Courtesy of Schlumberger.

Residual oil

This term refers to the hydrocarbons which remain in small pores of the rock after secondary recovery (Figure 2.15). Numerous techniques exist for enhanced recovery of residual oil, but essentially they all suffer from high costs. Cost-effective EOR is a key technical challenge for the industry.

Many techniques were developed in the early 1980s: polymer floods, surfactant floods, CO_2 or natural gas injection and various kinds of microbial treatment (Boxes 9 and 10). All involve poor economics, so that most research in this field has been stopped. The fundamental reason for the poor economics is simply that the volumes required are very large because all the pore space needs to be filled with the EOR material, which must therefore be very low-cost[11].

Hydrocarbon gas and CO_2 are particularly interesting materials for EOR. Depending on reservoir pressure and temperature, these gases can be immiscible with oil and act primarily to push (sweep) the oil in a secondary recovery mode. Or they can be miscible, in which case they increase the mobility of the oil and improve recovery beyond what is possible with secondary recovery, a process that can then be classified as tertiary recovery.

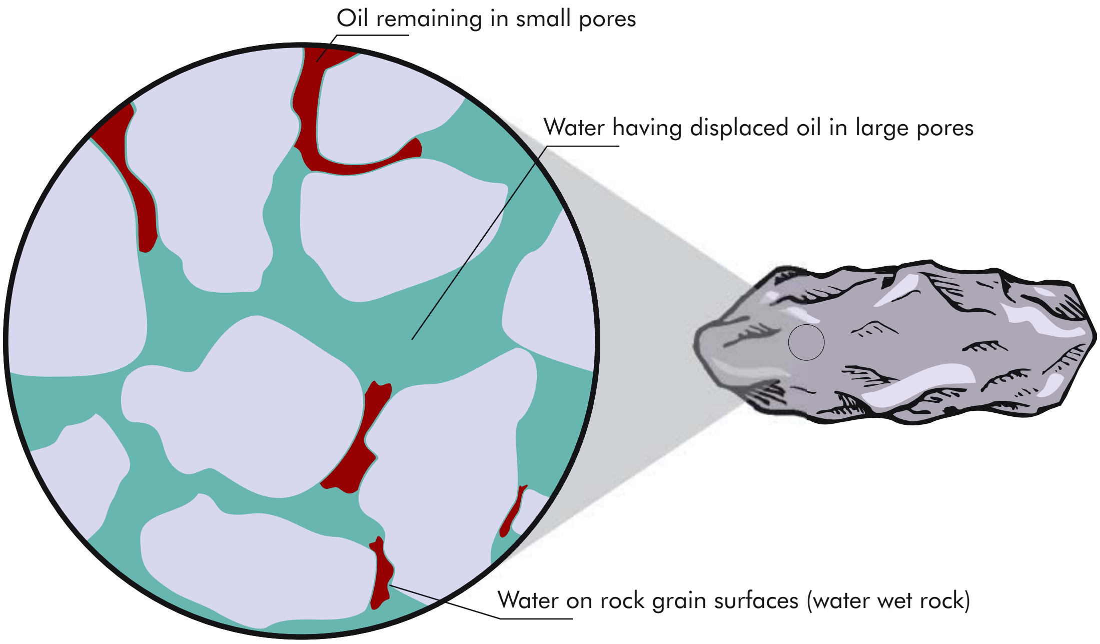
Box 9 • Chemical enhanced oil recovery (surfactants, polymers ...)

Surfactants are molecules with one hydrophilic ("water-loving") side and one side that is hydrophobic, or rather lipophilic ("oil-loving"). As such, they can accumulate at the interfaces between oil and water, changing the interfacial tension between the two and allowing small droplets of oil to be "solubilised" in water. Such substances are extensively used in detergents or shampoos. In the EOR context, they can be added to water injected into the reservoir and will help entrain more oil into the water. In technical terms, by changing the interfacial tension, they reduce the "residual oil saturation" (the amount of oil that cannot be pushed out by water).

Polymers are longer molecules which, added to the injection water at concentrations of a few tenths of percent, can play several roles, depending on the nature and properties of the polymer used. By imparting higher viscosity to the injected water, they favour a more regular displacement of oil by water. They often also have the ability to affect "wettability" and interfacial tension, thereby acting through mechanisms similar to those of surfactants. Finally, their viscosity often varies as a function of the size of the pores ("shear thinning" behaviour), and that can improve "areal sweep" by mitigating the tendency of water to flow through the higher permeability paths only. Other chemical substances can also be used to influence wettability, thereby affecting recovery.

Chemical EOR techniques were researched aggressively at the end of the 1970s and early 1980s. But they have turned out to be uneconomical within the context of relatively low oil prices over the past 20 years. Only a few pilot projects have remained active since then and technical progress in this area has been very slow. Russia and China are the only countries to have continued using variants of polymer EOR to any significant extent.

***Figure 2.15* • *Residual oil left in small pores after water has displaced the oil from large pores* (cartoon definition)**



Miscible CO_2 injection has been used as an EOR technique in Texas for 20 years. What makes it potentially very attractive for the future is that global warming and the need to reduce CO_2 emissions into the atmosphere may change the economics by placing a "negative" cost on CO_2; that is because the oil companies may get paid to use the surplus CO_2 through tax credits or emissions trading. This is potentially very important. But CO_2 capture and transportation issues are likely to place severe limits on applicability. It is striking that in places where there is already a large CO_2 tax, as in Norway, there are essentially no active plans for CO_2 EOR projects. A recent review by the Norwegian Petroleum Directorate (Norway CO_2 2005) concluded with a pessimistic assessment of CO_2 EOR potential in that country, primarily due to its being less cost-effective than alternative technologies[12]. In the UK side of the North Sea, BP has recently announced a pilot CO_2 EOR project in the Miller field. The United States, with its high density of depleted oil fields and of large sources of CO_2 emissions, remains the area with the greatest potential for such techniques. Experience with such CO_2 EOR in the United States and elsewhere suggests that it can increase recovery by between 5% and 15%. A recent study by the United States Department of Energy concluded that CO_2 EOR could generate 43 billion barrels of new oil reserves in six regions of the United States alone (DoE CO_2 2005).

11. Thermal EOR, or steam flooding, is not discussed in this chapter. In the context of this book, it is much more a technology for non-conventional oil production, rather than a conventional EOR technique; it is therefore discussed in the next chapter.

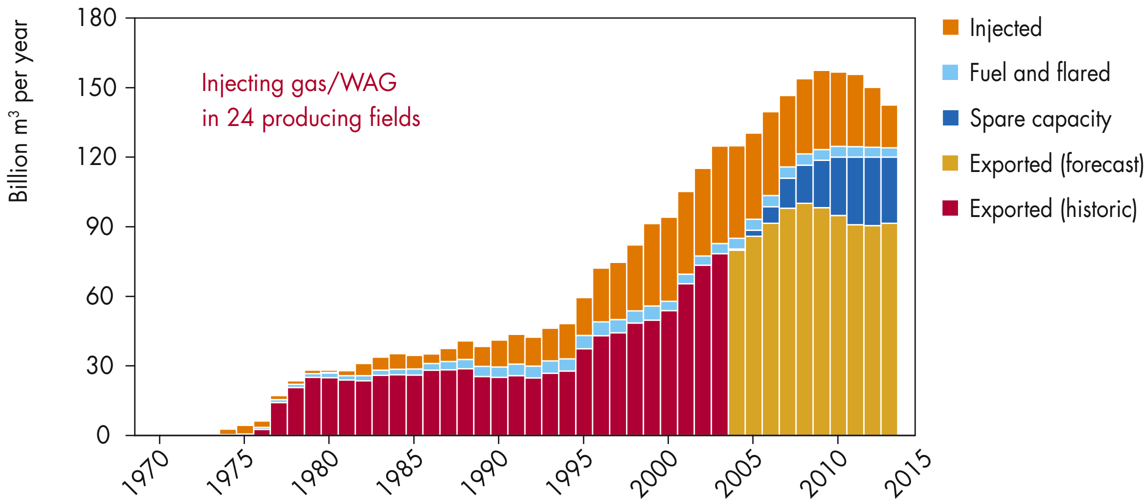
12. Norway, however, is a leader in carbon capture and storage, with the Sleipner project. This injects CO_2 into a water-containing formation, rather than into a hydrocarbon reservoir.

As stressed in other IEA publications (IEA, *CCS-2004*), active public policies are required to generalise implementation of CO_2 EOR using man-made CO_2 emissions. Indeed, CO_2 EOR is not considered economical if the price of CO_2 delivered to the well site exceeds a value somewhere between USD 10/tonne and USD 20/tonne (of course, this assessment is very reservoir-dependent). For example, if the cost of capturing CO_2 – say from a power plant – and bringing it to a well site amounts to USD 50/tonne, a carbon credit or incentive is needed to cover the difference. On the other hand, EOR can also be viewed as a means to reduce the cost of CO_2 capture and storage.

Hydrocarbon gas EOR can be attractive, too, when the gas is available in the same or nearby fields and when the infrastructure to transport it to market does not exist, in which case it is essentially a zero-value product likely to be simply burnt[13], thus producing significant CO_2 emissions. Hydrocarbon gas injection EOR schemes are used in many places around the world and increase recovery by between 5% and 10%. However, they are usually economic only when there is no available market for the gas[14]. They can be combined with water injection, either through alternating water and gas injection (WAG) or through simultaneous injection, as a water/gas mixture or as a foam. Figure 2.16 illustrates the growing use of gas for injection in Norwegian fields.

Microbial EOR (MEOR) is described in Box 10. This is probably the area where most research is still carried out, largely based on the premise that biology is a rapidly evolving science and that good surprises will emerge. A lot of long-term, basic-science investigation is certainly needed on the ecology of deep geological microbial systems and this can only be supported by state research systems. A breakthrough in MEOR could conceivably increase worldwide recovery by 5%.

Figure 2.16 • *Trend in injecting hydrocarbon gas for enhanced oil recovery in Norway*



The amount of gas injected (in orange) has been increasing both in absolute terms and in relation to the total amount of gas produced in Norway.

Courtesy of Norwegian Petroleum Directorate.

13. See Box 16 for a fuller discussion of such gas flaring and various approaches to reduce it.

14. Most of the injected gas can be recovered at the tail end of the production phase. This has low value if one tries to optimise net present value with a significant discount rate, but it can be more attractive to countries trying to optimise long-term recovery.

Box 10 • Microbial enhanced oil recovery (MEOR)

Several approaches to MEOR have been considered. One possibility is to try to stimulate the activity of organisms naturally occurring in the reservoirs by feeding appropriate nutrients through injection wells. Another is to inject suitable organisms that will colonise the reservoir, prompted either by injected nutrients or by metabolising in-situ *hydrocarbons. The hope is that the metabolitic products of microbial activity – typically bio-polymers, bio-surfactants and gas – can act to enhance oil mobility. Another possibility involves organisms whose natural activity has the effect of degrading hydrocarbons, thus making them less viscous and able to flow more easily. But most bacteria prefer to metabolise light hydrocarbons, with the opposite effect.*

In principle, by exploiting the organisms' ability to replicate in situ*, MEOR can get around the problems of other EOR techniques relating to the large injection volumes required. Although some positive effects have been reported, control of the process remains a major challenge. Indeed, microbial techniques can also be used to plug selected zones of the reservoir, improving the sweep of remaining zones by injection water. This process is known as "conformance control" and man-made polymers can also be used for such a purpose. Applications of this sort illustrate the negative effects that can also occur until more is understood about the development of bacterial colonies in reservoirs.*

Recovery in carbonate reservoirs

A special word is necessary regarding carbonate reservoirs. The IEA *World Energy Outlook 2004* Reference Scenario projects a massive increase in oil production from the Middle East, from 20 million barrels per day in 2002 to 50 million barrels per day in 2030. The region is dominated by carbonate reservoirs. Half of worldwide proven reserves are in such carbonate reservoirs, in which production performance is notoriously more difficult to predict than in reservoirs dominated by silicate minerals. There are usually two reasons for this. First, carbonate reservoir rocks are particularly heterogeneous, with small features that are difficult to detect using seismic or other measurements, as in the case of fractures, or "stylolites" (thin impermeable geological features) that sometimes dramatically affect the movement of fluids in the reservoir. The second reason is that the rocks tend to be "oil wet", which means that oil tends to stick to the rock better than water, thus reducing recovery from water injection. Significant progress in understanding and managing such reservoirs is likely to be needed if the Middle East region is to deliver the large production increase projected by the IEA Reference Scenario.

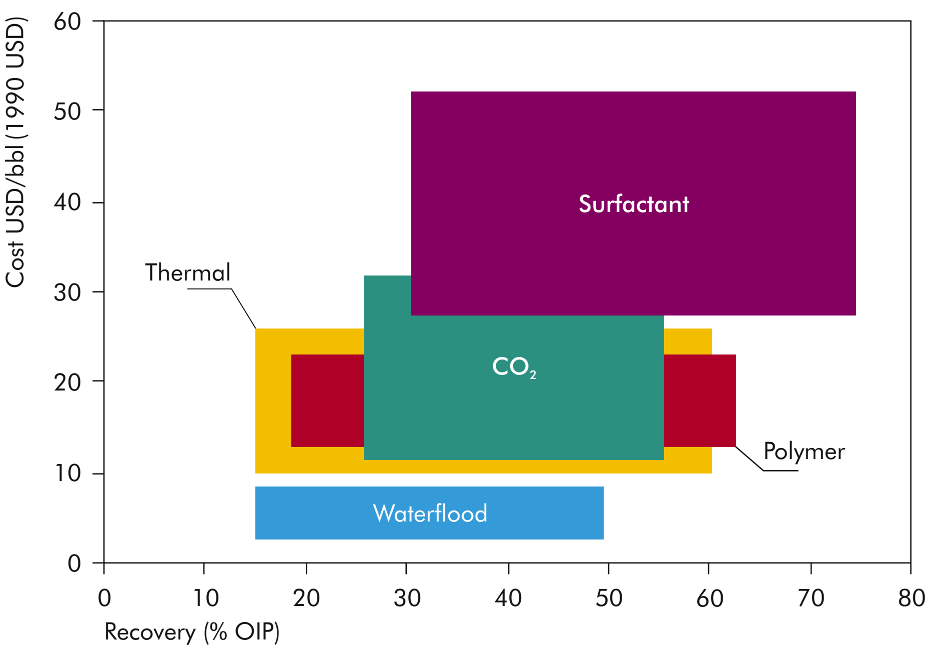
The key to industry's capacity to develop the required technologies will be close partnerships between the holders of the main carbonate reservoirs (primarily state companies in the Middle East) and the technology providers (primarily located in IEA countries).

Summary on improved oil recovery

As we have seen, many enhanced oil recovery techniques were developed in the early 1980s, but their further development was abandoned during the subsequent period of low oil prices. From this, a guess can be made regarding the point at which they will become economic again. Oil prices peaked in 1982 at about USD 65 per barrel[15] (2004 USD), a price considered right to make EOR economic. Assuming reasonable technical progress since 1982, it can be expected that interest will be triggered again at sustained oil prices of roughly USD 40/barrel (2004 USD). The sketch in Figure 2.17, published by Schlumberger in 1992 (Schlumberger 1992) and based on work at the French Petroleum Institute (IFP), implies significant EOR potential at USD 30/barrel in 1990 USD (equivalent to USD 43 in 2004 USD, on an inflation-adjusted basis). More recently (*Oil and Gas Journal*, March 2005), Cano Petroleum (***www.canopetro.com***) quoted lifting costs of USD 2/barrel to USD 4/barrel and full costs between USD 12 and USD 25/barrel for its planned projects in Oklahoma and Texas. These figures are based on alkaline-surfactant-polymer (ASP) injection, in which a solution of sodium hydroxide, surfactants and polymers is pumped in, with claimed additional recovery of 20% to 30% of original oil in place in very old fields. This is a delicate process, however, which remains to be fully proven.

Further cost reductions will call for some new fundamental research on rock-fluid interfaces and how they can be affected by small amounts of additives. Such research is needed now if it is to have an impact by 2030.

Figure 2.17 • *Estimated cost of various enhanced oil recovery methods, in 1990 USD per barrel*



Courtesy of Schlumberger.

15. *This is the peak in yearly averaged price; the price was actually higher for short periods between 1980 and 1982.*

As discussed at the beginning of this chapter, estimates of recoverable resources from USGS assume some EOR, but by no means all the potential of the technologies discussed above. Conservative recovery rate increases of 5% of oil in place add at least 300 billion barrels of extra recoverable oil to the USGS figures. Indeed, some authors (Rogner 1997; Rogner 2000) put this amount at 600 billion barrels. The geographical distribution of such "additional" oil should follow the pattern of the original oil in place, and therefore look fairly similar to the distribution of proven reserves (see Figure 1.10 in Chapter 1), although there might be slightly more in the United States (with a potential for at least an extra 50 billion barrels).

Box 11 • United States Geological Survey resources estimates, reserves growth and enhanced oil recovery

The most widely used estimates of world hydrocarbon resources come from the USGS World Petroleum Assessment 2000*. Viewed against other studies, its main merit is its public availability and the rather detailed descriptions of its methodology. The* Assessment *starts with a list of "petroleum systems", or geological regions around the world capable of being hydrocarbon-bearing. For each, the resources estimate comprises three parts: proven reserves, undiscovered resources and "reserves growth".*

Proven reserves are taken from published data or estimates from a panel of geologists familiar with the area. Undiscovered resources are estimated by a panel of geologists and assigned various probabilities regarding occurrence, size, depth or recovery factor.

Reserves growth is estimated as a multiplication factor over proven reserves, depending on when the reservoir was discovered. The idea is to account for the fact that proven reserves (plus cumulative production) in a given reservoir tend to increase with time. There can be many reasons for that. Initial estimates can be conservative, or additional drilling in or near the reservoir can reveal additional reserves. Or known resources in the reservoir that were originally technically recoverable but non-economical can become economical – and therefore proven – as a result of technological progress or changes in economic assumptions (for example, as infrastructure develops to produce the proven reserves, other resources may "piggy-back" economically on previous investments). Again, technological progress and simply experience can bring higher recovery than originally planned. USGS derives an average historical reserve growth factor from a database of United States fields (shown in Figure 2.18) and applies it to all fields in the world. The process is also applied to undiscovered fields on the basis of their (statistically) assumed discovery date, the geologists having estimated their sizes by analogy with proven reserves in known reservoirs.

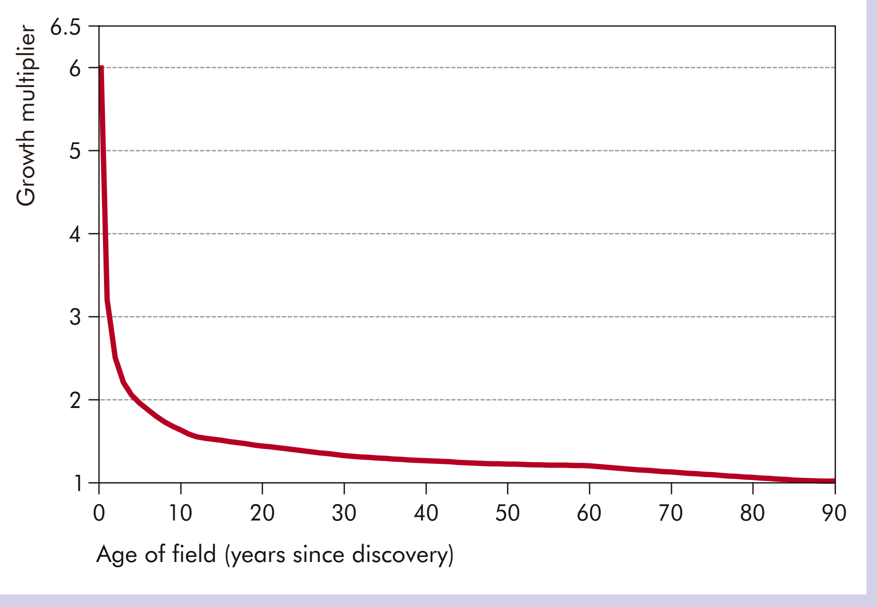
This process clearly assumes some EOR, since EOR may already be assumed in the figures for proven reserves, also because the reserve growth curve, calibrated on United States data, contains the amount of EOR historically performed in that country. However, the Assessment *does not take account of any contribution from EOR techniques not part of normal historical practice, or from greater use of currently practiced EOR. The underlying recovery rate is not clearly defined, but it is probably a bit higher than the historical United States rate. Indeed, other authors (Rogner 1997, Rogner 2000, Greene 2003) use figures similar to those of USGS, assuming that they correspond to a recovery of 40%, and that higher recoveries yield additional resources.*

For this book, based on inputs from industry experts, our estimate is 300 billion barrels (about 5% of total conventional oil in place) for potential EOR recovery beyond what is already contained in the USGS estimates.

It should be noted that some authors (ASPO) argue that the "reserve growth" phenomenon is an artefact of very conservative United States reporting on proven reserves, which should not be applied worldwide, particularly in OPEC countries where some observers claim that published proven reserves numbers are suspicious (Simmons 2005). However, further studies by USGS geologists have pointed to reserve growth observed also in large fields outside the United States, at a rate consistent with the assumption of the 2000 Assessment *(Klett 2003).*

Also to be noted regarding use of USGS data in this book, USGS actually reports probability distributions of occurrence of various amounts of resources. This book has used the USGS mean values. Pessimists could point out that using the lower range of the USGS estimates would give a less optimistic picture of remaining conventional oil. Finally, we have added together the USGS oil and NGL mean estimates, and (approximately) corrected the mean estimates of liquid and gas resources to take account of production and reserve changes since 1996. As we are concerned here with only the large-scale trends that can have a significant impact on future technology development and supply sources, this procedure, although clearly statistically incorrect, is sufficient for such a purpose. This is also why all figures have been rounded to no more that 2 significant digits.

Figure 2.18 • *USGS reserve growth function*



The curve has been calibrated from historical oil and gas reserves data from the United States lower 48 states.

Reproduced from USGS.

Box 12 • The IEA Implementing Agreement on Enhanced Oil Recovery

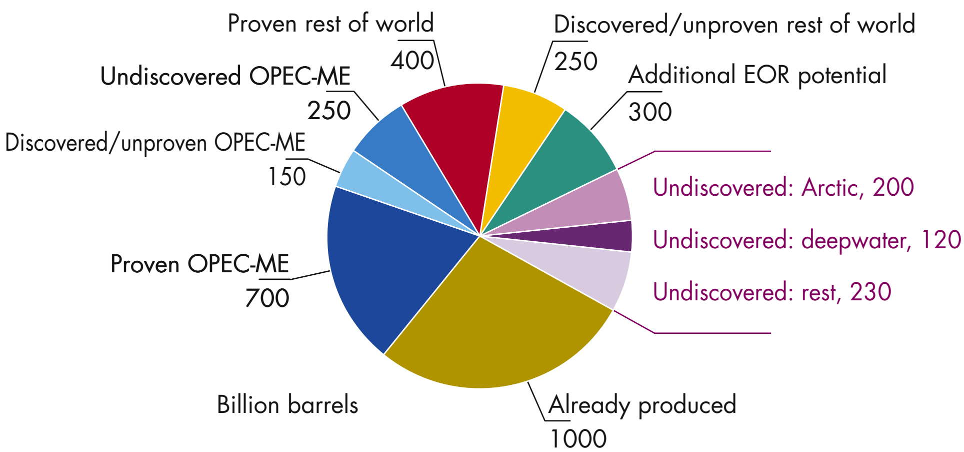
As part of its charter to foster security of energy supplies for its member countries, the IEA Energy Technology Office provides a network for international collaboration on energy technologies, including a legal framework for IEA "Implementing Agreement" technology programmes. These bring together scientists and experts from IEA member governments (also non-member governments and industrial sponsors) who all wish to share information, resources and findings on specific topics. Activities range from R&D collaboration, analysis and dissemination of information, to joint technology deployment efforts.

Created in 1979, the IEA Implementing Agreement on Enhanced Oil Recovery groups 12 countries (Australia, Austria, Canada, China, Denmark, France, Japan, Norway, Russia, the United Kingdom, the United States and Venezuela) with the goal of evaluating and disseminating the results of research and development in the field of EOR and undertaking demonstration, laboratory and field tests. The work programme focuses largely on basic research and laboratory investigations and includes studies of fluids and interfaces in porous media, research on surfactants and polymers, techniques for gas flooding, thermal recovery and emerging technologies. Workshops and symposia are organised every year to ensure dissemination of results.

New conventional resources: deepwater, Arctic, deep reservoirs

Most new fields to be discovered in the next 25 years are likely to be in "extreme" conditions. About one-fifth of the undiscovered conventional oil outside the Middle East is thought to be in offshore deepwater areas, and another third in Arctic regions, as shown in Figure 2.19. This is the reason behind the industry's strong interest in those two "frontier areas".

***Figure 2.19 •** World ultimately recoverable conventional oil* (as per Figure 2.3) *with breakdown of undiscovered oil, and addition of EOR potential*



Based on USGS data and IEA analysis

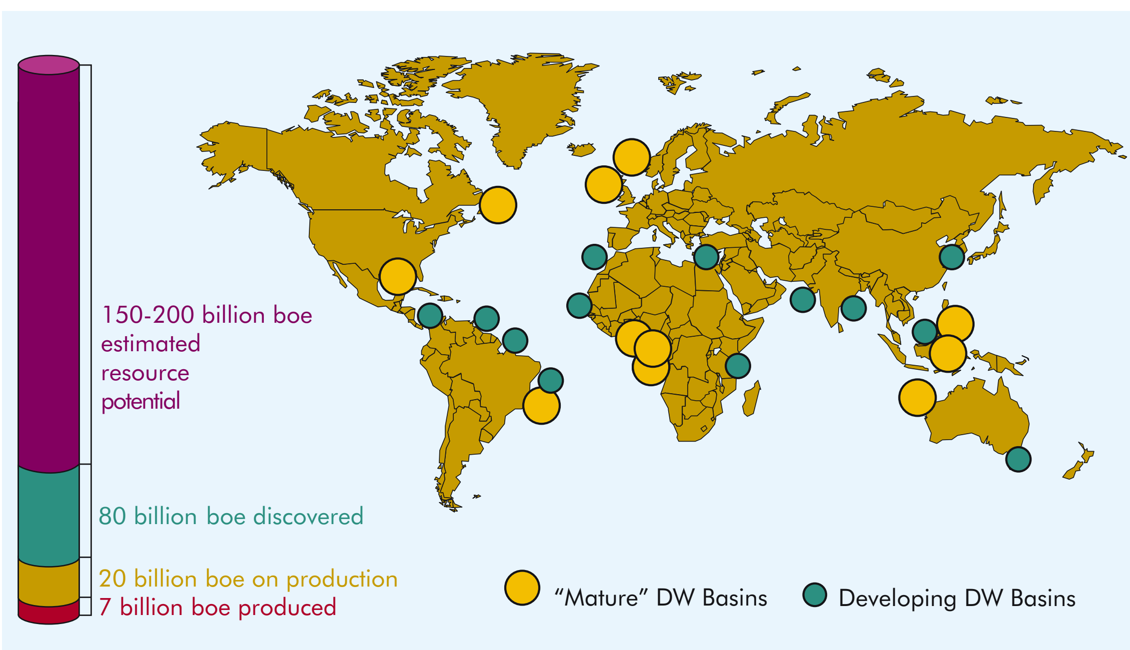
Deepwater

"Deepwater" refers to fields located offshore in significant depths of water. There is no clear definition of what water depth constitutes deepwater. Basically, at any given point in time, routinely practiced technologies are considered conventional offshore technologies, while state-of-the-art technologies that stretch the industry's production capabilities are considered deepwater. Sometimes the term "ultra-deepwater" is used to describe the water depths at which exploration is currently taking place, but for which available production technology is only just feasible.

Fields are now being developed in water depths of 2 000 metres in the Gulf of Mexico in the United States, offshore West Africa and offshore Brazil. The current world record is actually about 3 000 metres. Deepwater operations pose major technical and engineering challenges and they involve very high costs, which are only affordable for very prolific reservoirs. But deepwater represents a very significant resources potential (Figure 2.20).

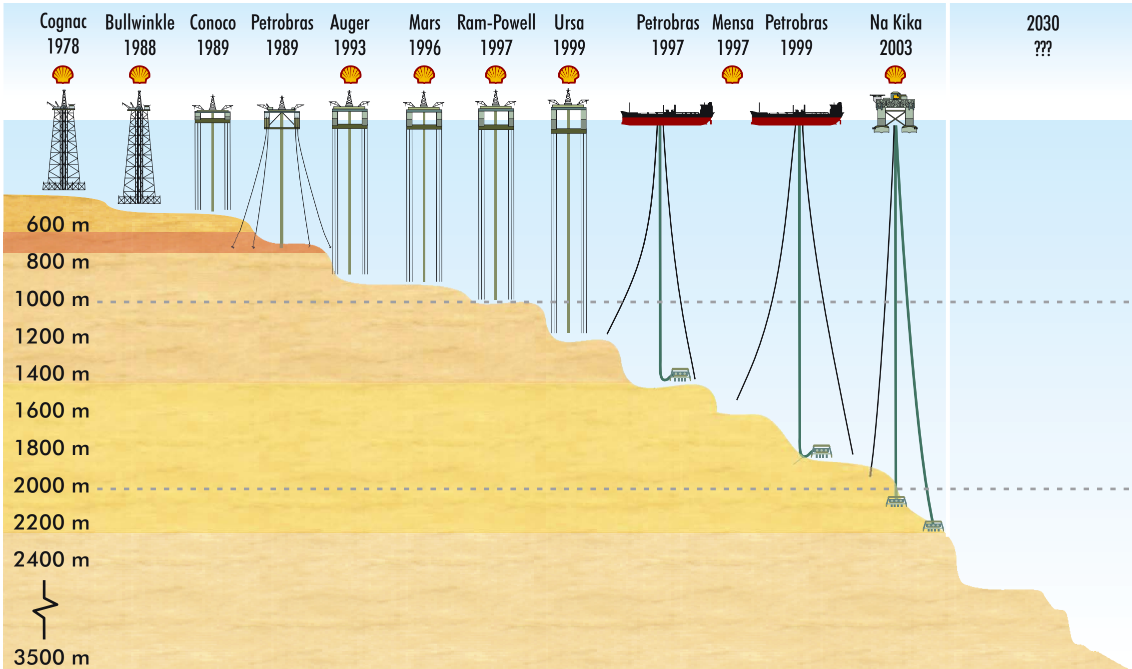
The industry's track record in pushing the limits of technology to facilitate access to deepwater resources is nothing short of amazing (Figure 2.21). This trend can be expected to continue, enabling access to even deeper waters and, more important, reducing the cost of drilling and producing within current frontiers. It is estimated that 40% of undiscovered deepwater resources are at a water depth of between 2 000 and 3 000 metres and 30% at between 3 000 and 4 000 metres. Beyond 4 000 metres water depth, no additional hydrocarbon deposits are likely to exist.

Figure 2.20 • *Future oil and gas deepwater potential in the world*



Source: Wood Mackenzie; courtesy of Shell.

Figure 2.21* • *Evolution of deepwater technology



Courtesy of Shell.

Situations in other parts of the world can be expected to replicate that of the United States Gulf Coast, where smaller and smaller accumulations within yesterday's frontier became economical as the deepwater limit moved further offshore: the largest discoveries in deeper water justify the development of infrastructure on which smaller fields can then piggyback. This is another instance where industry is likely to continue to innovate. Projections in most scenarios already assume such innovation when their decline curves remain roughly aligned with those of the past.

Numerous innovations have contributed to technology's ability to meet requirements and such progress will continue. Examples of promising techniques being considered by the industry are:

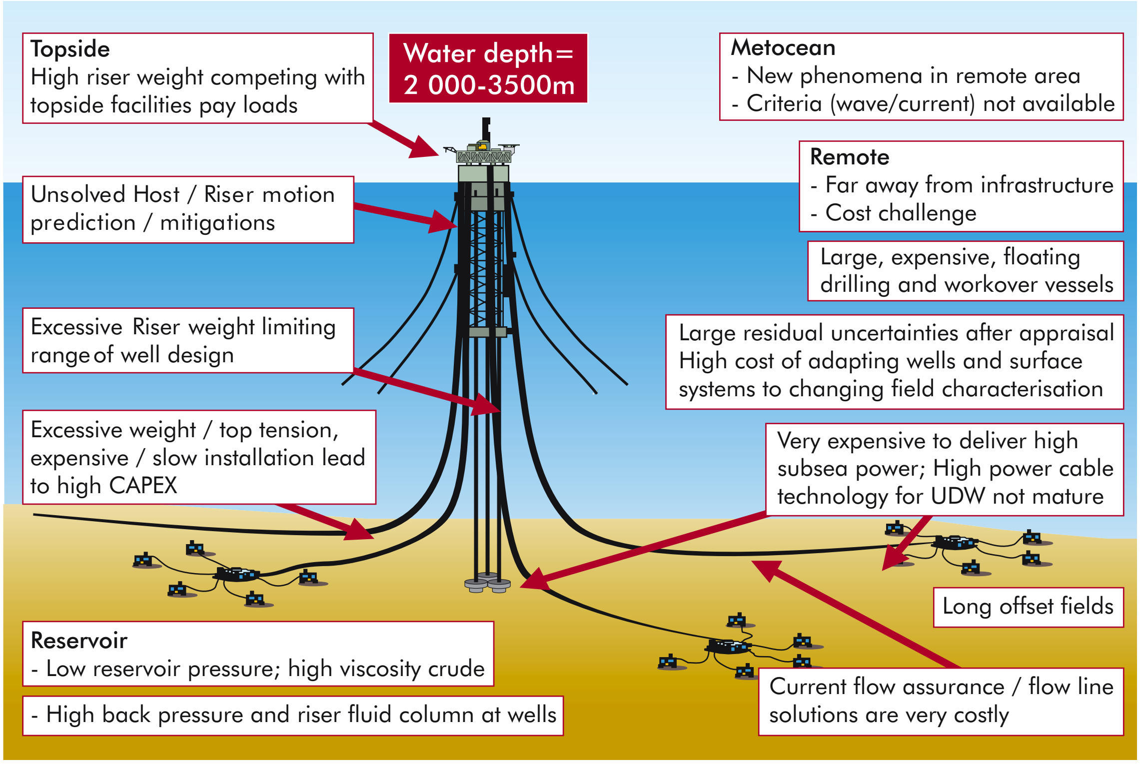
- Improved drilling problem avoidance; as each well is very expensive, any error can be very costly.
- Improved well bore stability control; sediments near the seabed are usually poorly consolidated and prone to instability during drilling.
- Faster drilling to mitigate the high per-day cost of drilling platforms.
- Mud-to-cement technology, a "holy grail" for using the drilling fluid to cement the casing to the well bore, thereby eliminating several steps in the well construction process.
- Casing while drilling and monobore wells (described earlier in this chapter under "Other regions").

Monobore wells, in particular, have the potential to permit drilling in deeper water with older drilling rigs originally designed for shallower waters, thus allowing re-use of previous-generation platforms and very significant costs savings. Drilling from the seabed has also been considered but appears unlikely to achieve competitiveness with conventional drilling platforms at this stage. As illustrated in Figure 2.22, for moving into deepwater there is not one “magic bullet” technology. It is more about solving a wide range of problems simultaneously.

Perhaps the most dramatic advances are to be seen in subsea technologies. Here, methods have evolved from use of very large production platforms, taking fluids from the wells and processing them for transportation, to an array of small, seabed facilities bringing raw fluids to places where they can be processed more cost-effectively. This evolution is sketched in Figure 2.23. Today's facilities require significant “subsea urban planning” but can reduce the environmental impact and enable smaller fields to be developed cost-effectively.

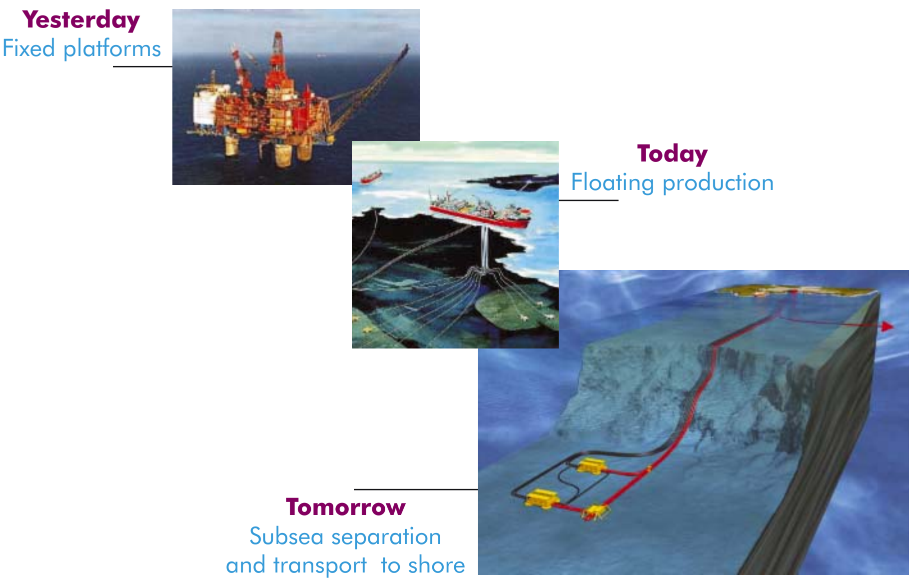
Seabed equipment is deployed and maintained using small remotely operated submarine robots. Another key basic science development contributing to this progress is the ability to transport multiphase fluid mixtures (oil, water, gas, sometime solid slurries) over growing distances by pipeline. Several IEA countries participate in collaborative research on such topics through the IEA Multiphase Flow Sciences Implementing Agreement (Box 13).

Figure 2.22 • *Key technology challenges for deepwater and ultra-deepwater (UDW)*



Courtesy of Shell.

***Figure 2.23** • Evolving deepwater operations, from large surface facilities to subsea technologies*



Courtesy of Norwegian Ministry of Petroleum and Energy.

Box 13 • The IEA Implementing Agreement on Multiphase Flow Sciences

The output from an oil or gas well is typically a "multiphase" mixture containing liquid oil, hydrocarbon gas, water and sometimes solids. Traditionally, the various elements are separated near the well site and the streams of each "phase" transported separately to their next destination (further processing, disposal).

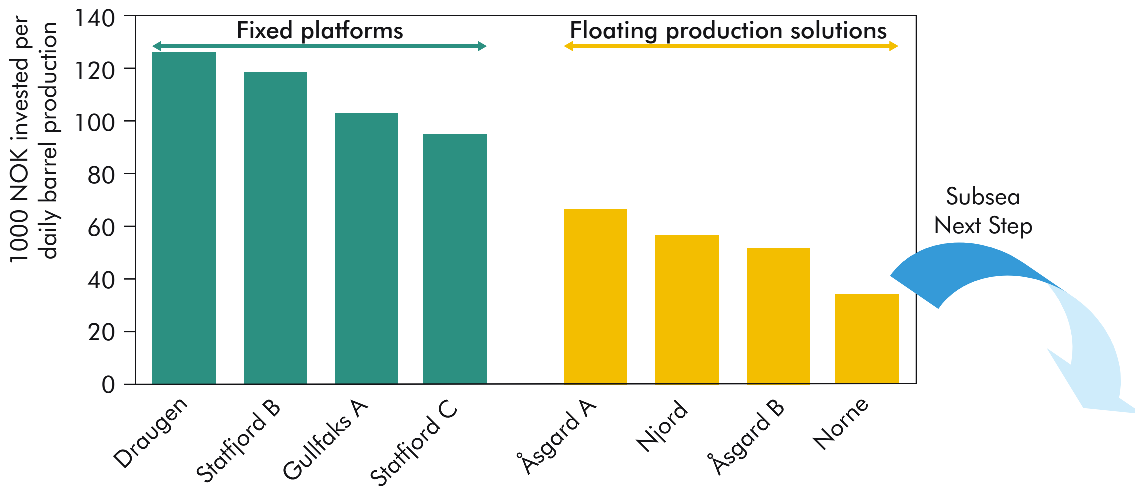
In subsea technologies, this traditional approach is often uneconomical as it would mean locating the separating equipment and several transport lines on the sea floor, an expensive endeavour. It is much more attractive to be able to transport the multiphase stream directly over long distances in a single line, for processing onshore or on a distant production platform. This is difficult, however, because the pressure drops in multiphase flows are very large and traditional pumps do not work efficiently on such flows.

Yet another trend is towards "downhole separation and re-injection", which involves attempting to separate the various phases at the bottom of the well itself, then to dispose of such unwanted substances as produced water by injecting them in deep geological formations, without bringing them to the surface.

All these technologies require better understanding of the complex physics of multiphase flows. In fact, multiphase flows occur in a large number of processes throughout the energy sector, notably in transportation of solid or pulverised coal, in combustion in boilers or engines and in water/steam cooling in boilers. Interest in all these questions prompted the establishment, in 1987, of the IEA Implementing Agreement on Multiphase Flow Sciences, in which six countries (Australia, Canada, Mexico, Norway, the United Kingdom and the United States) pool their resources and share knowledge on upcoming technologies.

But further technology is needed to make deepwater projects economical. Currently, out of the 80 billion barrels of oil equivalent (both oil and gas) discovered in deep waters, 30 billion barrels are not yet considered economic (at long-term oil prices of USD 25). The role of technology is crucial, as illustrated in Figures 2.24 and 2.25. With continued progress over the next 25 years, essentially all deepwater resources should become economical at long-term oil prices of between USD 20 and USD 35.

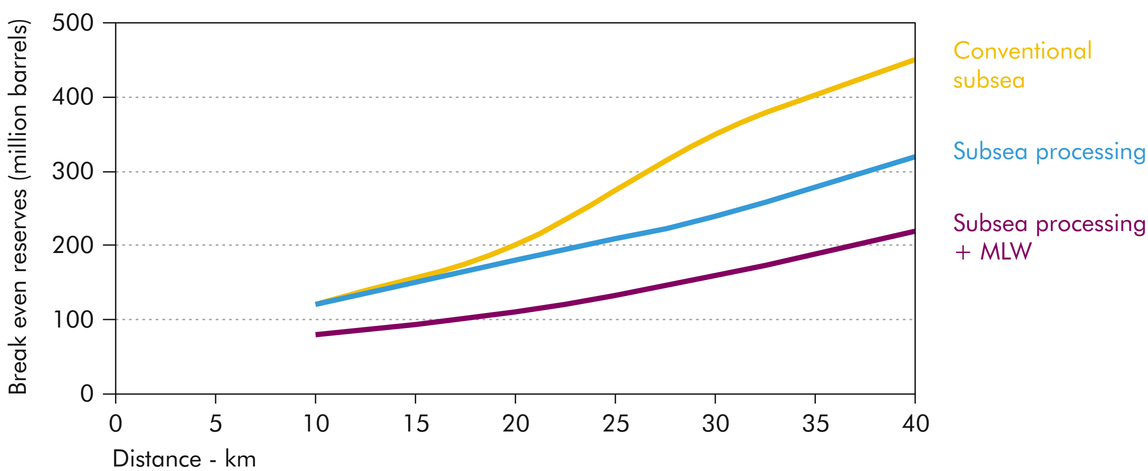
Figure 2.24 • *Cost impact of evolving offshore technology in the Norwegian sector of the North Sea*



Note: 1 NOK = USD 0.16. The fields developed earlier are on the left, those developed later are on the right. They cover the period from 1980 to 2000.

Courtesy of Norwegian Ministry of Petroleum and Energy.

Figure 2.25 • *Impact of technology in making smaller hydrocarbon accumulations economical further away from existing platforms*



The example here in deepwater offshore Angola shows that, for a given technology, as the new field gets farther from existing installations, larger reserves are required to justify the investment in connecting to installations (e.g. conventional subsea curve). Successive new generations of technologies (e.g. subsea processing, then subsea processing + multilateral wells) lower the curve, enabling smaller fields to be developed economically.

Courtesy of Norsk Hydro.

Arctic

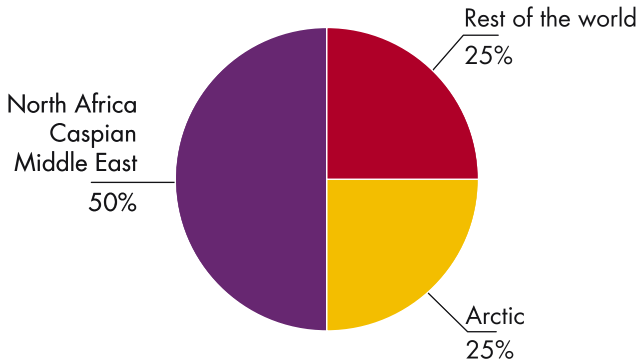
Another "frontier" area involves Arctic conditions in locations like northern Canada, Alaska, the east coast of Greenland, the Barents Sea, the Sea of Okhotsk, the Kara Sea or the Chukchi Sea. The east coast of Canada is also sometimes included in discussion of Arctic developments since, while not located north of the Arctic Circle, the platforms in this region can be exposed to similar temperature and ice conditions. Arctic areas are estimated to contain about 25% of remaining worldwide undiscovered conventional hydrocarbon resources (Figure 2.26).

Many of the challenges are similar to those found in the deepwater areas: remoteness, personnel safety, environmental footprint and high costs. To these must be added cold climate and the hazards of ice and icebergs (Figure 2.27).

The industry has been regularly pushing the technology envelope in opening access to new reserves. Past and present examples are Hibernia and Terra Nova offshore eastern Canada, Snøhvit in the Barents Sea, and fields offshore Sakhalin Island in Far East Russia. The trend is moving from massive platforms built to withstand icebergs to smaller, more mobile facilities coupled with iceberg-detection and deflection mechanisms. New transport solutions are also emerging (Figure 2.28).

Costs remain high, however, at somewhere between three and five times those of equivalent projects in temperate locations. This may restrict medium-term future Arctic projects to the most prolific prospects. So far, only a handful of projects have been developed. They suggest a steep learning curve in finding new approaches that reduce capital and running costs, but it is too early to predict how fast Arctic resources will be located and developed. In particular, many of the promising areas are in Russian waters, north of Siberia, where the continental shelf is less than 200 metres deep, even at significant distances from the coast. Developments will depend on the policies of the Russian government. In Chapter 7, we assume that most Arctic conventional resources will eventually become economical at long-term oil prices of between USD 20 per barrel (as in the case of projects already being developed) and USD 60 (roughly three times the typical economical price for conventional resources in temperate locations outside the Middle East).

Figure 2.26 • *Share of Arctic in undiscovered oil and gas resources*



Based on USGS data, courtesy of OG21, a task force of the Norwegian Ministry of Petroleum and Energy.

Figure 2.27 • *Arctic hazards*

Ice drift and offshore icing photos courtesy of Statoil; iceberg photo courtesy of the International Ice Patrol of the US Coast Guard ***http://www.uscg.mil/lantarea/iip/Photo_Gallery/Icebergs_1.shtml****; subsea sketch courtesy of PetroCanada; with thanks to P.G. Grini from OG21, a task force of the Norwegian Ministry of Petroleum and Energy.*

Figure 2.28 • *New transport solutions for Arctic seas*

Courtesy of Aker Arctic, with thanks to P. G. Grini from OG21, a task force of the Norwegian Ministry of Petroleum and Energy.

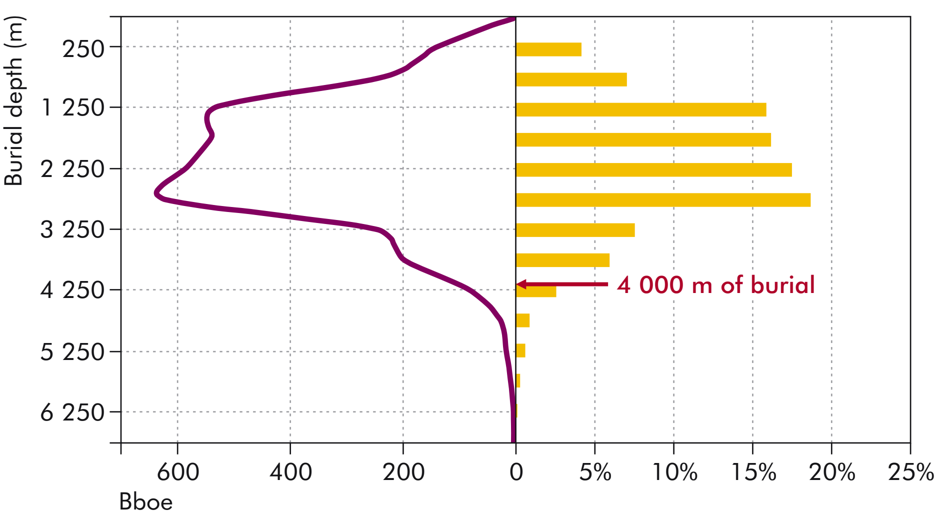
Super-deep reservoirs

As shown in the Figure 2.29, current resource estimates show very scarce resources below 4 000 metres sediment depth (whether onshore or offshore). However, this could result more from the absence of deeper exploration than from any fundamental reason. In fact, a survey of sedimentary basins around the world shows that many have sediment thicknesses reaching 10 km (Gulf of Mexico, Congo Basin, Western Siberia - see Figure 2.30). There is no reason why such deep sediments should not be hydrocarbon-bearing sediments.

Historically, the technology to drill super-deep wells has been pioneered by public scientific projects. For instance, the KTB super-deep drilling project in Germany reached 9 000 metres and the Kola Peninsula super-deep well in Russia reached 12 000 metres. An extension of such efforts to industrial applications is currently being supported by the United States Department of Energy as part of the Deep Trek program. New electronic technologies, new materials, new drilling techniques (notably cable-based) and new well completion techniques like monobore techniques are likely to be relevant.

Potential resources, beyond those currently included in published worldwide estimates, could easily reach 300 billion boe, 25% being liquid (oil) and the rest gas. The resources that could be found there would, at least in part, come on top of current USGS estimates, thus adding to the estimated total amount of hydrocarbons in place in the world. In spite of the technical challenges, super-deep reservoirs could be attractive when located near existing infrastructure, for example underneath mature producing areas. Prices that would make such resources economical are difficult to estimate at this early stage. That being said, some deep reservoirs are already successfully exploited, as in the case of the North Sea's Elgin-Franklin, at 6 000 metres below the seabed. Also, wells reaching depths of 9 000 metres are in the planning stages for the United States Gulf of Mexico (Hart's 2005).

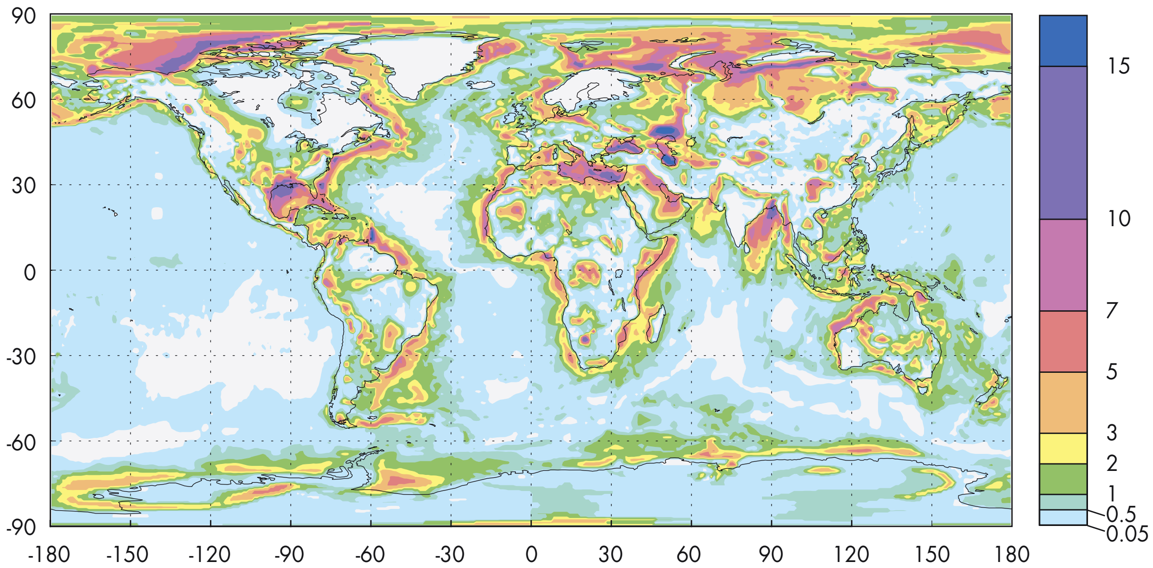
Figure 2.29 • *Estimates of hydrocarbon resources as a function of burial depth*



Left: amounts in billion barrels of oil equivalent; right: as percentage of total.

Courtesy of Total.

Figure 2.30 • *Map of sediment thickness in kilometres*



Reproduced from Scripps Oceanographic Institute; ***http://mahi.ucsd.edu/Gabi/sediment.html****, Laske 1997.*

Chapter 3 • NON-CONVENTIONAL OIL RESOURCES: HEAVY OIL, BITUMEN, OIL SANDS, OIL SHALES

Heavy oil, bitumen and oil sands

The IEA *World Energy Outlook* forecasts significant growth in heavy oil and bitumen production, particularly from Canadian oil sands[16]. Indeed, heavy oil and bitumen constitute a very large resources base, which it makes good sense to exploit. Estimates of heavy oil and bitumen resources worldwide amount to around 6 trillion barrels, of which 2 trillion barrels may be ultimately recoverable. Production and processing costs have fallen significantly over the past 20 years, making a portion of Canada's oil sands resources economical at oil prices below USD 20 per barrel.

Heavy oil resources are largely concentrated in Canada and Venezuela, which hold respectively some 2.5 trillion and 1.5 trillion barrels. If reserves can be proved with a 20% recovery rate, these two countries alone would account for more proven reserves than the conventional reserves of the Middle East. In fact, with more that 175 billion barrels accepted as proven in 2003, Canada now has the second largest proven reserves in the world, after Saudi Arabia. Most of the recent technological developments have taken place in Canada, where an attractive tax and royalty regime for heavy oils and oil sands, introduced in 1996, has prompted major new investment from private industry. As shown in Figure 3.1, Russia also has significant heavy oil deposits.

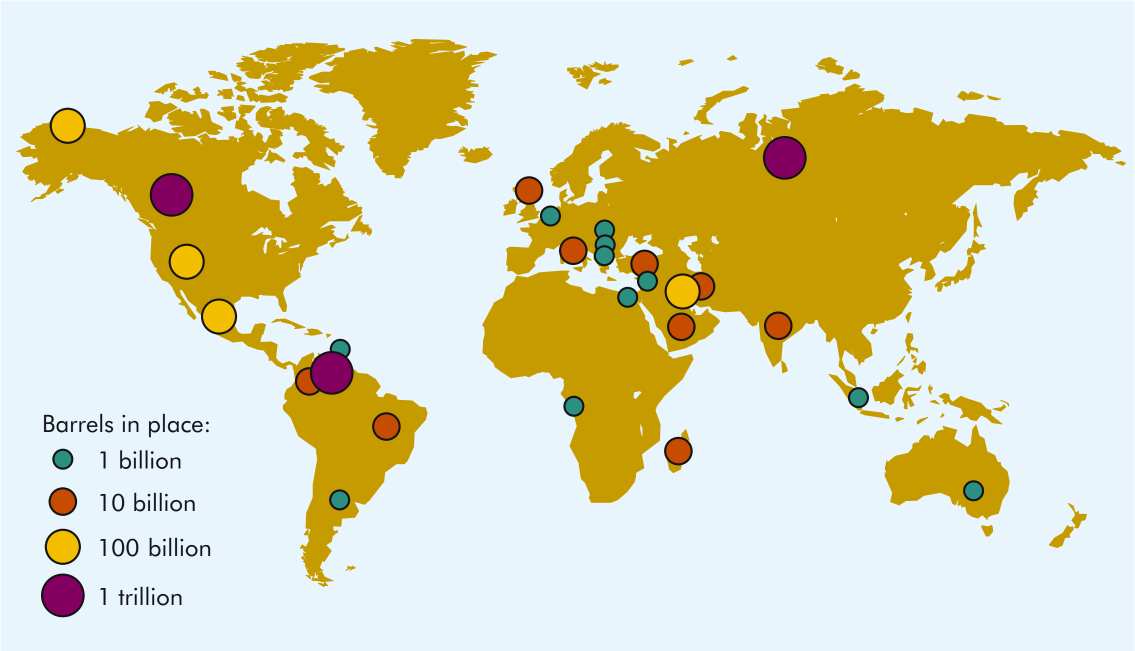
There are many types of heavy oil, and each calls for specific approaches. The main heavy oil types are discussed below.

Mineable bitumen

Some oil sands can be mined from the surface (Figure 3.2). The tar or bitumen is extracted from the rock using heat, water and/or solvents to treat this mined "ore". The extracted bitumen needs to be "upgraded" or diluted with lighter hydrocarbons before it can be transported by pipeline to a refinery. Upgrading consists in increasing the ratio of hydrogen to carbon, either by "coking" (removing carbon) or by "hydrocracking" (adding hydrogen). This results in what is known as "synthetic crude oil", which can be shipped to a refinery. Mineable oil sands are found primarily in Canada, where the Athabasca sands in Alberta alone represent resources of 600 billion barrels of oil (though only some can be mined). In 2004, 600 000 barrels per day of synthetic crude oil were produced from mining operations in Canadian oil sands. Production levels could grow to between 1 million and 2 million barrels per day by 2012. Figure 3.3 shows the gradual decline in costs over the past 20 years.

16. The term "tar sands" is also sometimes used, but "oil sands" is more generic. As discussed in the text there is a continuum between heavy oil and bitumen, and those terms will be used rather loosely in this study, heavy oil being more generic.

***Figure 3.1* • Heavy oil resources in the world**

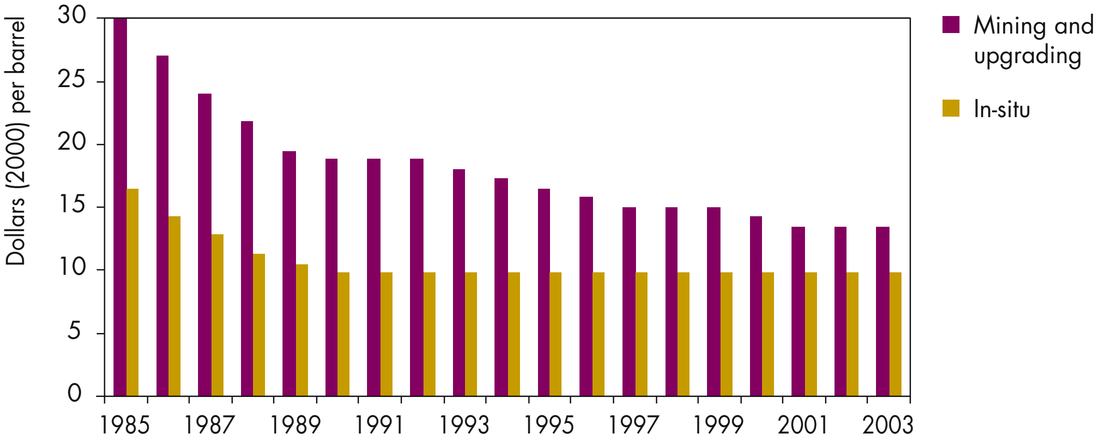


*Reproduced with kind permission from the Energy Institute, originally published in Modern Petroleum Technology (**www.energyinstpubs.org.uk**), with thanks also to Maurice Dusseault, University of Waterloo, Canada, for pointing out this figure.*

***Figure 3.2* • Oil sands outcrop in Canada**

Courtesy of Pat Collins, Private Consultant, Calgary, Canada, with thanks to Maurice Dusseault, University of Waterloo, Canada.

Figure 3.3 • *Oil production costs from Canadian oil sands*



Source: WEO-2004, IEA.

High-viscosity heavy oils

Some heavy oils and bitumen are too viscous to flow at reservoir conditions. They are usually found at relatively shallow depths that are nevertheless too deep to be mined. At such depths, temperatures are low, so that viscosity is high. They need special production technologies to facilitate their flow from reservoir to well head. Traditionally, these have been "steam flooding" techniques, which involve injecting hot steam to heat the oil *in situ*, thereby reducing its viscosity and allowing it to flow. But the last ten years have seen the advent of many new approaches such as steam-assisted gravity drainage (SAGD) or cold heavy oil production with sand (CHOPS). While large-scale implementation of these is only just starting, they can be expected to significantly boost production over the next few years. Indeed, they improve the economics to the point where Canadian heavy oil and bitumen deposits can be produced through the above *in-situ* techniques at oil prices below USD 20/barrel (Figure 3.3). Current production of heavy oil and bitumen in Canada, for example, is close to 1 million barrels per day and could double by 2012.

More easily flowing heavy oils

Yet another category of heavy oils are able to flow at reservoir temperature. They can therefore be produced economically, without additional viscosity-reduction techniques, through variants of conventional processes such as long horizontal wells, or multilaterals[17]. This is the case, for instance, in Venezuela's Orinoco belt, or in Brazil's offshore reservoirs. But such oils are too viscous at surface to be transported through conventional pipelines. They need heated pipelines, which make sense only over short distances. Or they must be either upgraded before transportation or diluted with light hydrocarbons to create a mix closer to conventional crude oil.

17. Multilaterals technology is an emerging technology in which several "branches" are drilled in the reservoir from the same "trunk" well drilled from the surface. This allows the producing length to be increased without a corresponding increase in cost. A brief description can be found in Box 8 in Chapter 2.

However, these traditional processes provide only a fairly low recovery factor. Venezuela estimates the amount of heavy oil recoverable through such processes in the Orinoco belt at some 250 billion barrels, against in-place resources of 1 700 billion barrels. Implementation of *in situ* viscosity reduction techniques would probably double the recovery rate.

Box 14 describes one of the recent new technologies, SAGD. Although this technique permits cost-effective production of heavy oils with excellent recovery, it is, like all heavy-oil extraction techniques, very energy-intensive. Energy is required to heat the oil and rock. In SAGD or in conventional steam techniques, this is achieved through steam injection. This steam, in turn, is currently provided by burning natural gas. Then the heavy oil or bitumen needs to be upgraded before it is used by a refinery, and this calls for hydrogen, which again comes from natural gas. In Canada, every barrel of heavy oil produced requires about 30 cubic metres of gas for heat production and 15 cubic metres for upgrading. As a result, heavy oil production can quickly become constrained by availability of natural gas. In Canada more particularly, this is expected to hamper heavy oil production as early as 2015[18].

Also, in a world where limiting carbon emissions is becoming important, one can question the logic of burning gas (a hydrogen-rich fuel) to extract heavy oil (a carbon-rich fuel). Heavy oil production requires much more energy than conventional oil production. In fact, the production process in the upstream oil and gas industry currently consumes the equivalent of some 6% of the energy content of the hydrocarbons produced. With heavy oil, this ratio can rise to 20% or 25%. In Canada, the CO_2 emissions linked to such increased energy usage are likely to compromise meeting the country's Kyoto Protocol emissions targets, thus curbing the increase in heavy oil production.

It is important, therefore, to develop other techniques that would be more energy and/or carbon efficient. A brute force approach being discussed in Canada is to install a nuclear power plant near the heavy oil fields to supply the required energy. An industry consortium is also investigating the use of geothermal energy from deep rocks underneath the heavy oil reservoirs. Another possibility is to capture the CO_2 produced by the heating and reforming plants and to store it in geological formations. Technologies for the latter exist but would increase production costs by some USD 5 to USD 7 per barrel, assuming a standard cost for carbon capture and storage (CCS) of USD 50 per tonne (IEA *CCS-2004*), although some of the processes, where they involve high-purity CO_2 streams, would have lower capture costs.

Other improvements in production technologies, however, could also contribute. A detailed *Oil Sands Technology Roadmap* has been developed by the Alberta Chamber of Resources (ACR 2004). Studies performed for this roadmap (Flint 2005) indicate that a range of technologies can reduce the amount of CO_2 generated during the various steps in the process. Different technologies apply to the different production options (like SAGD fuelled by natural gas, SAGD fuelled by heavy end residues or extraction through surface mining).

18. Water supply also creates constraints, particularly for mining operations; more details can be found in ACR-2004.

While each option offers different potential gains, the reduction in CO_2 generated could average 25%. CO_2 produced by upgrading plants constitutes a fairly pure CO_2 stream that could be captured at relatively low cost. This would apply also to steam plants if these were powered by gasification of heavy end residues. Finally, both Canada and Venezuela have good opportunities to re-cycle the captured CO_2 for use in enhanced oil recovery programmes in conventional oil fields. It is therefore reasonable to expect that both gas and CO_2 constraints affecting future heavy oil production will be eliminated over time, with only small increases in costs.

A number of alternative production techniques are in research or early development.

- *In-situ* combustion can provide the energy to heat the oil and facilitate its flow. This technology has been around for many years, but difficulties in controlling the process have been a hurdle to widespread use. New variants, involving recent progress in accurate placement of horizontal wells, are being investigated. Toe-to-heel-air-injection (THAI) is an example.
- Microbial techniques, already discussed in the previous chapter, consist in injecting microbes into the reservoir, where they exert their ability to decompose the heavy hydrocarbon molecules into lighter ones. But much more basic research is required.
- Use of light hydrocarbons as solvents has been tried to replace or work alongside steam to reduce the viscosity of the oil. This process, known as VAPEX, has not yet proved economical. In principle, another option might be to separate some of the produced oil into light and heavy components, to re-inject the light components as a solvent to assist production, and to use the heavy components to provide energy for the production and up-grading processes. A project going some way in this direction is already being developed. This Nexen/OPTI Long Lake project (***www.longlake.ca***) will use the heavy components as fuel to power a standard SAGD process, therefore eliminating the need for gas. It is due to be operational in 2006 with a production level of 70 000 barrels per day and economic feasibility at an oil price of around USD 20 per barrel. Other companies are at the planning stages of variants of such an approach.

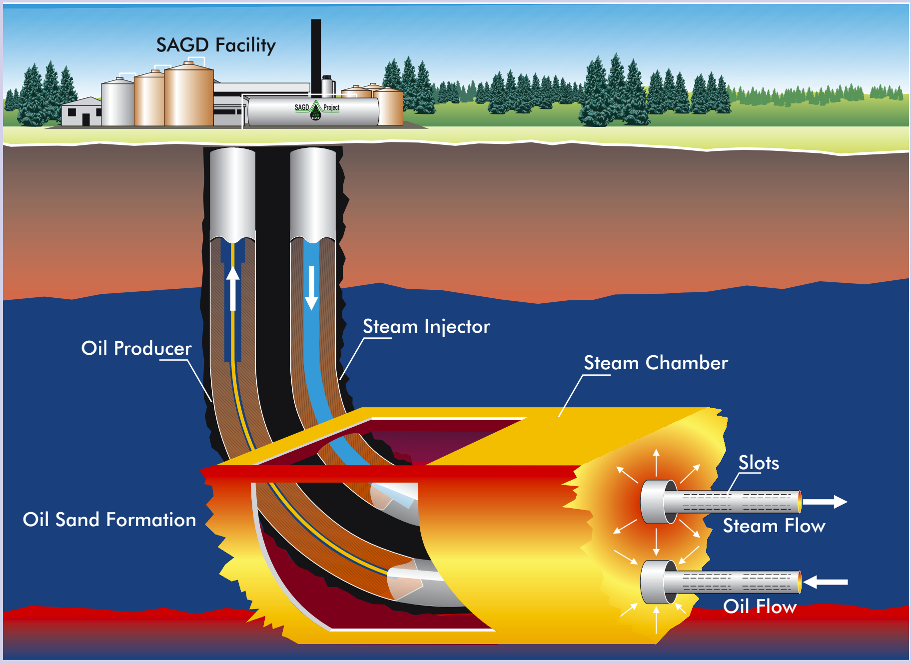
With the incentive of an appropriate tax and royalty framework, the track record of private industry in developing the required technologies has been excellent. In principle, it can be expected that demand for heavy oil will be large enough to sustain this record. It is worth noting that heavy oil carries essentially no exploration risk. The large deposits in Canada and Venezuela are well identified, and delineation of the most promising zones is possible at low cost because depths are shallow. So all the effort can be focused on optimisation of production costs, both capital and operating. However, competing approaches are now emerging for producing alternative liquid fuels for transportation in anticipation of a decline in conventional oil. Examples are gas-to-liquids (GTL) technology for converting natural gas into liquid fuel, or synfuel derived from coal (coal-to-liquids — CTL). As a result of this, the investment risk in production of heavy oil could deteriorate, creating an investment shortfall.

Box 14 • Steam assisted gravity drainage (SAGD)

For a long time, "steam flooding" has been the preferred technique for producing heavy oil. Steam is the agent for both heating the oil (reducing its viscosity and enabling it to flow) and pushing it towards the producing wells. Unfortunately, this technique has very low energy efficiency (much heat energy is lost and does not reach the oil to be mobilised). The recovery factor is also low, since the steam can break through the oil, or override the oil due to gravity.

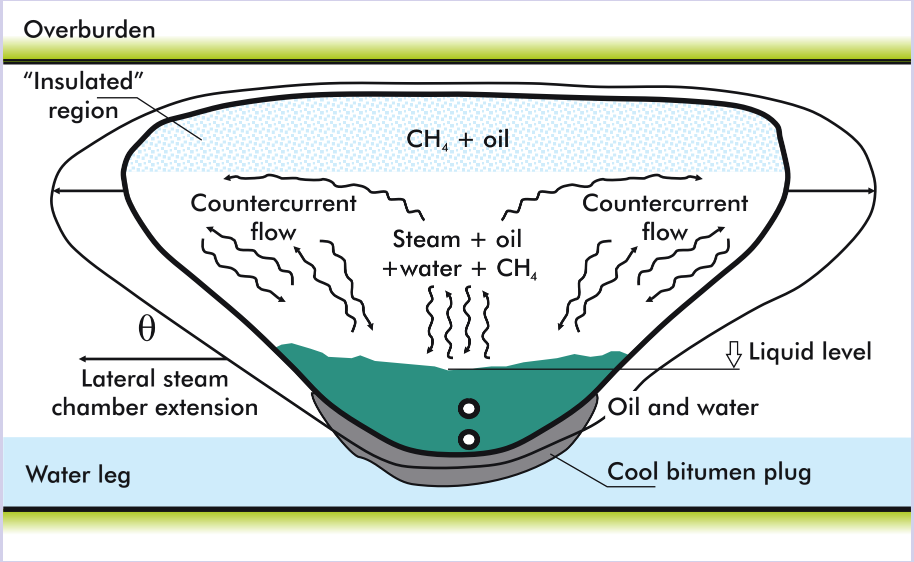
The advent of precision-placed horizontal wells has led to development of SAGD. As Figure 3.4 shows, two horizontal wells are drilled, one above the other, the upper well for steam injection, the lower well for oil production. This dual-well system ensures efficient use of heat within a virtual "steam chamber", as well as the excellent recovery rate achieved by gravity drainage, in which gravity stabilises the interface between oil and steam. Recovery factors can be as high as 60%. The intrinsic slowness of gravity drainage would mean low production rates if it were not possible to drill such long horizontal wells, one pair of which can drain a significant volume. The cornerstone in this very promising technique is the capability, developed by the industry over the past 15 years, to position horizontal wells very precisely over long distances. Because the wells are relatively shallow, moreover, drilling costs are sufficiently low to make large-scale developments with numerous wells affordable. SAGD has come into its own over the past three or four years and is now having a big impact on the economics of heavy oil production.

Figure 3.4 • *Schematic representation of SAGD*



Courtesy of Encana Corp. and Maurice Dusseault, University of Waterloo, Canada.

Figure 3.5 • *Schematic representation of SAGD — cross-section*



Courtesy of Maurice Dusseault, University of Waterloo, Canada.

From the angle of security of supply, this may not matter, since all three sources of energy are in large supply. In the interests of diversity of supply, IEA countries may wish to consider how to ensure that all three approaches arrive at competitive prices. The future competition between transportation fuels from heavy oil, gas and coal is discussed further in Chapter 7. Higher oil prices of course favour the development of all these alternative sources of fuels, as shown in the high-oil-price scenario of the IEA *World Energy Outlook* (IEA *WEO-2004*). This suggests that a USD 10 increase in oil prices increases non-conventional production by 1.5 million barrels per day by 2030.

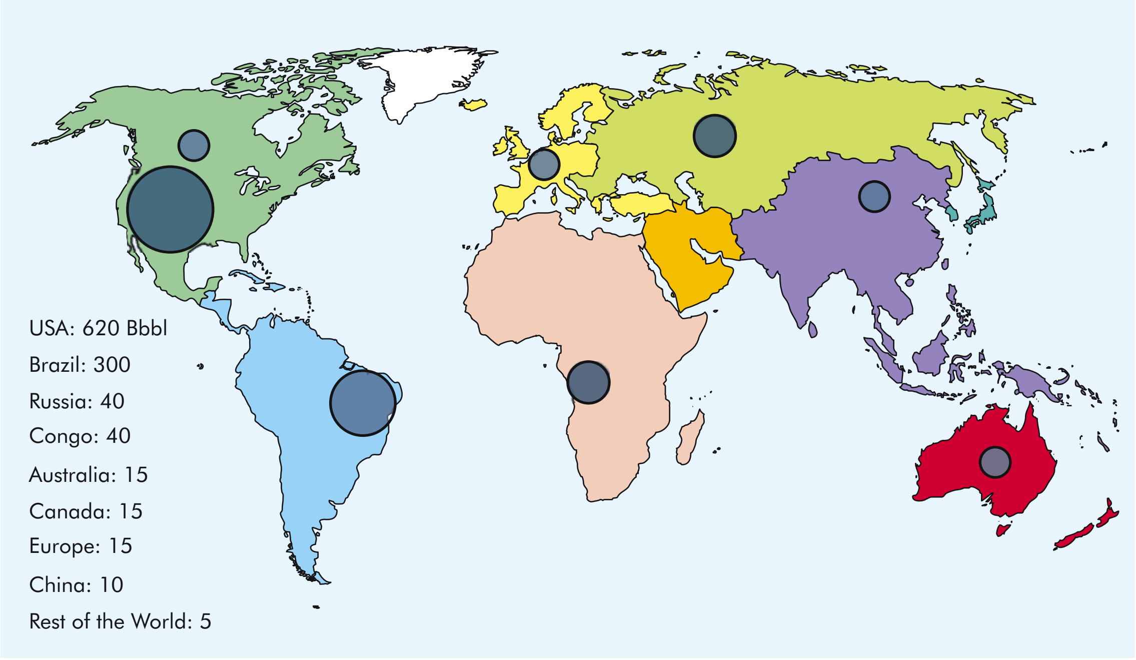
Overall, it is reasonable to expect that technological progress will enable most of the heavy oil resources in Canada, Venezuela and elsewhere to be economical at sustained oil prices of between USD 20 and USD 40, even including the cost of mitigation of CO_2 emissions associated with the production process. It should be stressed, however, that producing such a massive amount of resources can only be done over long periods of time. With current capital costs for Canadian oil sands at roughly USD 5 billion for 200 000 barrels per day capacity, simply mobilising the capital for exploitation of a significant fraction of the resources is likely to take several decades.

Oil shales

Oil shales in fact contain neither oil nor shale. The term describes a type of rock — such as shale, carbonate or marl — that contains a large proportion of solid organic compounds, known collectively as "kerogen". Had they been buried deeply enough for the effect of temperature to transform the kerogen, sediments of this sort would have generated oil or gas. But they are found at relatively shallow depths and have never been heated significantly. The kerogen they contain can be heated to a temperature of about 500° C to produce liquid oil, known as shale oil. The raw oil shale can even be used directly as a fuel akin to a low-quality coal. Indeed, they have been exploited as such for several centuries. Oil has been produced from oil shales since the 19th century.

Why are oil shales of interest? Because they could represent a very large potential source of reserves, if exploitable economically. Worldwide, oil shales are estimated to contain hydrocarbons totalling something like 2.6 trillion boe, of which 1.6 trillion are in the United States. Figure 3.6 shows estimated recoverable oil from oil shales around the world. The figures assume ability to use 50% of located oil shale deposits and turn 75% of the kerogen into oil. Other references cite slightly different estimates (World Energy Council: ***http://www.worldenergy.org/wec-geis/publications/reports/ser/shale/shale.asp***), illustrating different interpretations of limited current knowledge, including indications of significant deposits in Jordan (***http://www.worldenergy.org/wec-geis/edc/countries/Jordan.asp***).

Figure 3.6 • *Distribution of oil shales around the world, totalling 1 060 billion barrels of recoverable oil*



After Encyclopaedia Britannica 2005.

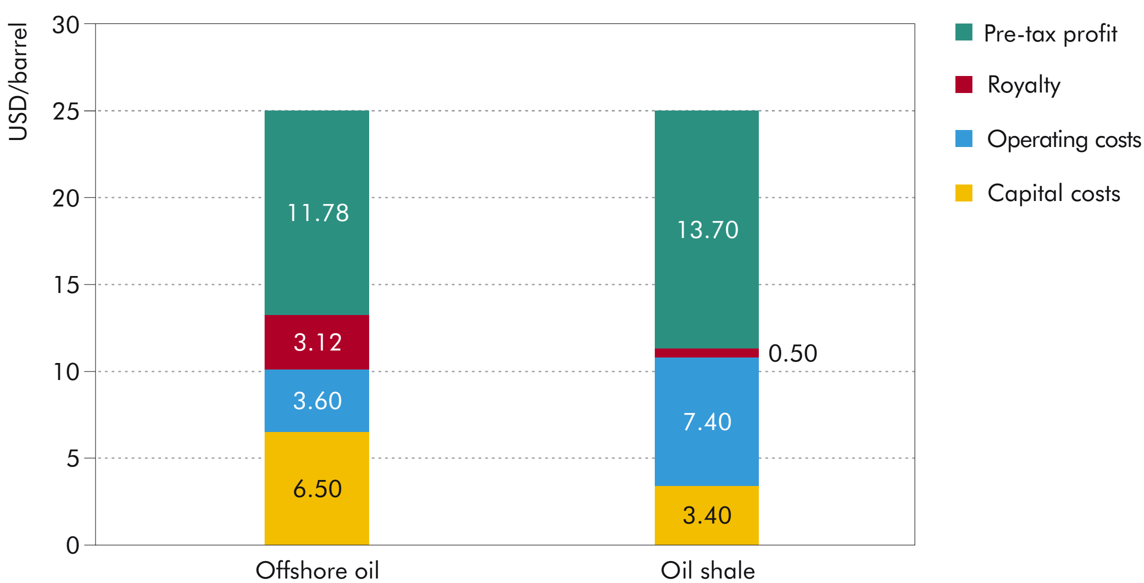
The United States has by far the largest known deposits. These resources have always been a source of great interest for the United States government in terms of offering a key to long-term security of supply. The United States Department of Energy (DoE) ran an extensive programme in the second half of the 1970s, resulting in substantial technology development and a number of demonstration projects. In the 1980s, however, shale oil was unable to compete with imported crude oil and the programme was stopped. DoE carried out a review of oil shales in 2004 (DoE Shales 2004), which contains an assessment of the state of the technology.

A handful of countries have been using oil shales on a small scale. Estonia has always had an active oil shale industry, largely to provide oil shale as a direct input fuel for electricity generation, but also to produce a small amount of oil. Brazil and China have small pilot plants. Australia has a pilot operation using the Stuart Shale deposit, but plans to enter full-scale industrial operation are on hold due to environmental concerns.

Oil shales that outcrop to the surface, or are at shallow depth, can be mined, much as coal or oil sands are mined, using standard mining technologies. The mined rock is then heated in a process called retorting, which pyrolyses the kerogen into oil. A number of designs for the retorter have been developed, of which the most recent and best performing model is expected to be economic at an oil price of USD 25/barrel.

Insight on indicative costs is provided in Figure 3.7. This shows an estimated cost structure for the Australian Stuart Shale phase-three proposal, based on a 200 000 barrels/day facility, compared to the cost structure for a typical offshore conventional oil project. A smaller proposed project in Estonia forecasts profitability at an oil price of about USD 20/barrel.

Figure 3.7 • *Cost structure for Stuart Shale project proposal, Australia*



From USA Department of Energy report (DoE Shales 2004).

As with any mining operation, however, extracting oil shales involves an environmental impact that can be significant. Tailings need to be disposed of, land must be properly reclaimed and the footprint must be minimised.

Most deposits are too deep, however, to be mined and they call for some form of *in-situ* retorting. In one variant, explosives or hydraulic fracturing are first used to rubblise the rock. This is necessary because oil shales generally have very low permeabilities. For that reason, paths must be created to ensure that the oil that will be formed under temperature can be drained towards producing wells. The rock must then be heated to about 500° C to produce the required liquid hydrocarbons from the kerogen. Heat can be supplied through wells using various techniques, or created by an *in-situ* combustion process. The latter (similar to *in-situ* combustion for heavy oil, or to *in-situ* coal gasification) is difficult to control and pilot projects have resulted in very variable recovery rates. The former, while easier to control, is a relatively inefficient process. The *in-situ* techniques not only offer access to deeper deposits, but they also side-step many of mining's environmental issues associated with land use. On the basis of demonstrations carried out in the late 1970s and early 1980s, these processes are expected to be economical with oil prices at USD 25/barrel. For example, according to the *Oil and Gas Journal* (25 April, 2005), Shell is working on a pilot *in-situ* retorting project using electrical heating, which is expected to be economical at an oil price of USD 20/barrel.

Nevertheless, exactly as with heavy oils, producing oil shales is a more energy-intensive process (and therefore CO_2-intensive) than producing conventional oil. Retorting, whether done at the surface or *in-situ*, makes the largest claim on energy input, possibly as much as 30% of the energy value of the oil produced. If this energy is produced from fossil fuels, the corresponding potential CO_2 emissions may need to be avoided through CO_2 capture and its storage in geological formations. For example, compared with conventional oil production, the Australian Stuart Shale project was estimated to generate an additional 180 kg of CO_2 per barrel of oil produced (***www.iea.org/textbase/work/2002/calgary/Smithdoc.pdf***). Assuming standard CO_2 capture and storage costs of USD 50 per tonne, as well as some modest efficiency improvements in future projects, the additional cost would be close to USD 8 per barrel. It should be noted that the economic analysis in Figure 3.7 already incorporates some CO_2 mitigation costs.

As already indicated, Canada's recent experience with oil sands and heavy oil bears witness to the powerful force of a stable and attractive tax and royalty regime to catalyse fresh investment. Could the same approach work for oil-shale development? The United States DoE reckons that it would be possible for the United States to produce 2 million barrels of oil per day from domestic oil shales by 2020. The early projects discussed above appear economical at sustained oil prices of around USD 25/barrel, even assuming CO2 mitigation costs. But these projects obviously focus on locations where the kerogen concentration in the shale is highest, whereas costs depend primarily on the volume of rock to be heated, and not on the kerogen content in that rock. In fact, most of the located massive oil shale resources are probably at kerogen concentrations two to four times lower than those in the pilot projects. This is why we have placed economical production at a level of between USD 25 and USD 70 per barrel for future viable exploitation.

Chapter 4 • NON-CONVENTIONAL GAS RESOURCES AND METHANE HYDRATES

Non-conventional gas

As discussed in Chapter 1, there is no unique definition for “non-conventional gas”. The term is usually used in reference to types of gas reservoir that have been developed only recently, and so far almost exclusively in the United States. They are primarily of two sorts: “coal bed methane” and “tight gas”. They represent very large resources, amounting to at least 250 trillion cubic metres (1.5 trillion boe), roughly of the same order of magnitude as conventional gas. These resources are currently exploited primarily in the United States, where they supply some 25 % of gas production.

Coal bed methane

It is well known that most coal deposits contain methane which has been adsorbed into the coal. The release of such methane has always been a major source of accidents in coal mines, where this danger is mitigated by circulating air to move the gas out into the atmosphere. Until recently, this “coal mine methane” was just vented to the atmosphere. But there is now concern about methane as a powerful greenhouse gas, with a contribution to global warming 21 times as great as CO_2, per unit mass. This concern has recently prompted several countries to start recovering this coal-mine methane for use in generating energy. In this process, it is turned into CO_2, reducing its impact on global warming by a factor of roughly seven (as well as substituting for other fuels and their emissions).

Coal deposits are widespread around the world and commonly mined. Less well known is the fact that a much larger quantity of coal is buried in deposits at depths where it cannot be mined. Studies and pilot projects have focused on *in-situ* gasification of such deep coal beds, but the technology is not yet widely used and, in any event, it would be cost-effective only for relatively shallow coal deposits.

This leaves a vast amount of more deeply buried coal that cannot be exploited. However, just like coal in ordinary mines, these deeper coal beds also contain adsorbed methane. “Coal bed methane” (CBM) is the methane (along with other light hydrocarbon gases) contained in such coal beds where the deposit's depth or the coal's poor quality rule out economical extraction of the coal. The methane found in such coal beds can be extracted. The technology is very similar to production technology for conventional gas reservoirs: wells are drilled into the coal bed, the pressure is reduced and the gas moves to the surface through the wells. The main difficulties are as follows.

- Coal beds tend to have low permeabilities, so that fluids do not flow easily through them unless the reservoirs are stimulated, for example, with hydraulic fracturing.

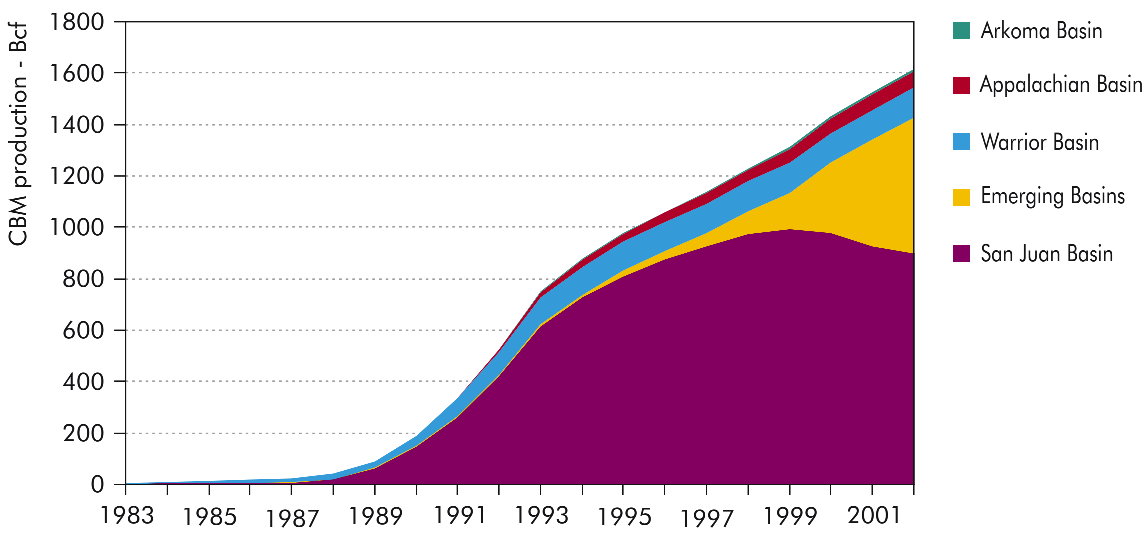
- The coal can contain large amounts of water in its pore spaces, whereas the gas is adsorbed on the coal surfaces. This means that large amounts of water often have to be produced before any gas reaches the surface, which delays production, and therefore the net present value of the investment in wells and production facilities. It also add to costs, since this water may have to be disposed of or treated before use.
- Since no entirely reliable technology yet exists to assess how much gas a particular coal bed can yield, the methane gas extraction process is often one of trial and error.

The technologies to produce gas resources economically from coal beds have nevertheless been developed in the United States, primarily through programmes led by the Department of Energy (DoE) in the 1980s, including attractive tax regimes. Today, CBM represents around 10 % of gas production in the United States.

The map in Figure 4.2 shows the major CBM basins in the United States. New basins are currently being developed rapidly, as shown in Figure 4.1. The key to economic development of these fields is drilling a large number of low-cost wells (see Chapter 2), including horizontal wells.

Coal bed methane is probably widely spread around the globe. Large amounts are known to exist, notably in Australia, Canada, China, Germany, India, Indonesia, Poland, Russia and South Africa (see, for example, Table 3 in White 2005). These resources are to be found in settings similar to those in the United States, at depths too deep to be mined but relatively shallow. Outside those countries, comparatively little is known, but coal beds are certainly present at various depths in most sedimentary basins, which would suggest that worldwide undiscovered resources are quite extensive.

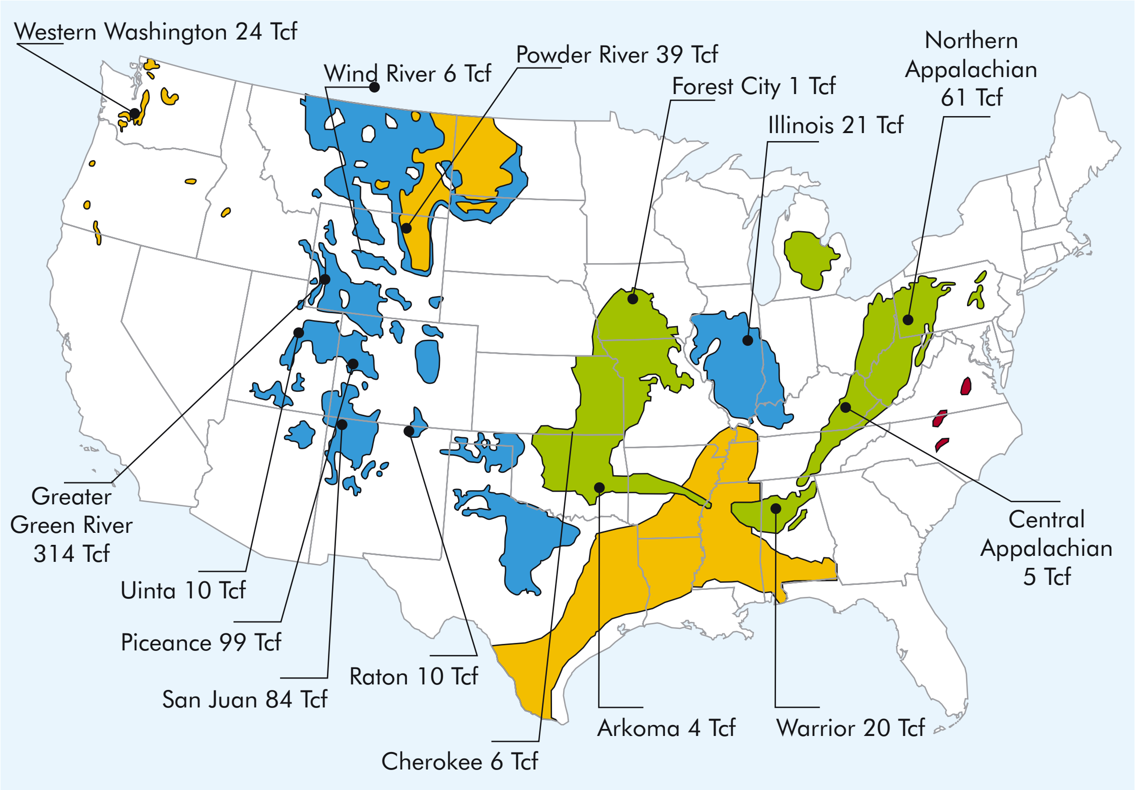
Figure 4.1 *• Coal bed methane gas production in the United States, by basin*



Note: 1 billion cubic feet is approximately 28 million cubic metres or 180 000 boe.

Courtesy of Gas Technology Institute, United States.

Figure 4.2* • *United States coal bed methane resources - 20 trillion cubic metres



Courtesy of Gas Technology Institute, United States.

The example of the United States has shown, however, that the key to economic recovery is a large enough concentration of activity to create economies of scale in drilling low-cost wells. To date, the relative abundance of more prolific conventional gas reservoirs in many parts of the world has inhibited the large-scale exploitation of CBM outside the United States. Pilot projects have been developed in some other regions (Canada, China, Russia). As the basic technology is for the most part available, local markets can be expected to drive further development in the field. The principal missing piece in the technology picture is probably improved characterisation of coal bed reservoirs. This is a difficult problem, with which progress is likely to be slow; the United States DoE has already focused significant effort on this area in the 1980s. It should be noted, however, that some environmental concerns revolving around land use and water disposal have arisen over the reservoir development technology based on a large number of wells, which is used in the United States.

An interesting possible development might be use of CO_2 injection to enhance methane production from coal beds. Indeed, CO_2 in principle adsorbs more strongly on coal surfaces than does methane. So injecting CO_2 could both produce the coal bed methane and sequester the CO_2 through adsorption onto the coal (White 2005). If the CO_2 is captured from power plants, for example, the result is reduced greenhouse gas emissions. This technology is nevertheless still in its infancy and pilot projects have given mixed results.

Tight gas

"Tight gas" refers to gas found in rocks with extremely low permeabilities. While not formally defined, the permeability level characterising tight gas would be below 0.1 millidarcy (the customary unit of measurement of permeability). These rocks can be conventional reservoir rocks (carbonates, sands) with very low permeability, or shales (clay-rich rocks normally considered impermeable). In the latter case, the rocks are known as "gas shales", by analogy with oil shales, discussed in Chapter 3. Both are "source rocks", that is, rocks which were buried together with organic material. Gas shales have been buried long enough for the organic material to "mature" into gas and oil, whereas oil shales have not been buried long enough for this maturing process to take place.

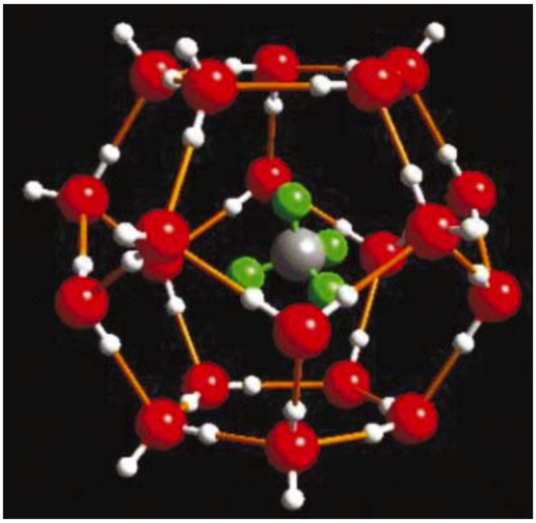
Such reservoirs are considered non-conventional because gas would not flow at economic rates without the use of special technologies. Two common approaches, among others, can provide the solution. One is to create long artificial fractures in the rock by pumping up the wells at high pressure until the rock fractures, a process called hydraulic fracturing. Another approach involves drilling long horizontal wells that intersect natural fractures. Fractures, whether natural or artificial, are needed to provide a path for the gas to flow to the wells. Such approaches are currently used economically only in the United States, where volume effects have brought the cost of drilling and hydraulic fracturing operations down to a level where development is viable. In the United States, tight gas resources represent about 15 trillion cubic metres (100 billion boe), and they currently supply about 15% of the nation's gas production.

Very little is known about the presence of such tight gas formations elsewhere in the world. Most other countries with abundant conventional gas have not embarked on exploration to detect tight gas. Many geologists expect other sedimentary basins to contain formations similar to the Barnett Shale in Texas (possibly the largest gas reservoir in the United States) and these formations elsewhere could hold significant resources. Certainly, the effect of volume on drilling and fracturing costs observed in the United States is having an impact in other regions of the world, notably Russia, where introduction of USA-style hydraulic fracturing technology is one of the factors behind the revival of Russian oil production over the past five years.

Here again, since the technology is largely available, local markets are likely to drive further development of this type of resources. Alongside ample conventional gas resources, the potential of those non-conventional gas reservoirs underlines the fact that adequate investment in transportation infrastructure is likely to be the only requirement to mobilise sufficient future supplies of gas.

Methane hydrates: resources for the long-term future?

Figure 4.3* • *Methane hydrate ice-like structure, with methane molecule in a cage of water molecules

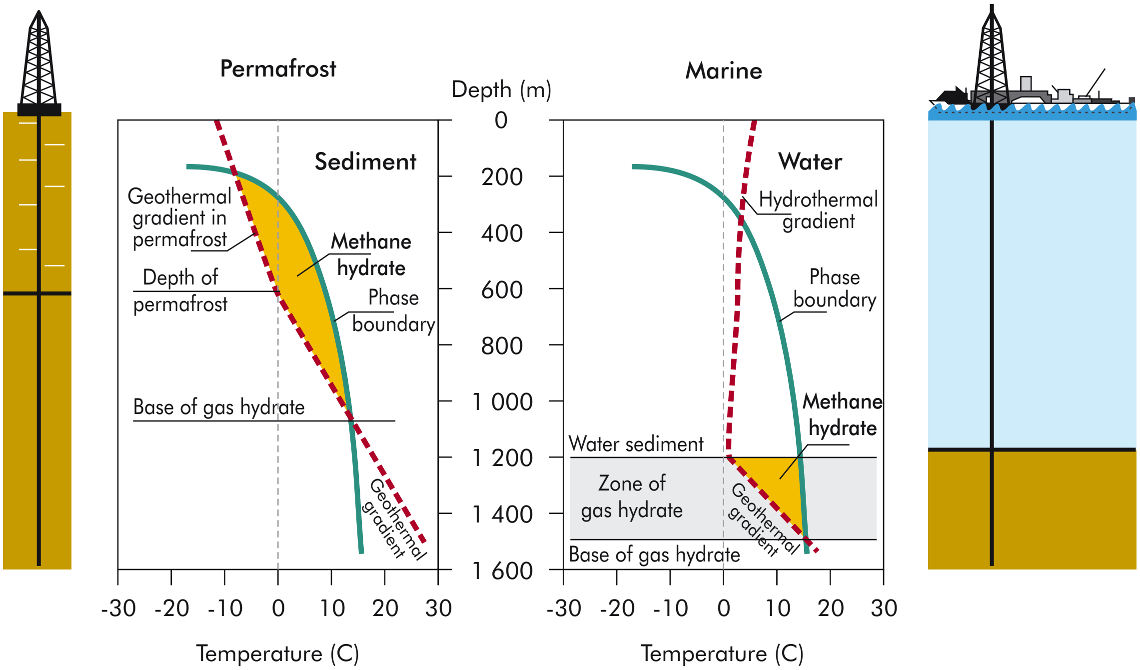


Courtesy of S. Dallimore, National Resources Canada.

Methane hydrates are crystal-like solids (Figure 4.3) formed when methane is mixed with water at low temperature and moderate pressure. More generally, these solids are referred to as "clathrates", since other gases such as ethane, propane or CO_2 can also form similar solids when mixed with water.

Methane hydrates can be found on the seabed or in permafrost Arctic regions, when the temperature and pressure are within the "hydrate existence domain" shown in Figure 4.4. In permafrost this is typically between 200 metres and 1 000 metres sediment depth; at the sea bottom, this can be between 500 metres and 1 500 metres water depth.

Figure 4.4* • *Hydrates existence domain as a function of pressure and temperature



Courtesy of S. Dallimore, National Resources Canada.

They are thought to be the most abundant source of hydrocarbon gas on earth. But little is known about quantities. Estimates vary between 1 000 trillion and 10 000 000 trillion cubic metres, which represents between twice as much and 20 000 times the size of conventional gas resources. In a recent review, Milkov (Milkov 2004) suggests that total resources might amount to 2 500 trillion cubic metres. The map in Figure 4.5 indicates where the presence of methane hydrates has been established (primarily from scientific efforts such as the international Ocean Drilling Program). However, a large proportion of the seabed deposits may be at low concentrations spread over large areas, making them a difficult target for exploitation. In any event, the challenge is how to produce them safely and economically. Several government-supported international projects are conducting research in this field.

When are they likely to become a reality? The tremendous potential of gas hydrates as energy resources, and the limited scientific and technical knowledge on how to explore and produce them, has prompted public investment. The largest project is probably that of Japan's Ministry of Economy, Trade and Industry (METI). Spanning 16 years (2000-2016), this project is aimed at complete assessment of the feasibility of producing natural gas from gas hydrate deposits on the seabed or in permafrost regions. The United States and Canada also have a number of demonstration projects in progress, most notably the joint USA/Canada/Japan Malik project, which demonstrated gas production for a few days in 2002 from a permafrost deposit in Northern Canada. The United States Department of Energy's 1999 National Hydrate Plan also targets production technology for 2009-2014. Various industrial companies are involved in these demonstration projects.

Figure 4.5 • *Map of confirmed methane hydrate presence*

Courtesy of S. Dallimore, National Resources Canada.

Taking an optimistic view, technology to exploit gas hydrates commercially could be available as soon as 2020. This would make a huge difference to forecasts of future gas supply. It would have a considerable effect on the two main drivers of the liquefied natural gas (LNG) expansion effort, Japan (in the past) and the United States (in future); they would suddenly find themselves with large-scale local supplies. The impact is unlikely to be felt greatly before 2030, but it could start affecting the investment climate for LNG projects and Middle East gas as early as 2020.

A more pessimistic view would bear in mind that the Malik experience (AAPG 2004) so far indicates that the only deposits anywhere near economic viability are those containing free gas below the hydrates, and that innovation is still required if deposits without free gas are to be developed economically. Certainly, much more publicly funded research is needed. The Malik project, for instance, is proposing to carry out a longer-term production test in 2006. Further work of this sort will provide more insight into the role that methane hydrates can play in tomorrow's energy systems.

CHAPTER 5 • TRANSPORTATION

Transportation of hydrocarbons around the world is set to increase enormously. The IEA *World Energy Outlook* Reference Scenario projects that a large share of increased demand for oil over coming decades will be met by supplies from the Middle East, delivered to IEA countries, China, India and other emerging economies. This will mean moving much greater volumes of oil over large distances. Inter-regional trade in oil will double from 31 million barrels per day in 2002 to 65 million barrels in 2030 (IEA *WEO-2004*, Reference Scenario).

The same will apply in the case of gas. Increased gas demand in many countries, fuelled in part by its relatively lower CO_2 impact, and coupled with liberalisation of gas markets and development of the liquefied natural gas (LNG) trade, will also hugely expand the amount of gas transported over long distances. Inter-regional trade will triple, rising from its 2002 level of 417 billion cubic metres to 1 260 billion cubic metres in 2030 (IEA *WEO-2004* Reference Scenario)

This picture of the future raises a number of issues linked to bottlenecks in shipping lanes, to safety and environmental concerns, and to capacity and cost efficiency. In all these areas, technological innovation and international co-operation will be needed.

Gas transportation

Traditional transport chains: pipelines and liquefied natural gas

Both modes of transport have been used for many years. They will continue to dominate the market.

The three main challenges for these chains are:

- Reducing costs.
- Reducing environmental impact.
- Safety and public acceptance.

In the case of LNG, cost reductions will continue to stem in large part from economies of scale in liquefaction plants and in LNG carrier ships. Capital costs of LNG liquefaction plants have decreased from USD 500 per tonne/year capacity in 1990 to some USD 250 in 2004. And they could fall by another factor of two over the coming 20 years. Improvements in energy efficiency will have a positive impact on both costs and environmental performance. A number of technologies are under study, notably bringing electrically driven liquefaction trains, open rack vaporisers, enhanced boil-off control and improved energy recovery. For example, use of "membrane technology" in LNG tankers (an Invar/polyurethane tank-wall material) has significantly reduced energy losses in LNG tankers over the past five years. Moreover, this has not in any way slowed the decline in capital costs of LNG tankers, which have fallen at least 25% since 1985 and are expected to shrink by another 25% over the coming 20 years. This favourable cost development will owe much to the advent of larger ships with capacities of more than 200 000 cubic metres, compared with the current generation of 138 000 cubic metre vessels.

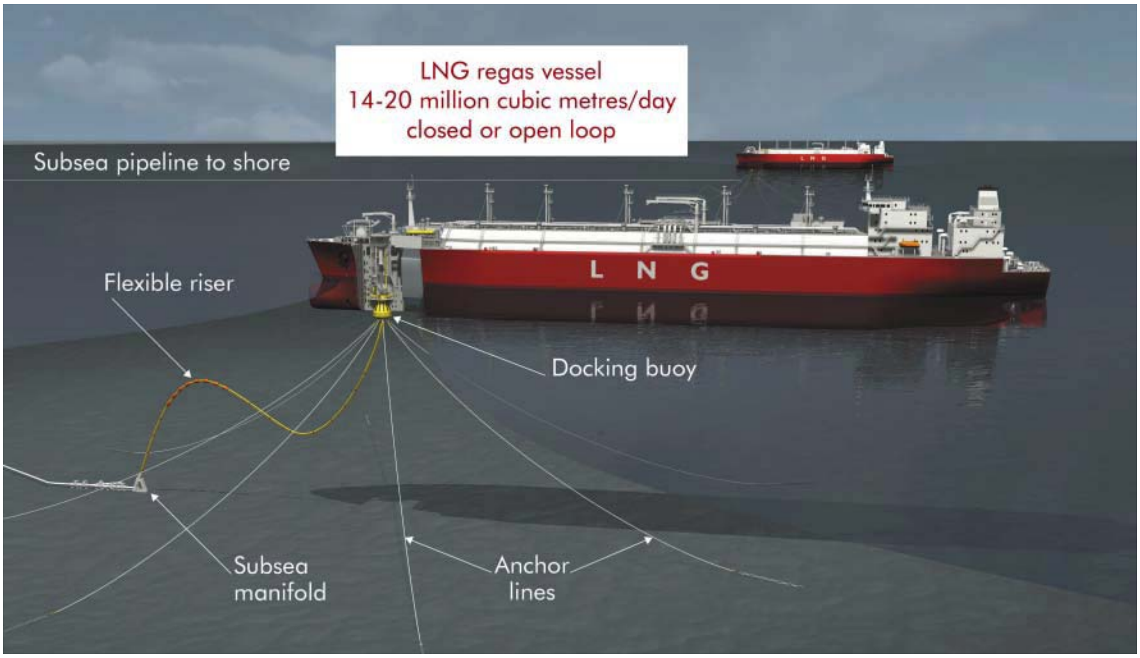
Although the LNG track record on safety is impressive (close to 40 000 safe LNG ship voyages in the past 40 years), public acceptance, reflecting fear of terrorist threats, remains an issue, particularly in the United States. This is likely to trigger development of offshore floating facilities, first for re-gasification terminals, then possibly for liquefaction units. Designs for such facilities already exist and, although costs are still high, the first offshore floating re-gasification facility began to operate in March 2005 (Figure 5.1).

Gas pipelines have seen steady improvements in both cost and throughput. The use of higher-grade steels enables them to be operated at greater pressure, so increasing throughput. It can also permit reduced pipe thickness, thus lowering costs (Figure 5.2).

This trend is expected to continue over coming years. Recent developments have brought X100-grade steel into use. X120-grade and composite reinforced pipes are on the horizon (Figure 5.3). At the same time, new techniques for laying and welding pipes, including horizontal drilling (instead of trenching) or high-frequency welding, will further contribute to cost reductions and lower environmental impact.

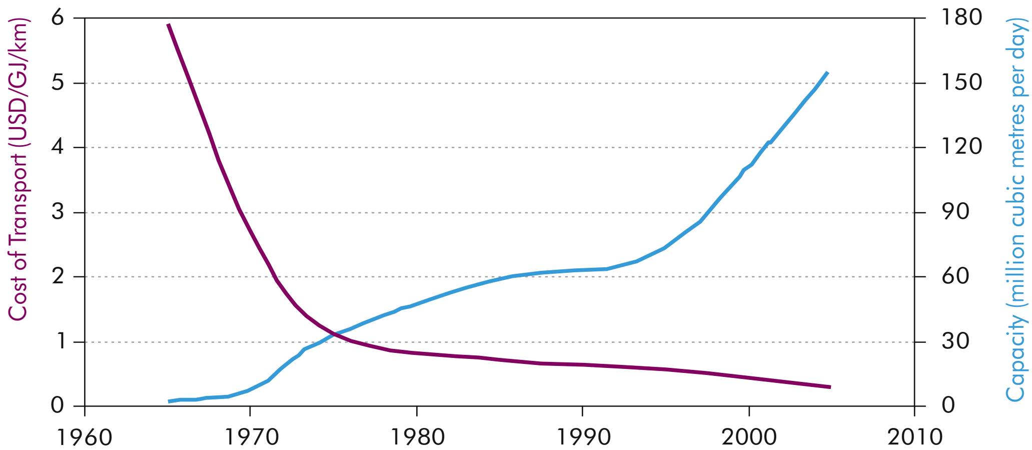
Contributions to greenhouse gas emissions abatement will come from improvements in compressor and turbine efficiencies. Compressors, usually powered by gas turbines, provide the energy required to move the gas down the pipeline. In large long-distance pipeline networks like those in Russia, as much as 10% of the gas entering the system is used to power the compressors. Another contribution to greenhouse gas abatement will come from improvements in pipe corrosion management, or new third-party damage-avoidance systems, which will reduce fugitive emissions of methane and improve safety.

Figure 5.1 • *New offshore re-gasification technology*



Courtesy of Excelerate Energy; reproduced with permission.

Figure 5.2 • *Reduction in pipeline transportation costs over time*



Note that the reference appears to contain a typographical error and the right axis should have units of dollars per GigaJoule per 1000 km, and not USD per GigaJoule per km as indicated. 1 GJ of gas corresponds to about 29 cubic metres.

Reproduced from Gower 2003 with permission from International Gas Union.

Figure 5.3 • *Composite reinforced line pipe, developed by Transcanada*

Courtesy of Gaz de France.

Technology improvements notwithstanding, pipelines and LNG projects will nevertheless remain extremely capital-intensive. For example, the Shell LNG plant project in Sakhalin (a Russian island north of Japan) involves a USD 10 billion investment, and the recently completed Russia-Turkey Blue Stream gas pipeline more than USD 3 billion. Such large outlays will continue to need justification in the form of large local gas supplies from giant gas fields and connections to large markets if they are to make economic sense.

One possible advance for improving returns on the large capital expenditure that a pipeline represents might stem from the advent of multicore pipelines, through which several different products could be carried in parallel lines along the same route. For instance, they could in future carry CO_2 or hydrogen, in addition to natural gas. Another rapidly developing approach, of a rather different sort, involves laying communication optical fibres along pipeline routes to carry data, which could not only improve economics but also help improve pipeline monitoring.

In spite of these promising technological developments, large amounts of gas resources still have no access to an economic transportation chain to market. This gas is usually called “stranded” gas, a possibly confusing term, since all gas is stranded until a transport infrastructure has been built, at which point it is no longer stranded. It would be more appropriate to refer to gas resources that are currently uneconomic to bring to market[19].

19. This includes “lean gas”, gas containing too much CO_2 or nitrogen to be directly commercialised, and for which constructing a processing facility to remove the unwanted components may not be economical.

The amount of such gas of course depends on current gas prices, as well as current technology and current transport infrastructure. Estimates are thus bound to vary over time. At present, something like 50 trillion cubic metres of discovered gas resources fall into this category (Cedigaz, quoted in IEA *WEO-2001*). New technologies enabling this gas to reach its markets are thus critical for future supply.

Emerging options

Compressed natural gas (CNG)

In this technology, gas is not liquefied but simply compressed and transported in suitable ships. On arrival, it can be de-compressed for use or fed into a high-pressure pipeline. Typically, this mode of transport is less capital-intensive than LNG, since compression plants are cheaper than liquefaction plants, and there is no need for a re-gasification terminal on arrival. But volumes (for a given mass of gas) are larger, so that shipping costs are correspondingly greater. As a result, this technology is thought to be economical for smaller amounts of gas travelling over shorter distances.

A number of projects are currently being investigated but there is not, as yet, any large-scale commercial application.

Micro-LNG

Designs for small-scale liquefaction units have been proposed. Small-scale LNG tankers are in use in Japan and in Norway. LNG is also carried by road trucks, although large-scale use of this approach could raise safety concerns. Combining these technologies could render economical the development of smaller-scale gas accumulations for smaller markets. The rapidly developing availability of re-gasification terminals would play in favour of this approach. However, no commercial project has yet been demonstrated.

Transport as gas hydrates

Naturally occurring gas hydrates have been discussed as resources in Chapter 4. They are solids formed when gas and water are mixed at moderate pressures and at moderately low temperatures (see Figure 4.4 in Chapter 4). This temperature is of course much higher than the temperature of liquefied gas (minus 160° C). Once a solid has been formed, it can be transported as pellets, for example by land or sea. On arrival, appropriate re-gasification facilities are needed. Paper studies indicate that this is feasible and should be economic for smaller gas accumulations, even over long distances. However, feasibility and safety have yet to be demonstrated.

Gas to liquids (GTL) – Box 15

GTL is based on a rather different approach to monetising natural gas deposits. Instead of being transported to the market, gas is produced and then transformed locally into a liquid that has commercial value. Examples here are: methanol (currently used as a chemical feedstock and a potential fuel for future fuel cells); dimethylether (DME), which is currently used as a carrier fluid in aerosols and could in due course fuel vehicles; or diesel fuel for direct use to fuel diesel-engine vehicles.

Box 15 • Gas-to-liquids basics

Current GTL technology uses variants of the Fischer-Tropsch (FT) process, originally developed in Germany and used extensively in South Africa to produce gasoline from coal.

In a first step, natural gas is transformed into "syngas", a mixture of carbon monoxide and hydrogen. This can be done either by steam reforming of methane (through the reaction $CH_4 + H_2O \rightarrow CO + 3\ H_2$*), or by partial oxidation (through the reaction* $CH_4 + \frac{1}{2}\ O_2 \rightarrow CO + 2\ H_2$*).*

The first path is a highly endothermic reaction, requiring an input of energy, and it produces excess hydrogen over what is needed for the second step, below. The second path requires an expensive oxygen separation unit. In some processes, a combination of both paths is used.

In the second step, the syngas is converted into longer-chain hydrocarbons similar to diesel fuels, using a catalytic conversion: $CO + 2\ H_2 \rightarrow -CH_2- + H_2O$*.*

Various catalysers can be used, and this is in fact where most of the technology improvements are taking place. Currently, the trend is from iron to cobalt, and others will emerge in the future. This is a highly exothermic reaction, producing a lot of heat. Depending on plant design, some of this heat can be used in the steam reforming process or to provide energy for other applications.

In large-scale plants, typical yields are 3 500 barrels per million cubic metres of gas. Energy efficiency is roughly 70%, so the process releases large quantities of CO_2 *per unit of output. A large GTL plant would be a prime target for capture and storage of* CO_2*.*

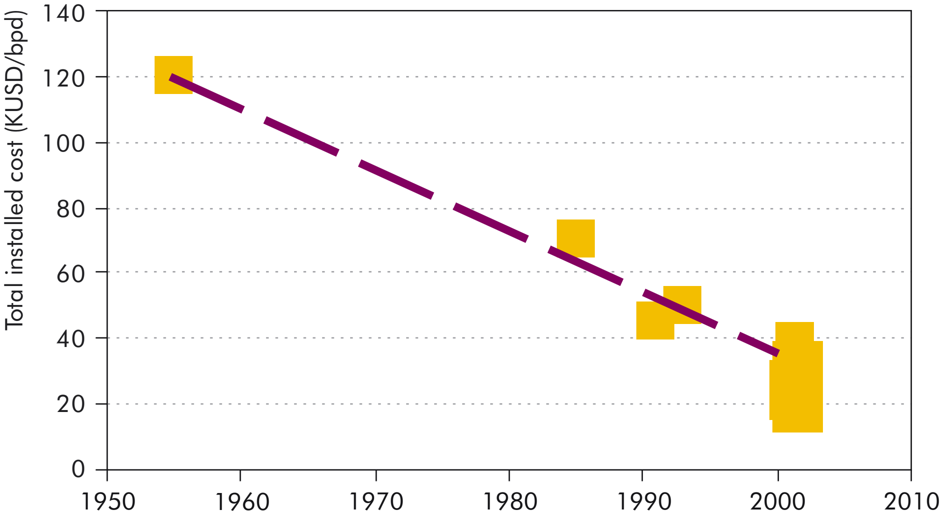
A number of research groups are working on single-step reactions (as opposed to the two-step syngas plus FT process), which could be more efficient. They usually involve some sort of plasma discharge. Industrial applications appear to remain a long way off.

*An alternative pathway is to produce methanol from methane (a well established industrial process), and DME from methanol (a recent but well developed process). DME can be used as an alternative to liquid petroleum gas (LPG, i.e. butane and propane), or even as an alternative to diesel (**www.aboutdme.org**).*

GTL has potential in three different roles.

- An alternative to LNG for monetisation of extensive gas resources located far from large markets. A number of big GTL plants are planned or being built in Qatar, with the prospect of initiating production of 30 000 barrels per day of diesel in 2006 and reaching several hundred thousand barrels per day by 2010. Conversion rates are around 300 cubic metres of gas per barrel of liquid produced. Experience with pilot plant projects around the world shows that economies of scale have made large GTL plants roughly competitive with LNG plants in terms of the economics. But fluctuations in relative prices of gas and diesel, or supply contract conditions, may create a preference for one over the other: gas tends to be traded through long-term supply contracts, whereas a well developed spot market exists for diesel. As with LNG, GTL is a capital-intensive technology, with initial plant costs amounting to some USD 30 000 per barrel per day of capacity (Figure 5.4).

Figure 5.4* • *Evolution of capital costs of GTL plants, in USD per barrel-per-day capacity



Presented at IAEE conference in Prague, 2003. Reproduced with permission from I.I. Rahmim, E-MetaVenture.

- A technology to monetise smaller "stranded" gas fields or associated gas (see Flaring, Box 16). Smaller GTL plants do not appear to be economical at present, but a number of companies are working on new plant designs which could change that (Figure 5.5). Such plants would compete with micro-LNG or CNG, offering the advantages of a more flexible market for the product. More demonstration projects of these various technologies for stranded gas are needed. Pushing the technology on small-scale GTL could also have a positive impact on production costs of biofuels, via biomass-to-liquid (BTL) processes, which are similar to GTL and CTL (coal-to-liquids) technologies. Indeed, the main reason why biofuels are still expensive compared with fossil fuels is that the input crops need to be collected over a large area to feed a large-scale facility. Cost-effective, small-scale facilities would facilitate development of cheaper biofuels.

Figure 5.5* • *Prototype small-scale GTL plant

Courtesy of Alchem.

- A technology for the direct supply of "non-conventional oil" in the form of refined transportation fuel. By diversifying sources, this could contribute to security of supply of transportation fuels. But most of the gas resources suitable for large-scale GTL are located in the OPEC Middle East countries. GTL's contribution to security of supply could therefore be regarded as a weak argument, even though these countries have been more open to partnerships concerning their gas resources than their oil resources. Transportation fuels from GTL processes also have other environmental advantages over classic diesel, since they have very low sulphur content and high efficiency.

The IEA *World Energy Outlook* (IEA *WEO-2004*) projects GTL diesel production to reach 2.4 million barrels per day by 2030.

Box 16 • Flaring: a special case of stranded gas

Associated gas always accompanies oil when it is produced. This is because oil has been brought from high pressure in the reservoir to low pressure at surface for transportation. Dissolved gas comes out of solution, as with the opening of a bottle of champagne.

The content of associated gas is usually expressed as the gas-oil ratio (GOR), the volumetric ratio of gas to oil at surface conditions. GORs vary widely between different reservoirs around the world (roughly correlating with oil gravity). They range from around 10 to several thousands. In fact, hydrocarbon deposits with larger GOR are usually called gas condensate fields, rather than oil fields, and are exploited for their gas. The corresponding mass ratios and energy content ratios range from 0.009 to 5, and from 0.01 to 5 respectively.

Ideally, oil companies would like to monetise this gas, which means either serving a local market near the production or transporting it to more distant markets. Very often, particularly in remote areas, a sufficiently large market does not exist locally to create demand for a large portion of the gas, and the total amount of gas is not sufficient to justify the capital investment in a pipeline, or an LNG plant and tankers to transport the gas over a long distance.

The next-best option is to re-inject the gas into the reservoir. Depending on the reservoir's characteristics, this can be very attractive because it increases total recovery of oil. In other cases, though, it might also decrease recovery, due to early breakthroughs of gas, leading to gas cycling. Moreover, re-injection is a costly process, since the gas needs to be compressed to the high pressures found in the reservoir. If there is little or no promise of increased oil production, this path cannot be justified economically.

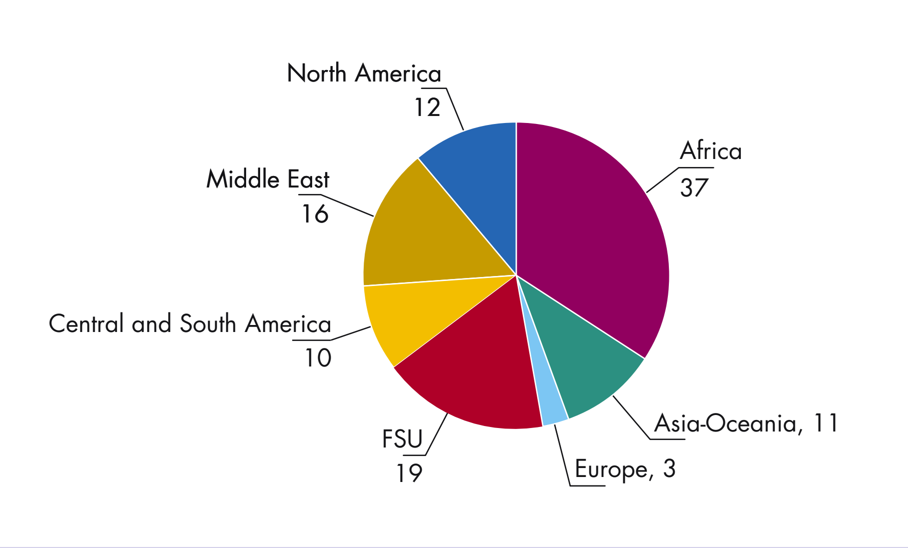
The only remaining option is therefore to simply discard the gas by releasing it into the atmosphere (venting). But this practice is often restricted by regulations or shunned because of safety concerns, so that operators prefer to burn the gas in a process called flaring. Although such an approach involves expenditure – capital cost for burners, energy for pumping and mixing, equipment maintenance cost – outlay is not generally high enough to have a significant impact on project economics.

For every oil production project, a company will typically examine these options and select the most economic, bearing in mind local laws and regulations. Not surprisingly, flaring is prevalent in places like Western Siberia or Nigeria, where the local market is not large enough to absorb the gas, and likely capital expenditure is too large to justify building the transport infrastructure.

The amount of gas being flared worldwide is not known accurately, but estimates have been made by bodies like the World Bank's flaring reduction project, as shown in Figure 5.6. In addition to being a waste of potentially useful fuel, flaring also releases CO_2 into the atmosphere. Roughly 1% of anthropogenic CO_2 emissions come from flaring, which is why many companies and countries have undertaken efforts to reduce flaring. For example, Saudi Arabia has essentially eliminated flaring, harnessing the gas for local energy supply instead. BP reports that the group has eliminated continuous flaring in all but one of its large fields. But further progress will depend on emergence of some of the technologies described above: CNG, micro-LNG and GTL. In Russia, for example, where gas transportation is a monopoly and internal gas prices are low, technologies such as GTL should be attractive for the oil companies, since they already have an established market for the produced liquids.

*A recent intergovernmental initiative "Methane to Markets" has been set up precisely to promote use of suitable technologies (**http://www.methanetomarkets.org/**).*

Figure 5.6 • *Estimates of amounts of flared gas in billion cubic metres per year*

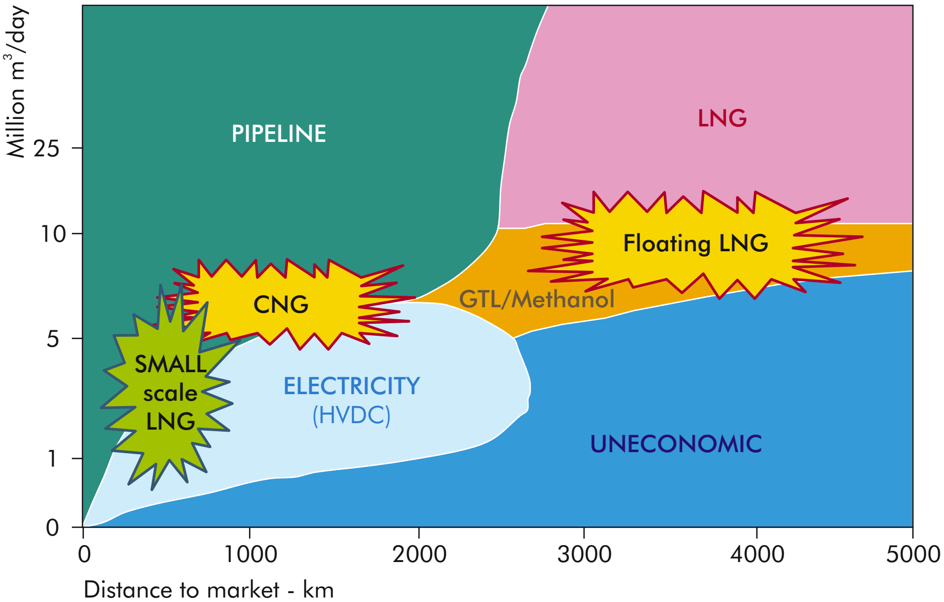


World total is in the order of 110 billion cubic metres (700 million boe).

World Bank and Cedigaz data.

Figure 5.7 summarises the possible role of these new technologies in the future economics of gas transportation. It emphasises the need for more progress on technologies to monetise small, isolated, gas reservoirs.

Figure 5.7* • *Applicability of various gas transport technologies



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Oil and gas shipping bottlenecks

As illustrated in Figure 1.12 in Chapter 1, a great deal of the oil transported around the world today has to pass through a small number of chokepoints like the Bosphorus, Straights of Hormuz, Straights of Malacca, Golf of Suez, Straights of Denmark. With forecast increased dependency on oil from the Middle East, this will be increasingly the case. A significant part of the growing LNG trade will also originate in the Middle East, thus adding to the bottlenecks. Some of these waterways, notably the Bosphorus, are already saturated and often involve long delays. Compounding this, concern is growing over these bottlenecks' exposure to terrorist threats and major supply disruptions[20]. Environmental risks are also growing with the expanding traffic.

Technology developments will definitely be needed to alleviate these risks. Possible developments could involve bypassing such chokepoints with short-distance pipelines. An example is the project for the Russia-Bulgaria-Greece oil pipeline, bypassing the Bosphorus. Foreseeable developments in rapid loading and unloading, with corresponding port infrastructure, could also play a key role. Floating loading and unloading facilities can facilitate access by larger ships to existing ports, thus reducing the total number of circulating ships.

20. Reference OECD 2003 provides a useful overview of terrorists' threats to the overall maritime transport system.

Preventing disasters in maritime transport is not confined to transportation of oil and gas. Generic development in on-board information technologies, communication technologies and sensing technologies will continue to have a large impact. Particularly important will be:

- automatic identification of ships and obstacles,
- traffic control centres, enhanced man-machine interface,
- environment monitoring
- and the monitoring of stress on hulls.

Improved tanker designs to withstand disaster will come on line in new models. But, since a ship's life typically spans roughly 30 years, major impact on the fleet is relatively slow, even if recent International Maritime Organisation regulations will accelerate the retirement of single-hull tankers. Finally, ongoing advances in disaster and emergency responses all over the world will improve performance in such efforts as containing and removing oil spills, and emergency unloading and towing of tankers.

In general, this is an area where governments and international collaboration need to play a key role.

CHAPTER 6 • ENVIRONMENT AND SAFETY

Environmental footprint

As discussed in previous chapters, projected demand growth will take exploration for oil and gas, and the production of these hydrocarbons, into new areas and new environments. There will be increasing numbers of wells in existing areas and new types of resources will be developed. Such a rapidly changing scenario will be accepted by public opinion only if accompanied by substantial progress in environmental performance. Remaining undiscovered oil is, by definition, in places where it has not been sought before, and these tend to be remote, relatively pristine environments. The industry must be able to demonstrate unambiguously that it is feasible to explore for hydrocarbons and extract them with minimal impact.

A sustained watch needs to be kept notably over air emissions, discharges to water (including drilling discharges and produced water), solid and other wastes, contamination of land and groundwater, ecological impact, physical and visual impact of construction and facilities, land use, use of raw materials and natural resources, also the incidence of noise or odours.

The industry is well aware of this challenge and has been actively pursuing new technologies that will help. We are seeing such improvements as smaller well bores (leading to smaller drilling platforms, less waste), clean well-site energy sources like fuel cells, re-injection of waste products in geological formations or closed-loop drilling-fluid systems. The drive to lower production costs also helps reduce emissions, since a large fraction of production costs can be traced back to energy use and therefore its associated emissions. In fact, experience confirms that challenging the engineers to find more environmentally friendly solutions can also often lead to more cost-effective approaches and *vice-versa*.

Figure 6.1 • *Oil production 1920s-style in the oil fields of Baku, Azerbaijan*

Progress has been significant since the pioneering days of Baku (Azerbaijan) in the early 1900s (Figure. 6.1). This is a far cry from modern developments in sensitive areas such Wytch Farm in southern England (Figure 6.2 and Box 17).

Data reported by the Oil and Gas Producers Association (OGP) from its member companies (Figure 6.3) shows that there is significant progress in areas like oil spills or oil-in-water discharges, where the industry has been focusing for several years. In areas that have only recently become important, however, such as greenhouse gas emissions, more work is required. Significantly, reported emissions appear to increase initially, reflecting improvements in the reporting process, before mitigation measures begin to take effect.

Technologies such as long horizontal or multilateral wells reduce both the number of wells that need to be drilled and the number of well sites, thereby minimising land use (Figure 6.4). Similarly, slim-hole drilling, monobore wells and improved surface equipment reduce the footprint of each drilling site (Figure 6.5). Subsea technologies reduce visual impact.

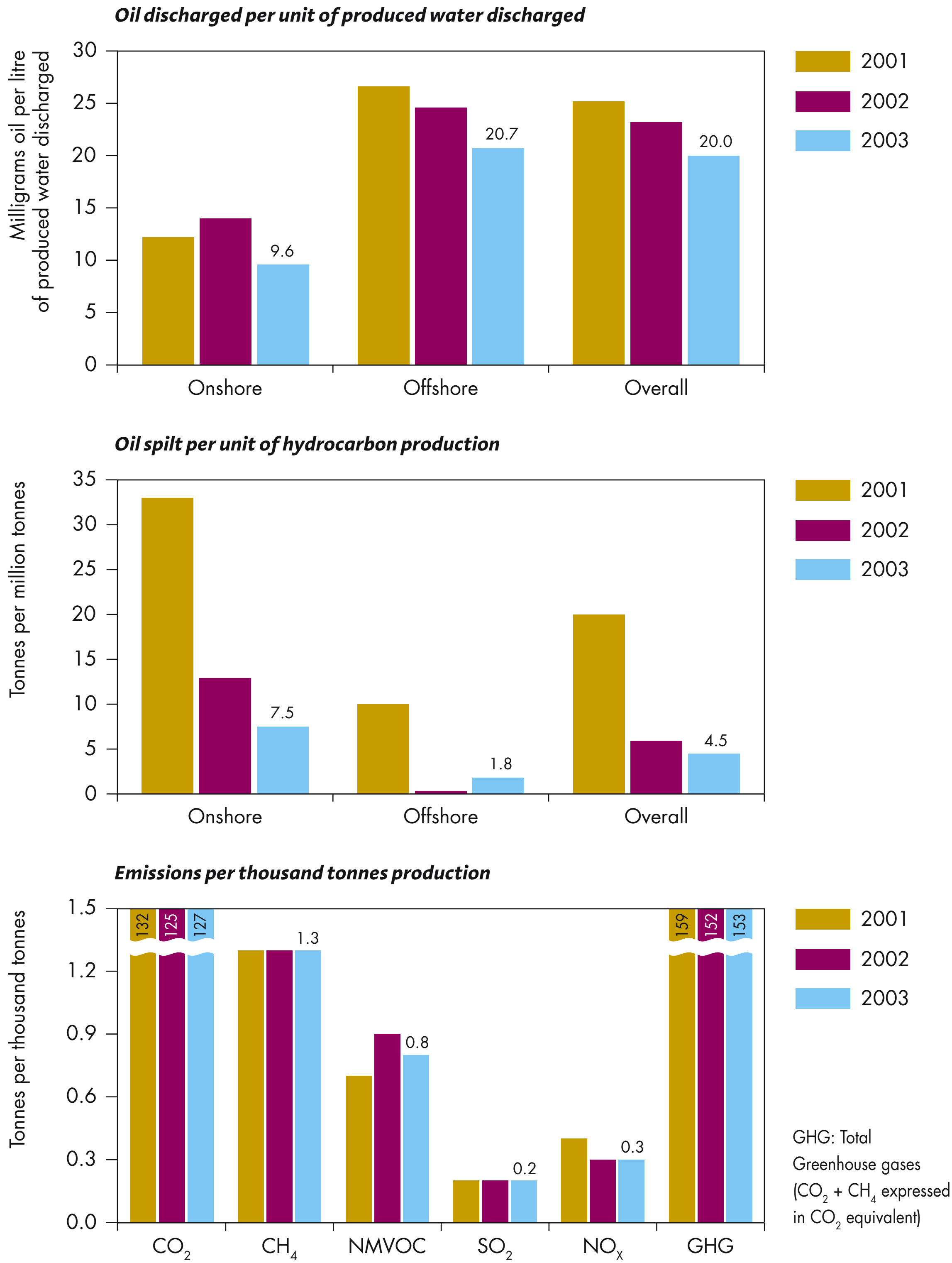
Environmental sensitivity is still too often a one-off activity, however, and not yet fully embedded in the design of each project. The required specialist skills are often in short supply within the oil and gas companies.

This is an area where continuing partnerships between the public, governments, environmental organisations and industry are critical for further progress. For instance, only limited understanding exists of the impact of deepwater subsea technologies on the deep marine environment, since the environment itself has not been studied extensively. Intensified collaboration between industry and the scientific community would help to better identify and implement solutions. As an example, oil and gas activity in the Norwegian North Sea led to the discovery of previously unknown cold water coral reefs and measures for their protection could then be implemented.

Figure 6.2 • *Oil production facility in the 1990s — the Wytch Farm field, United Kingdom*

Courtesy of BP.

***Figure 6.3 •** Trends in key environmental impact indicators*



Note: NMVOC stands for non-methane volatile organic compounds.

*These three pictures are taken from OGP Report 359: Environmental Performance in the E&P Industry; reproduced with permission from, and thanks to, OGP – available at **http://www.ogp.org.uk***

Box 17 • An example of modern development: Wytch Farm

The Wytch Farm reservoirs are located at a depth of some 1 600 metres under Poole Harbour on the southern coast of England. The Poole Harbour area has an extremely sensitive ecological environment, protected by the Ramsar intergovernmental convention on wetlands, and by European Union legislation. It is also an area of great natural scenic beauty, with an important tourism industry. BP's Wytch Farm facility comprises a number of well sites and a central gathering station. Wells are drilled from shore, using the latest horizontal well drilling technology and reach the reservoir up to 10 km under the sea with absolutely no impact on the marine environment.

The BP Wytch Farm facilities were developed following extensive environmental assessments. Ecological and archaeological surveys, as well as visual impact assessments were undertaken, to identify how environmental impact could be mitigated. Mitigation measures were incorporated from the start in the construction and operation of the facility. For example, to minimise visual impact, height restrictions and colour specifications have been imposed for plant and equipment. Lighting is carefully shrouded and positioned. BP has an ongoing landscape management plan to maintain a vegetation screen around the sites. Noise limits have been set extremely low, so that low-noise technology and acoustic screening are routinely used.

The sites are designed to prevent ground and groundwater pollution. Well-sites are hard-surfaced and lined with a sealant liner. Releases to water are minimised since all water produced and any potentially contaminated rainwater are re-injected back into the reservoir.

Beyond the original planning and design of the site, ongoing operations are constantly scrutinised to ensure compliance with stringent requirements and total environmental commitment on the part of everybody who works at Wytch Farm.

Edited from inputs from BP.

Figure 6.4 *• Tapping larger volumes of reservoir with a smaller surface footprint in Alaska*

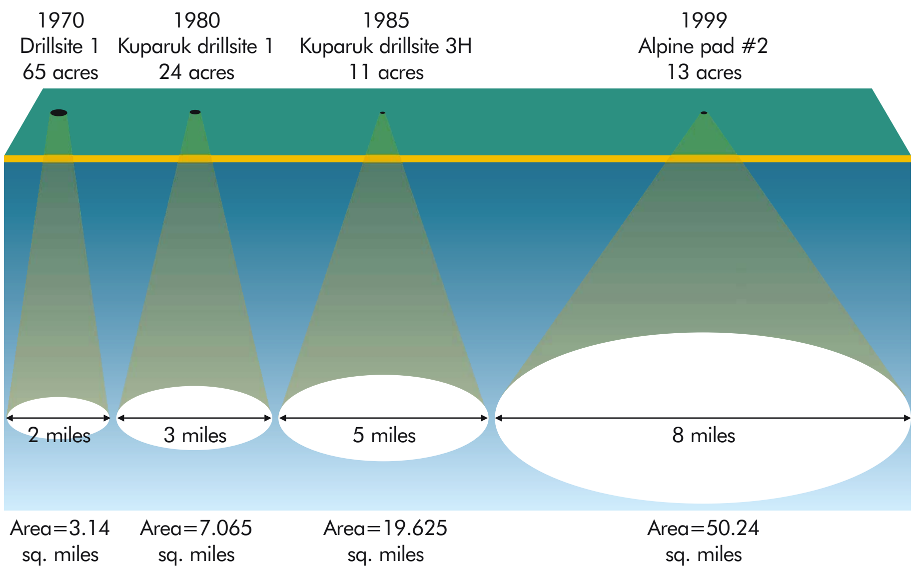
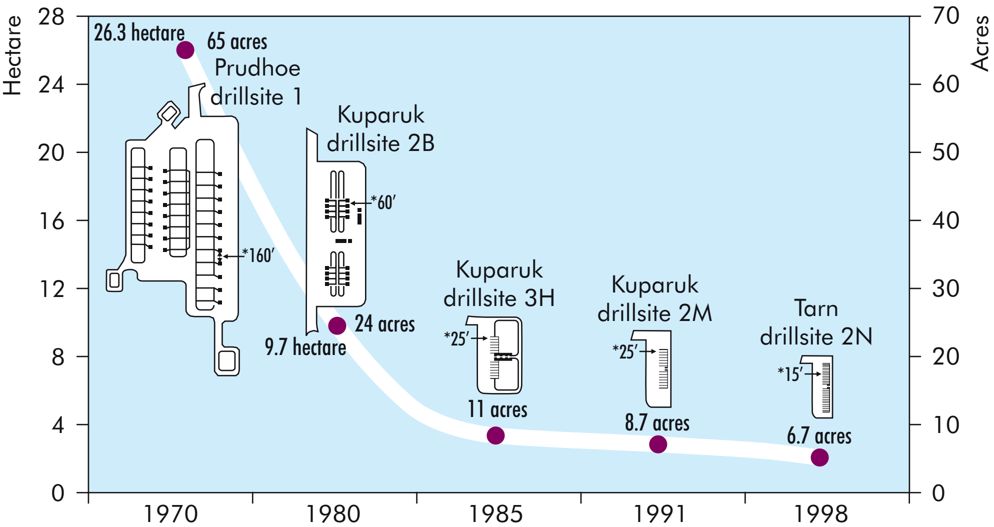


Figure 6.5* • *Decreasing drill-site footprints in Alaska



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Box 18 • An example of modern development: the Europipe gas pipeline landing

Norway's gas is meeting a major share of Western Europe's needs. Gas is transported from the Norwegian North Sea terminals through an under-sea pipeline. Design started in 1985 and the pipeline route called for a landing on Germany's Lower Saxony coastline.

But the area pinpointed is an ecologically sensitive environment, designated a national park. The area is also protected as a wetland of international importance under the Ramsar Convention on conservation and wise use of wetlands and their resources. It is a Special Protection Area under the European Commission Birds Directive and a World Heritage Site.

After extensive assessment of environmental impact, Statoil proposed routing through the Accumer Ee tidal inlet between the islands of Langeoog and Baltrum. A solution including a 2.6 km-long tunnel under the tidal flats was chosen for crossing the national park. Built in 1994, this was then the longest tunnel ever constructed in that sort of sand and clay substrate. The construction under the tidal flats was a particularly testing operation technically, as well as a safety and environmental challenge. To minimise future additional environmental impacts, a second pipeline was immediately placed inside the tunnel to anticipate future demand growth.

A comprehensive ecological monitoring programme documented rapid recovery within the construction area, most of the reported impacts in the landfall area being within natural variations. To compensate for any potential negative ecological impact, a 17-hectare biotope with ponds and sand dunes was constructed near Emden. This area has developed into a habitat for a number of rare and threatened species of plants, insects, amphibians and birds. The creation of this habitat was welcomed by the local nature conservation authorities and environmental organisations and it now enjoys its own protection status.

Edited from inputs from Statoil.

CO_2 and climate change

Reductions in greenhouse gas emissions from exploration, production and transport of hydrocarbons is necessarily a major component in any greenhouse gas reduction programme. In fact, at least 6% of the fossil fuel energy produced is used in the production process itself (IEA, *CCS-2004*, Table 3.1). Efficiency gains can therefore considerably reduce global emissions. This will certainly weigh heavily in the balance when technology options are being developed and deployed.

CO_2 emissions are also a factor to consider in the choice of new resources to be developed. As we have seen in previous chapters, heavy oils and bitumen are intrinsically more carbon-rich than conventional oil. But their extraction also calls for much heavier use of energy – as do oil shales – and this results in correspondingly higher CO_2 emissions if that energy is fossil-fuel sourced. Using current technologies, the GTL process also has a limited energy efficiency rating and sizeable CO_2 emissions.

As with many challenges, there are nevertheless opportunities to be exploited. In addition to being part of the problem, the upstream oil and gas industry can also be very much part of the solution. CO_2 can be used for enhanced oil recovery or for gas recovery in coal beds. Depleted oil and gas reservoirs can be used for long-term storage of CO_2. In general, well established oil and gas technologies are precisely those that need to be applied for CO_2 storage in geological formations. The required technologies are for the most part already available within private industry's portfolio. But a fundamental issue that must be addressed concerns the monitoring of CO_2 storage sites over the very long term. Partnerships with public institutions will be needed if monitoring is to be durable and robust.

Security and safety

Because they are often located in remote places, unmanned or operated remotely, many oil and gas assets are vulnerable to potential terrorist attacks. Traditional access control and security measures much like those used in other types of installation are being implemented on more and more sites. Innovation, however, is needed to incorporate better protection of the assets in the design of the facilities themselves. Given the concerns for safety of LNG installations, for instance, particularly in the United States (Sandia 2004), technologies to contain natural-gas fires rapidly could be researched, developed and implemented. This is an area where government support is critical; first, because the threats are generally beyond the control of private organisations and, second, because the required skills and expertise are often to be found within government institutions.

Another aspect of safety requiring technological development is resistance to natural hazards. Installation safety margins are usually based on historical hazards and thus designed for the storm or landslide that has been seen to occur once in a hundred years. Climate change, however, could bring natural hazards that are increasingly outside those established norms. This is not, of course, an issue affecting oil and gas installations alone. But it clearly requires joint consideration by industry and regulatory authorities.

CHAPTER 7 • GETTING ON TRACK

The previous chapters have discussed where the world's supplies of oil and gas could come from in the next 25 years and beyond. We have looked at the technologies which will be needed to secure those supplies, and at the sort of price context in which they are likely to be applicable. Many of those technologies are being pioneered by private industry. A few are driven by government programmes. Industry has a solid track record as the driver behind new technologies that have provided low-cost, uninterrupted supplies of oil and gas up till today. Given that track record, coupled with the long list of promising technologies discussed in this book, there is every reason to be optimistic that the development process can continue with minimal intervention by public authorities.

The previous chapters have also indicated that there is no shortage of hydrocarbons in the ground. The key issue is at what oil prices the various resources will become available. This is a difficult question to answer because it means predicting the impact to be expected from future technologies.

Finally, oil and gas will compete with alternative sources of energy, whether these are fossil (coal) or renewable. It is important to try to understand how the various alternatives will contribute to future energy supply. In the case of hydrocarbons, an idea of which of the possible resources are likely to play a big role is crucial in order to prioritise investments and R&D. In particular, as discussed in Chapter 3, non-conventional heavy oil will be competing in the liquid transportation fuel markets with gas-to-liquids (GTL) and coal-to-liquids (CTL) technologies[21]. In turn, in a CO_2 emissions-constrained world, those alternative fossil fuels will themselves be competing with emerging fuel technologies such as biofuels or hydrogen (generated from CO_2-free primary energies), as well as with technologies for improved energy efficiency.

Modelling future technology trends

The IEA has recently started a study analysing these questions as they relate to transportation fuels. Since transportation represents a large share of future oil demand, this is an important step ahead. This work is part of the IEA Energy Technology Perspectives project. Based on the MARKAL modelling methodology, this project is developing and using a global energy technology model, the ETP model (IEA *CCS-2004*), to investigate how different technologies may affect the world energy system in the long term. The model includes several hundred technologies covering energy supply, electricity generation and all end-use sectors, in each of the 15 regions represented. The calculations identify the mix of technologies and fuels that minimises the cost of the world energy system in a given scenario.

21. It is beyond the scope of this book to discuss CTL technology and its possible evolution. See, for example, Steynberg 2004.

In the model, the costs of the various options can also be balanced against their CO_2 emissions, accounting for emissions from the full fuel chain ("well to wheels"), or assuming that emissions from the production process are captured and stored in geological formations (CCS). Reductions in CO_2 emissions can be assigned an economic value that reflects the severity of climate change mitigation policies: the stricter the policies, the higher the value.

The model looks at the period to 2050. This timeframe is needed because it is really only after 2030 that significant changes can be expected in the supply mix between the various technologies. The period to 2030 is already largely "locked-in" by the long lifetime of existing investments. Various scenarios are analysed, based on different assumptions regarding CO_2 policies or on the future cost developments of some of the technologies.

Preliminary results (Gielen 2005) suggest that oil and gas will continue to dominate the transportation fuel market at least until 2050, but that their share could begin to decrease after 2030 as alternative fuels start to gain greater market share. In a world that is not CO_2-constrained, liquid fuels from coal (CTL) and ethanol will begin to displace oil. In a world that is CO_2-constrained, fuel demand could decline by between 25% and 30% as a result of enhanced efficiency. And there are large changes in how remaining fuel demand is distributed: smaller shares for oil products and for synfuels from coal and gas, with a much larger share for biofuels. Under certain technology assumptions, hydrogen can also play an increasing role. A full discussion of the key questions here will appear in a forthcoming IEA publication (IEA-Hydrogen 2005).

An important ingredient in any modelling exercise of this sort is a guess at the impact of technology on future costs of various fuels. In the case of oil, this key factor is examined below.

Impact of technology on future supply

Box 19 discusses various published "cost curves", or levels of oil prices at which the industry is capable of adding to proven reserves. Such curves often contain unclear or unsubstantiated assumptions about the impact of future technology development. Taking the arguments in the previous chapters, along with extensive inputs from industry experts, we have been able to project what magnitude of resources might be turned into reserves as a function of oil prices, taking into account likely technological progress. We focus on oil, for which extraction represents the dominant cost, and not on gas, where the cost of transportation dominates the economics. The following assumptions are incorporated.

- All Middle East oil (proven and yet to be proved or discovered) is cheap.
- Other proven reserves are below USD 20/barrel by definition; a good portion of "reserve growth" and undiscovered oil will cost less then USD 25/barrel, according to evolving technology.
- Deepwater will deliver 100 billion barrels at between USD 20 and USD 35/barrel.
- Arctic areas can deliver 200 billion barrels at costs between USD 20 and USD 60/barrel.

- Super-deep reservoirs will be a small contributor, and a relatively expensive one, for oil (they contain mostly gas).
- EOR can deliver 300 billion barrels above what is contained in the USGS reserve growth estimates, but some will remain quite expensive.
- Non-conventional heavy oil has large potential (some 1 000 billion barrels between deposits in Canada, Venezuela and other countries) at between USD 20 and USD 40/barrel, including CO_2 and environmental mitigation costs (e.g. CCS).
- Oil shales begin to be economical at USD 25/barrel and a significant portion of resources can be exploited at less than USD 70/barrel, including CO_2 and environmental mitigation costs.

These estimates are illustrated in Figures 7.1 and 7.2. In Figure 7.1, the y axis shows the oil price (Brent) at which the exploitation of various resource volumes becomes an economical option, taking into account the cost of capture and storage of CO_2 produced during the extraction of non-conventional oils. The x axis shows cumulative resources. In contrast with classic cost curves, this presentation facilitates a link with the type of resources, and therefore with the different technologies required. It also underlines that such projections are not an exact science and that only a range of costs can be projected. The bar labelled "WEO required cumulative need to 2030" shows the cumulative oil demand expected between 2003 and 2030 according to the IEA *World Energy Outlook 2004;* this provides a useful "scale" for levels of available oil.

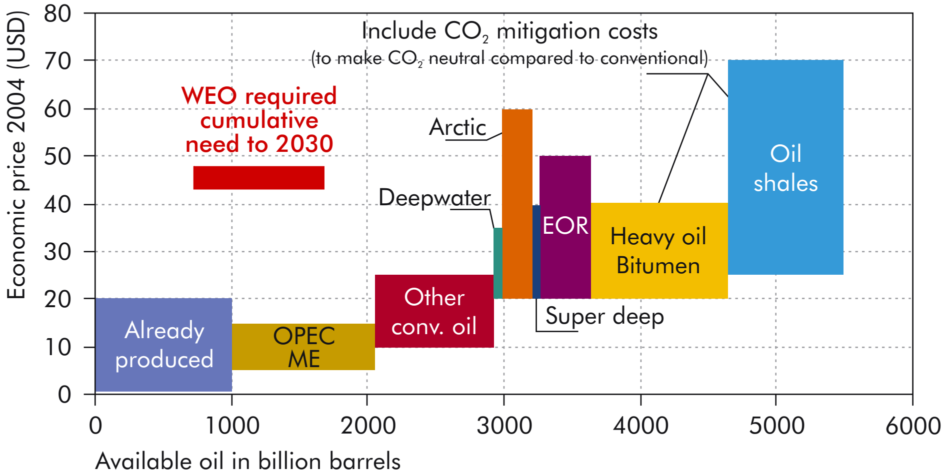
Figure 7.2 plots the same data in a different way. The x axis represents the oil price, and the y axis the corresponding cumulative economically exploitable resources. Currently, most companies base their investment decisions on a long-term price of USD 20 to USD 25 per barrel. The graph suggests that accepting a long-term price of USD 30 to USD 35 per barrel, for example, would have a large impact on future reserves.

It is important to stress that if resources become economical at a given price, allowing for normal return on investment, this does not necessarily mean they will be exploited. Many other factors come into play: demand, competition from more appealing investments, regulations, tax and royalty frameworks, access to resources or geopolitical factors. This means the price levels indicated are necessary but not sufficient on their own.

Also, these figures are based on long-term, sustained prices, not temporary peak-of-cycle prices, and they assume long-term costs for equipment and services. The latter costs also go through cycles and have increased considerably between 2003 and 2005; we take the view that, long-term, market mechanisms will remove tightness in the supply chain.

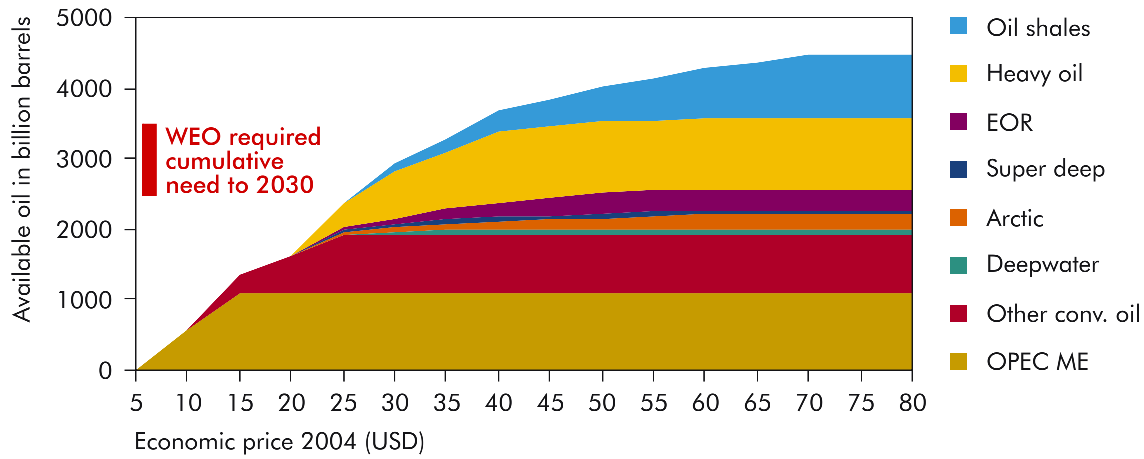
Another caveat concerning Figures 7.1 and 7.2 is that, as discussed above, gas-to-liquids and coal-to-liquids technologies may turn out to be more attractive than some of the resources represented in the graphics. In particular, coal-to-liquids account for very large potential resources of liquid petroleum products. Indications are that mine-mouth plants are economical today at oil prices ranging from USD 30 to USD 60, depending on location.

Figure 7.1 • *Oil cost curve, including technological progress: availability of oil resources as a function of economic price*



Source: IEA.

Figure 7.2 • *Oil cost curve, alternative presentation – the same data as in Figure 7.1*



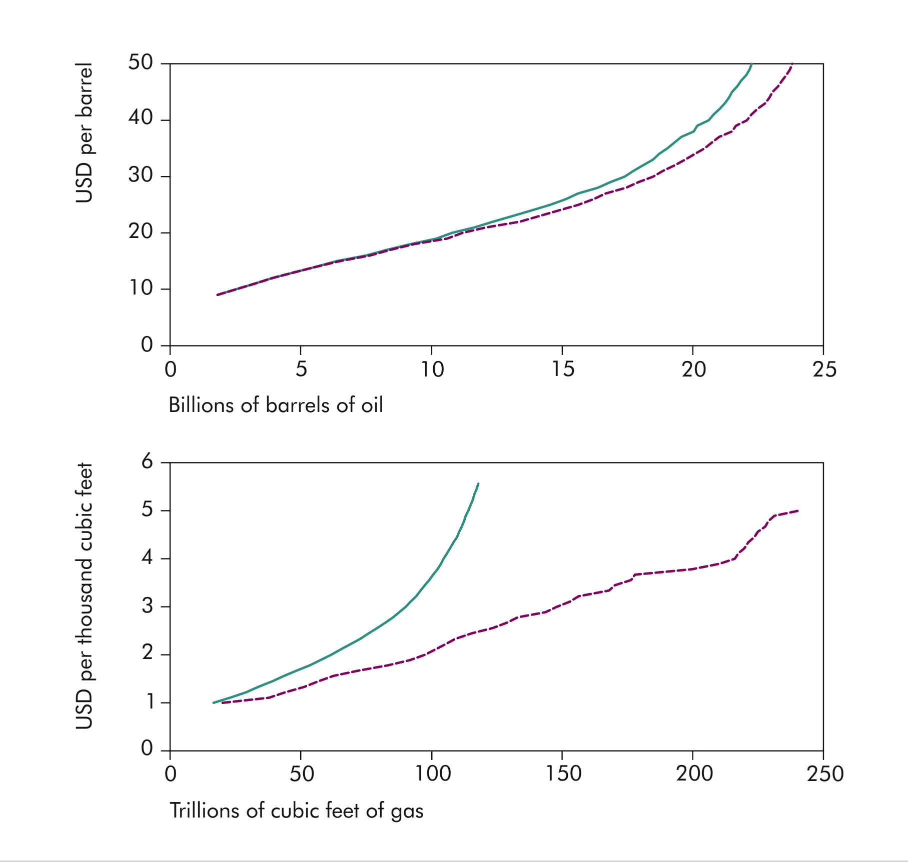
Source: IEA.

Box 19 • Cost curves and learning curves

If there is no shortage of hydrocarbons in the ground, and if the key question concerns the oil prices at which the various resources will become available, how can we answer that question? How can we foresee the impact of future technologies? All economic models that are used to make projections – notably the ETP model mentioned earlier in this chapter – need to make assumptions about the costs and performance of future technologies. This box takes a brief look at relevant published work. A number of approaches have been discussed in the literature, usually based on cost curves and/or learning curves.

For example, in the 1995 United States Geological Survey assessment of United States oil and gas resources (USGS 1995), E. D. Attanasi shows "incremental cost functions", estimates of "the resources the industry is capable of adding to proved reserves" as a function of marginal costs.

Figure 7.3 • *Incremental costs of finding, developing, and producing new oil and gas resources in the United States*



Solid lines are for conventional resources, dashed for the total of conventional and non-conventional. Although not specified in the publication, the units are probably in 1994 USD . 1 000 cubic feet is approximately 28 cubic metres.

Reproduced from USGS-1995.

These curves (Figure 7.3) are obtained from the probability distribution of resources in various locations, as a function of depth, coupled with various experts' estimates of the current costs of finding, developing and producing those resources. So these curves are a snapshot at one point in time, assuming 1994 technology with no cost reductions through subsequent technology learning.

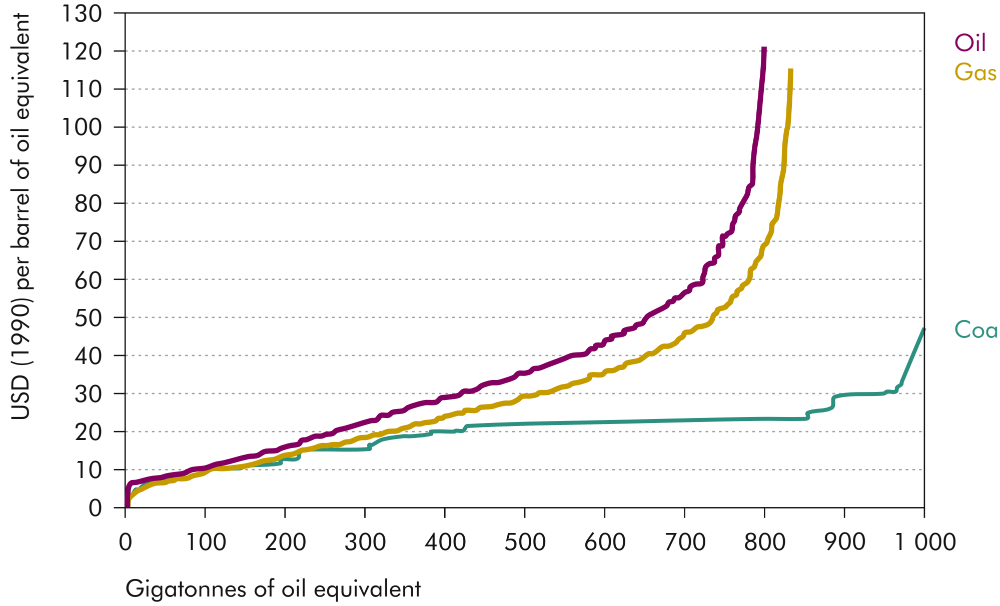
In its National Energy System Model, the United States Energy Information Agency (EIA) breaks up conventional oil and gas exploration and production into sub-activities (e.g. drilling) and applies a yearly "learning" cost reduction to each activity separately, ranging from about 0.5% to 1.5 % per year. For non-conventional gas, EIA identifies future key technological steps and makes assumptions about their timing and their impact on costs.

H. H. Rogner produces a similar curve at world level (Figure 7.4) in his 1997 "Assessment of World Hydrocarbon Resources" (Rogner 1997). This is obtained by taking experts' estimates of current (1997) costs and applying a cost reduction of 1% per year from learning. So his curve is not a snapshot in time. It is supposed to represent future costs, assuming that the starting point will always be production of the lowest-cost resources (which is not the case in a world where OPEC can exercise partial monopoly power). A similar approach was used in the European Commission funded SAUNER project (SAUNER 2000). Interestingly, Rogner underestimated learning effects: his estimates (Table 10 in Rogner 1997) of the costs of various resources were not confirmed by what happened after 1997. Indeed, current costs of non-conventional oil in Canada are significantly below his figures (USD 20 to USD 25 in 2004 USD, as opposed to his USD 35 to USD 38 in 1990 USD). This indicates that learning can be significantly faster than in his hypothesis.

David Greene (Greene 2003) uses very similar methodology to Rogner's. His curves for non-conventional oil are reproduced in Figure 7.5. His assumptions for oil shales in particular appear very pessimistic compared to current cost estimates published by other authors (see Chapter 3) and his learning curves also appear very modest.

Learning curves have long been used to model the impact of technological progress (see, for example, McDonald-2001 and references therein). In the learning curve approach, costs are assumed to decrease exponentially as a function of cumulative output (for example, with a learning rate of 20%, the 200th item produced is 20% cheaper than the 100th item produced, and the 2000th item produced is 20% cheaper than the 1000th item produced). C. O. Wene (Wene 2004) argues that, since roughly 1988, a typical learning rate in oil and gas exploration and development costs has been around 20% (as a function of cumulative reserves additions, meaning that costs are reduced 20% every time cumulative additions are doubled). However, these results are heavily dependant on the assumption that 1988 represents a significant technology break and a suitable starting point for the learning curve. Extrapolation to the future assumes that there will not be another similar technology break. In addition, it can be argued that standard technology learning curve models do not apply very well to extractive industries such as oil and gas, as it is not a question of repeatedly making the same "product" but one of tackling more and more difficult geological settings, or different types of resource.

***Figure 7.4 •** Oil, gas and coal cost curves from Rogner*



Note: 1 tonne of oil equivalent is approximately 7 barrels of oil equivalent.

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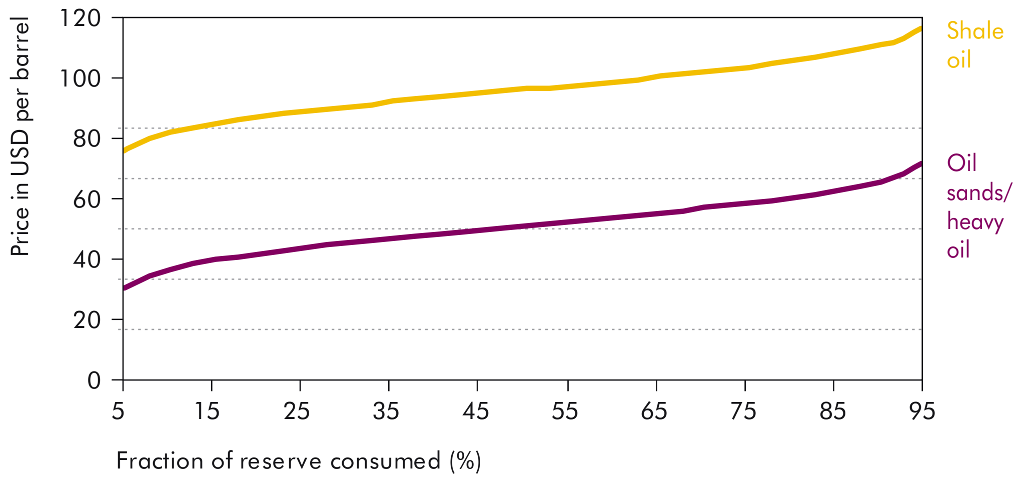
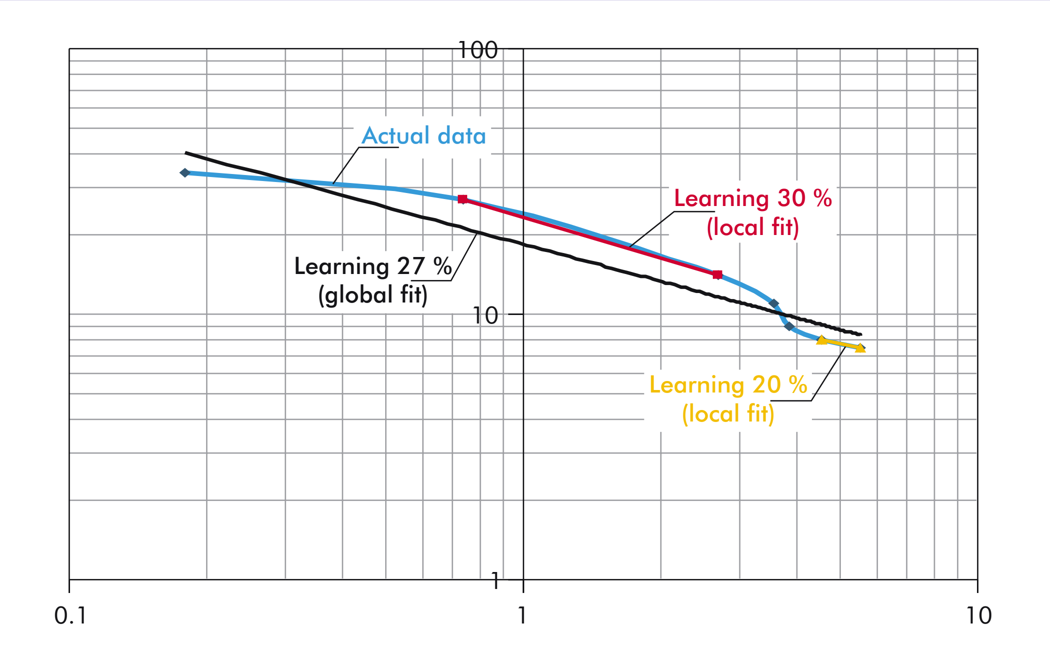
***Figure 7.5 •** Non-conventional oil cost curves from Greene*



Reproduced from Greene 2003.

There is probably scope for a learning curve analysis at a local level for one particular type of resource (e.g. oil sands extracted by mining, or deepwater resources in a water depth range between 1 000 and 2 000 metres in the Gulf of Mexico). But it will not, in general, be possible to extrapolate such studies to other resources. Interestingly, Canadian oil sands display a learning curve with about 20% learning, as expected by Wene (Figure 7.6). Because non-conventional oil production is in its infancy (10 billion barrels produced, compared with more than 1 000 billion barrels recoverable), a 20% learning rate would have a large effect, allowing resources currently costing USD 100/barrel to eventually come down to USD 20/barrel.

Figure 7.4 • *Canadian oil sands learning curves - log (costs) versus log (cumulative production)*



IEA analysis of data published in Oil and Gas Journal *- similar to Figure 3.3 in Chapter 3.*

The role of governments

It should be noted, however, that neither private enterprises nor national companies necessarily have the incentive to assume the risk of tackling new types of resources such as oil sands or oil shales. Such players might choose, for example, to focus instead on maximising returns from their investments in deepwater in a high oil-price environment. Diversifying energy sources to ensure security of supply in a relatively mild price environment is a public-good objective that may not necessarily be met by the play of free markets. A case in point is the recent boom in Canadian heavy oil and oil sands, in large part the result of a royalty regime more favourable than that for conventional oil. This regime was required to trigger the iterative investments in new technologies that have now made such resources economical. Similarly, the boom in coal bed methane in the United States was initiated by public investment in the early 1980s (along with a favourable tax regime) to provide for demonstration of the technologies that were required for this type of gas reservoir, which was unusual at the time. Helping to mitigate risk at the early stage of investment in new types of resources is therefore an approach that certainly merits consideration.

It should be noted, too, that there does not tend to be great interest in new types of resources among service and supply-sector players, who are now responsible for a large chunk of the industry R&D. They need to have ready customers for their new products and cannot easily justify developing products for a market that does not yet exist. Partnerships between suppliers and operators ready to take on the risks associated with new resources are crucial to technological progress.

Furthermore, private industry cannot be relied upon to invest in research on technologies that are too far from being economical. For example, EOR technologies have seen only limited progress since their boom in the early 1980s. This is because they were just off the industry's radar screen during the period of low oil prices in the 1990s. Persistently higher oil price over a period will of course revive interest, but only after oil prices have been high for some time. Continuing active research when oil prices are low would contribute to containing future price increases before they appear.

Historically, governments from IEA countries with oil and gas resources on their territories have been the most active in supporting technology development in the oil and gas industry (for example, Canada, Norway, United States). The most notable exceptions are Japan and, to some extent, France. However, most of the remaining conventional resources and future production are in non-IEA countries. All IEA countries will become more and more dependant on OPEC Middle East. Also, all IEA countries already play a key role in technology development, or have the potential to do so. The IEA countries thus share a similar incentive to contribute to worldwide technology development that can ensure a reliable supply of reasonably priced oil and gas during the coming decades, when oil and gas will remain the primary sources of energy in the world.

Throughout the previous chapters, we have noted some areas where government policies could have an impact on technology development. They will be summarised in the following key conclusions.

Key conclusions

A number of evaluations and pointers emerge from the previous chapters and from extensive consultations with industry experts during preparation of this study.

- Resources are abundant enough to fuel the world's energy systems at reasonable prices for the foreseeable future, as shown in Figures 7.1 and 7.2.
- A determined effort will be needed in research and development to make the necessary technologies available to develop these resources cost-effectively. The potential for new and more effective technologies is high.
- Industry clearly has the means, capability and incentives to undertake the required R&D. Measures to encourage R&D efforts would be beneficial.
- Public policy can play a key role in numerous ways, notably by focusing on the following:
  - Providing a framework favourable to investment in new resources, including appropriate licensing, taxation, royalties and support for demonstration projects. Experience has shown that these can be instrumental in catalysing the technology learning required to make non-conventional resources competitive.
  - Providing a policy climate that ensures continued active co-operation between technology developers in IEA countries and hydrocarbon resources holders in OPEC countries.
  - Taking the lead in promoting technology development and facilitating investments that can reduce shipping bottlenecks.
  - Actively participating in developing and facilitating the implementation of technologies that improve the safety of installations.
  - Ensuring that CO_2 emissions reduction is given sufficient value to foster more widespread CO_2 enhanced oil recovery (EOR) and thus higher recovery rates.
  - Supporting basic science in the biology and ecology of subsurface bacterial systems, since this can trigger breakthroughs in use of biotechnologies to enhance recovery or to transform heavy hydrocarbons.
  - Vigilantly supporting industry's efforts to reduce its environmental footprint and thus to access resources in new areas.
  - Continuing to spearhead science and technology advances linked to future exploitation of methane hydrate deposits, while ensuring strong industry participation. These resources are potentially very important to long-term supply but currently too far off for sole reliance on industry contributions.

Policy approaches drawing on these observations can help build the partnerships between industry and government that are needed to protect the interests of all stakeholders. Along with continued international collaboration on advancing technological development in the upstream oil and gas industry, such approaches will be needed if the hydrocarbon markets of tomorrow are to deliver on their promises.

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