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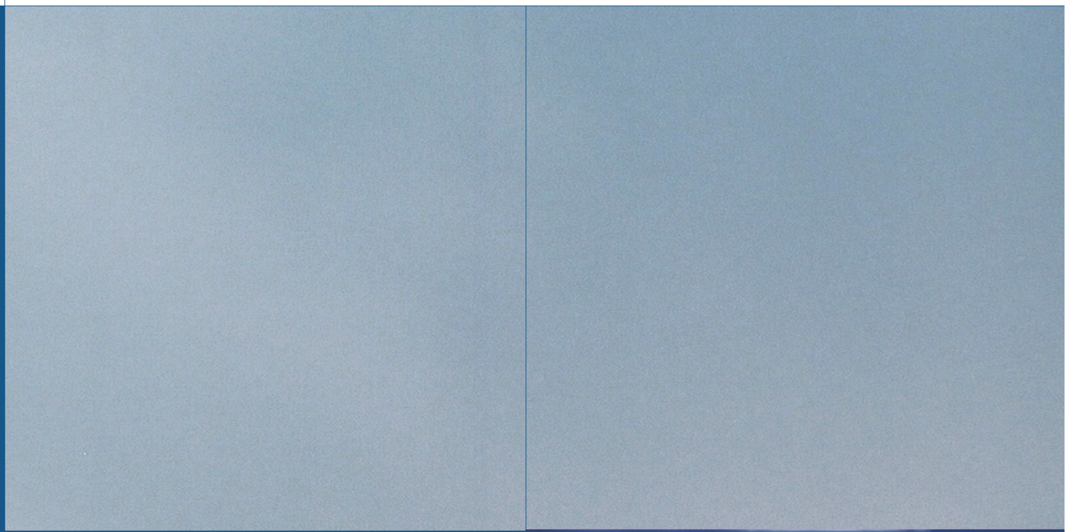
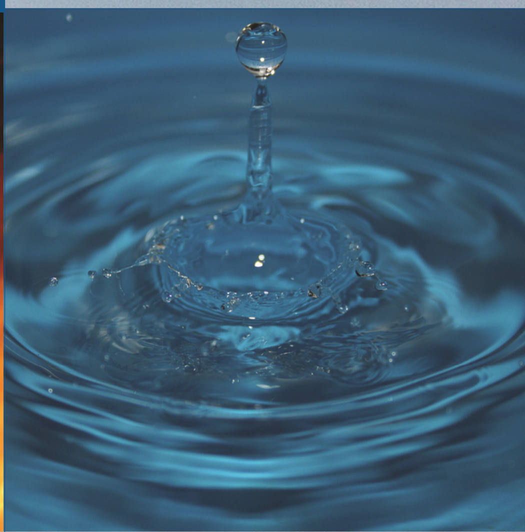
2010 Survey of Energy Resources

World Energy Council





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World Energy Council

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Foreword

This, the 22nd edition of the World Energy Council's *Survey of Energy Resources* (SER), is the latest in a long series of reviews of the status of the world's major energy resources. It covers not only the fossil fuels but also the major types of traditional and novel sources of energy.

The *Survey* is a flagship publication of the World Energy Council (WEC), prepared triennially and timed for release at each World Energy Congress. It is a unique document in that no entity other than the WEC compiles such wide-ranging information on a regular and consistent basis. This highly regarded publication is an essential tool for governments, industry, investors, NGOs and academia.

The WEC is grateful to all those Member Committees, institutions and specialists who have contributed their expertise and data to this *Survey*.

Special thanks go to Dr Iulian Iancu, Chairman of the SER Executive Board, to Ms Elena Nekhaev, Director of Programmes, to Dr Robert Schock, Director of Studies, and to the Studies Committee for guiding the production of the *Survey*.

Finally the WEC thanks the Joint Editors Judy Trinnaman and Alan Clarke for compiling, validating and formatting the data and country notes. Once again they have successfully and professionally completed this enormous task, both achieving an excellent quality and keeping to the planned schedule. The WEC is grateful to them for their knowledge, dedication, tenacity and inspiration.

C.P. Jain
Chair WEC Studies Committee

Introduction

In 1936 the World Power Conference, the organisation which eventually became the World Energy Council, published the first of a series of *Statistical Year-books*. This pioneer work represented 'an attempt to compile and publish international statistics of power resources, development and utilization, upon a comprehensive and comparable basis'. Nearly three-quarters of a century later, this essentially remains the objective of the Year-book's direct descendant, namely the twenty-second edition of the WEC's *Survey of Energy Resources*.

Despite considerable development along the way, with gradually extended coverage of energy resources (notably in the field of the 'Renewables') and the provision of more comprehensive tables and increasingly detailed Country Notes, the basic problems facing the compilers of the *Survey* remain much the same. They were indeed foreshadowed by a somewhat melancholy comment in the Introduction to *Statistical Year-book No. 1*: 'The work of editing the tables, and more particularly the definitions, proved even more arduous and difficult than had been anticipated'.

Any review of energy resources is critically dependent upon the availability of data, and reliable, comprehensive information does not always exist. While the basis of the data compilation for the present *Survey* was the input provided by WEC Member Committees (in response to a questionnaire sent out in July 2009), completion necessitated recourse to a multitude of national and international sources and, in a few instances, to estimation. As was the case for previous editions of the SER, the World Energy Council has neither commissioned nor itself carried out any fresh quantification of energy resources/reserves.

Notwithstanding the efforts of an UN/ECE Ad Hoc Group of Experts to codify and standardise the terminology of reserves and resources reporting (leading to the UN Framework Classification for Fossil Energy and Mineral Reserves and Resources), it remains a fact that, at the present time, almost every country that possesses significant amounts of mineral resources still uses its own unique set of expressions and definitions. It will take some considerable time for the methodology devised by the UN to be applied globally. In the meantime, the resources and reserves specified in the present *Survey* conform as far as possible with the definitions specified by the WEC.

Whilst each major energy source has its own characteristics, applications, advantages and disadvantages, the fundamental distinction is between those that are finite and those that are, on any human scale, effectively perpetual or everlasting.

The Finite Resources comprise a number of organically-based substances – coal, crude oil, oil shale, natural bitumen & extra-heavy oil, and natural gas, together with the metallic elements uranium and thorium. One type of energy resource – peat – is to some extent intermediate in nature, with both finite and perpetual elements in its make-up.

The principal Perpetual Resources are solar energy, wind power and bioenergy, all of which are ultimately dependent on an extra-terrestrial source, namely the Sun. Other perpetual resources are derived from geothermal heat at various depths, and from various forms of marine energy – tidal energy, wave power and ocean thermal energy conversion (OTEC).

Reserves and Resources

In WEC usage, *resources* refer to amounts that are known or deduced to be present and potentially accessible. Energy resources may be categorised as either finite (e.g. minerals) or perpetual, such as the so-called Renewable resources (solar, wind, tidal, etc.).

In the context of finite resources and reserves, the World Energy Council distinguishes between amounts in place and quantities recoverable, and between proved and additional (i.e. non-proved). Combining these concepts, the following four categories are obtained:

- Proved Amount in Place, of which:
- Proved Recoverable Reserves;
- Additional Amount in Place, of which
- Additional Reserves Recoverable

These four categories form the basis of the fossil fuels section of the Questionnaire sent out to WEC Member Committees requesting input for the SER. Additional data on the main fossil fuels compiled for the present *Survey* consist of the information available on known resources, in terms of the remaining discovered amount in place at end-2008. For the first time, the amounts under this heading, together with the corresponding recoverable reserves, have been requested in respect of three levels of probability or confidence, namely *proved* (or measured), *probable* (or indicated) and *possible* (or inferred).

While the data provided in this connection by WEC Member Committees or extracted from official published sources are by no means complete in regional or global terms, nor necessarily all entirely comparable, they serve to illustrate the scope for eventual access to further coal, oil and natural gas supplies, over and above that indicated by current estimates of economically recoverable reserves.

In addition, the Questionnaires sent to WEC Member Committees requested information, as available, on undiscovered resources of the principal fossil fuels, in terms of the estimated additional amount in place and the amount recoverable from such resources. The information received in this regard is reported in the Country Notes on coal, oil and natural gas, but overall was insufficient to form the basis of a worldwide summary table.

In all cases, the responses to the Questionnaires reflect the Member Committees' interpretation of the WEC categories in their own context.

Other organisations, whether national (e.g. ministries, geological survey centres, etc.) or international (e.g. technical journals) have their own classifications and definitions, which generally differ to a greater or lesser extent from those employed by the WEC. The only category in which there is any substantial degree of commonality is Proved Recoverable Reserves, and it is this category which attracts the most attention worldwide.

In discussing the subject of proved recoverable reserves, two important points should be borne in mind:

** although the terms used may be identical, the meaning attributed to each word can vary widely from one source to another; in particular, 'proved' may include 'probable' reserves and the term 'recoverable' may not be strictly adhered to, amounts being in fact 'in-situ';*

** conceptually, proved recoverable reserves of any one finite resource in any particular country are not immutable, but subject to virtually constant change, due (inter alia) to shifts in economic criteria, improvements in recovery techniques and the promotion/demotion of deposits from one level of probability to another.*

Data Sources

As indicated above, the data provided by WEC Member Committees have been supplemented by information culled from other sources. It should thus be noted that the resulting tabulations of reserves and resources are <u>a compilation of existing data, not a set of specially-commissioned national assessments</u>. The same qualification applies to all the various published annual surveys of oil and gas reserves – *Oil & Gas Journal*, *World Oil*, Cedigaz, OPEC, OAPEC, BP, etc.

Difficulties in obtaining information continue to be compounded by trends in the energy sector. As further deregulation and privatisation take place, the availability of data tends to be reduced as some data-reporting channels may be lost or specific items become confidential. Moreover, problems in the quantification of energy resources persist, in particular for those universally-found resources: solar energy, wind power and bioenergy, owing to their evolutionary status and generally decentralised nature.

As Editors, we strive to develop and maintain contacts in the energy world and hope that in time the availability of data will not only improve but expand to cover those energy resources that presently go unrecorded (or under-recorded).

We are grateful to all those who have helped to produce this *Survey*: we extend our thanks to the WEC Member Committees, to the authors of the Commentaries, to Dr Iulian Iancu, Chairman of the SER Executive Board, and to Bob Schock and the WEC Studies Committee for guiding the production of the *Survey*.

Judy Trinnaman and Alan Clarke
Editors

Contents

1. Coal

COMMENTARY

This commentary consists of two sections:

- a description of the provenance, location and magnitude of proved reserves of coal, compiled by the Editors;
- a review of the global status of coal contributed by the World Coal Institute.

Coal Reserves

One of the principal aims of the *Survey* of Energy Resources is to present an up-to-date quantification of the world's resources of fossil fuels, both the resources that are known or projected to exist in the earth, and the portion (reserves) that can be extracted.

Whereas it is not in practice feasible for the WEC to assess global resources of coal on a bottom-up, country-by-country basis, it is possible – albeit rather difficult – to follow this procedure in respect of proved recoverable reserves. The results of this exercise are, as usual, subject to numerous reservations and qualifications – see the Country Notes for more details.

For the present *Survey*, reserves data were as far as possible compiled in respect of the end of 2008 (Table 1.1).

World coal reserves on this basis amount to some 860 billion tonnes, of which 405 billion (47%) is classified as bituminous coal (including anthracite), 260 billion (30%) as sub-bituminous and 195 billion

(23%) as lignite. In this connection, it should be borne in mind that distinctions between the ranks of coal are sometimes difficult to draw, so that the breakdown for any particular country or region should be regarded as possibly no more than indicative.

The countries with the largest recorded coal reserves are basically unchanged from recent editions of the SER: the USA, the Russian Federation and China continue to lead the way, with nearly 60% of global reserves between them, while Australia and India are also in the top rank. In all some 75 are reported to possess proved reserves of coal, eight more than in the 2007 *Survey*, owing to the availability of estimates for Armenia, Bangladesh, Belarus, Bosnia-Herzegovina, Georgia, Laos, Macedonia (Republic) and Tajikistan (mostly courtesy of BGR).

Compared with the end-2005 reserves compiled for the 2007 *Survey*, the new level of global reserves is some 13 billion tonnes, or 1.6%, higher. While the additional countries covered account for some of this increase, by far the major factor is the re-assessment of German lignite incorporated by the BGR in their 2006 annual reserves report. Another major change by comparison with the 2007 *Survey* is a downward revision of South Africa's reserves (already taken into account in the *Interim Update* of the SER [2009]).

The determination of fossil-fuel resources and reserves is far from being an exact science and, moreover, assessments are prone to vary to a considerable degree, both between assessors/compilers and with respect to any one source over the course of time. Some of these differences and discrepancies are, of course, due to variations in definitions, coverage and timing, whilst others are attributable to a specific re-evaluation, as in the two instances mentioned above. Without according due regard to these considerations, it can be misleading, if not actually dangerous, to treat successive compilations as a straightforward time series.

One feature of coal reserves and resources is the considerable length of time that elapses between major re-assessments on a national scale. Most of the world's coal resources are well charted, and while a certain amount of exploration continues in some areas, country-wide surveys are generally few and far between: several major coal countries' resources (e.g. Canada and South Africa) have not been comprehensively re-assessed for more than 25 years. For some countries it is difficult to establish whether their quoted reserves are expressed in terms of remaining recoverable coal, or need to be adjusted for past years' production. Lastly it should be appreciated that definitions, methodology, terminology and conventions vary widely. While the Editors make every effort to maximise comparability of the reserves data across the world, national conventions have to be respected, with the inevitable result that the interpretation of the term 'proved recoverable reserves' is not the same from one country to another. Thus, for example, U.S. coal reserves cover a broader spectrum of deposits than, say, those reported by the UK. The Country Notes provide more details.

Figure 1.1 Top ten hard coal producers, 2008 (Source: SER)

	million tonnes
China	2 716
USA	993
India	484
Australia	332
South Africa	251
Russian Federation	246
Indonesia	229
Kazakhstan	100
Poland	84
Colombia	74

Figure 1.2 Coal used in electricity generation, 2008 (Source: IEA)

	%
South Africa	94
Poland	93
China	81
Australia	76
Israel	71
Kazakhstan	70
India	68
Czech Republic	62
Morocco	57
Greece	55
USA	49
Germany	49

Work coordinated by the United Nations Economic Commission for Europe over a number of years has resulted in the UN Framework Classification for Fossil Energy and Mineral Reserves and Resources – 2009. The gradual adoption of the UNFC would undoubtedly prove a major factor in increasing the harmonisation of coal resource assessments.

The Oil commentary (Chapter 2) provides more detail on the design and application of the UNFC.

Coal Use and Demand

The world benefits from a plentiful supply of coal. It has many uses critically important to economic development and poverty alleviation worldwide – with the most significant being electricity generation, steel and aluminium production, cement manufacturing and use as a liquid fuel. Around 5.8 billion tonnes of hard coal and 953 million tonnes of brown coal were used worldwide in 2008. Since 2000, global coal consumption has grown faster than any other fuel – at 4.9% per year. The five largest coal users - China, USA, India, Japan and Russia - account for around 72% of total global coal use.

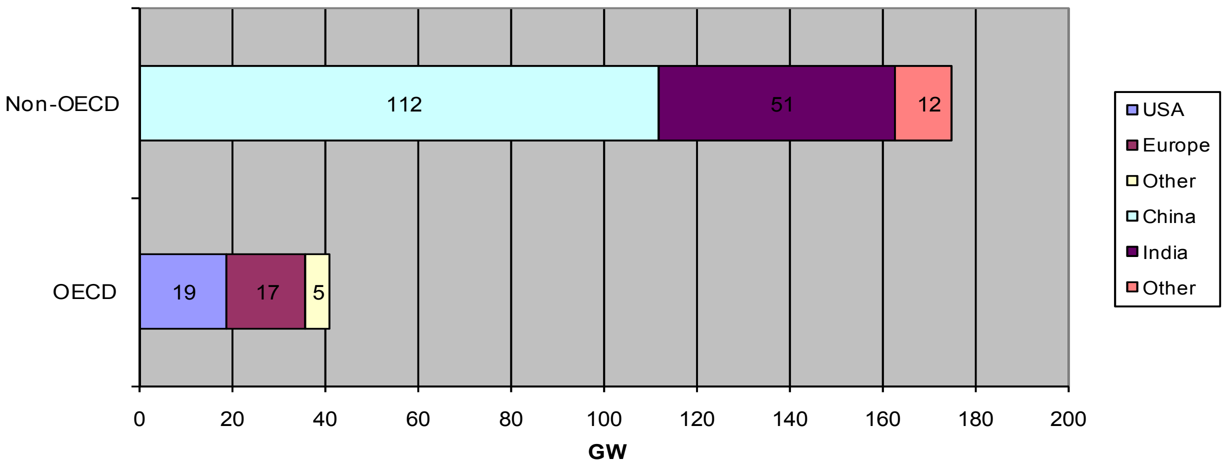
The use of coal is expected to rise by over 60% by 2030, with developing countries responsible for around 97% of this increase. China and India alone will contribute 85% of the increase in demand for coal over this period. Most of this is in the power generation sector, with coal's share in global electricity generation set to increase from 41% to 44% by 2030, according to the International Energy Agency (IEA).

Different types of coal have different uses: steam coal (also known as thermal coal) is mainly used in power generation, and coking coal (also known as metallurgical coal) is mainly used in steel production.

The biggest market for coal is Asia, which currently accounts for 56% of global coal consumption. China, and to a lesser extent India, are responsible for a significant proportion of this. Many countries do not have natural energy resources sufficient to cover their energy needs, and therefore need to import energy. Japan; Taiwan, China; and Korea (Republic), for example, import significant quantities of steam coal for electricity generation and coking coal for steel production.

Despite the global economic downturn of 2008 and 2009, world primary energy demand is expected to continue to rise over the coming decades, largely driven by the increasing energy needs of developing countries. Although 2009 saw annual global energy use fall for the first time since 1981, energy demand has generally grown fairly rapidly over recent years. According to the IEA, global demand for energy is now expected to grow at a rate of 1.5% a year to 2030. China and India alone will account for over 50% of the total increase over this period. Fossil fuels currently supply around 80% of primary energy and this figure is expected to remain largely the same through to 2030.

Figure 1.3 Coal-fired power generation capacity under construction in 2008
(Source: Platts World Electric Power Plants Database)



Countries possessing large, indigenous sources of coal will continue to use this affordable source of energy to raise electrification levels. In fact, the rapid electrification in South Africa, India and China would have been impossible without affordable coal. Coal also provides a significant direct contribution to economic development at a local level, particularly in developing countries. Coal is currently mined in over 50 countries, and provides direct employment opportunities for staff in host countries ranging from manual labour to senior management and technical and research positions. Much of the coal industry in developing countries is export-oriented. It is a major source of foreign hard currency earnings, as well as saving import costs.

China and India

China has turned to its indigenous, abundant reserves of coal to meet demand for energy, with its total hard coal and lignite production of 2 782 million tonnes in 2008 making it the world's largest coal producer. Coal has played a vital role in China, providing access to electricity to over 450 million people in just 15 years. Utilisation of its coal resource enabled the country to double energy output from 1990 to 2005, with IEA figures indicating that coal provided 65% of that increase. China is also now the world's largest producer of steel (producing 501 million tonnes in 2008), non-ferrous metals, cement and various other materials, which contribute to the construction of a modern manufacturing base and associated technology, communication and service industry infrastructure. As a result, the country is the largest consumer of raw materials in the world. It generates most of its electricity from coal – currently around 81% and has demonstrated how coal can be used to pull people out of poverty and propel an entire society toward higher standards of living.

Likewise, India's expanding economy and increased access to electricity has been partially due to its large indigenous coal reserves. Coal accounts for around 68% of electricity demand in India and coal use is expected to grow by some 3.3% per annum to 2030, more than doubling in absolute terms. After the railways, the coal industry is the second largest industrial employer in India, providing jobs for over 450 000 people. The country has rapidly risen to become the world's third largest coal producer with 484 million tonnes of hard coal production in 2008. India is now the largest economy in the world in terms of purchasing power parity and has been experiencing an upward trend of economic growth for over three decades.

Coal Trade

Coal is traded around the world, being shipped huge distances by sea to reach markets. Over the last twenty years seaborne trade in steam coal has increased on average by about 7% each year with seaborne coking coal trade increasing by 1.6% a year. Overall international trade in coal reached 938 million tonnes in 2008; while this is a significant amount of coal it still only accounts for about 17% of total coal consumed, as most is still used in the country in which it is produced.

Transportation costs account for a large share of the total delivered price of coal, therefore

Figure 1.4 Top coal importers, 2008

(Source: IEA)

million tonnes	Steam	Coking	Total
Japan	128	58	186
Korea (Republic)	76	24	100
Taiwan, China	60	6	66
India	31	29	60
Germany	37	9	46
China	35	11	46
UK	37	7	44

international trade in steam coal is effectively divided into two regional markets:

- the Atlantic market, made up of importing countries in Western Europe, notably the UK, Germany and Spain;
- the Pacific market, which consists of developing and OECD Asian importers, notably Japan, Republic of Korea and Taiwan, China. This market currently accounts for about 57% of world seaborne steam coal trade.

Australia is the world's largest coal exporter. It shipped 261 million tonnes of hard coal in 2008, out of its total production of 332 million tonnes. Australia is also the largest supplier of coking coal, accounting for 53% of world exports.

Coal and Energy Security

Coal has an important role to play in meeting the demand for a secure energy supply. As the *Survey* shows, coal is abundant and widespread, with commercial mining taking place in about 70 countries. Coal is the most abundant and economical of fossil fuels; on the basis of proved reserves at end-2008, coal has a reserves to production ratio of about 128 years, compared with 54 for natural gas and 41 for oil.

Coal is readily available from a wide variety of sources in a well-supplied worldwide market. It can be transported to demand centres quickly, safely and easily by ship and rail. A large number of suppliers are active in the international coal market, ensuring competitive behaviour and efficient functioning. It can also be easily stored at power stations and stocks can be drawn on in emergencies.

Coal is also an affordable source of energy. Prices have historically been lower and more stable than oil and gas prices and coal is likely to remain the most affordable fuel for power generation in many developed and industrialising countries for several decades.

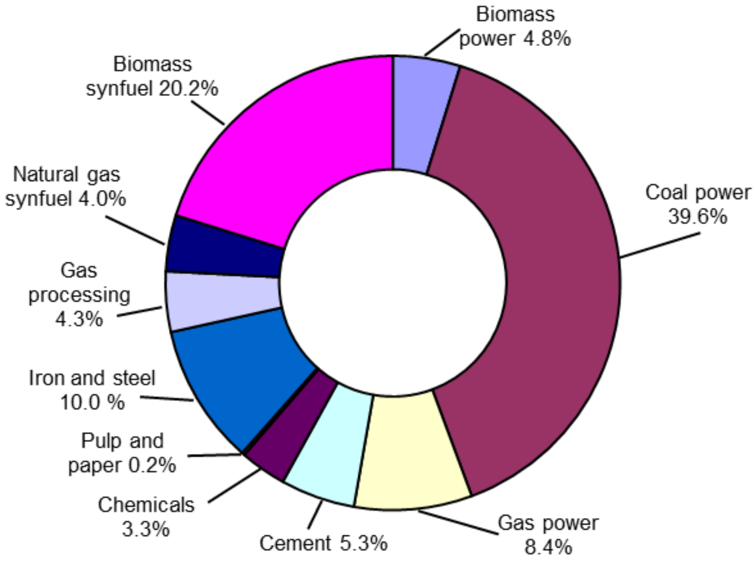
Coal can also be used as an alternative to oil. The development of a coal-to-liquids industry can serve to hedge against oil-related energy security risks. Using domestic coal reserves, or accessing the relatively stable international coal market, can allow countries to minimise their exposure to oil price volatility while providing the liquid fuels needed for economic growth.

Coal, Climate Change and CCS

The coal industry is committed to minimising its GHG emissions and action is being taken in a number of areas. Carbon Capture and Storage (CCS) will form a vital part of global efforts to reduce CO_2 emissions. CCS technology is the only currently available technology that allows very deep cuts to be made - at the scale needed – in atmospheric emissions of CO_2 from fossil fuels.

Failure to widely deploy CCS will seriously hamper international efforts to address climate change. Both the UN Intergovernmental Panel on Climate Change (IPCC) and the WWF have identified CCS as a critical technology to stabilise atmospheric greenhouse gas concentrations in an economically

Figure 1.5 Sector CCS contribution in 2050
(Source: IEA)



efficient manner. The IPCC found that CCS could contribute up to 55% of the cumulative mitigation effort by 2100 while reducing the costs of stabilisation to society by 30% or more.

The IEA has produced a Technology Roadmap for CCS, estimating that the world has a maximum theoretical CO_2 storage capacity of around 16 800 gigatonnes (annual global anthropogenic CO_2 emissions in 2006 were around 28 gigatonnes). Under the IEA's projections, the coal power sector has the greatest potential for CCS mitigation, contributing almost 40% of the total abatement provided by the application of CCS technologies.

Recent years have seen an increase in CCS activities around the world, with a number of coal projects reaching the advanced stages of planning and early stages of operations (Fig. 1.6). Projects such as Schwarze Pumpe in Germany and Lacq in France have begun actively capturing CO_2 from coal plants utilising oxyfuel combustion technology (oxygen-fired pulverised coal combustion). A number of key private/public partnership coal CCS projects are also being developed. These include the FutureGen project in the United States, GreenGen in China, and ZeroGen in Australia. These projects are providing the groundwork for the co-operation between government and industry that will be required to fully commercialise CCS technologies.

In 2009, the Australian Government launched the Global CCS Institute (GCCSI), a new initiative aimed at accelerating the global deployment of CCS. It has provided this new body with AUD 100 million per annum. This, combined with increased CCS investment pledges from a number of governments around the world, has laid the foundations for early pilot projects to be developed.

In addition to CCS, the increasing efficiency of coal-fired power plants around the world is contributing to emissions cuts in the sector. Improving efficiency levels increases the amount of energy that can be extracted from a single unit of coal. Increases in the efficiency of electricity generation are essential in tackling climate change. A one percentage point improvement in the efficiency of a conventional pulverised coal combustion plant results in a 2-3% reduction in CO_2 emissions. Highly efficient modern coal plants emit almost 40% less CO_2 than the average coal plant in service at the present time.

Coal Mine Methane

The coal industry is also seeking to increase deployment of technologies to capture and utilise the methane emitted from mining operations. Coal mine methane (CMM) currently contributes around 8% of total global anthropogenic methane emissions. Methane from working underground mines makes up the majority of these emissions from coal mining related activities - around 90% in 2006 according to figures from the U.S. Environmental Protection Agency.

Figure 1.6 Coal-based CCS projects
(Source: WCI)

	Location	Capacity (MW)	Year	Comments
FutureGen	USA	275	2012	FutureGen is a public-private partnership to build a first-of-its-kind coal-fired, near-zero emissions power plant. The project will cost approximately US$ 1.5 billion to develop and will test the feasibility of producing low-cost electricity and hydrogen from coal with near-zero CO_2 emissions.
ZeroGen	Australia	530	2015	ZeroGen is a joint State Government/coal industry project to build a commercial scale 530 MW (gross) IGCC plant with up to 90% CCS. The Mitsubishi Corporation and Mitsubishi Heavy Industries have joined the project, with the latter to provide ZeroGen with both the IGCC and carbon capture technologies. Pre-feasibility and feasibility studies are expected to be completed by September 2011 enabling construction to commence in 2012 and commissioning in late 2015.
GreenGen	China	650	2015	GreenGen is a joint government-industry alliance with project leaders including Peabody Energy. The planned IGCC plant will capture CO_2 for enhanced oil recovery.
SaskPower	Canada	100	2015	SaskPower's Boundary Dam project will use low-sulphur lignite with post-combustion capture or oxyfuel technology. The project will use the CO_2 for enhanced oil recovery in the region.
Powerfuel	UK	900	2014	The Powerfuel IGCC CCS project is to be located at the Hatfield Colliery (South Yorkshire). The colliery is owned and operated by Powerfuel.
E.ON	UK	450	Post-2012	The E.ON IGCC project will be built alongside their existing gas-fired power plant in Killingholme. The first phase of the project would be the construction of the power plant with CCS being added in a second phase.
E.ON	Netherlands	1 100	Post-2012	E.ON Benelux and the Rotterdam Climate Initiative plan to develop the project on the Maasvlakte, with a view to implementing CCS at a new fleet of power stations from 2020 onwards.
RWE	Germany	400-450	2014	The first of the RWE proposals will use IGCC technology. This project will be able to separate hydrogen after gas treatment and cleaning to use directly as an energy source or in synthetic fuel production.
RWE nPower	UK	1 000	2016	The second of the RWE proposals will investigate supercritical technology combined with post-combustion CCS.
ScottishPower	UK	3 390	2014	ScottishPower plans to demonstrate CCS at its 3 390 MW Longannet coal power station using a full-scale carbon capture unit from 2014 onwards, following initial testing of a prototype unit which began in 2009.
Vattenfall	Germany	250	2015	Vattenfall has been operating a 30 MW CCS pilot plant at Schwarze Pumpe since 2008. This plant will provide a platform for the R&D required in order to build a 250 MW Oxyfuel demonstration plant at Jänschwalde, with construction scheduled to start in 2011, for completion in around 2015.

China, Russia, Poland and the United States account for over 77% of CMM emissions. Such emissions are projected to grow 20% between 2000 and 2020, with China increasing its share from 40% to 45%. It is therefore important that technologies continue to be deployed to utilise CMM rather than emitting to atmosphere.

At present, there are more than 220 CMM projects worldwide in 14 countries. These projects help to avoid around 3.8 billion cubic metres of methane emissions every year. Notably the methane utilisation and reduction technologies available are being deployed at a rapid rate in countries with large coal industries, such as Australia, China and the United States.

A number of the projects utilising CMM for energy purposes in China are currently approved or awaiting approval under the Kyoto Protocol's Clean Development Mechanism (CDM). Of these projects, a number plan to utilise CMM as a fuel within power generation systems. The greatest potential for CMM projects in the developing world lies under the CDM owing to the increased profitability that the generation of emissions reduction credits can provide, which acts as an economic driver.

The Road Ahead

There is no doubt that coal will continue to have a key role as part of a balanced global energy mix, particularly in light of China, India, and other developing countries' use of the fuel to bring millions out of poverty and generate significant economic growth. Technologies to reduce the greenhouse gas emissions associated with coal mining and power generation have been developed and are being deployed around the world.

The benefits of coal are felt globally every day – through greater levels of energy security, through access to affordable electricity, steel and aluminium production, in the manufacture of cement, and the increasing production of transport fuels from liquefied or gasified coal.

It is important that the world retains these benefits and that it succeeds in minimising or eliminating carbon emissions that result from the traditional burning of coal. The continued development of CCS will have a vital role to play in ensuring that coal's future in the global energy mix will be compatible with a low-carbon economy. Pledges by individual governments to accelerate the deployment of CCS, and actions by coal companies and others to fund CCS activities, are to be encouraged. However, as significant as these have been, the world needs to see more investment in CCS and other low-carbon technologies in the very near future.

Milton Catelin
World Coal Institute

DEFINITIONS

Proved amount in place is the resource remaining in known deposits that has been carefully measured and assessed as exploitable under present and expected local economic conditions with existing available technology.

Maximum depth of deposits and **minimum seam thickness** relate to the proved amount in place.

Proved recoverable reserves are the tonnage *within* the proved amount in place that can be recovered in the future under present and expected local economic conditions with existing available technology.

Estimated additional amount in place is the indicated and inferred tonnage *additional to* the proved amount in place that is of foreseeable economic interest. It includes estimates of amounts which could exist in unexplored extensions of known deposits or in undiscovered deposits in known coal-bearing areas, as well as amounts inferred through knowledge of favourable geological conditions. Speculative amounts are not included.

Estimated additional reserves recoverable is the tonnage *within* the estimated additional amount in place that geological and engineering information indicates with reasonable certainty might be recovered in the future.

NOTE: The quantifications of reserves and resources presented in the tables that follow incorporate, as far as possible, data reported by WEC Member Committees. Such data will reflect the respective Member Committees' interpretation of the above Definitions in the context of the reserves/resources information available to them, and the degree to which particular countries' terminology and statistical conventions are compatible with the WEC specifications.

TABLES

TABLE NOTES

The tables cover bituminous coal (including anthracite), sub-bituminous coal and lignite. Data for peat are given in Chapter 8. There is no universally accepted system of demarcation between coals of different rank and, in particular, what is regarded as sub-bituminous coal tends to vary from one country to another. Moreover, if it is not isolated as such, sub-bituminous is sometimes included with bituminous and sometimes with lignite.

Tables 1.2i, 1.2ii and 1.2iii show the available data on known resources of coal, in terms of amount in place and recoverable reserves, for the categories proved (or measured), probable (or indicated) and possible (or inferred). The majority of the data are those reported by WEC Member Committees for the present *Survey*; they have been supplemented by comparable data derived from official publications.

For more detail regarding the provenance and coverage of individual countries' assessments, see the relevant Country Note.

Table 1.1 Coal proved recoverable reserves at end-2008 (million tonnes)

	Bituminous including anthracite	Sub-bituminous	Lignite	Total
Algeria	59			59
Botswana	40			40
Central African Republic			3	3
Congo (Democratic Rep.)	88			88
Egypt (Arab Rep.)	16			16
Malawi		2		2
Morocco				
Mozambique	212			212
Niger	70			70
Nigeria	21	169		190
South Africa	30 156			30 156
Swaziland	144			144
Tanzania	200			200
Zambia	10			10
Zimbabwe	502			502
Total Africa	**31 518**	**171**	**3**	**31 692**
Canada	3 474	872	2 236	6 582
Greenland		183		183
Mexico	860	300	51	1 211
United States of America	108 501	98 618	30 176	237 295
Total North America	**112 835**	**99 973**	**32 463**	**245 271**
Argentina		500		500
Bolivia	1			1
Brazil		4 559		4 559
Chile		155		155
Colombia	6 366	380		6 746
Ecuador			24	24
Peru	44			44
Venezuela	479			479
Total South America	**6 890**	**5 594**	**24**	**12 508**
Afghanistan	66			66
Armenia	163			163
Bangladesh	293			293

Table 1.1 Coal: proved recoverable reserves at end-2008 (million tonnes)

	Bituminous including anthracite	Sub-bituminous	Lignite	Total
China	62 200	33 700	18 600	114 500
Georgia	201			201
India	56 100		4 500	60 600
Indonesia	1 520	2 904	1 105	5 529
Japan	340		10	350
Kazakhstan	21 500		12 100	33 600
Korea (Democratic People's Rep.)	300	300		600
Korea (Republic)		126		126
Kyrgyzstan			812	812
Laos	4		499	503
Malaysia	4			4
Mongolia	1 170		1 350	2 520
Myanmar (Burma)	2			2
Nepal		1		1
Pakistan		166	1 904	2 070
Philippines	41	170	105	316
Taiwan, China	1			1
Tajikistan	375			375
Thailand			1 239	1 239
Turkey	529		1 814	2 343
Uzbekistan	47		1 853	1 900
Vietnam	150			150
Total Asia	**145 006**	**37 367**	**45 891**	**228 264**
Albania			794	794
Belarus			100	100
Bosnia-Herzegovina	484		2 369	2 853
Bulgaria	2	190	2 174	2 366
Czech Republic	192		908	1 100
Germany	99		40 600	40 699
Greece			3 020	3 020
Hungary	13	439	1 208	1 660
Ireland	14			14
Italy		10		10
Macedonia (Republic)			332	332
Montenegro	142			142
Norway		5		5
Poland	4 338		1 371	5 709
Portugal	3		33	36

Table 1.1 Coal: proved recoverable reserves at end-2008 (million tonnes)

	Bituminous including anthracite	Sub-bituminous	Lignite	Total
Romania	10	1	280	291
Russian Federation	49 088	97 472	10 450	157 010
Serbia	9	361	13 400	13 770
Slovakia	2		260	262
Slovenia		24	199	223
Spain	200	300	30	530
Ukraine	15 351	16 577	1 945	33 873
United Kingdom	228			228
Total Europe	**70 175**	**115 379**	**79 473**	**265 027**
Iran (Islamic Rep.)	1 203			1 203
Total Middle East	**1 203**			**1 203**
Australia	37 100	2 100	37 200	76 400
New Caledonia	2			2
New Zealand	33	205	333	571
Total Oceania	**37 135**	**2 305**	**37 533**	**76 973**
TOTAL WORLD	**404 762**	**260 789**	**195 387**	**860 938**

Notes:

1. Sources: WEC Member Committees, 2009/10; data reported for previous WEC Surveys of Energy Resources; national and international published sources

Table 1.2i Bituminous coal (including anthracite): known resources at end-2008 (million tonnes)

		Proved (measured)	Probable (indicated)	Possible (inferred)
Australia	amount in place	56 200	13 300	106 000
	recoverable reserves	39 200	8 200	66 700
Canada	amount in place	4 651	10 510	16 870
	recoverable reserves	3 474	NA	NA
Colombia	amount in place	NA	NA	NA
	recoverable reserves	6 366	4 572	4 237
Czech Republic	amount in place	1 524	5 928	8 742
	recoverable reserves	192	NA	NA
Hungary	amount in place	14	106	1 870
	recoverable reserves	13	103	1 478
India	amount in place	105 820	123 470	37 920
	recoverable reserves	56 100	NA	NA
Indonesia	amount in place	4 479	1 075	6 670
	recoverable reserves	1 520	899	
Japan	amount in place	4 603	1 988	7 375
	recoverable reserves	340	U	U
New Zealand	amount in place	45	942	included with Probable
	recoverable reserves	33	313	included with Probable
Poland	amount in place	16 967	26 233	9 193
	recoverable reserves	4 338	NA	NA
Romania	amount in place	28	1 394	810
	recoverable reserves	10	224	16
Serbia	amount in place	22	25	27
	recoverable reserves	9	NA	NA
Turkey	amount in place	NA	NA	NA
	recoverable reserves	529	425	368
United Kingdom	amount in place	386	262	2 527
	recoverable reserves	228	155	1 396
United States of America	amount in place	241 607	included with Proved	417 529
	recoverable reserves	108 501	included with Proved	187 504

Table 1.2ii Sub-bituminous coal: known resources at end-2008 (million tonnes)

		Proved (measured)	Probable (indicated)	Possible (inferred)
Brazil	amount in place	6 513	10 799	6 535
	recoverable reserves	4 559	7 559	4 575
Bulgaria	amount in place	342	87	NA
	recoverable reserves	190	50	NA
Canada	amount in place	3 430	7 050	55 230
	recoverable reserves	872	NA	NA
Hungary	amount in place	626	1 253	1 321
	recoverable reserves	439	891	916
Indonesia	amount in place	11 956	10 942	18 888
	recoverable reserves	2 904		
Japan	amount in place	NA	995	3 185
	recoverable reserves	NA	U	U
Korea (Republic)	amount in place	209	194	616
	recoverable reserves	126	79	121
New Zealand	amount in place	376	2 085	included with Probable
	recoverable reserves	205	682	included with Probable
Pakistan	amount in place	277	1 362	3 333
	recoverable reserves	166	817	1 999
Romania	amount in place	8	115	116
	recoverable reserves	1	N	
Serbia	amount in place	436	85	36
	recoverable reserves	361	NA	NA
United States of America	amount in place	161 783	included with Proved	268 010
	recoverable reserves	98 618	included with Proved	163 371

Table 1.2iii Lignite: known resources at end-2008 (million tonnes)

		Proved (measured)	Probable (indicated)	Possible (inferred)
Australia	amount in place	44 300	61 200	112 300
	recoverable reserves	37 200	55 100	101 100
Bulgaria	amount in place	5 639	930	NA
	recoverable reserves	2 174	1	NA
Canada	amount in place	13 941	33 005	53 765
	recoverable reserves	2 236	NA	NA
Czech Republic (incl. sub-bituminous)	amount in place	2 812	2 784	4 470
	recoverable reserves	908	NA	NA
Hungary	amount in place	1 562	1 717	2 503
	recoverable reserves	1 208	960	2 208
Indonesia	amount in place	5 816	3 721	6 588
	recoverable reserves	1 105		
Japan	amount in place	160	137	889
	recoverable reserves	10	U	U
New Zealand	amount in place	2 297	9 817	included with Probable
	recoverable reserves	333	7 078	included with Probable
Pakistan	amount in place	3 174	10 315	53 249
	recoverable reserves	1 904	6 190	31 950
Poland	amount in place	1 661	11 902	NA
	recoverable reserves	1 371	NA	NA
Romania	amount in place	3 802	6 731	2 909
	recoverable reserves	280	94	0
Serbia	amount in place	20 400	NA	NA
	recoverable reserves	13 400	NA	NA
Turkey	amount in place	9 837	1 344	262
	recoverable reserves	1 814	NA	NA
United States of America	amount in place	39 024	included with proved	391 159
	recoverable reserves	30 176	included with proved	302 470

Table 1.3 Coal: 2008 production (million tonnes)

	Bituminous	Sub-bituminous	Lignite	Total
Botswana	0.9			0.9
Congo (Democratic Rep.)	0.1			0.1
Egypt (Arab Rep.)	N			N
Malawi		0.1		0.1
Mozambique	N			N
Niger	0.2			0.2
Nigeria		N		N
South Africa	251.0			251.0
Swaziland	0.2			0.2
Tanzania	N			N
Zambia	0.2			0.2
Zimbabwe	2.7			2.7
Total Africa	**255.3**	**0.1**		**255.4**
Canada	32.5	25.7	9.9	68.1
Mexico	1.9	9.6		11.5
United States of America	504.0	489.1	68.7	1 061.8
Total North America	**538.4**	**524.4**	**78.6**	**1 141.4**
Argentina		0.3		0.3
Brazil		6.6		6.6
Chile	0.2		0.3	0.5
Colombia	73.1	0.4		73.5
Peru	0.1			0.1
Venezuela	6.4			6.4
Total South America	**79.8**	**7.3**	**0.3**	**87.4**
Afghanistan	N			N
Bangladesh	0.6			0.6
Bhutan	0.1			0.1
China	2 716.0		66.0	2 782.0
Georgia	N			N
India	483.7		32.1	515.8
Indonesia	229.0			229.0
Japan	1.2			1.2

Table 1.3 Coal: 2008 production (million tonnes)

	Bituminous	Sub-bituminous	Lignite	Total
Kazakhstan	100.3		4.6	104.9
Korea (Democratic People's Rep.)	26.0	7.4		33.4
Korea (Republic)		2.8		2.8
Kyrgyzstan	0.1		0.3	0.4
Laos	0.6			0.6
Malaysia		1.2		1.2
Mongolia	0.2		9.6	9.8
Myanmar (Burma)			0.3	0.3
Nepal		N		N
Pakistan	0.5	2.5	0.9	3.9
Philippines		3.6		3.6
Tajikistan	0.2	N		0.2
Thailand			18.0	18.0
Turkey	2.6		76.2	78.8
Uzbekistan	0.1		3.0	3.1
Vietnam	39.8			39.8
Total Asia	**3 601.0**	**17.5**	**211.0**	**3 829.5**
Albania			N	N
Austria				
Bosnia-Herzegovina			11.2	11.2
Bulgaria	N	2.7	26.1	28.8
Czech Republic	12.2		47.9	60.1
France		0.3		0.3
Germany	19.1		175.3	194.4
Greece			65.7	65.7
Hungary			9.4	9.4
Italy		0.1		0.1
Macedonia (Republic)			7.3	7.3
Montenegro			1.7	1.7
Norway		3.4		3.4
Poland	84.3		59.7	144.0
Romania	2.8		32.4	35.2
Russian Federation	246.0		80.5	326.5
Serbia	0.1	0.4	36.9	37.4

Table 1.3 Coal: 2008 production (million tonnes)

	Bituminous	Sub-bituminous	Lignite	Total
Slovakia			2.4	2.4
Slovenia		0.5	4.0	4.5
Spain	7.3	2.9		10.2
Ukraine	59.5		0.2	59.7
United Kingdom	18.1			18.1
Total Europe	**449.4**	**10.3**	**560.7**	**1 020.4**
Iran (Islamic Rep.)	2.6			2.6
Total Middle East	**2.6**			**2.6**
Australia	295.6	36.5	65.5	397.6
New Zealand	2.5	2.2	0.2	4.9
Total Oceania	**298.1**	**38.7**	**65.7**	**402.5**
TOTAL WORLD	**5 224.6**	**598.3**	**916.3**	**6 739.2**

Notes:

1. Sources: WEC Member Committees, 2009/10; *World Mineral Production*, 2004-2008, British Geological Survey; *BP Statistical Review of World Energy*, 2009; published national and international sources; estimates by the Editor

COUNTRY NOTES

The following Country Notes on Coal have been compiled by the Editors, drawing upon a wide variety of material, including information received from WEC Member Committees, national and international publications.

Major international published sources consulted included:

Energy Balances of OECD Countries, 2009 Edition; International Energy Agency;

Energy Balances of Non-OECD Countries, 2009 Edition; International Energy Agency;

Energy Statistics of OECD Countries, 2009 Edition; International Energy Agency;

Energy Statistics of Non-OECD Countries, 2009 Edition; International Energy Agency;

Coal Information 2009; International Energy Agency;

Major coalfields of the world; June 2000; IEA Coal Research.

Argentina

Proved amount in place (total coal, million tonnes)	8 052
Proved recoverable reserves (total coal, million tonnes)	500
Production (total coal, million tonnes, 2008)	0.3

The principal coal-mining areas are located in the west of the country along the foothills of the Andes and in the Andes themselves, in the provinces of Catamarca, La Rioja, San Juan, Mendoza, Neuquén, Río Negro, Chubut and Santa Cruz, with smaller coalfields in Córdoba, the centre of Chubut and the Atlantic coast of Santa Cruz.

The biggest coalfield is Río Turbio, located to the west of the city of Río Gallegos in the southern province of Santa Cruz, close to the border with Chile. Río Turbio's coal is a steam coal with low sulphur content (down to 1%), falling into the sub-bituminous rank; it constitutes 99% of the hard coal resources of the country, and supports the only coal extraction activity in the Argentine Republic. The Río Turbio coalfield, including the concession for operating the associated railway and port facilities, was privatised in 1994.

The Argentinian WEC Member Committee has reported proved amounts in place of 752 million tonnes of sub-bituminous coal and 7 300 million tonnes of lignite. The latter rank is found in two principal deposits, Río Coyle with some 5 billion tonnes in place, and the middle course of the Río Santa Cruz, with 2.35 billion. Both these deposits lie in the Río Leona formation.

For sub-bituminous, the maximum deposit depth is given as 300 m, with a minimum seam thickness of 1.8 m. The lignite resources are at a maximum depth of 680 m. The only proved recoverable reserves reported are 500 million tonnes of sub-bituminous. Undiscovered coal of this rank estimated to be in place amounts to

300 million tonnes, of which 100 million is regarded as recoverable.

Coal output from the Río Turbio mine is currently about 300 thousand tonnes per annum, and is used for electricity generation. A 240 MW coal-fired mine-mouth power plant, currently under construction, is scheduled to enter service in mid-2011. According to the Argentinian Member Committee, this development will require a quadrupling of Rio Turbio's output.

Australia

Proved amount in place (total coal, million tonnes)	100 500
Proved recoverable reserves (total coal, million tonnes)	76 400
Production (total coal, million tonnes, 2008)	397.6

Australia is endowed with very substantial coal resources, with its proved recoverable reserves ranking 4th in the world. The major deposits of black coal (bituminous and sub-bituminous) are located in New South Wales and Queensland, especially in the Sydney and Bowen basins; smaller but locally important resources occur in Western Australia, South Australia and Tasmania. The main deposits of brown coal are in Victoria, the only State producing this rank. Other brown coal resources are present in Western Australia, South Australia and Tasmania.

The coal resource data included in the present *Survey* have been derived from Australia's Identified Mineral Resources 2009, published by Geoscience Australia, supplemented by data provided by the Australian WEC Member Committee for the 2007 *Survey*. The proved amount of coal in place, reflecting 'Economic Demonstrated Reserves (EDR)' as at end-2008, comprised 56.2 billion tonnes of black coal, (including an estimated 3.3 billion tonnes of sub-bituminous) and 44.3 billion tonnes of brown coal/lignite. Within these tonnages, the proportion deemed to be recoverable ranged from 39.2 billion tonnes (70%) of the bituminous coal to 37.2 billion tonnes (84%) of the lignite. A little over half of the recoverable bituminous, and all of the recoverable lignite, have been reported to be surface-mineable. About 36% of Australia's massive reserves of bituminous coal are of coking quality. The maximum depth of the deposits ranges from 600 m in the case of bituminous coal to 200 m for sub-bituminous and 300 m for lignite. Minimum seam thicknesses are 0.3, 1.5 and 3.0 m, respectively.

'Subeconomic demonstrated resources' and 'inferred resources', additional to the proved amount in place, are vast: Geoscience Australia's current assessment puts those of black coal at 119 billion tonnes, of which 75 billion tonnes is estimated to be recoverable. Comparable figures for brown coal are 174 billion tonnes and 156 billion tonnes, respectively.

For a variety of reasons (e.g. environmental restrictions, government policies, military lands), not all of the tonnages classified as EDR are currently accessible: black coal reserves are only slightly affected, but the 'Accessible EDR' of brown coal are put at 32.2 billion tonnes, 13.4% lower than the quoted level of EDR, although still massive in tonnage terms.

In 2008 Australia produced 332 million tonnes of saleable black coal (bituminous and sub-bituminous) and 66 million tonnes of brown coal. The major domestic market for black coal is electricity generation: in 2007, power stations and CHP plants accounted for 87% of total black coal consumption, with the other major consumer being the iron and steel industry. Brown coal is used almost entirely for power generation.

Australia has been the world's largest exporter of hard coal since 1984: in 2008, it exported 261 million tonnes. About 52% of 2008 exports were of metallurgical grade (coking coal), destined largely for Japan, the Republic of Korea, India and Europe.

Brazil

Proved amount in place (total coal, million tonnes)	6 513
Proved recoverable reserves (total coal, million tonnes) (see remarks below)	4 559
Production (total coal, million tonnes, 2008)	6.6

Brazil has considerable reserves of sub-bituminous coal, which are mostly located in the southern states of Rio Grande do Sul, Santa Catarina and Paraná.

The Brazilian WEC Member Committee has reported that the remaining proved amount of sub-bituminous coal in place at end-2008 was 6,513 million tonnes. Assuming an average recovery factor of 70%, Brazil’s proved recoverable reserves are now estimated at 4,559 million tonnes. This is a lower level than those previously reported, as the Member Committee has been able to obtain a breakdown of the Ministry of Mines and Energy’s assessment of ‘measured/indicated/inventoried’ resources into ‘proved’ and ‘probable’ amounts in place.

The maximum depth of the deposits is 870 m, whilst the minimum seam thickness is 0.5 m. It is estimated that 21% of the stated level of proved recoverable reserves could be exploited through surface mining; in 2008, 64% of Brazilian coal production was obtained by this method.

The Member Committee quotes additional discovered amounts of coal in place at lower levels of confidence as approximately 10.8 billion tonnes classified as ‘probable’ and more than 6.5 billion tonnes as ‘possible’. It also estimates that a further amount of around 8.3 billion tonnes of coal is recoverable from undiscovered resources.

Almost all of Brazil's current coal output is classified as steam coal, of which more than 85% is used as power-station fuel and the remainder in industrial plants. Virtually all of Brazil's metallurgical coal is imported: about 70% is used as input for coke production.

Canada

Proved amount in place (total coal, million tonnes)	22 022
Proved recoverable reserves (total coal, million tonnes)	6 582
Production (total coal, million tonnes, 2008)	68.1

The Canadian WEC Member Committee has reported the following estimates of recoverable reserves (in millions of tonnes), as provided by Natural Resources Canada: bituminous coals (including anthracite) 3 474; sub-bituminous grades 872; and lignite 2 236. The corresponding amounts of coal remaining in place from which these tonnages could be extracted are (respectively) 4 651, 3 430 and 13 941 million tonnes.

Estimates of the remaining tonnages of coal in place that are considered to be additional to the 'proved' or 'measured' amounts of each rank total more than 300 billion tonnes. Within this enormous *in situ* figure, remaining discovered resources add up to 176.5 billion tonnes, of which 'probable/indicated' resources total 50.6 billion tonnes and 'possible/inferred' 125.9 billion. Undiscovered resources ('hypothetical/speculative') are estimated to add another 126 billion. While these figures are necessarily highly approximate, they do serve to underline Canada's massive coal endowment.

The levels of remaining recoverable reserves reported by the Member Committee can be traced back to an assessment of Canada's coal resources at end-1985 made by Romaniuk and Naidu for the Geological Survey of Canada, as subsequently developed by Frank Mourits of Natural Resources Canada. The amounts reported have not been adjusted for Canada's cumulative production of coal during 1986-2008, which was approximately 1 587 million tonnes. However, Natural Resources Canada have advised that, pending the availability of official revisions to the end-1985 assessment, it should be assumed that in sum such revisions (i.e. new discoveries plus net adjustments to previous reserve estimates) 'possibly equated to cumulative production during 1986-2008'. As there is no evidence of major coal discoveries in Canada during this period, there then has to be a presumption of a substantial upward revision of recoverable reserves, through the uprating of resources (e.g. from 'indicated' to 'measured'), an improvement in recovery ratios, or a combination of the two.

Canadian coal reserves are mainly located in the western provinces of Saskatchewan, Alberta and British Columbia, with smaller deposits in the eastern provinces of Nova Scotia and New Brunswick. Bituminous deposits are found in the two eastern provinces together with Alberta and British Columbia; Alberta also possesses sub-bituminous grades, while lignite deposits are found only in Saskatchewan.

Western Canada dominates coal production, accounting for over 95% of the total. Alberta is the largest coal-producing province, mainly of thermal grades. British Columbia is the second largest, producing mainly metallurgical coals.

Saskatchewan produces lignite. In 2008, about 48% of Canadian coal production, principally of metallurgical grades, was exported.

Around 88% of Canadian coal consumption is used for electricity generation, 7% in the steel industry and 5% in other industries. Alberta is the largest coal-consuming province, Ontario the second. Ontario and Nova Scotia rely on coal imports.

The Canadian coal industry is privately owned. Output is mainly from surface mines: there are two operating underground mines, Campbell River, British Columbia and Grande Cache, Alberta. Production from these operations is relatively small, about 1 million tonnes of coal annually. The potential exists to reopen the underground mine at the Donkin coal resource in Nova Scotia.

China

Proved amount in place (total coal, million tonnes)	NA
Proved recoverable reserves (total coal, million tonnes) (see remarks below)	114 500
Production (total coal, million tonnes, 2008)	2 782

China is a major force in world coal, standing in the front rank in terms of reserves, production and consumption. In the continued absence of reliable published information regarding China's coal resources and reserves, compounded by problems of definition and terminology, there has been a considerable amount of controversy over the best level to quote for proved recoverable reserves. Not infrequently, commentators appear to confuse in-place amounts with recoverable tonnages.

The levels of proved recoverable reserves as at end-1990, originally provided by the Chinese WEC Member Committee for the 1992 *Survey*, have been retained for each successive edition. In billions of tonnes, they amount to: bituminous coal and anthracite 62.2; sub-bituminous coal 33.7 and lignite 18.6, implying a reserves-to-production ratio of 38, on the basis of the level of 2009 production quoted by BP in its Statistical Review of World Energy, June 2010.

The same figure for total proved reserves (114.5 billion tonnes) was quoted at the 11th Session of the UN Committee on Sustainable Energy (Geneva, November 2001), in the context of an estimate of 988 billion tonnes for China's coal resources. This reference, in a paper co-authored by Professor Huang Shengchu, a vice-president of the China Coal Information Institute, indicated a degree of continuity in the official assessments of China's coal reserves and supported the retention of the level originally advised by the Chinese WEC Member Committee in 1991.

Further confirmation that the level of proved reserves used in the present and previous Surveys is of the right order is provided by the Chinese Statistical Yearbook, published by the National Bureau of Statistics. Since 2002, this publication has specified China's 'ensured reserves' of coal which, according to the Ministry of Land and Natural Resources, have an average recovery ratio of 35%. Applying this rate to the 'ensured reserves' quoted for 2008 in the Yearbook (326.1 billion tonnes) produces 114.1 billion tonnes, a figure almost identical to the level of proved recoverable reserves adopted for this *Survey*.

Information received in mid-2007 in a private communication from an expert Chinese source confirms a level of approximately 1 000 billion tonnes for China's 'demonstrated' or 'explored' reserves, including all levels of probability from 'proved' to 'prospective', on an *in situ* basis.

Coal deposits have been located in most of China's regions but three-quarters of proved recoverable reserves are in the north and northwest, particularly in the provinces of Shanxi, Shaanxi and Inner Mongolia.

After more than 20 years of almost uninterrupted growth, China's coal production peaked at nearly 1.4 billion tonnes in 1996, followed by a number of years during which output was constrained by the closure of many small local mining operations. Annual output has followed a steep upward path since 2002 and reached a new peak in 2008. By far the greater part of output is of bituminous coal: lignite constitutes only about 3%.

China's power stations and heat plants accounted for 58% of its total coal consumption in 2007; the iron and steel industry and other industrial users are the other main consumers.

Coal exports have fallen back sharply in recent years, dropping from 94 million tonnes in 2003 to only about half that level in 2008.

Colombia

Proved amount in place (total coal, million tonnes)	NA
Proved recoverable reserves (total coal, million tonnes)	6 746
Production (total coal, million tonnes, 2008)	73.5

Colombia's vast coal resources are located in the north and west of the country. Data on 'measured reserves', published in 2004 by the Instituto Colombiano de Geología y Minería (Ingeominas), Ministerio de Minas y Energía, indicate a total of 7 064 million tonnes, of which the Cerrejón Norte, Central and Sur fields in the department of La Guajira accounted for 56% and fields in the department of Cesar for 29%. For the present *Survey*, the WEC Member Committee for Colombia has reported proved recoverable reserves of 6 746 million tonnes based on the Ingeominas end-2003 measured reserves, adjusted for cumulative coal production in 2004-2008, inclusive. 'Indicated reserves' quoted by Ingeominas in the afore-mentioned publication were 4 572 million tonnes, whilst 'inferred' tonnages were 4 237 million and 'hypothetical' resources 1 120 million. The 'indicated' and 'inferred' levels are reported by the Member Committee under the headings of 'probable' and 'possible', respectively.

Virtually all Colombia's coal resources fall into the bituminous category: the reserves in the Alto San Jorge field in Córdoba, with an average calorific value in the sub-bituminous/lignite bracket, are shown under sub-bituminous in Table 1.1. The measured reserves of Alto San Jorge were 381 million tonnes at end-2003 and annual output is approximately 350 000 tonnes, implying end-2008 reserves of about 380 million tonnes.

Development of Colombian coal for export has centred on the Cerrejón deposits which are located in the Guajira Peninsula in the far north, about 100 km inland from the Caribbean coast. The coal is found in the northern portion of a basin formed by the Cesar and Rancheria rivers; the deposit has been divided by the Government into the North, Central and South Zones.

Exports account for more than 90% of Colombia's coal production; Cerrejón North remains one of the world's largest export mines.

Czech Republic

Proved amount in place (total coal, million tonnes)	4 336
Proved recoverable reserves (total coal, million tonnes)	1 100
Production (total coal, million tonnes, 2008)	60.1

The Czech Republic WEC Member Committee has reported coal resources and reserves provided by the Czech Geological Survey (Geofond). The remaining discovered amount in place (in Czech terminology, 'economic explored reserves') are quoted as 1 524 million tonnes of bituminous coal and 2 812 million tonnes of brown coal/lignite, of which respectively 192 and 908 million tonnes are classed as recoverable ('exploitable') reserves. Note that according to Geofond data almost the whole of the latter amount consists of brown coal (906 out of 908).

In addition to the proved amounts, the Member Committee reports substantial quantities of probable ('economic prospected') and possible ('potentially economic') reserves: in millions of tonnes, these are quoted as respectively 5 928 and 8 742 for bituminous and 2 784 and 4 470 for brown coal/lignite. Total known resources remaining in place are thus some 16.2 billion tonnes of bituminous and 10.1 billion tonnes of brown coal/lignite.

The maximum depth of deposits varies from 1,600 m in the case of bituminous to 500 m for brown coal/lignite; minimum seam thicknesses range from 0.6 (for bituminous) to 1.5 for brown coal/lignite.

Bituminous coal deposits are mainly in the Ostrava-Karviná basin in the east of the country, and lie within the Czech section of the Upper Silesian coalfield. The principal sub-bituminous/lignite basins are located in the regions of North and West Bohemia, close to the Krusne Hory (Erzgebirge or Ore Mountains), which constitute the republic's north-western border with Germany. Currently all Czech output of bituminous coal and lignite is deep-mined.

The Czech WEC Member Committee points out that Czech coal statistics now show brown coal (previously classed as sub-bituminous coal) with lignite.

In 2008, Czech output of bituminous coal was 12.2 million tonnes, whilst that of brown coal/lignite reached 47.9 million tonnes. Approximately two-thirds of the republic's bituminous coal production consists of coking coal. In 2008, total exports of coal amounted to 7.5 million tonnes, equivalent to 12.5% of production.

Apart from its coking coal, which is consumed by the iron and steel industry, most of the republic's bituminous coal is used for electricity and heat generation, with industrial and private consumers accounting for relatively modest proportions. This pattern of utilisation also applies to brown coal/lignite, which is still the main power station fuel.

Germany

Proved amount in place (total coal, million tonnes)	NA
Proved recoverable reserves (total coal, million tonnes)	40 699
Production (total coal, million tonnes, 2008)	194.4

The German WEC Member Committee has reported coal reserves on the basis of data provided by the German Federal Institute for Geosciences and Natural Resources (BGR). Proved recoverable reserves are given as 40,699 million tonnes, almost all of which is lignite. The level of hard coal reserves in this category is confined to the projected amount of the (highly subsidised) German hard coal production until 2018, when subsidised hard coal mining is due to be phased out. The hard coal component has a maximum deposit depth of 1 500 m below the surface, and a minimum seam thickness of 0.6 m, whilst the corresponding parameters for lignite are 500 and 3 m, respectively.

The assessment of lignite reserves has been significantly revised since that reported for the 2007 SER. In previous *Surveys* only the proved recoverable amount of lignite reserves in existing and planned surface mines was reported. For better comparability with reserve data from other countries the present numbers report the entire German lignite reserves.

BGR's category 'resources' (using its own definition, which differs from WEC usage) amounts to around 82.9 billion tonnes of hard coal and 36.5 billion tonnes of lignite. These levels convey an indication of the enormous size of the additional amounts of coal 'in place', over and above the *in situ* tonnages hosting the recoverable reserves.

Over three-quarters of German hard coal production is derived from the Ruhr Basin (Ruhr and Ibbenbüren mining districts). The coal qualities range from anthracite to high-volatile, strongly-caking bituminous coal. The second largest German coalfield is situated in the Saar Basin, with substantial deposits of weakly-caking bituminous coal. All German hard coal is deep-mined from seams at depths exceeding 900 m.

The lignite deposit in the Rhineland region is the largest single formation in Europe in terms of lignite production. In the former East Germany there are major deposits of lignite in the Central-German (at Halle/Leipzig) and Lusatian mining districts, which have considerable domestic importance.

Germany's output of hard coal fell from 76.6 million tonnes in 1990 to 19.1 million tonnes in 2008, whilst lignite production more than halved, from 357.5 to 175.3 million tonnes over the same period. Germany is still the world's largest lignite producer.

The principal markets for bituminous coal are electricity generation, iron and steel, and cement manufacture: other industrial and household uses are relatively modest. The bulk of German lignite is consumed in power stations, although a considerable tonnage (over 11 million tpa) is converted into lignite products such as briquettes, dust, coal for fluidised circulating beds and coke for the industrial, residential and commercial markets.

Greece

Proved amount in place (total coal, million tonnes)	5 800
Proved recoverable reserves (total coal, million tonnes)	3 020
Production (total coal, million tonnes, 2008)	65.7

Coal resources are all in the form of lignite. According to the Ministry of Development's *Energy Outlook of Greece* (February 2009), total 'remaining exploitable deposits' of lignite in 2008 were 3 020 million tonnes. Apart from a very small amount of private mining, all production is carried out by the mining division of the Public Power Corporation (DEI). There are two lignite centres, Ptolemais-Amynteo (LCPA) in the northern region of Western Macedonia, and Megalopolis (LCM) in the southern region of the Peloponnese. These two centres control the operations of five open-cast mines; LCPA mines account for nearly 80% of DEI's lignite output.

A 330 MW lignite-fired power station at Florina in Western Macedonia came into operation in June 2003. In the lignite-mining areas, there are now eight dedicated power stations (total generating capacity: 5 288 MW), which produce more than two-thirds of Greece's electricity supply. Greece is the second largest producer of lignite in the European Union and the 6th largest in the world.

India

Proved amount in place (hard coal only, million tonnes)	105 820
Proved recoverable reserves (total coal, million tonnes)	60 600
Production (total coal, million tonnes, 2008)	515.8

Coal is the most abundant fossil fuel resource in India, which is the world's third largest coal producer. The principal deposits of hard coal are in the eastern half of the country, ranging from Andhra Pradesh, bordering the Indian Ocean, to Arunachal Pradesh in the extreme northeast: the eastern States of Chhattisgarh, Jharkhand, Orissa and West Bengal together account for about 77% of reserves. The Ministry of Coal (quoting the Geological Survey of India) states that at 1 April 2009, India's geological resources of bituminous coal comprised 105.8 billion tonnes of 'proved resources', 123.5 billion tonnes of 'indicated resources' and 37.9 billion tonnes of 'inferred resources'. Coking coals constitute 17% of the tonnage of proved resources. The resources quoted are the result of exploration down to a depth of 1 200 m.

Research in India has indicated that only about 21% of total geological resources can be regarded as recoverable. On the basis of expert advice from an Indian research institute, proved recoverable reserves of hard coal have been estimated as 21% of the total geological resources of 267 210 million tonnes as at 1 April 2009, giving a (slightly rounded) level of 56 100 million tonnes.

Considerable uncertainty remains regarding India's coal reserves, particularly as to (i) whether they represent remaining tonnages or need to be reduced by the subtraction of past years' production, and (ii) whether it is appropriate to assess coal resources down to a depth of 1 200 metres, when current coal mines in India do not generally exceed 300 m. Although it is not possible to draw definitive conclusions from the information available, the downside implications of these considerations should be borne in mind.

Lignite deposits mostly occur in the southern State of Tamil Nadu. All-India resources of lignite are quoted in the 11th Five Year Plan as 38.27 billion tonnes as at 1 April 2006, with proved reserves put at 4.5 billion tonnes. About 2.4 billion tonnes in the Neyveli area of Tamil Nadu have been stated to be regarded as 'mineable under the presently adopted mining parameters'. Annual production of lignite is currently in the region of 32 million tonnes, almost all of which is used for electricity generation.

Although India's coal reserves cover all ranks from lignite to bituminous, they tend to have a high ash content and a low calorific value. The low quality of much of its coal prevents India from being anything but a small exporter of coal (traditionally to the neighbouring countries of Bangladesh, Nepal and Bhutan) and conversely, is responsible for sizeable imports (in 2007, 22 million tonnes of coking coal and 28 million tonnes of steam coal), mainly from Australia, China, Indonesia and South Africa.

Coal is the most important source of energy for electricity generation in India: about three-quarters of electricity is generated by coal-fired power stations. In addition, the steel, cement, fertiliser, chemical, paper and many other medium and small-scale industries are also major coal users.

Indonesia

Proved amount in place (total coal, million tonnes)	22 252
Proved recoverable reserves (total coal, million tonnes)	5 529
Production (total coal, million tonnes, 2008)	229.0

Indonesia possesses very substantial coal resources: the *Handbook of Energy and Economic Statistics of Indonesia 2009*, released by the Ministry of Energy and Mineral Resources at the end of October 2009, includes resource/reserve data as at 1 January 2009. These indicate a total resource base of nearly 105 billion tonnes, with measured resources totalling 22.3 billion, indicated 15.7, inferred 32.1 and hypothetic 34.6. Within these tonnages, total coal reserves are put at 18 780 million tonnes.

Using another ministerial source (*Indonesia Energy Statistics 2008*), it is possible to deduce a further breakdown of the reserves total. Although the latter publication is of slightly earlier provenance, and implies substantial subsequent revisions to resource estimates for the provinces of Sumatera and Kalimantan, the data for proven and probable reserves are in aggregate very close to the total reserves figure in the *Handbook*: 18 711 against the 18 780 quoted above. Thus, pending the availability of an official breakdown of the latest reserves figure, it seems reasonable to take Indonesia's proved recoverable reserves as approximately 5 300 million tonnes, the level given in *Indonesia Energy Statistics 2008*.

A question then arises as to the breakdown of this total recoverable reserve figure by rank. For the 2007 *Survey*, the Indonesian WEC Member Committee quoted proved recoverable reserves at end-2005 as 1 721 million tonnes of bituminous coal, 1 809 million tonnes of sub-bituminous and 798 million tonnes of lignite, giving a total of 4 328 million. On a strictly provisional basis, again pending advice from Indonesia, the total of 5 300 million tonnes has been split by rank in the same proportions as in the 2007 Questionnaire: bituminous 2 107; sub-bituminous 2 216; lignite 977.

It is uncertain whether the above–quoted level of 5 300 million tonnes includes cumulative past production of coal in Indonesia. As the latter amounted to some 1.75 billion tonnes at the end of 2008, it is important to try to establish whether or not it should be deducted. Unfortunately, the Geology Agency has not been able to respond on this matter. Pending the receipt of advice, proved reserves have been retained at the published level of 5.3 billion tonnes.

Indonesian coals in production generally have medium calorific values (5 000 - 7 000 kcal/kg or 21-29 MJ/kg), with relatively high percentages of volatile matter; they benefit from low ash and sulphur contents, making them some of the cleanest coals in the world.

Competitive quality characteristics have secured substantial coal export markets for Indonesia: it is now the world's second largest coal exporter, after Australia. In 2008, approximately 203 million tonnes of coking coal and steam coal were shipped overseas, representing 82% of hard coal production. Asian customers take more than 85% of Indonesia's coal exports.

Within Indonesia, coal's main market is power generation, which accounted for 47% of internal consumption in 2007.

Kazakhstan

Proved amount in place (total coal, million tonnes)	62 200
Proved recoverable reserves (total coal, million tonnes)	33 600
Production (total coal, million tonnes, 2008)	104.9

The Kazakhstan WEC Member Committee reports that at end-2008 the remaining discovered amounts of coal in place were (in billions of tonnes): 24.7 of bituminous coal and 37.5 of lignite, within which the estimated recoverable amounts were 21.5 and 12.1, respectively. It has also provided the following notes on Kazakhstan's coal endowment:

Total geological reserves and predicted coal resources of the Republic of Kazakhstan are rated at 150 billion tonnes. Balance coal reserves of A+B+C1+C2 category as of 1 January 2007 are rated at 33.6 billion tonnes, including 21.5 of bituminous coal and 12.1 of lignite. Non-commercial coal reserves in basins and deposits, as of 1 January 2007, are rated (in billions of tonnes) at 28.6, including 3.2 of bituminous coal and 25.4 of lignite.

[The expression A+B+C1+C2 refers to the Russian classification of geological reserves (originating in the former USSR) which uses the following categories: A – detailed exploration work completed; B – exploration work not as detailed as in A; C1 - widely spaced drill holes etc.; C2 – preliminary calculation. Geological reserves are sub-classified into 'balance' and 'sub-balance' reserves on the basis of specified economic factors. In the case of Kazakhstan, 'balance coal reserves' are reported as proved recoverable reserves, but they may be more akin to 'proved+probable' reserves.]

The greater part (63%) of counted (i.e. measured) reserves consists of bituminous coal, found in the Karaganda, Ekibastuz and Teniz-Korzhankol basins, the Kushokinsk, Borly, Shubarkol and Karazhyr deposits, and elsewhere. The remainder (37%) consists of lignite, mainly from the Turgay, Nizhne-Iliyskiy and Maikuben basins.

Kazakhstan coal is characterised by a wide range of metamorphism stages, from gas bituminous coal (GB) up to forge coal (F).

The Karaganda, Ekibastuz and Maikuben basins, and Kushokinsk, Borly, Shubarkol and Karazhyr deposits, as well as some other (small) deposits in various regions of the Republic (where coal mining is presently of insignificant volume, to meet local requirements), are developed and operating.

Distribution analysis of coal reserves and forecast coal resources in regions of the Republic shows that the main part of balance reserves is located in Central Kazakhstan (Karaganda Oblast) and North Kazakhstan (Pavlodar and Kostanay Oblasts). The eastern, western and southern regions of the Republic are in deficit of coal.

After a period of decline in the 1990s, total national output of coal has advanced strongly in recent years. Production in 2008 was 104.9 million tonnes, with hard coal grades accounting for over 95% of total output. Kazakhstan is a major coal exporter (almost 30 million tonnes in 2007), with Russia and Ukraine as its main customers. The prime internal markets for Kazakh coal are power/CHP plants and the iron and steel sector.

New Zealand

Proved amount in place (total coal, million tonnes)	2 719
Proved recoverable reserves (total coal, million tonnes)	571
Production (total coal, million tonnes, 2008)	4.9

The coal resources and reserves summarised above reflect the levels reported by the New Zealand WEC Member Committee for the 2007 SER, which were in turn based upon the report *Coal Resources of New Zealand*, published by the Ministry of Commerce in 1994. The assessments in this report appear to relate to the situation as at around the end of 1994. Cumulative production of New Zealand during the period 1993-2008 was nearly 67 million tonnes but it is not possible to adjust the figures for reserves, as the breakdown by rank available for cumulative production appears to be inconsistent with that used in the coal resources report.

Pakistan

Proved amount in place (total coal, million tonnes)	3 451
Proved recoverable reserves (total coal, million tonnes)	2 070
Production (total coal, million tonnes, 2008)	3.9

At the request of the Pakistan WEC Member Committee, the Geological Survey of Pakistan (GSP) has provided information on resources and reserves as at the end of 2008 (which corresponds with more detailed data on ‘coal reserves/resources as on June 30, 2009’ quoted in the *Pakistan Energy Yearbook 2009*, compiled by the Hydrocarbon Development Institute of Pakistan, December 2009).

Pakistan’s total coal resource is reported as some 185 billion tonnes, within which 'measured reserves' are 3.45 billion tonnes, 'indicated reserves' nearly 12 billion tonnes, 'inferred reserves' 57 billion and 'hypothetical resources' 113 billion. Clearly a high proportion of the quoted total resource has, at this point in time, a relatively low degree of geological assurance, being comprised of inferred reserves (lying within a radius of 1.2 to 4.8 km from a point of coal measurement) and hypothetical resources (undiscovered coal, generally an extension of inferred reserves in which coal lies more than 4.8 km from a point of measurement). A recovery factor of 0.6 has been applied to the measured reserves, resulting in estimated recoverable amounts (in million tonnes) of 166 of sub-bituminous and 1 904 of lignite.

The bulk (around 99%) of Pakistan's huge coal resource, notably the Thar field, is located in the province of Sindh. The economic coal deposits of Pakistan are restricted to Palaeocene and Eocene rock sequences only.

The coals of Pakistan are high in sulphur and ash contents. The moisture percentage is also high in Sindh coal, especially in the Thar coal. The ranks of Pakistani coals range from lignite to high-volatile bituminous. The demonstrated Thar coalfield has the largest resources (over 175 billion tonnes *in situ*) and out of that about 12 billion tonnes are 'demonstrated reserves' (of which 2.7 billion classed as 'measured'). The estimated production of coal in calendar year 2008 was 3.9 million tonnes (interpolated between the fiscal years 2007-08 and 2008-09).

Small tonnages of indigenous coal are used for electricity generation and by households, but by far the largest portion is used to fire brick kilns.

Poland

Proved amount in place (total coal, million tonnes)	18 628
Proved recoverable reserves (total coal, million tonnes)	5 709
Production (total coal, million tonnes, 2008)	144.0

The Polish WEC Member Committee reports that at end-2008 Poland’s remaining discovered amount of bituminous coal in place was 16 967 million tonnes, of which 4 338 million tonnes were estimated to be recoverable. The corresponding tonnages for lignite are reported as 1 661 million tonnes in place, of which 1 371 is regarded as recoverable. In both cases the recoverable tonnages relate to established amounts in developed deposits.

The proved amount of hard coal in place is based on a maximum deposit depth of 1 000 m and a minimum seam thickness of 1 m; the corresponding parameters for lignite are a maximum deposit depth of 350 m and minimum seam thickness of 3 m.

Over and above the tonnages quoted above, the Member Committee has advised substantial amounts of both ranks of coal at lower levels of probability, on the basis of a recent (2009) study. Additional known *in situ* resources of bituminous grades comprise 26 233 million tonnes classified as ‘probable’ and 9 193 million tonnes in the ‘possible’ category, with a further total of some 25.5 billion tonnes potential additional recovery from known resources. Supplementary *in situ* resources of lignite are reported as 11 902 million tonnes in the ‘probable’ category.

Poland's hard coal resources are mainly in the Upper Silesian Basin, which lies in the southwest of the country, straddling the border with the Czech Republic: about 80% of the basin is in Polish territory. Other hard-coal fields are located in the Lower Silesia and Lublin basins. There are a number of lignite deposits in central and western Poland, with four of the larger basins currently being exploited for production, virtually all through surface mining.

The quality of the Upper Silesian hard coals is generally quite high, with relatively low levels of sulphur and ash content. Of Poland's proved reserves of hard coal, 42.5% is reported to be of coking quality.

Although output of hard coal has declined during the past twenty years, and especially since 1997, Poland is still one of the world's major coal producers (see Table 1.3), with a 2008 output of some 84 million tonnes of hard coal and 60 million tonnes of lignite.

Apart from Russia, Poland is the only world-class coal exporter in Europe. However its 2008 exports fell sharply to less than 8 million tonnes, of which steam coal accounted for 80% and coking coal for 20%. Germany, the Czech Republic and Austria were Poland's largest export markets for coal.

About 63% of inland consumption of hard coal goes to the production of electricity and bulk heat, industrial uses account for 24% and residential/commercial/agricultural uses 13%. Almost all lignite production is consumed in CHP plants.

Russian Federation

Proved amount in place (total coal, million tonnes)	194 000
Proved recoverable reserves (total coal, million tonnes)	157 010
Production (total coal, million tonnes, 2008)	326.5

The only data on coal resources that the Russian WEC Member Committee was able to provide for the 2007 *Survey of Energy Resources* were based on information released by the Ministry of Natural Resources in May 2006: 'discovered' reserves of 194 billion tonnes, which were equated with the proved amount in place of all ranks of coal, and 'balance' reserves of more than 200 billion tonnes, which were taken to correspond with the additional amount in place. As the WEC Member Committee has been unable to obtain any more coal resource data, for reasons of confidentiality, the levels adopted for proved recoverable reserves in the present instance are unchanged from those given for end-1996 in the 1998 *Survey of Energy Resources*.

Although it would be possible to partially update the end-1996 proved recoverable reserves by deducting cumulative coal production for the years 1997-2008, in the absence of information regarding new discoveries and revisions to earlier assessments of recoverable coal, it is not possible to devise realistic up-to-date estimates of the Russian Federation’s end-2008 reserves.

The proved amount of coal in place reported for end-1996 comprised 75.8 billion tonnes of bituminous coal, based on a maximum deposit depth of 1 200 m and a minimum seam thickness of 0.6-0.7 m; 113.3 billion tonnes of sub-bituminous grades (at depths of up to 600 m and minimum thickness 1.0-2.0 m); and 11.5 billion tonnes of lignite (at 300 m and 1.5-2.0 m, respectively).

Proved recoverable reserves were reported as just over 49 billion tonnes of bituminous coal, of which 23% was considered to be surface-mineable and 55% was suitable for coking. Of the 97.5 billion tonnes of proved recoverable reserves of sub-bituminous coal, 74% was suitable for surface mining, while all of the 10.5 billion tonnes of recoverable lignite reserves fell into this category. Overall, about 94 billion tonnes of Russia's proved reserves were deemed to be recoverable by opencast or strip mining.

Russian coal reserves are widely dispersed and occur in a number of major basins. These range from the Moscow Basin in the far west to the eastern end of the Donets Basin (most of which is within Ukraine) in the south, the Pechora Basin in the far northeast of European Russia, and the Irkutsk, Kuznetsk, Kansk-Achinsk, Lena, South Yakutia and Tunguska basins extending across Siberia to the Far East.

The principal economic hard coal deposits of Russia are found in the Pechora and Kuznetsk basins. The former, which covers an area of some 90 000 km^2, has been extensively developed for underground operations, despite the severe climate and the fact that 85% of the basin is under permafrost. The deposits are in relatively close proximity to markets and much of the coal is of good rank, including coking grades. The Kuznetsk Basin, an area of some 26 700 km^2, lies to the east of the city of Novosibirsk and contains a wide range of coals; the ash content is variable and the sulphur is generally low. Coal is produced from both surface and underground mines.

Lying east of the Kuznetsk and astride the trans-Siberian railway, the Kansk-Achinsk Basin contains huge deposits of brown (sub-bituminous) coal with medium (in some cases, low) ash content and generally low sulphur; large strip-mines are linked to dedicated power stations and carbo-chemical plants. The vast Siberian coal-bearing areas of the Lena and Tunguska basins constitute largely unexplored resources, the commercial exploitation of which would probably be difficult to establish.

From a peak of around 425 million tonnes in 1988, Russia's total coal production declined dramatically following the disintegration of the USSR, reaching a low point of around 232 million tonnes in 1998, since when output has regained an upward trajectory, totalling about 326 million tonnes in 2008. In 2007, approximately 71% of Russian coal consumption was accounted for by power stations and district heating plants; the iron and steel industry and the residential sector were the other main centres of coal usage.

Serbia

Proved amount in place (total coal, million tonnes)	20 858
Proved recoverable reserves (total coal, million tonnes)	13 770
Production (total coal, million tonnes, 2008)	37.4

Serbia has Europe's largest proven deposits of lignite. The Serbian WEC Member Committee reports that the proved amount of coal remaining in place is nearly 21 billion tonnes, of which by far the greater part (98%) is lignite. Within the other ranks, 9 million out of the 22 million tonnes of bituminous coal in place (41%) is deemed to be recoverable, while the corresponding figures for sub-bituminous are 361 million out of 436 million (83%). The recovery factor attributed to the lignite reserves is approximately 66%. Lignite deposits have been assessed to a maximum depth of 380 metres, with a minimum seam thickness of 10.6 metres.

Additional information provided by the Serbian Member Committee for the present *Survey* includes some details of the remaining discovered amount in place at end-2008. In millions of tonnes, the relevant 'probable' levels are 25 of bituminous and 85 of sub-bituminous, with 'possible' amounts of 27 and 36, respectively. Comparable figures for lignite were not available. An additional 1.53 million tonnes of undiscovered bituminous coal is reported, of which 1.4 million tonnes is considered to be recoverable.

The pattern of Serbia's coal reserves is replicated in its current production levels: lignite (all of which is surface-mined) accounted for nearly 98% of total output in 2008. Most of the lignite is used for electricity generation, with minor quantities being briquetted or directly consumed in the industrial and residential sectors.

South Africa

Proved amount in place (total coal, million tonnes)	NA
Proved recoverable reserves (total coal, million tonnes)	30 156
Production (total coal, million tonnes, 2008)	251.0

Assessments of South Africa's coal resources remain in a state of flux. While a number of surveys (e.g. de Jager, 1983; Bredell, 1987; and later studies by the Minerals Bureau) have attempted to quantify the reserves present in each of South Africa's many coalfields, there is not yet total consensus in respect of the tonnages that are currently economically and technologically recoverable.

For the purpose of the present *Survey*, a figure of 30 156 million tonnes has been adopted, based on advice from an expert South African source. This level is derived from the de Jager report, with the individual coalfield reserves adjusted by subtracting cumulative coal production over the period 1982-2008, and then a view being taken of the mineability of coal in major prospective producing areas, in particular the Waterberg coalfield, but also the Springbok Flats, Limpopo and parts of the Free State coalfields. The net outcome is a total for South Africa's proved recoverable coal reserves that is more than one-third lower than the level reported for the 2007 *Survey*, but that is arguably more realistic in the present circumstances.

Coal occurs principally in three regions:

* the shaly Volksrust Formation, which covers most of central and northern Mpumalanga province (formerly the Transvaal). The coal is found in isolated basins and troughs which results in the fields being disconnected and widely separated;

* the sandy Vryheid Formation of the northern part of the main Karoo basin (northern Free State, northern Kwazulu-Natal and southern Mpumalanga): this generally continuous area is probably the most important economically;

* the Molteno Formation, which is confined to the north-eastern Cape. It is of minor economic importance compared to other coalfields in South Africa.

Some lignite deposits are known along the Kwazulu-Natal and Cape coasts, but are considered to be of scant economic importance.

Coal occurrences have been divided into 19 separate coalfields, 18 of which are located in an area extending some 600 km from north to south by 500 km from east to west. The Molteno field lies some 300 km south of the main coal-bearing region.

South Africa's coals are generally low in sulphur but high in ash. Beneficiation is essential for export-quality coal. Lower-quality coal is for the local power generation market.

Eskom, the South African electric utility, accounts for about 65% of coal consumption. A further large slice is consumed by the Sasol plants in making synthetic fuels and chemicals from coal. The third main user is the industrial sector, including the iron and steel industry. Coal use in residential and commercial premises is relatively small, while demand by the railways has virtually disappeared.

Coal exports are equivalent to about 27% of South African output and are mainly destined for Europe and Asia/Pacific. The main route for exports is via Richards Bay, Kwazulu-Natal, where there is one of the world's largest coal-export terminals.

Thailand

Proved amount in place (total coal, million tonnes)	2 075
Proved recoverable reserves (total coal, million tonnes)	1 239
Production (total coal, million tonnes, 2008)	18.0

Thailand has sizeable resources of lignite, notably at Mae Moh in the north of the country. For the 2004 SER, the Thai WEC Member Committee reported proved recoverable reserves of 1 354 million tonnes; the maximum deposit depth taken into consideration was approximately 700 m, while the minimum seam thickness was 0.30 m.

For the present *Survey*, the Member Committee has reported the remaining discovered amount in place for lignite as 2 075 million tonnes, reflecting the assessment of total lignite reserves (of which Mae Moh accounts for nearly 55%) given in the 2008 edition of the annual publication *Thailand Energy Situation*, issued by the Department of Alternative Energy Development and Efficiency. In this context, the reserves are defined as including 'the remaining reserve from produced area as well as the measured and indicated reserve from undeveloped area'. For present purposes, proved recoverable reserves of Thai lignite have been estimated on the basis of the end-2002 figure of 1 354 million tonnes as reported, reduced by cumulative production of 115 million tonnes for the years 2003-2008, inclusive.

Annual output of lignite has declined in recent years, with the 2008 total down to just under 18 million tonnes, 14% less than its peak level in 2005. All of Mae Moh's production is consumed by the adjacent power plant (2 625 MW). On the other hand, most of the lignite produced by other Thai mines is used by industry, chiefly in cement manufacture. Imports of bituminous coal are mostly destined for consumption in the iron and steel sector.

Ukraine

Proved amount in place (total coal, million tonnes)	45 164
Proved recoverable reserves (total coal, million tonnes)	33 873
Production (total coal, million tonnes, 2008)	59.7

Ukraine's coal endowment is one of the largest in Europe. For the 2007 *Survey*, the WEC Member Committee for Ukraine reported that the proved amount of coal in place exceeded 45 billion tonnes, of which 45% ranked as bituminous, 49% as sub-bituminous and about 6% as lignite. The reported mining parameters associated with these resource assessments were (respectively) maximum depths of 1,800, 800 and 400 metres, and minimum seam thicknesses of 0.55, 0.60 and 2.7 metres.

A recovery factor of 75% was attributed to all three ranks, implying proved recoverable reserves of some 15 billion tonnes of bituminous, 17 billion of sub-bituminous and 2 billion of lignite. Most of the bituminous and sub-bituminous deposits are located in the Donets Basin in eastern Ukraine.

Over and above the massive tonnages reported as proved, the WEC Member Committee quoted estimated additional amounts in place totalling more than 11 billion tonnes, with a broadly similar breakdown by rank as for the proved component, and the same implied recovery factor of 75%.

Production in 2008 of washed and screened coal (described as ‘coal available’, although the Russian version of the title translates as ‘prepared coal’) is reported by the State Statistics Committee of Ukraine as 59.5 million tonnes, but without a breakdown by rank. The corresponding output of raw coal was approximately 77 million tonnes. The principal outlets for Ukrainian coal are the iron and steel industry (51% in 2007) and power stations (37%).

N.B.: late information received from the Ukrainian Member Committee in June 2010 provided data for 'Resources on the State Balance' at 1 January 2009. These indicate that the proved and additional amounts of coal in place quoted in the first and third paragraphs above appear to refer to the A+B+C1 and C2 categories respectively (see the Country Note on Kazakhstan for an outline of the Russian reserve classification system).

United Kingdom

Proved amount in place (total coal, million tonnes)	386
Proved recoverable reserves (total coal, million tonnes)	228
Production (total coal, million tonnes, 2008)	18.1

Coal deposits are widely distributed and for many years the UK was one of the world's largest coal producers, and by far its largest exporter. Production rose to a peak of nearly 300 million tonnes/yr during World War I and thereafter did not fall below 200 million tonnes/yr until 1960. Output began a long-term decline in the mid-1960s, falling to less than 100 million tpa by 1990. Reflecting continued competition from natural gas and imported coal, UK coal production was only just over 18 million tonnes in 2008, including coal/slurry recovered from non-mine sources such as dumps, ponds, rivers, etc. The UK's cumulative output of coal to the end of 2008 is reported to be 27.3 billion tonnes.

The UK coal industry was privatised at the end of 1994, with the principal purchaser being RJB Mining (now UK Coal plc), which acquired 16 deep mines from British Coal. At the end of March 2009 there were six major deep mines, seven smaller deep mines and 33 open-cast sites in production. Deep-mined coal output in 2008 was 8.10 million tonnes and open-cast sites produced 9.51 million tonnes. Production from slurry etc. amounted to 0.45 million tonnes. There is now virtually no UK production of coking coal - output in 2008 was only 307 000 tonnes.

The decline of the British coal industry has been accompanied by a sharp decrease in economically recoverable reserves. The figure reported for proved recoverable reserves of bituminous coal by the United Kingdom WEC Member Committee for the purpose of the present *Survey* is 228 million tonnes. This assessment, and all other UK coal resources/ reserves data reported by the Member Committee, have been supplied by the Coal Authority, the body which regulates the licensing of British coalmines and performs the residual functions of the former British Coal.

The amount of coal in place that hosts the proved recoverable reserves is put at 386 million tonnes, implying an average recovery factor of 0.59. At lower levels of confidence are a 'probable' amount in place of 262 million tonnes, of which 155 is deemed to be recoverable (also with a recovery factor of 0.59), and a 'possible' *in situ* tonnage of 2 527 million tonnes, of which 1 396 (55%) is classed as recoverable. A further amount of 1 636 million tonnes is reported by the Member Committee as representing potential additional recovery from known resources. The UK's known resources of coal are dwarfed by its undiscovered resources, with nearly 185 billion tonnes estimated to be in place, of which about 41 billion is deemed to be recoverable.

United States of America

Proved amount in place (total coal, million tonnes)	442 414
Proved recoverable reserves (total coal, million tonnes)	237 295
Production (total coal, million tonnes, 2008)	1 062

The United States coal resource base is the largest in the world. The US WEC Member Committee reports a proved amount in place at end-2008 of some 442 billion tonnes (based on the Energy Information Administration's 'Demonstrated Reserve Base'). This total is comprised of 241.6 billion tonnes of bituminous coal (including anthracite) with a maximum deposit depth of 671 m and minimum seam thickness of 0.25 m; 161.8 billion tonnes of sub-bituminous (at up to 305 m depth and 1.52 m minimum seam thickness) and 39.0 billion tonnes of lignite (at up to 61 m depth and 0.76 m minimum seam thickness).

The reported proved recoverable reserves amount to 237.3 billion tonnes, equivalent to about 28% of the global total. They comprise 108.5 billion tonnes of bituminous coal (including anthracite), 98.6 billion tonnes of sub-bituminous and 30.2 billion tonnes of lignite. The overall ratio of proved recoverable reserves to the proved amount in place is 0.54. This ratio varies widely from one rank to another, reflecting relative degrees of accessibility and recoverability: bituminous deposits average 0.45, sub-bituminous 0.61 and lignite 0.77. Open-cast or surface mining techniques can be applied to 27.6% of bituminous reserves, to 42.8% of the sub-bituminous and to 100% of the lignite.

N.B.: the data for proved amount in place and recoverable reserves are measured and indicated (proved and probable), in a commingled data base. The data cannot be separated into 'proved only' and 'probable only'.

On top of the tonnages summarised above, the US WEC Member Committee reports enormous quantities of coal as inferred resources, being the difference between Remaining Identified Resources and the Demonstrated Reserve Base: in total these come to well over a trillion tonnes, composed of 418 billion tonnes of bituminous, 268 billion sub-bituminous and 391 billion lignite. These estimates are derived from a US Department of the Interior study of coal resources as at 1 January 1974, but are regarded as still providing valid indications of the magnitude of the USA's additional coal resources. Assuming a similar recovery ratio for such resources as for those reported as proved, the US Member Committee estimates the recoverable portion as amounting to some 653 billion tonnes, comprised of 188 bituminous, 163 sub-bituminous and 302 lignite.

Enormous additional (hypothetical) coal resources are also reported. These represent deposits that extend deeper than the proved amount in place, include thinner beds in some areas, and are based on older source data in many cases. The amounts involved comprise 698 billion tonnes of bituminous coal, 1 036 billion tonnes of sub-bituminous and 296 billion tonnes of lignite, giving a total of some 2 trillion tonnes.

The USA's coal deposits are widely distributed, being found in 38 states and underlying about 13% of the total land area. The Western Region (owing largely to Montana and Wyoming) accounts for about 47% of the EIA's 'Demonstrated Reserve Base', the Interior Region (chiefly Illinois and western Kentucky) for 32% and the Appalachian Region (chiefly West Virginia, Pennsylvania and Ohio) for 21%. Bituminous coal reserves are recorded for 27 states, whereas only 8 states have sub-bituminous reserves, of which 90% are located in Montana and Wyoming, and 10 have lignite reserves, mostly in Montana and Texas.

US coal output is the second highest in the world, after China, and accounted for about 16% of global production in 2008. Coal is the USA's largest single source of indigenous primary energy, although running neck-and-neck with natural gas in 2009. The electric power sector accounted for about 93% of US domestic coal consumption in 2008. In that year, coal exports amounted to 74 million tonnes: the USA remains a leading supplier of coking coal and other bituminous grades to the rest of the world.

Uzbekistan

Proved amount in place (total coal, million tonnes)	NA
Proved recoverable reserves (total coal, million tonnes)	1 900
Production (total coal, million tonnes, 2008)	3.1

Uzbekcoal, the republic's major coal company, quotes Uzbekistan's explored reserves as 1 853 million tonnes of brown coal and 47 million tonnes of black coal. Total coal resources are put at more than 5.7 billion tonnes.

Two coal fields are presently being developed: the Angren brown coal field in the Tashkent region (being exploited by the Uzbekcoal and Apartak companies via open-pit mining) and the Shargun anthracite deposit in the Surkhandarya region. Some bituminous coal is produced from the Baysun field, also in the southern region of Surkhandarya. Reflecting a modernisation programme at Angren, Uzbekistan's lignite production has increased in recent years to over 3 million tpa. According to Uzbekcoal, over 85% of lignite production is consumed by the electric power sector, some after being processed by underground gasification. Bituminous output remains on a very small scale (around 70 000 tpa).

2. Crude Oil and Natural Gas Liquids

COMMENTARY

Introduction

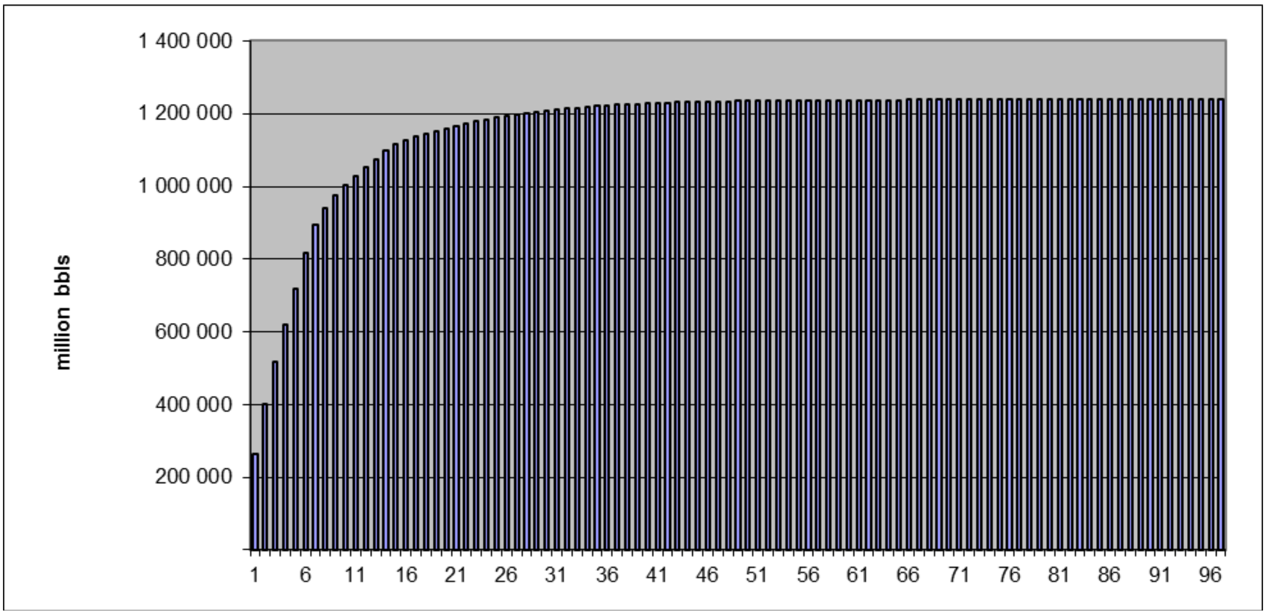
Proved reserves data are relied upon today as one of the few, if not the most widely available, indicators of future availability of crude oil and NGL. Their aggregation confirms some important and well-known characteristics:

- Global proved reserves of crude oil and NGL are reported to be approximately 1 239 billion barrels. This is an increase of 24 billion barrels (+1.9%) relative to the 2007 *Survey*. In 2008 production was 82.1 million barrels per day.

- The distribution of reserves is such that most of the quantities are concentrated in the largest fields and found in the countries where these are located. Fig. 2.1 illustrates this point well.

- Production bears a different relationship to the reported proved reserves in different countries, as seen in Fig. 2.2a. About 66% of the global proved reserves are produced at a rate of about 1.2% per year (a reserves to production [R/P] ratio of about 85 years) from only six countries, while about 21% are produced at a rate of about 6% per year (an R/P ratio of about 17 years). The remaining 13% is produced by three countries at a rate of about 3.2% per year (at an R/P ratio of about 32 years). These are average values taken over

Figure 2.1 Cumulative reserves by country, plotted in order of decreasing increment (Source: WEC SER)



several countries together. Variation can be marked from one country to another, particularly in the large group with low R/P ratios. The top six produced about 26 million b/d in 2008, the next three, about 14 million b/d and the 88 countries in the rest of the world, about 42 million b/d. Fig. 2.2b compares the average R/P ratios for the three groups of countries with the world average.

These observations convey the impression that production can be managed by drawing on reserves that are already proved in the countries where the R/P ratio is high, whereas it will need to be managed by adding proved reserves in the countries with low R/P ratios.

Before jumping to these or other conclusions, and certainly before making judgement on how production may develop, it is useful to review the meaning of the 'proved reserves' concept. This is best explained by examining its history.

The Proved Reserves Concept

The mindset behind the concept of 'proved reserves' was initially that of the geologist, determined to distinguish between what he had observed directly, termed *proven*, what he had interpreted to be present based on interpolation between observations and reasonable extrapolation, termed *probable*, and what he could infer might be present by extrapolation of his observations to unknown areas, termed *possible*. Undiscovered resources that are the target for exploration efforts often formed a separate and fourth category of prospective resources in the petroleum traditions. In petroleum, undiscovered resources are often dealt with in a very specific manner, subdividing them into plays, where prospects may be found; leads, where seismic shows the presence of structures and some of them have been confirmed discoveries; and prospects where the geometry is mapped, but drilling has not taken place to confirm presence and quality of hydrocarbons.

The geologist's mindset led to the categorisation of quantities into the proved, probable and possible in the early part of the 1900s. It was shared also in Russia and later in the Former Soviet Union where letter categories A, B, C and D were used. The principles are fundamental and are still in use. They were developed for quantities initially in place, for which they work best. From the earliest classifications, the term 'proved reserves' has never been used to describe the entire resources base.

Figure 2.2a Cumulative production vs cumulative reserves plotted by country in order of decreasing reserves increment
(Source: WEC SER)

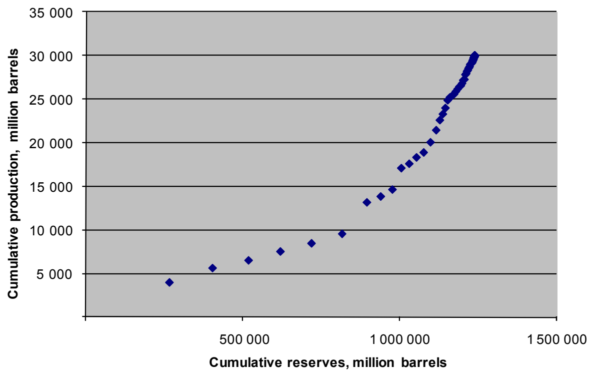
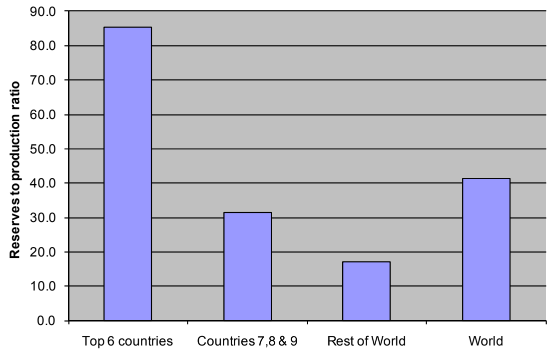


Figure 2.2b Comparison of reserves to production ratios in 2008
(Source: WEC SER)



In the 1960s and 1970s there were step changes in the application of quantitative methods in science, technology and economics, as slide rules were replaced by calculators and computers. In this environment, a significant change took place in the mindset. McKelvey expressed this in the well-known resource classification of 1972 that carries his name . He chose to add the economic dimension to the classification, by categorising resources both with respect to geological certainty and economic viability. The latter then firmly addressed the recoverable quantities. Today, there is no discussion about the validity of this concept. 'Proved reserves' have become accepted as being a quantity that can be recovered economically from a known reservoir with reasonable certainty.

Building coherence between 'recoverable quantities' and management information

Reasonable certainty invokes the use of probabilities in explicit or implicit form. Recoverability requires social, technological and industrial conditions to be met in addition to purely economic ones. This had to lead to a third change of mindset – the use of both probabilities and of project status as criteria for classification. A process was initiated between 1987 and 1994 in the United Nations (through the work of the UN Economic Commission for Europe [UNECE]) and at the World Petroleum Congress. The first results appeared in 1997 with the Society of Petroleum Engineers/the World Petroleum Council (SPE/WPC) reserves definitions asserting standards for use of probabilities, and with the UN Framework Classification for Solid Fuels and Mineral Commodities of 1997 adding feasibility as a third criterion for classification, in addition to economic viability and geological uncertainty. In 2000, the SPE/WPC joined by the American Association of Petroleum Geologists (AAPG) followed up by expanding its 1997 definitions to a project-status based classification. This was respected when the UN classification was extended to include petroleum in 2004.

A number of institutions have since examined their definitions and classifications, including the Committee for Mineral Reserves International Reporting Standards (CRIRSCO), SPE/WPC/AAPG/Society of Petroleum Evaluation Engineers (SPEE), the Governments of the Russian Federation and China, the US Securities and Exchange Commission and others, resulting in improved harmonisation. The processes culminated in 2009 with the issuing of the UN Framework Classification for Fossil Energy and Mineral Reserves and Resources (UNFC-2009), to which this *Survey* refers.

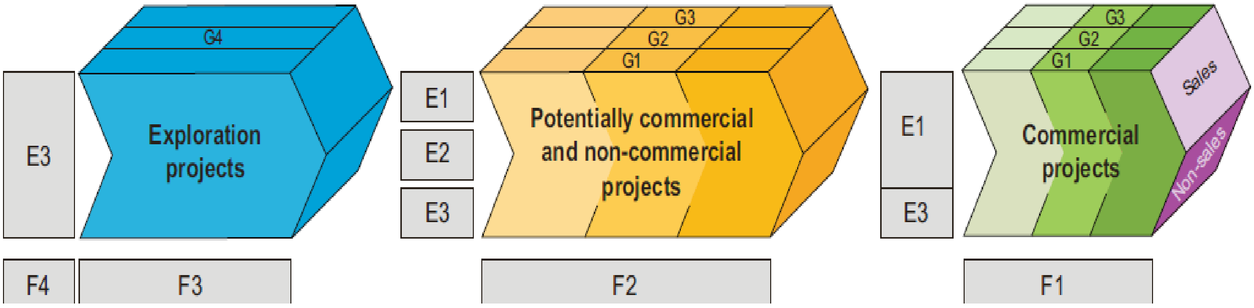
The United Nations Framework Classification for Fossil Energy and Mineral Reserves and Resources - 2009

The UNFC-2009 aims to serve the following four principal needs:

1. for international energy and mineral studies, to facilitate the formulation of robust and far-sighted policies;

2. for governments to manage their resources accordingly, allowing market prices to

Figure 2.3 The UNFC and the project value chain (Source; Statoil)



be transferred to the wellhead with as little loss as possible;

3. industries' needs for information while deploying technology, management and finance (to enable them to secure energy supplies and efficiently capture value within the established frameworks) in order to serve their host countries, shareholders and stakeholders;

4. the financial community's need for information to allocate capital appropriately, providing reduced costs and improved far-sightedness through the application of lower risk-compensated discount factors.

The projects are categorised with respect to economic and social viability, project feasibility and maturity and uncertainty with respect to the quantities addressed. The categorisation of projects rather than of accumulations provides coherence with other critical management information such as production, cash flows, value, demand for various input factors etc.

This key aspect of UNFC-2009 reflects the critical relationship between the quantities that can be recovered economically and the recovery processes (projects) that must be implemented to achieve those recoveries. It facilitates the recognition of potential wastage of resources through flaring or inefficient recovery processes and therefore also the potential for improvements.

By way of illustration, Fig. 2.3 shows a normal value chain starting with exploration, proceeding to the evaluation of discoveries, design of one or more consecutive development projects, building of the facilities and extraction. At the building and extraction phase, there will not normally be any hindrances to extraction in the economic and social domain. A distinction is made between sales production and non-sales production. For petroleum projects the non-sales production will normally be on-site fuel usage and flared gas[1].

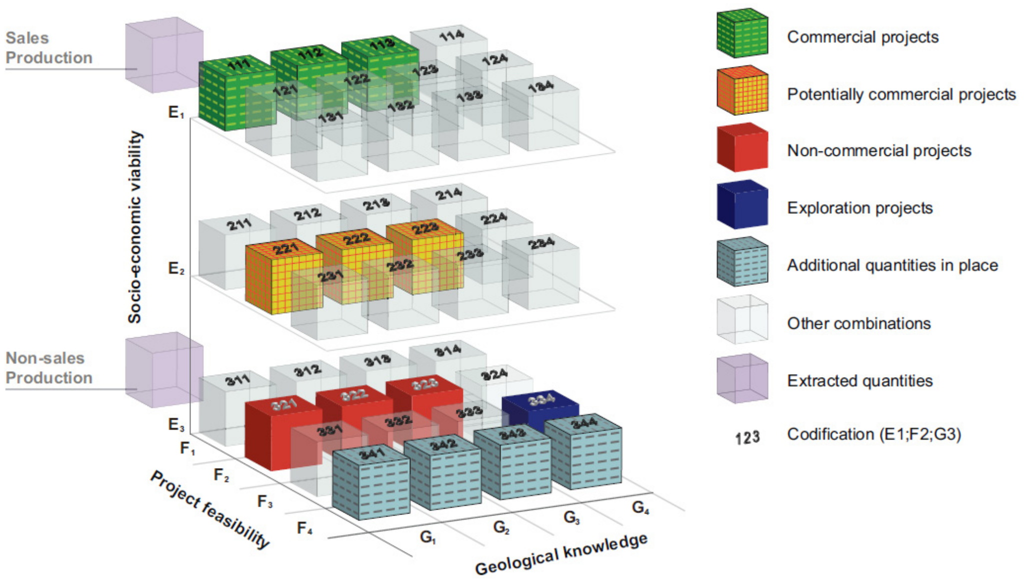
In the evaluation phase, there may be restrictions both in the technical and industrial domain and in the social and economic domain. The UNFC allows projects to be categorised independently with respect to maturity in both of these domains. The effects on recovery of improved social and economic framework conditions and of improved technical and industrial processes can then be seen and distinguished.

Fig. 2.4 shows the condensed and formal representation of the UNFC-2009 with the unique and language-independent numbering system for the categories. The E categories are in the economic and social domain; the F categories in the project feasibility and industrial domain; and the G categories in the geological domain, reflecting uncertainties in recoverable quantities.

Many resource inventories are still based on a characterisation of the geological endowment only. The UNFC is therefore also designed to be a harmonisation tool, allowing these early inventories to be mapped to a UNFC inventory without loss of information. With use, these pre-existing inventories can be expanded to contain the UNFC project detail required for efficient resource management.

[1] The quantities in place in an accumulation or a deposit that will not be recovered by the aggregate of identified projects are also included in the classification, thus allowing material balance to be respected, whilst facilitating the identification of the potential for further improvements in recovery.

Figure 2.4 UNFC-2009 (Source : UNFC)



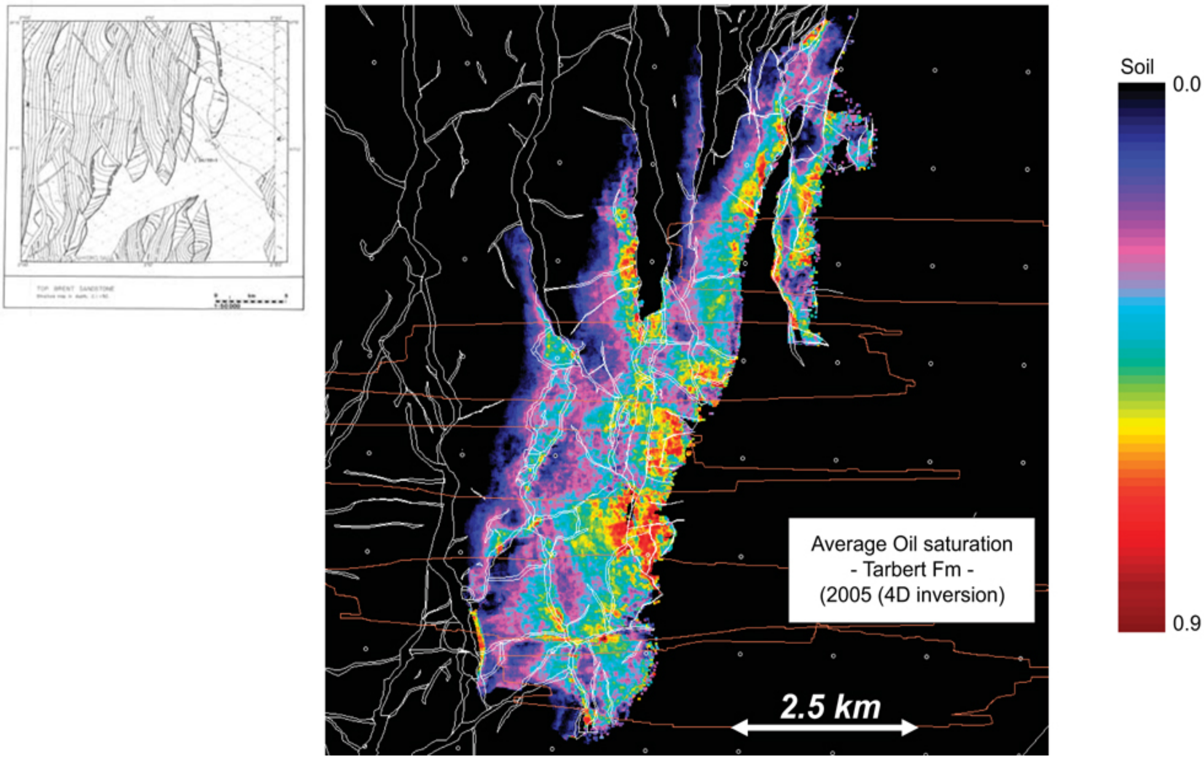
There has clearly been an evolution of the mindset for the use of 'proved reserves'. When the World Energy Council asked for 'proved reserves' to be reported for this *Survey*, this was in essence the quantities that are indisputably economic to produce in the future and that therefore are categorised as E1. They are to be produced by projects that are certain to be carried out and that therefore are characterised as F1, and they are the reasonably certain (low) estimates of the uncertain quantities that will be produced by these projects and that therefore are categorised as G1. By convention, the categories are always quoted in the alphabetical order, whereby the class of quantities reported in the *Survey* will be named E1, F1, G1, or since the order is always the same, 111. The latter has the advantage that it is understood in all languages using Arabic numerals.

The term 'reserves' is not used in the UNFC-2009 except in the title. This avoids the confusion caused by the many different meanings that have been attached to the term over time.

It is very clear that there are recoverable quantities of crude oil and NGL in addition to the quantities found in class 111. Firstly, the law of large numbers will cause the recoverable quantities from a group of projects to have a reduced uncertainty range near the sum of the expected values. When the low estimates are added up, it will be less and less probable that the recoverable quantities will ever be as low as this sum (or in other words that all the outcomes will come out low). This statistical effect will result in an apparent growth in the sums of proved reserves as the projects are depleting their respective recoverable quantities. Secondly, the quantities that have been found and that will be produced by immature, new or improved hydrocarbon recovery projects are not reported. Thirdly, the prospective quantities to be discovered through the very substantial exploration efforts that the industry is making are excluded. Fourthly and finally, the quantities that will be recovered, but are not forecast to be sold (but that could be, if efficiency measures were successful) are also excluded.

Thus interpreting the SER oil data in this light, it is apparent that the countries producing at the very high R/P ratios of 85 years or so are operating less mature projects on average than the countries that are producing at much lower ratios, averaging about 17 years. In the latter case it can be expected that more of the projects are firmly committed, whilst in the former, it would be reasonable to expect that investment decisions will come in the future. In the detailed

Figure 2.5 Map of Gullfaks in 1978 and its Tarbert formation in 2005 (Source: Statoil)



formulation of specifications to the classification that the UNECE is now undertaking in cooperation with stakeholders and professional organisations, it can be expected that a precise line will be drawn between the F1 and F2 project categories. It is important that all stakeholders, including those that produce at high R/P ratios, are active in the discussion of where to draw the line. This will, of course, not affect the recoverable quantities, but it will determine how they will be communicated in the future.

Securing Supplies

It is not known with great precision what the recoverable quantities of oil and gas are, nor how demand will grow. Both depend on human actions. It is known that they are in great demand, and that they are finite. It is also known that 100% of the oil or gas in the ground cannot be recovered, and that the actual percentage will depend on the recovery processes applied.

The recovery processes are for the most part physically irreversible processes. The implication is that the amount that can be recovered and used depends on the entire history of past efforts, in addition to future efforts. Said in plain words, if there is a failure to invest early for high recoveries in the long term, resources will be lost. The potential is destroyed. Flaring gas, early depressurisation of oil and condensate reservoirs, and dilution of oil by inefficient displacement fluids are all examples of this.

Decisions to invest for high recoveries in the long term are decisions to secure supplies. Solid partnerships are required between governments, industry and financiers that align interests in reaching the bold decisions required, strengthening the ability of the partnership to capture the opportunities and mitigate the risks that come with them.

Immediate investments to gain production in the longer term are based on the decision maker's current opinion of future wellhead values to him. The higher and the more predictable they are, the easier it is to undertake the required efforts to recover the substantial quantities of resources that are economically marginal.

This may sound simple: it is not. It requires a comprehensive approach to address the economic and social conditions affecting prices at the wellhead, the efficiency and cost of recovery operations and the geological conditions. The international community of governments, industry and financiers all influence the recoverable quantities and can increase them substantially if they act in concert.

To secure supplies in this way becomes increasingly important as crude oil and NGL resources become scarcer and are fetched from the harsh environments of the Arctic, deep water areas, heavy oil, natural bitumen and the difficult reservoirs. The world is indeed fortunate to be in a position to develop technologies to exploit these resources. That journey started in the late 1960s and early 1970s as a result of the availability of improved tools for quantitative analysis, allowing analytical modelling of any project that could be modelled physically. This was the secret behind the successful North Sea developments. They were not executed on the basis that the work had been done before – nothing similar had ever been done. They were developed on the basis that they could be modelled in the computer, in a multitude of alternatives and tested against all the conditions that they could encounter.

The success can be attributed to many, through the systems and institutions at work. In this, the individual also matters, and there have been champions. On the technical side, many will remember the French engineer and executive of Elf, Jacques Bosio, who pioneered subsea completions at the Grondin Field in Gabon and offshore horizontal drilling of producing wells at Rospo Mare in Italy. Together with the improvements in remote sensing and in particular 3- and 4-dimensional seismic surveys, these measures have contributed massively and will continue to contribute to the efficiency with which hydrocarbons are found and exploited. The skills have been perfected over the decades, affording those who master them the freedom to excel in environments that no one has yet ventured into.

An example

Many examples could demonstrate the effects described above. Unfortunately, it is difficult to document cases in the public domain without violating the restrictions imposed on the industry by security regulators. Before Statoil became a publicly-owned company listed on the stock exchange, it agreed with its partners (Norsk Hydro and Saga, who have both since merged with Statoil) to release for public use - principally for education and research - all the information then available on one of its operated fields. This was the Gullfaks Field on the Norwegian Continental Shelf. The record demonstrates very well the simplicity that is achieved by describing the recoverable quantities as the effect of projects and not (just) as a property of the geology.

The location of the Gullfaks field, adjacent to the Statfjord Field (Fig. 2.8). The reservoirs are deltaic, tidal and fluvial sands, mainly of Jurassic age, that have been broken by faults near the Viking Graben.

Gullfaks is primarily an oil field. Depletion is currently in an advanced stage, making it a relevant case to study. Past production has caused the field to change from a few large and prolific reservoirs to many smaller ones. To be exploited, these require advanced techniques and management talent. The map used to determine the commerciality of the reservoirs in 1978 is shown in Fig. 2.5, together with a 2005 map of one of its reservoirs. Fig. 2.5 demonstrates the improvement in imaging technology during the period. The Tarbert formation shows the distribution of un-recovered oil.

Figure 2.6 Production performance of Gullfaks, planned and observed up to 31 December 2009
(Source: Norwegian Petroleum Directorate)

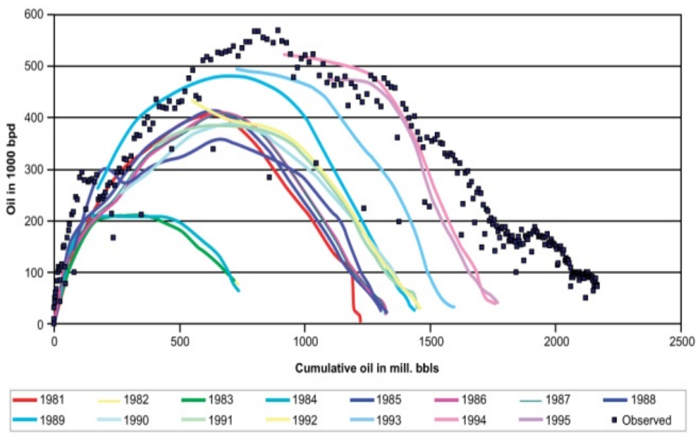
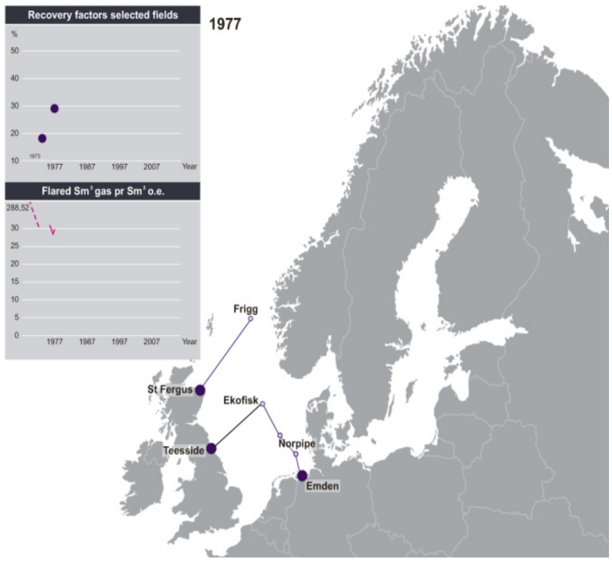


Figure 2.7 The Norwegian Continental Shelf in 1977
(Source: Norwegian Petroleum



Decisions to develop the field have been staged, taking advantage of markets, infrastructure, technology and field knowledge as it evolved. Some of the early decisions affected production quite late. While their effects were substantial, both with respect to production rates and quantities recovered, some of the projects were marginally economic at the time of decision, owing to the long period between investment and an increase in production and revenue.

The sea depth in the area is 130-220 metres. The field has been developed with three integrated processing, drilling and accommodation facilities, with concrete bases and steel topsides: Gullfaks A, B and C. Gullfaks B has a simplified processing plant with only first-stage separation. Gullfaks A and C receive and process oil and gas from the nearby reservoirs Gullfaks Sør and Gimle. The facilities are also involved in production and transport from nearby Tordis, Vigdis and Visund. The Tordis production is processed in a separate facility on Gullfaks C.

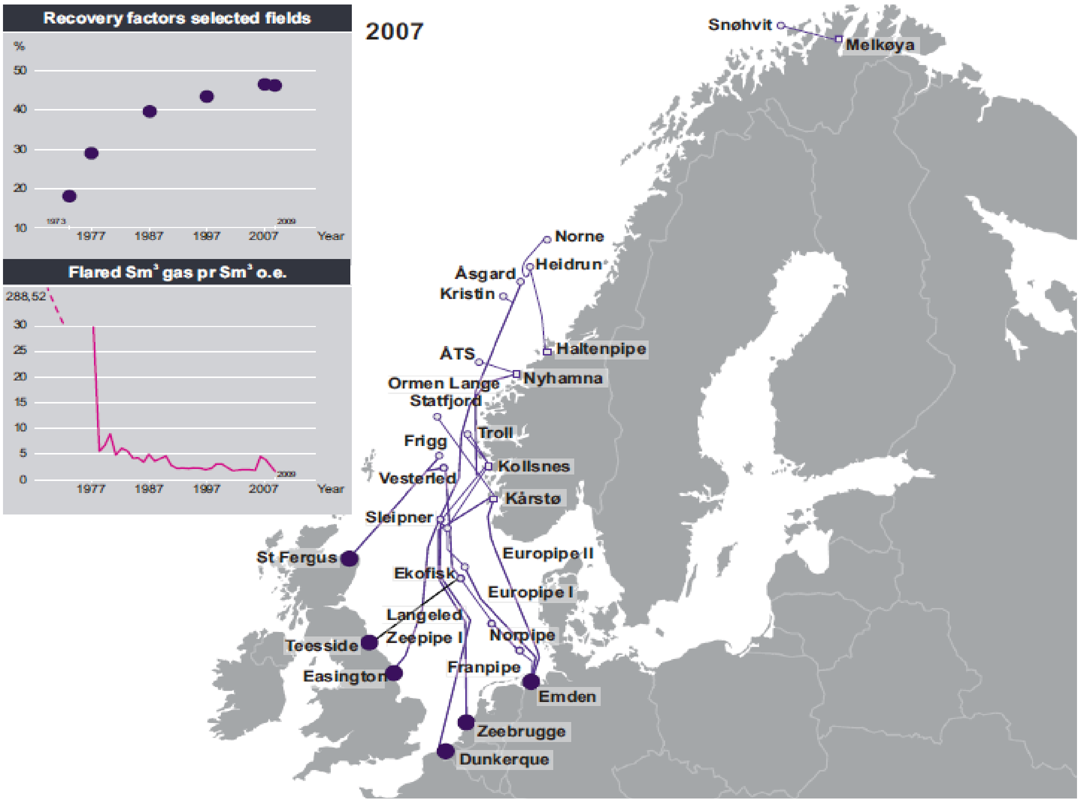
The original plan for development and operation (PDO) for the Gullfaks field included the Gullfaks A and Gullfaks B facilities. A PDO for the eastern section (Gullfaks C) was approved on 1 June 1985. The PDO for Gullfaks Vest addition was approved on 15 January 1993, and recovery from the Lunde formation was approved on 3 November 1995. In December 2005, an amended PDO for the Gullfaks field was approved. This plan covers prospects and small discoveries in the area around Gullfaks which can be drilled and produced from existing facilities, made possible by improvements in drilling technology.

The various projects and the changes in the views on how they will perform are reflected in Fig. 2.6 in the form of production rate as a function of cumulative prior production. With each major investment decision, recoverable quantities are moved from the F2 categories in the UNFC-2009 terminology to the F1 categories. The ensemble of plans and project performances is shown against the background of the actual average monthly production performance (one dot per month)[2].

Fig. 2.6 sheds some light on the way the ratio of remaining recoverable quantities (of proved reserves) to production changes over the life of any given project. Initially the ratio falls rapidly from a high value (in theory infinity) as production builds up. Once the production capacity is reached, the ratio will fall linearly with production. In the period of production decline the ratio will stabilise. In fact, if production declines exponentially over time, the slope of the

[2] Source: Norwegian Petroleum Directorate

Figure 2.8 The Norwegian Continental Shelf in 2007
(Source: Norwegian Petroleum Directorate)



decline in the plot used in Fig. 2.6 will be a straight line and the R/P ratio will remain constant. This is also a useful insight for reading Fig. 2.2a.

The Gullfaks projects, recovering 69% of the oil originally in place, are designed in a context of a legal, regulatory and fiscal framework, and in an infrastructure and industrial environment aiming for high value creation and recovery for the entire Norwegian Continental Shelf. Leaving details aside, Figs. 2.7 and 2.8 show the infrastructure development and the results.

Development of the infrastructure has followed a natural sequence from the southern proximity to European markets, northwards to more distant resources, allowing (through reuse) a fuller return on the capital employed in infrastructure. Gas issues have been as important as oil issues. The flaring of gas was strongly curtailed during the first years of production, at a cost and under intense protest. Ever since, the overall development of the Norwegian Continental Shelf has been planned and executed to ensure full utilisation of the gas. This has been achieved, while building flexibility through tying the sources and markets together in a gas network. Fiscal elements that reduce the wellhead value of oil and gas, such as royalty and unbalanced taxation rules, have been replaced by rules aligning the interests of government and industry for efficient resource management. High taxation rates have been complemented by depreciation rules that protect economically marginal projects from not being realised. The Government has elected to use direct financial participation as a means of obtaining economic benefits for the state in lieu of higher conventional income taxes. This has contributed to moving large marginal resources from the UNFC category E2[3] to E1.

[3] E1 is defined as: Extraction and sale is expected to become economically viable in the foreseeable future. E2 is defined as: Extraction and sale is not expected to become economically viable in the foreseeable future or evaluation is at too early a stage to determine economic viability. The phrase ‘economically viable’ encompasses economic (in the narrow sense) plus other relevant ‘market conditions’, and includes consideration of prices, costs, legal/fiscal framework, environmental, social and all other non-technical factors that could directly impact the viability of a development project.

The result of this and the efforts of research, development and industrial management have been improved resource management, as evidenced by the improvements in recovery efficiency and avoidance of gas flaring and use as fuel, as shown in Fig. 2.8.

Conclusion

The needs for energy are increasing as are the requirements for reduced environmental change. The only way in which these needs can be reconciled under the second law of thermodynamics is to improve efficiencies in every respect. This must take place through improved and constructive international cooperation, inspired by the World Energy Council and informed by the *Survey of Energy Resources*. A central premise for success is accurate communication of information that is relevant for the many critical decisions required. At stake is energy security for all, and in particular for the large and growing population now emerging from poverty, craving energy for their daily chores – a light bulb to extend the working day, a refrigerator to avoid endless daily struggles at the market and some rudimentary transport to allow the children to attend school and the parents to reach their workplaces. This must take place with tolerable environmental costs, whether for mitigating the risks associated with change or for adaptation to them.

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DEFINITIONS

Crude oil is a naturally occurring mixture consisting predominantly of hydrocarbons that exists in liquid phase in natural underground reservoirs and is recoverable as liquids at typical atmospheric conditions of pressure and temperature. Crude oil has a viscosity no greater than 10 000 mPa.s (centipoises) at original reservoir conditions; oils of greater viscosity are included in Chapter 4 - Natural Bitumen and Extra-Heavy Oil.

Natural gas liquids (NGLs) are hydrocarbons that exist in the reservoir as constituents of natural gas but which are recovered as liquids in separators, field facilities or gas-processing plants. Natural gas liquids include (but are not limited to) ethane, propane, butanes, pentanes, natural gasoline and condensate; they may include small quantities of non-hydrocarbons.

If reserves/resources/production/consumption of NGLs exist but cannot be separately quantified, they are included (as far as possible) under crude oil. In the tables the following definitions apply to both crude oil and natural gas liquids:

Proved amount in place is the resource remaining in known natural reservoirs that has been carefully measured and assessed as exploitable under present and expected local economic conditions with existing available technology.

Proved recoverable reserves are the quantity *within* the proved amount in place that can be recovered in the future under present and expected local economic conditions with existing available technology.

Estimated additional amount in place is the resource *additional to* the proved amount in place that is of foreseeable economic interest. Speculative amounts are not included.

Estimated additional reserves recoverable is the quantity *within* the estimated additional amount in place that geological and engineering information indicates with reasonable certainty might be recovered in the future.

R/P (reserves/production) ratio is calculated by dividing the volume of proved recoverable reserves at the end of 2008 by volumetric production in that year. The resulting figure is the time in years that the proved recoverable reserves would last if production were to continue at the 2008 level.

NOTE: The quantifications of reserves and resources presented in the tables that follow incorporate, as far as possible, data reported by WEC Member Committees. Such data will reflect the respective Member Committees' interpretation of the above Definitions in the context of the reserves/resources information available to them, and the degree to which particular countries' terminology and statistical conventions are compatible with the WEC specifications.

TABLES

TABLE NOTES

Table 2.2 shows the available data on known resources of crude oil and NGLs, in terms of amount in place and recoverable reserves, for the categories proved (or measured), probable (or indicated) and possible (or inferred). The majority of the data are those reported by WEC Member Committees for the present *Survey*; they have been supplemented by comparable data derived from official publications. For more detail regarding the provenance and coverage of individual countries' assessments, see the relevant Country Note.

Table 2.1 Crude oil and natural gas liquids: proved recoverable reserves at end-2008

	million tonnes	million barrels
Algeria	2 731	23 241
Angola	1 282	9 500
Benin	1	8
Cameroon	168	1 212
Chad	222	1 500
Congo (Brazzaville)	274	1 940
Congo (Democratic Rep.)	25	180
Côte d'Ivoire	64	471
Egypt (Arab Rep.)	561	4 200
Equatorial Guinea	231	1 705
Ethiopia	N	N
Gabon	504	3 684
Ghana	2	15
Libya/GSPLAJ	5 712	44 271
Mauritania	14	100
Morocco	N	1
Nigeria	4 953	37 200
Senegal	N	N
South Africa	2	15
Sudan	904	6 700
Tunisia	69	535
Total Africa	**17 719**	**136 478**
Barbados	N	2
Belize	1	7
Canada	3 126	21 846
Cuba	19	124
Guatemala	13	83
Mexico	1 611	11 865
Trinidad & Tobago	80	606
United States of America	3 429	28 396
Total North America	**8 279**	**62 929**
Argentina	348	2 520
Bolivia	54	465
Brazil	1 088	8 053
Chile	4	30

Table 2.1 Crude oil and natural gas liquids: proved recoverable reserves at end-2008

	million tonnes	million barrels
Colombia	226	1 668
Ecuador	909	6 511
Peru	124	1 121
Surinam	12	80
Venezuela	13 997	99 377
Total South America	**16 762**	**119 825**
Azerbaijan	950	7 000
Bangladesh	3	28
Brunei	160	1 200
China	2 466	18 052
Georgia	5	35
India	740	5 836
Indonesia	497	3 750
Japan	9	68
Kazakhstan	2 907	22 762
Korea (Republic)	N	2
Kyrgyzstan	5	40
Malaysia	701	5 357
Mongolia	2	15
Myanmar (Burma)	7	50
Pakistan	42	313
Philippines	15	138
Taiwan, China	N	2
Tajikistan	2	12
Thailand	50	453
Turkey	44	172
Turkmenistan	81	600
Uzbekistan	70	594
Vietnam	626	4 700
Total Asia	**9 382**	**71 179**
Albania	30	199
Austria	7	50
Belarus	27	198
Bulgaria	2	15
Croatia	10	73

Table 2.1 Crude oil and natural gas liquids: proved recoverable reserves at end-2008

	million tonnes	million barrels
Czech Republic	2	12
Denmark	108	811
France	14	103
Germany	16	118
Greece	1	10
Hungary	5	40
Italy	62	434
Lithuania	2	12
Netherlands	6	48
Norway	920	7 491
Poland	15	113
Romania	55	411
Russian Federation	10 647	79 000
Serbia	10	74
Slovakia	1	9
Slovenia	N	N
Spain	20	150
Ukraine	151	1 290
United Kingdom	408	3 060
Total Europe	**12 519**	**93 721**
Bahrain	16	125
Iran (Islamic Rep.)	17 329	137 610
Iraq	15 478	115 000
Israel	N	2
Jordan	N	1
Kuwait	13 679	101 500
Oman	744	5 500
Qatar	3 094	25 405
Saudi Arabia	34 518	264 063
Syria (Arab Rep.)	335	2 459
United Arab Emirates	12 555	97 800
Yemen	345	2 670
Total Middle East	98 093	752 135

Table 2.1 Crude oil and natural gas liquids: proved recoverable reserves at end-2008

	million tonnes	million barrels
Australia	255	2 335
New Zealand	20	162
Papua New Guinea	9	70
Total Oceania	**284**	**2 567**
TOTAL WORLD	**163 038**	**1 238 834**

Notes :

1. Sources: WEC Member Committees, 2009/10; *Oil & Gas Journal*, December, 2009; *Annual Report 2008*, OAPEC; *Annual Statistical Bulletin 2008*, OPEC; *World Oil*, September 2009; *BP Statistical Review of World Energy 2009*; various national sources

Table 2.2 Crude oil and natural gas liquids: known resources at end-2008 (million barrels)

		Proved (measured)	**Probable (indicated)**	**Possible (inferred)**
Argentina	amount in place	NA	NA	NA
	recoverable reserves	2 520	827	696
Czech Republic	amount in place	105	35	71
	recoverable reserves	12	NA	NA
Denmark	amount in place	3 487	included with proved	
	recoverable reserves	811	included with proved	440
Germany	amount in place	NA	NA	NA
	recoverable reserves	117	132	NA
Hungary	amount in place	830	234	489
	recoverable reserves	40	8	96
Italy	amount in place	896		
	recoverable reserves	434	651	728
Kazakhstan	amount in place	NA	NA	NA
	recoverable reserves	22 762	37 584	101 790
Mexico	amount in place			
	recoverable reserves	11 865	11 632	11 485
Norway	amount in place			
	recoverable reserves	7 491	2 462	1 659
Peru	amount in place			
	recoverable reserves	1 121	955	5 291
Poland	amount in place	88	90	NA
	recoverable reserves	113	included with proved	NA
Romania	amount in place			
	recoverable reserves	411	70	47
Thailand	amount in place			
	recoverable reserves	453	760	310
Trinidad & Tobago	amount in place			
	recoverable reserves	606	335	1 561
United Kingdom	amount in place			
	recoverable reserves	3 060	2 708	2 700

Table 2.3 Crude oil and natural gas liquids: 2008 production

	million tonnes	thousand barrels per day	R/P ratio
Algeria	85.9	1 993	31.9
Angola	93.5	1 894	13.7
Cameroon	4.3	84	39.4
Chad	6.9	127	32.3
Congo (Brazzaville)	12.9	249	21.3
Congo (Democratic Rep.)	1.3	25	19.7
Côte d'Ivoire	2.3	45	28.6
Egypt (Arab Rep.)	36.3	722	15.9
Equatorial Guinea	17.9	361	12.9
Gabon	11.8	235	42.8
Ghana	0.3	6	6.8
Libya/GSPLAJ	86.5	1 846	65.5
Mauritania	0.5	11	24.8
Morocco	N	N	11.0
Nigeria	105.3	2 170	46.8
Senegal	N	N	
South Africa	0.9	19	2.2
Sudan	23.7	480	38.1
Tunisia	4.2	88	16.6
Total Africa	**494.5**	**10 355**	**36.0**
Barbados	0.1	1	5.5
Canada	155.0	3 201	18.6
Cuba	2.8	50	6.8
Guatemala	0.8	14	16.2
Mexico	157.4	3 158	10.3
Trinidad & Tobago	6.9	149	11.1
United States of America	305.0	6 734	11.5
Total North America	**628.0**	**13 307**	**12.9**
Argentina	34.8	723	9.5
Bolivia	1.9	47	27.0
Brazil	94.0	1 899	11.6
Chile	0.5	16	5.1

Table 2.3 Crude oil and natural gas liquids: 2008 production

	million tonnes	thousand barrels per day	R/P ratio
Colombia	30.5	618	7.4
Ecuador	26.2	514	34.6
Peru	5.3	120	25.5
Surinam	0.7	12	18.2
Venezuela	131.6	2 566	>100
Total South America	**325.5**	**6 515**	**50.3**
Azerbaijan	45.5	914	20.9
Bangladesh	0.3	6	12.8
Brunei	8.4	175	18.7
China	189.8	3 795	13.0
Georgia	0.1	1	95.6
India	38.1	820	19.4
Indonesia	49.1	1 004	10.2
Japan	0.9	19	9.8
Kazakhstan	72.0	1 554	40.0
Korea (Republic)	N	N	
Kyrgyzstan	0.1	1	>100
Malaysia	34.3	754	19.4
Mongolia	0.2	3	13.7
Myanmar (Burma)	1.0	20	6.8
Pakistan	3.2	66	13.0
Philippines	0.6	15	25.1
Taiwan, China	N	N	18.2
Tajikistan	N	1	56.5
Thailand	13.4	325	5.3
Turkey	2.2	43	10.9
Turkmenistan	10.2	205	8.0
Uzbekistan	4.8	111	14.6
Vietnam	15.4	317	40.5
Total Asia	**489.6**	**10 149**	**19.2**
Albania	0.5	10	54.4
Austria	0.9	19	7.2
Belarus	1.7	33	16.4
Bulgaria	N	N	89.0

Table 2.3 Crude oil and natural gas liquids: 2008 production

	million tonnes	thousand barrels per day	R/P ratio
Croatia	1.0	22	9.1
Czech Republic	0.2	4	8.2
Denmark	14.0	287	7.7
France	1.1	22	12.8
Germany	3.1	62	5.2
Greece	0.1	1	27.3
Hungary	1.2	28	3.9
Italy	5.5	105	11.3
Lithuania	0.1	3	10.9
Netherlands	2.2	46	2.9
Norway	114.6	2 456	8.3
Poland	0.8	15	20.6
Romania	4.5	92	12.2
Russian Federation	488.5	9 886	21.8
Serbia	0.7	17	11.9
Slovakia	N	N	63.2
Slovenia	N	N	
Spain	0.1	3	>100
Ukraine	4.8	111	31.8
United Kingdom	71.7	1 526	5.5
Total Europe	**717.3**	**14 748**	**17.4**
Bahrain	2.0	43	7.9
Iran (Islamic Rep.)	220.1	4 504	83.5
Iraq	119.3	2 423	>100
Israel	N	N	>100
Jordan	N	N	
Kuwait	137.3	2 784	99.6
Oman	37.8	763	19.7
Qatar	60.8	1 378	50.4
Saudi Arabia	515.3	10 846	66.5
Syria (Arab Rep.)	17.5	351	19.1
United Arab Emirates	139.5	2 980	89.7
Yemen	15.2	317	23.0
Total Middle East	1 264.8	26 389	77.9

Table 2.3 Crude oil and natural gas liquids: 2008 production

	million tonnes	thousand barrels per day	R/P ratio
Australia	23.7	556	11.5
New Zealand	2.8	60	7.4
Papua New Guinea	1.9	41	4.7
Total Oceania	**28.4**	**657**	**10.7**
TOTAL WORLD	**3 948.1**	**82 120**	**41.2**

Notes :

1. Sources: WEC Member Committees, 2009/10; *BP Statistical Review of World Energy 2009; Oil & Gas Journal;* other international and national sources.
2. Conversions from barrels to tonnes (or vice versa) have been carried out using specific crude oil and NGL factors for each country.

COUNTRY NOTES

The following Country Notes on Crude Oil and Natural Gas Liquids provide a brief account of countries with significant oil reserves/production. They have been compiled by the Editors, drawing upon a wide variety of material, including information received from WEC Member Committees, national and international publications.

The principal international published sources consulted were:

- Annual Statistical Bulletin 2008; OPEC;
- BP Statistical Review of World Energy, 2009;
- Energy Balances of OECD Countries, 2009 Edition; International Energy Agency;
- Energy Balances of Non-OECD Countries, 2009 Edition; International Energy Agency;
- Energy Statistics of OECD Countries, 2009 Edition; International Energy Agency;
- Energy Statistics of Non-OECD Countries, 2009 Edition; International Energy Agency;
- Oil & Gas Journal, various issues; PennWell Publishing Co.;
- Our Industry Petroleum; 1977; The British Petroleum Company Ltd.;
- Secretary General's 35th Annual Report, A.H. 1428-1429/A.D. 2008; OAPEC;
- World Oil, September 2009; Gulf Publishing Company.

Brief salient data are shown for each country, including the year of first commercial production (where it can be ascertained).

Algeria

Proved recoverable reserves (crude oil and NGLs, million barrels)	23 241
2008 production (crude oil and NGLs, thousand b/d)	1 993
R/P ratio (years)	31.9
Year of first commercial production	1950

Indigenous oil reserves are the third largest in the African region, after Libya and Nigeria. The principal oil provinces are located in the central and southeastern parts of the country, with the largest oil field being Hassi Messaoud, which was discovered in 1956. Substantial volumes of NGLs (condensate and LPG) are produced at Hassi R'mel and other gas fields. Algerian crudes are of high quality, with a low sulphur content.

The levels retained for the present *Survey* are those advised by the Algerian WEC Member Committee for the 2007 SER: 12 511 million cubic metres (78.7 billion barrels) of oil in place and 3 695 million cubic metres (23.2 billion barrels) of proved recoverable oil reserves. Published sources generally quote Algeria’s reserves as around 12.2 billion barrels, which would appear to exclude NGLs.

Algeria has been a member of OPEC since 1969 and is also a member of OAPEC. The bulk of its crude oil exports are consigned to Western Europe and North America.

Angola

Proved recoverable reserves (crude oil and NGLs, million barrels)	9 500
2008 production (crude oil and NGLs, thousand b/d)	1 894
R/P ratio (years)	13.7
Year of first commercial production	1956

Proved reserves of oil (9 500 million barrels, as quoted by *World Oil* and OPEC) are the second largest in sub-Saharan Africa. *Oil & Gas Journal* has recently raised its estimate to the same level (as at 1 January 2009). BP now give 13 500 million barrels, which may include probable reserves, as their figure equates to that quoted by the BGR, which uses a proved-plus-probable basis.

The early discoveries (from 1955 onwards) were made on land, but the greater part of Angola's oil resources lies in the coastal waters of its enclave of Cabinda and off the northwestern mainland. Major discoveries have since been made in deep water locations. Offshore exploration and production activities largely escaped disruption during the long civil war, and output has risen sharply since 2001. By far the greater part of the crude produced is exported. Angola became a member of OPEC with effect from 1 January 2007.

Argentina

Proved recoverable reserves (crude oil and NGLs, million barrels)	2 520
2008 production (crude oil and NGLs, thousand b/d)	723
R/P ratio (years)	9.5
Year of first commercial production	1907

In terms of oil resources, Argentina lies in the middle ranks of South American countries, with a level of reserves only just below those of Colombia and Peru combined. The main oil-producing areas are the west-central areas of Neuquén and Cuyo-Mendoza, the Noroeste area near Bolivia in the north, the southern province of Chubut and the Austral area in the far south (including Argentina's portion of Tierra del Fuego). Offshore fields have been discovered in the San Jorge basin off Chubut province and near Tierra del Fuego.

Proved recoverable oil reserves at end-2008 are reported by the Argentina WEC Member Committee (quoting the Secretaría de Energía) as 400.7 million m3 (2 520 million barrels), an increase of 14.8 % on the end-2005 figure quoted in the 2007 SER. Several published assessments of proved reserves come out slightly higher than the level reported above, reflecting the end-2007 situation.

The Member Committee reports additional recoverable oil as comprising 131.5 million m^3 (827 million barrels) of probable reserves and 110.7 million m^3 (696 million barrels) of possible reserves, with further potential recovery from known resources as 185.6 million m^3 (1 167 million barrels).

Oil output in 2008 comprised 36.6 billion m^3 (692000 b/d) of crude oil plus just over 3 million tonnes (31 000 b/d) of NGLs. The Golfo San Jorge and Neuquina basins account for the bulk of oil production. A sizeable proportion of Argentinian crude is exported.

Australia

Proved recoverable reserves (crude oil and NGLs, million barrels)	2 335
2008 production (crude oil and NGLs, thousand b/d)	556
R/P ratio (years)	11.5
Year of first commercial production	1964

Although drilling for oil took place as long ago as 1892, it was not until well after World War II that Australia achieved oil-producer status. Since then, numerous oil fields have been discovered, notably in the following areas: Gippsland Basin (Bass Strait), off Victoria; Cooper Basin, South Australia; Eromanga and Surat Basins, Queensland; Carnarvon Basin (North West Shelf) off Western Australia; Bonaparte Basin in the Timor Sea.

The latest data on oil reserves published by Geoscience Australia as a component of its report on the *Oil and Gas Resources of Australia 2008* (OGRA) relates to the situation as at 1 January 2009. At this point in time there were (in terms of millions of barrels) 881.6 of crude oil, 704.5 of condensate and 749.0 of naturally-occurring LPG in Category 1 (comprising 'current reserves of those fields which have been declared commercial. It includes both proved and probable reserves'). The total crude oil-plus-NGLs figure of 2 335 million barrels compares with the 1 January 2005 total of 2 085 million barrels quoted in OGRA 2004 for this category (which was entitled 'remaining commercial reserves' in another OGRA 2004 table).

Geoscience Australia also provides an alternative assessment, using the McKelvey classification, resulting in 'Economic Demonstrated Resources' (in millions of barrels) of 1 181 crude oil, 2 137 condensate and 1 095 LPG, giving a grand total of 4 413. 'Subeconomic Demonstrated Resources', expressed in similar terms, are given as 249 crude oil, 614 condensate and 379 LPG, for a total of 1 242 million barrels.

Probably as a result of adopting differing definitions of 'proved reserves' and differing treatments of natural gas liquids, commercially published estimates of Australian proved reserves tend to vary considerably: *Oil & Gas Journal* quotes 1 500 million barrels (raised to 3318 as at 1 January 2010), *World Oil* 4 181, OPEC 4 158 and BP 4 200. These discrepancies may be due in part either to the inclusion of Category 2 reserves (see below) and/or to the adoption of the McKelvey classification, in which 'economic demonstrated resources' include an element of extrapolation. For example, OGJ's latest figure appears to comprise crude oil plus condensate, on a McKelvey basis; this provides a good illustration of the difficulties involved in comparing published reserves data.

The estimated additional reserves recoverable, on the basis of Geoscience Australia's Category 2 – 'estimates of recoverable reserves which have not yet been declared commercially viable' - are as follows (in millions of barrels): crude oil 549.7; condensate 2045.3; and naturally-occurring LPG 725.8, giving a total crude plus NGLs of 3 320.8 million barrels. This latter figure is 14% lower than the comparable Category 2 total of 3 861 million barrels for 1 January 2005, as quoted in the 2007 *Survey*.

Production of oil (including condensate and other NGLs) in 2008 averaged 556 000 b/d, of which crude oil accounted for 62%, condensate 21% and LPG/ethane for 17%. About 58% of Australia's total oil output in 2008 was exported, mostly to Asian countries and the USA.

Azerbaijan

Proved recoverable reserves (crude oil and NGLs, million barrels)	7 000
2008 production (crude oil and NGLs, thousand b/d)	914
R/P ratio (years)	20.9
Year of first commercial production	1873

This is one of the world's oldest oil-producing areas, large-scale commercial production having started in the 1870s. During World War II the republic was the USSR's major source of crude, but then decreased in importance as the emphasis moved to Siberia. Azerbaijan's proved recoverable reserves (as reported by *Oil & Gas Journal*, OAPEC and BP) stand at 7 billion barrels, unchanged from the level quoted in the 2004 and 2007 *Surveys*.

The development of Azerbaijan's offshore oil resources in the Caspian Sea, currently under way, has re-established the republic as a major oil producer and exporter. With new Caspian fields coming into production, oil output has risen year by year since 1998. The bulk of Azerbaijan's production is obtained offshore.

Brazil

Proved recoverable reserves (crude oil and NGLs, million barrels)	8 053
2008 production (crude oil and NGLs, thousand b/d)	1 899
R/P ratio (years)	11.6
Year of first commercial production	1940

Brazil's proved reserves feature significantly within the Western Hemisphere - not quite in the same league as the four largest producers (Venezuela, USA, Canada and Mexico), but greater than those of any other country in South America apart from Venezuela. Most of the reserves discovered prior to the mid-1970s were in the northeast and central regions, remote from the main centres of oil demand in the south and southeast. Discoveries in offshore areas, in particular the Campos Basin, transformed the reserves picture.

The estimates of Brazil's proved oil reserves reported for previous editions of the SER have been based on the 'measured/indicated/inventoried reserves' published by the Ministério de Minas e Energia in its *Balanço Energético Nacional* (BEN), which broadly equate to 'proved+probable' reserves. For the present *Survey*, the WEC Member Committee for Brazil has been able to supply as a separate item the 'proved' component (8 053) of the BEN 2009 figure of 12 801 million barrels. The remaining amount of 4 748 million barrels is allocated to 'probable' reserves, while the BEN's 'inferred/estimated' category is classified as 'possible'. Of the proved reserves reported by the Member Committee, 93% is located offshore.

The standard published assessments of proved reserves continue to reflect recent generations of the BEN equivalent of 'proved+probable' reserves.

Oil production has followed a strongly upward trend for more than 10 years, reaching an average of 1.9 million b/d in 2008. Much interest is currently being shown in Brazil's offshore (especially deep-water) oil fields and in particular the massive reserves discovered in the pre-salt formation, with production from the Tupi field expected to begin around the end of 2010.

Brunei

Proved recoverable reserves (crude oil and NGLs, million barrels)	1 200
2008 production (crude oil and NGLs, thousand b/d)	175
R/P ratio (years)	18.7
Year of first commercial production	1929

Although the earliest discoveries (Seria and Rasau fields) were made on land, virtually all subsequent oil fields have been found in offshore waters. Proved recoverable reserves reflect the level of 1 200 million barrels quoted in the OPEC *Annual Statistical Bulletin 2008*. There is now consensus among the main published sources that total oil reserves lie within a range of 1 100 to 1 200 million barrels. Total oil output was 175 000 b/d, (including an estimated 14 000 b/d of natural gasoline), an overall fall of more than 20% since 2006. More than 90% of Brunei's oil output is exported, mostly to Japan, Thailand, Korea (Republic) and Singapore.

Canada

Proved recoverable reserves (crude oil, NGLs, synthetic crude and natural bitumen, million barrels)	21 846
2008 production (crude oil, NGLs, synthetic crude and natural bitumen), thousand b/d)	3 201
R/P ratio (years)	18.6
Year of first commercial production	1862

The levels of proved recoverable reserves adopted for the present *Survey* correspond with the 'Remaining Reserves as at 2008-12-31' given in the *2008 Report of the Reserves Committee* of the Canadian Association of Petroleum Producers (CAPP) in the CAPP *Statistical Handbook* (as at February 2010). Reserves comprise 765 million m^3 of conventional crude oil, 200 million m^3 of natural gas liquids (66 pentanes plus and 134 ethane/propane/butane), and 2 508 million m^3 of oil sands and natural bitumen (1 451 'developed mining - upgraded and bitumen' and 1 057 'developed in situ - bitumen').

Two provinces (Alberta and Saskatchewan) account for the bulk of western Canada's conventional crude oil reserves. The East Coast Offshore reserves hold 233 million m^3 of crude oil. Most of the NGL reserves are located in Alberta.

In all, Canada's proved oil reserves now amount to 3 473 million m^3, equivalent to 21 846 million barrels. Compared with the end-2005 levels quoted in the 2007 *Survey*, total reserves have increased by over 45%, owing almost entirely to a substantial rise in the amount of oil deemed to be recoverable from Canada's oil sands, with a 49% growth in developed synthetic oil reserves and a 169% leap in developed bitumen reserves.

The Energy Resources Conservation Board (ERCB) reports that in 2007 Canada had 27.45 billion m^3 (172.7 billion barrels) of 'established oil sands reserves'. This term is defined by the National Energy Board (June 2006) as 'the sum of the proven reserves and half probable reserves'. The ERCB figure amply illustrates the enormous extent of the oil sands resource.

There is no consensus as regards the treatment of Canadian oil sands/bitumen in compilations of proved oil reserves. Some published compilations (e.g. OPEC, OAPEC, BGR) continue to exclude it entirely, whilst at the other extreme, *Oil & Gas Journal* includes the whole of the ERCB's 'established oil sands reserves'(see above).

The approach adopted for the present *Survey* reflects the practice of the CAPP Reserves Committee and is also broadly comparable with that used by BP in its *Statistical Review of World Energy, 2009* and by *World Oil* in its annual compilation of Estimated Proven World Reserves. BP states that it includes 'an official estimate of 22.0 billion barrels for oil sands under active development', whilst *World Oil* states that its 'oil sands reserve estimate is based on 50 years times current production capacity'.

The quantities of oil sands/bitumen included in Canada's proved reserves adopted for the present *Survey* correspond with 'remaining established reserves' of 'developed non-conventional oil' at end-2008 published by CAPP in its *Statistical Handbook* and included by the Reserves Committee of CAPP in its 2008 Report. 'Established reserves' are defined by CAPP as 'those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgement portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical or similar information, with reasonable certainty'. 'Developed synthetic crude oil and bitumen reserves' are defined by CAPP as 'those recoverable from developed experimental/demonstration and commercial projects'.

In 2008, output of conventional crude was 214500 m^3/d, that of NGLs (condensates and gas-plant liquids) 103 200 m^3/d and production from oil sands 191 300 m^3/d.

Canada is the world leader in the production of oil from deposits of oil sands. The estimated ultimately recoverable resource from this 'newly conventional' supply is 55 billion cubic metres, second only to Saudi Arabia - see Chapter 4: Natural Bitumen and Extra-Heavy Oil.

Chad

Proved recoverable reserves (crude oil and NGLs, million barrels)	1 500
2008 production (crude oil and NGLs, thousand b/d)	127
R/P ratio (years)	32.3
Year of first commercial production	2003

The West African republic of Chad joined the ranks of the world's crude oil producers in July 2003, after the construction of a 1 070 km export pipeline from the oil fields in the Doba Basin of southern Chad through Cameroon to a new terminal at Kribi. The development of the Doba Basin fields (in the initial stages, Bolobo, Komé and Miandoum, followed in 2005-2007 by Nya Moundouli and Maikeri) and the pipeline is handled by a consortium consisting of ExxonMobil (40%), Petronas, the Malaysian state oil company (35%), and ChevronTexaco (25%).

In 2002 recoverable reserves were stated by Esso Exploration & Production Chad, Inc. to be 'slightly more than 900 million barrels'. For the purpose of the present *Survey*, *Oil & Gas Journal*'s estimate of 1 500 million barrels as at end-2008 has been adopted for proved reserves, as further fields have been developed and brought into production.

The oil offered for export is called Doba Blend. Initial supplies were typically of 24.8° API and 0.14% sulphur; after March 2004, when the Komé field came on-stream, the blend's characteristics moved to a lower gravity (20.5° API) and a slightly higher sulphur content (0.16%). Chevron's current assay gives a gravity of 21.1° API (corresponding to a specific gravity of 0.927) and a sulphur content of 0.10%.

China

Proved recoverable reserves (crude oil and NGLs, million barrels)	18 052
2008 production (crude oil and NGLs, thousand b/d)	3 795
R/P ratio (years)	13.0
Year of first commercial production	1939

The first significant oil find was the Lachunmia field in the north-central province of Gansu, which was discovered in 1939. An extensive exploration programme, aimed at self-sufficiency in oil, was launched in the 1950s; two major field complexes were discovered: Daqing (1959) in the northeastern province of Heilongjiang and Shengli (1961) near the Bo Hai gulf.

China's reserves remain a state secret, and thus it is necessary to have recourse to published sources. For the purposes of the present *Survey*, the level of 18 052 million barrels quoted by *World Oil* has been retained. Other published assessments of China's oil reserves for end-2008 (in millions of barrels) range from OPEC's 15 493 to OAPEC at 16 300, with *Oil & Gas Journal* (16 000) and BP (15 500) at intermediate levels. It is worth noting that OGJ has recently raised its estimate substantially, quoting 20 350 million barrels as at 1 January 2010.

China's oil reserves are by far the largest of any country in Asia: oil output is on a commensurate scale, with the 2008 level of approximately 190 million tonnes accounting for about 53% of the regional tonnage. China exported 3.7 million tonnes of its crude oil in 2008.

Colombia

Proved recoverable reserves (crude oil and NGLs, million barrels)	1 668
2008 production (crude oil and NGLs, thousand b/d)	618
R/P ratio (years)	7.4
Year of first commercial production	1 921

Initially, oil discoveries were made principally in the valley of the Magdalena. Subsequently, other fields were discovered in the north of the country (from the early 1930s), and in 1959 oil was found in the Putamayo area in southern Colombia, near the border with Ecuador. More recently, major discoveries have included the Caño Limón field near the Venezuelan frontier and the Cusiana and Cupiagua fields in the Llanos Basin to the east of the Andes.

However, the remaining proved reserves have been shrinking in recent years and, despite a modest rise in 2008, are still at a very low level in relation to production, according to the data provided to the Colombian WEC Member Committee by the Unidad de Planeación Minero Energético (UPME) of the Ministerio de Minas y Energía. This source quotes proved recoverable oil reserves as 1 458 million barrels, implying an R/P ratio of only 6.4. However, in January 2010 it was reported by ANH (the National Hydrocarbons Agency) that end-2008 reserves were some 1.7 billion barrels.

Colombia's oil production rose at a modest rate from 2003 to 2007, but increased by more than 10% in 2008.

Congo (Brazzaville)

Proved recoverable reserves (crude oil and NGLs, million barrels)	1 940
2008 production (crude oil and NGLs, thousand b/d)	249
R/P ratio (years)	21.3
Year of first commercial production	1957

The proved recoverable reserves shown above reflect the end-2008 level of crude reserves published by *World Oil* in September 2009. *Oil & Gas Journal* has retained the level of 1 600 million barrels that it has been quoting since its end-2006 assessment.

After becoming a significant oil producer in the mid-1970s, Congo (Brazzaville) is now the fourth largest in sub-Saharan Africa. Most of the fields in current production are located in coastal waters. The average quality of oil output has improved over the years, aided by the coming on-stream of Elf's deep-water Nkossa field. The bulk of oil production is exported.

Denmark

Proved recoverable reserves (crude oil and NGLs, million barrels)	811
2008 production (crude oil and NGLs, thousand b/d)	287
R/P ratio (years)	7.7
Year of first commercial production	1972

Denmark's proved recoverable reserves are the fourth largest in Europe (excluding the Russian Federation). The Danish Energy Authority (DEA) does not employ the terms 'proved', 'probable' and 'additional' reserves, but uses the categories 'ongoing', 'approved', 'planned' and 'possible' recovery. The figure for proved reserves (129 million m^3 or 811 million barrels) reported by the DEA to the Danish WEC Member Committee has been calculated as the sum of 'ongoing' and 'approved' reserves, while the figure for potential additional recovery from known resources has been calculated as the sum of 2 million m^3 'planned' reserves and 68 million m^3 'possible' reserves, for a total of 70 million m^3 or 440 million barrels. The reserve numbers are the expected values in each category.

The Member Committee also reports 60 million m^3 (377 million barrels) as estimated to be recoverable from presently undiscovered resources. Denmark's oil reserves and resources may be viewed against the background of its cumulative oil production to end-2008 of some 332 million barrels.

All the oil fields discovered so far are located in the North Sea. Out of 21 fields or areas with reserves in the ongoing/approved category, four (Dan, Halfdan, Skjold and South Arne) account for 75% of the total volume.

The principal fields in production in 2008 were Halfdan, Dan, Valdemar, South Arne and Gorm, which together accounted for 78% of national oil output. Over 60% of Danish crude is exported, chiefly to other countries in Western Europe.

Ecuador

Proved recoverable reserves (crude oil and NGLs, million barrels)	6 511
2008 production (crude oil and NGLs, thousand b/d)	514
R/P ratio (years)	34.6
Year of first commercial production	1917

The early discoveries of oil (1913-1921) were made in the Santa Elena peninsula on the southwest coast. From 1967 onwards, numerous oil fields were discovered in the Amazon Basin in the northeast of the country, adjacent to the Putamayo fields in Colombia: these eastern (Oriente) fields are now the major source of Ecuador's oil production. The republic reactivated its membership of OPEC in October 2007, after suspending it in December 1992.

In view of Ecuador's resumption of its membership of OPEC, the level of proved reserves published in the latter's 2008 *Annual Statistical Bulletin* has been adopted for inclusion in the present *Survey*. The end-2008 level of proved reserves given by OPEC (6 511 million barrels) is appreciably higher than that in other current published sources, apart from *Oil & Gas Journal*, which has raised its estimate from 4 660 million barrels at 1 January 2009 to 6 500 at 1 January 2010.

Ecuador's 2008 oil output of 514 000 b/d (including a small amount of NGLs) was 5.7% below the peak level achieved in 2006. About two-thirds of crude oil production is exported, the rest being refined locally.

Egypt (Arab Republic)

Proved recoverable reserves (crude oil and NGLs, million barrels)	4 200
2008 production (crude oil and NGLs, thousand b/d)	722
R/P ratio (years)	15.9
Year of first commercial production	1911

Egypt has the sixth largest proved oil reserves in Africa, with over half located in its offshore waters. The main producing regions are in or alongside the Gulf of Suez and in the Western Desert.

According to the executive chairman of the Egyptian General Petroleum Corporation, speaking in December 2008, Egypt's reserves of crude oil and condensates were 4.2 billion barrels at the end of June 2008. Published reports of Egypt's reserves fall within a fairly narrow band, ranging from the *Oil & Gas Journal*'s 3 700 to *World Oil*'s 4 341 (both million barrels): the differences between these sources are probably mostly a function of timing.

Egypt is a member of OAPEC, although its crude oil exports account for less than 10% of its production. Total oil output (including condensate and gas-plant LPGs) has been slowly increasing since 2005.

Equatorial Guinea

Proved recoverable reserves (crude oil and NGLs, million barrels)	1 705
2008 production (crude oil and NGLs, thousand b/d)	361
R/P ratio (years)	12.9
Year of first commercial production	1992

The Alba offshore condensate field was discovered in 1984 near the island of Bioko, a province of Equatorial Guinea, by the American company Walter International. In 1996, four years after Alba was brought into production, Mobil and its U.S. partner United Meridian began producing from Zafiro, another offshore field. Output built up rapidly in subsequent years: crude oil production in Equatorial Guinea exceeded 360 000 b/d in 2008.

For the purposes of the present *Survey*, the level of proved reserves published by *World Oil* (1 705 million barrels), and also quoted by BP, has been adopted; *Oil & Gas Journal* has retained its end-2006 assessment of 1 100 million barrels.

Gabon

Proved recoverable reserves (crude oil and NGLs, million barrels)	3 684
2008 production (crude oil and NGLs, thousand b/d)	235
R/P ratio (years)	42.8
Year of first commercial production	1961

Extensive oil resources have been located, both on land and offshore. In terms of proved recoverable reserves, Gabon ranks third largest in sub-Saharan Africa, after Nigeria and Angola.

The level of proved recoverable reserves adopted for the present *Survey* is that quoted by *World Oil* (3 684 million barrels). *Oil & Gas Journal* has retained its much lower level of 2000 million barrels. Other published sources show similar divergence: OPEC's number being close to OGJ's, whilst BP opts for the higher level favoured by *World Oil*.
Gabon was a member of OPEC from 1975 to 1995, when it withdrew on the grounds that it was unfair for it to be charged the same membership fee as the larger producers but not to have equivalent voting rights.

In recent years over 90% of Gabon's oil output has been exported, mainly to the USA.

Ghana

Proved recoverable reserves (crude oil and NGLs, million barrels)	15
2008 production (crude oil and NGLs, thousand b/d)	6
R/P ratio (years)	6.8
Year of first commercial production	1978

Ghana's oil output is currently one of Africa's smallest, but recent exploration successes seem likely to propel it into at least the middle rank of regional producers.

The Jubilee field, a substantial oil discovery that straddles two deep water exploration licence areas (Deepwater Tano and West Cape Three Points) in Ghana's offshore, is being developed by the field operator Tullow Oil, with first production scheduled for the fourth quarter of 2010. In March 2009, Tullow announced another promising discovery (Tweneboa) in the Deepwater Tano licence area, about 25 km west of the Jubilee field.

India

Proved recoverable reserves (crude oil and NGLs, million barrels)	5 836
2008 production (crude oil and NGLs, thousand b/d)	820
R/P ratio (years)	19.4
Year of first commercial production	1890

Drawing upon *Basic Statistics on Indian Petroleum & Natural Gas 2008-09*, published by the Ministry of Petroleum & Natural Gas, the level of total oil reserves (as at 1 April 2009) adopted for the present *Survey* is 775 million tonnes, of which 369 million tonnes is located offshore. Onshore reserves have risen by 7.7% from the 376 million tonnes (at 1 April 2005) reported for the 2007 *Survey* to 405 million tonnes, whereas offshore reserves have fallen by 10% from 410 to 369 million tonnes.

The Ministry points out that its reserve estimates relate to 'proved and indicated amounts'. They are therefore analogous to the 'proved plus probable', or 2P category. Published compilations of reserves tend to reflect the official figures, with minor variations attributable to the use of different conversion factors and/or differences in timing.

For more than 60 years after its discovery in 1890, the Digboi oil field in Assam, in the northeast of the country, provided India with its only commercial oil production: this field was still producing in 2009, albeit at a very low level. Since 1960 numerous onshore discoveries have been made in the western, eastern and southern parts of India; the outstanding find was, however, made in offshore waters in 1974, when the Mumbai High oil and gas field was discovered. In 2008-2009 offshore fields provided 66% of national oil output.

Total production of oil (including gas-plant liquids) has fluctuated in recent years within a range of 36-38 million tonnes per annum. In 2008, India produced 34.0 million tonnes of crude oil, plus about 2 million tonnes of natural gasoline and a similar tonnage of gas-plant LPGs, all of which was used internally.

Cairn Energy has made 25 discoveries in Rajasthan (in India's northwest). Initial attention is being concentrated on the Mangala, Bhagyam and Aishwariya (MBA) oil fields. Production from Mangala began in August 2009, when Processing Train One came into operation. The start-up of Trains Two and Three is scheduled for the second quarter of 2010, together with the commissioning of a 600 km heated pipeline from the Mangala Processing Terminal to the port of Salaya in Gujarat. Production from Mangala, currently about 20 000 b/d, is planned to rise to the currently approved plateau rate of 125 000 b/d in the second half of 2010. An eventual peak rate of 240 000 b/d is envisaged, subject to Government approval and additional investment.

Indonesia

Proved recoverable reserves (crude oil and NGLs, million barrels)	3 750
2008 production (crude oil and NGLs, thousand b/d)	1 004
R/P ratio (years)	10.2
Year of first commercial production	1893

The first commercial discovery of oil was made in north Sumatra in 1885; subsequent exploration led to the finding of many more fields, especially in southern Sumatra, Java and Kalimantan.

Proved recoverable reserves at end-2008 were 3 750 million barrels, according to data released by the Directorate General of Oil and Gas and published in the *Handbook of Energy & Economic Statistics of Indonesia 2009*. This level is somewhat lower than that quoted by most external published sources, but in the majority of cases this merely reflects the passage of time. *Oil & Gas Journal*, OAPEC, OPEC and BGR all appear to be quoting the year-earlier official level of proven reserves: 3 990 million barrels as at 1 January 2008.

In 2008 Indonesia exported about 38% of its output of crude oil and condensate, as well as about half of its production of gas-plant LPGs. The bulk of its oil exports are consigned to Japan, Australia and the Republic of Korea.

After being a member since 1962, Indonesia suspended its OPEC membership in December 2008.

Iran (Islamic Republic)

Proved recoverable reserves (crude oil and NGLs, million barrels)	137 610
2008 production (crude oil and NGLs, thousand b/d)	4 504
R/P ratio (years)	83.5
Year of first commercial production	1913

The first commercial crude oil discovered in Iran was at Masjid-i-Sulaiman in 1908. Further exploration in the next two decades resulted in the discovery of a number of major oil fields, including Agha Jari and Gach Saran. Fields such as these confirmed Iran in its role as a global player in the oil industry.

After many years as a major oil producer, the country's oil resources are still enormous: proved reserves, as reported for the present *Survey* by the Iranian WEC Member Committee, comprise 100.65 billion barrels of crude oil plus 36.96 billion barrels of NGLs. Total reported reserves are almost identical to those quoted by BP and closely in line with those given by other standard published sources (136.15-138.20), which is possibly somewhat surprising, in that several of these sources specifically exclude natural gas liquids from their compilations.

The Member Committee reports that approximately 14% of Iran’s proved reserves of crude and 55% of its NGLs are located offshore.

Iran was a founder member of OPEC in 1960. In 2008, about 60% of Iran's crude oil output of 4.1 million b/d was exported, mostly to Europe and Asia.

Iraq

Proved recoverable reserves (crude oil and NGLs, million barrels)	115 000
2008 production (crude oil and NGLs, thousand b/d)	2 423
R/P ratio (years)	>100
Year of first commercial production	1928

Crude oil deposits were discovered near Kirkuk in northern Iraq in 1927, with large-scale production getting under way in 1934-1935 following the construction of export pipelines to the Mediterranean. After World War II more oil fields were discovered and further export lines built. Proved reserves, as quoted by OAPEC, OPEC and most of the other standard published sources, remain at 115 billion barrels, third after Saudi Arabia and Iran in the Middle East, and indeed in the world. The only exception is *World Oil*, which since end-2006 has estimated Iraq's crude reserves at a somewhat higher level, currently 126 billion barrels.

Iraq was a founder member of OPEC in 1960 and it is also a member of OAPEC. According to provisional data published by OPEC, crude oil exports amounted to 1 855 thousand b/d in 2008, with 34% destined for the USA, 32% for Asia/Pacific and 21% for Western Europe.

Italy

Proved recoverable reserves (crude oil and NGLs, million barrels)	434
2008 production (crude oil and NGLs, thousand b/d)	105
R/P ratio (years)	11.3
Year of first commercial production	1861

Like France and Germany, Italy has a long history of oil production, albeit on a very small scale until the discovery of the Ragusa and Gela fields in Sicily in the mid-1950s. Subsequent exploration led to the discovery of a number of fields offshore Sicily, several in Adriatic waters and others onshore in the Po Valley Basin.

The Italian WEC Member Committee reports that proved recoverable reserves at end-2008 were 62 million tonnes (equivalent to approximately 434 million barrels), out of a remaining proved amount in place of 128 million tonnes. Recoverable reserves at lower levels of probability comprised 93 million tonnes (651 million barrels) of probable reserves and 104 million tonnes (728 million barrels) of possible reserves. The Member Committee also estimates that undiscovered *in situ* oil resources are in the order of 55 to 370 million tonnes (in round terms, some 400 to 2 700 million tonnes).

Total oil output (including minor quantities of NGLs) peaked at 6.1 million tonnes in 2005, subsequently declining to about 5.2 million in 2008. Italy's cumulative oil production to the end of 2008 is reported to have been 157 million tonnes.

Kazakhstan

Proved recoverable reserves (crude oil and NGLs, million barrels)	22 762
2008 production (crude oil and NGLs, thousand b/d)	1 554
R/P ratio (years)	40.0
Year of first commercial production	1911

Kazakhstan's oil resources are the largest of all the former Soviet republics (apart from the Russian Federation). Previous editions of the *Survey of Energy Resources* have had to rely on external published sources for assessments of Kazakhstan's oil resources. Now that Kazakhstan has become a member of the World Energy Council, the SER has the benefit of advice from the Kazakhstan Member Committee, which reports that proved recoverable reserves of crude oil/condensate were 2 907 million tonnes (22 762 million barrels) at end-2008. At end-2007, probable reserves were 4 800 million tonnes (approximately 38 billion barrels) and possible reserves 13 billion tonnes (102 billion barrels). About 62% of the proved reserves are located beneath the waters of the Caspian Sea.

The Member Committee also reports that more than 90% of the republic's oil reserves are concentrated in its 15 largest oil fields, namely Tengiz, Kashagan, Karachaganak, Uzen, Zhetybai, Zhanazhol, Kalamkas, Kenkiyak, Karazhanbas, Kumkol, Buzachi Severnye, Alibekmola, Prorva Tsentalnaya and Vostochnaya, Kenbai, Korolyovskoye.

Output of oil more than doubled between 2000 and 2008 to some 72 million tonnes (1 554 000 b/d), including condensate and other NGLs. In 2007, exports accounted for about 92% of the republic's oil production.

Kuwait

Proved recoverable reserves (crude oil and NGLs, million barrels)	101 500
2008 production (crude oil and NGLs, thousand b/d)	2 784
R/P ratio (years)	99.6
Year of first commercial production	1946

Note: Kuwait data include its share of Neutral Zone.

The State of Kuwait is one of the most oil-rich countries in the world: it currently ranks fourth in terms of the volume of proved reserves. Oil was discovered at Burgan in 1938 and commercial production commenced after World War II. Seven other oil fields were discovered during the next 15 years and output rose rapidly. Kuwait was one of the founder members of OPEC in 1960 and is also a member of OAPEC.

The level of proved recoverable reserves adopted for the present *Survey* is 101.5 billion barrels, as quoted by OAPEC, OPEC and BP. *Oil & Gas Journal* opts for a slightly higher level of 104.0 billion barrels, while *World Oil* gives the marginally lower figure of 99.425.

Kuwait's crude production in 2008 averaged 2.78 million b/d, of which 1.74 million b/d, or 63%, was exported. The main markets for Kuwaiti crude were Japan, other Asian countries, North America and Western Europe.

Libya/GSPLAJ

Proved recoverable reserves (crude oil and NGLs, million barrels)	44 271
2008 production (crude oil and NGLs, thousand b/d)	1 846
R/P ratio (years)	65.5
Year of first commercial production	1961

Libya accounts for about one-third of Africa's proved oil reserves. The majority of the known oil reservoirs lie in the northern part of the country; there are a few offshore fields in western waters near the Tunisian border. The crudes produced are generally light (over 35^{o} API) and very low in sulphur.

The level of proved reserves adopted for the present *Survey* is based upon data published by OPEC in its *Annual Statistical Bulletin 2008*, and is some 1.4% higher than the level of around 43 700 million barrels quoted by other published sources (with the exception of the *Oil & Gas Journal* recently published figure for 1 January 2010). As OPEC quoted 43 663 in respect of end-2007, it may be deduced that their end-2008 level of 44 271 million barrels represents an updated assessment which other published sources (apart from OGJ) have not yet had an opportunity to reflect.

Libya joined OPEC in 1962 and is also a member of OAPEC. It exported over 80% of its oil output in 2008, mostly to Western Europe.

Malaysia

Proved recoverable reserves (crude oil and NGLs, million barrels)	5 357
2008 production (crude oil and NGLs, thousand b/d)	754
R/P ratio (years)	19.4
Year of first commercial production	1913

Oil was discovered at Miri in northern Sarawak in 1910, thus ushering in Malaysia's long history as an oil producer. However, it was not until after successful exploration in offshore areas of Sarawak, Sabah and peninsular Malaysia in the 1960s and 1970s that the republic really emerged as a major producer.

For a number of years, there appears to have been considerable uncertainty with regard to the level of Malaysia's proved oil reserves. At the time of the compilation of the 2007 SER, proved reserves, as reported by *Oil & Gas Journal*, having remained in the vicinity of 4 billion barrels from the early 1990s to end-2001, had recently been reduced to 3 billion barrels. This level was retained by OGJ through to end-2007, when it reverted to 4 billion barrels.

As another example, OPEC, in its 2007 *Annual Statistical Bulletin*, quoted Malaysia's reserves as 3 056 million barrels in 2003, declining gradually to 2 840 in 2007. A year later, the ASB gave a substantially revised series, rising from 5 160 million barrels in 2004 to 5 357 in 2006-2008. The *World Oil* assessment has climbed from 2 892 at end-2005 to 5 200 at end-2008, while BP's figure has risen from 4 200 to 5 500 over the same period.

Thus, while there is no agreement amongst the various compilers, there appears to be a general tendency for the incorporation of higher levels than previously. For the present *Survey*, OPEC's level of 5 357 million barrels has been adopted.

Since 2006, crude oil production has been gradually increasing, but condensate output has fallen slightly. In 2007, about half of Malaysian crude oil/condensate production was exported, chiefly to Thailand, Korea Republic, Indonesia, Japan and India.

Mexico

Proved recoverable reserves (crude oil and NGLs, million barrels)	11 865
2008 production (crude oil and NGLs, thousand b/d)	3 158
R/P ratio (years)	10.3
Year of first commercial production	1904

Mexico's massive oil resource base has given rise to one of the world's largest oil industries, centred on the national company Petróleos Mexicanos (Pemex), founded in 1938.

The Mexican WEC Member Committee has reported proved recoverable reserves (at 1 January 2009) of 10 404 million barrels of crude oil and 1 461 million barrels of NGLs (378 condensate plus 1 083 plant liquids), which correspond with the 'proved reserves' given by Pemex in its 2009 edition of *Las reservas de hidrocarburos de México*. In addition to these proved oil reserves (totalling 11 865 million barrels), Pemex quotes probable reserves as 11 632 (10 376 crude oil, 82 condensate and 1 174 plant liquids) and possible reserves as a further 11 485 (10 150 crude oil, 101 condensate and 1 234 plant liquids (all figures expressed in millions of barrels).

Within Mexico's total oil reserves of some 35 billion barrels, the North zone accounts for 41.0%, the Marine Northeast for 35.1%, the South zone for 13.0% and the Marine Southwest for 10.9%. As regards its proved reserves, 68% of the crude oil, 78% of the condensate and 37% of the gas-plant liquids are located in offshore waters.

Commercial oil production began in 1904 and by 1918 the republic was the second largest producer in the world. The discovery and development of oil fields along the eastern coast of the country - in particular, the offshore reservoirs off the coast of the State of Campeche - have brought annual production up to its present level. In 2008 oil output comprised 2 792 000 b/d crude oil and 366 000 b/d of condensates and gas-plant liquids; exports of crude totalled 1 817 000 b/d, of which some 78% was consigned to the USA.

Nigeria

Proved recoverable reserves (crude oil and NGLs, million barrels)	37 200
2008 production (crude oil and NGLs, thousand b/d)	2 170
R/P ratio (years)	46.8
Year of first commercial production	1957

Nigeria's proved oil reserves are the second largest in Africa, after those of Libya. The country's oil fields are located in the south, mainly in the Niger delta and offshore in the Gulf of Guinea. Nigeria has been a member of OPEC since 1971.

Published assessments of Nigeria's proved recoverable reserves (as at end-2008) are now close to consensus, after divergences in earlier years. For the purposes of the present *Survey*, the level of 37 200 million barrels reported by OPEC (*Annual Statistical Bulletin 2008*) has been adopted. Other published sources quote very similar figures, within a narrow range (36 200 to 37 200).

Nigeria exports much the greater part of its crude oil output, chiefly to North America and Western Europe, and imports the bulk of its refined product requirements.

Norway

Proved recoverable reserves (crude oil and NGLs, million barrels)	7 491
2008 production (crude oil and NGLs, thousand b/d)	2 456
R/P ratio (years)	8.3
Year of first commercial production	1971

Starting with the discovery of the Ekofisk oil field in 1970, successful exploration in Norway's North Sea waters has brought the country into No. 1 position in Europe (excluding the Russian Federation), in terms of oil in place, proved reserves and production.

On the basis of data published by the Norwegian Petroleum Directorate (NPD), total remaining oil reserves at end-2008 amounted to 7 491 million barrels, comprised of 919 million m^3 (5 780 million barrels) of crude oil, 120 million tonnes (1 440 million barrels) of NGLs and 43 million m^3 (270 million barrels) of condensate. ‘Remaining reserves’ are defined as ‘remaining recoverable petroleum resources in deposits for which the authorities have approved the plan for development and operation (PDO) or granted a PDO exemption’. They ‘also include petroleum resources in deposits that the licensees have decided to develop, but for which the authorities have not as yet completed processing of either a PDO approval or a PDO exemption'.

In addition to 'remaining reserves', the NPD reports 'contingent resources', defined as 'discovered quantities of petroleum for which no development decision has yet been made', and 'potential from improved recovery': together these represent 688 million m^3 (4 327 million barrels) of crude oil, 42 million tonnes (502 million barrels) of NGLs and 32 million m^3 (201 million barrels) of condensate - a total additional recoverable resource of just over 5 billion barrels. Over and above these amounts, the NPD estimates that Norway possesses about 9.6 billion barrels of 'undiscovered resources', comprising 1 260 million m^3 (7 925 million barrels) of crude oil and 265 million m^3 (1 667 million barrels) of condensate. Undiscovered resources include 'petroleum volumes expected to be present in defined plays, confirmed and unconfirmed, but which have not yet been proven by drilling'.

As a frame of reference, it may be noted that Norway's cumulative oil production to the end of 2008 consisted of 3 405 million m^3 (21 417 million barrels) of crude oil, 116 million tonnes (1 386 million barrels) of NGLs and 96 million m^3 (604 million barrels) of condensate, for a grand total of 23 407 million barrels of oil, compared with its total remaining discovered and undiscovered oil resources of 22 106 million barrels.

Following 16 years of unremitting growth, Norwegian oil production levelled off in the late 1990s and since 2001 has followed a gently downward path. Nearly 84% of Norway's 2008 crude oil production of some 2.1 million b/d was exported, mostly to Western European countries, Canada and the USA.

Oman

Proved recoverable reserves (crude oil and NGLs, million barrels)	5 500
2008 production (crude oil and NGLs, thousand b/d)	763
R/P ratio (years)	19.7
Year of first commercial production	1967

In a regional context, this is one of the less well-endowed Middle East countries but its proved reserves are, nevertheless, quite substantial (5.5 billion barrels at end-2008, according to OAPEC). Other published sources of reserves data generally concur.

Three oil fields were discovered in the northwest central part of Oman in the early 1960s; commercial production began after the construction of an export pipeline. Many other fields have subsequently been located and brought into production, making the country a significant oil producer and exporter; it has, however, never joined OPEC or OAPEC.

Production of crude oil and condensate steadily increased over the years but peaked in 2001, subsequently falling to an average of 757 000 b/d in 2008. A high proportion of Oman's crude oil output is exported, mainly to China, Japan and Southeast Asia.

Papua New Guinea

Proved recoverable reserves (crude oil and NGLs, million barrels)	70
2008 production (crude oil and NGLs, thousand b/d)	41
R/P ratio (years)	4.7
Year of first commercial production	1992

Five sedimentary basins are known to exist in PNG. Most exploration activity, and all hydrocarbon discoveries to date, have occurred in the Papuan Basin in the southern part of the mainland. After many campaigns of exploration (starting in 1911), the first commercial discoveries were eventually made during the second half of the 1980s. Commercial production began in 1992 after an export pipeline had been built.

Based on reserves data for end-2008 published by Oil Search Limited, a leading operator in PNG, the country's total proved reserves stood at just over 70 million barrels, with probable reserves adding another 34 million barrels. These estimates have been derived from Oil Search's own reserves, grossing-up its stated reserves in each field/licence area by dividing by the relevant percentage interest. The result of these calculations is somewhat lower than the level quoted by *Oil & Gas Journal* (88 million barrels) and substantially less than that given by *World Oil* (210 million barrels).

Output in 2008 averaged 41 022 b/d of crude oil, plus a very minor quantity of condensate obtained during the production of Hides sales gas. The oil exported is a blend called Kutubu Light (45° API).

Peru

Proved recoverable reserves (crude oil and NGLs, million barrels)	1 121
2008 production (crude oil and NGLs, thousand b/d)	120
R/P ratio (years)	25.5
Year of first commercial production	1883

Peru is probably the oldest commercial producer of oil in South America. The latest available national published reserves data were published by the Ministerio de Energía y Minas in its 2007 *Libro Anual de Reservas*. This shows that proved recoverable reserves at end-2007 consisted of 447.4 million barrels of crude oil and 674.1 million barrels of NGLs, of which the developed volumes account for 344.2 and 259.0 million barrels, respectively. The implied total of 1 121 million barrels corresponds quite closely with the levels published by BP and *World Oil*, although the latter normally aims to exclude NGLs from its reserves figures. *Oil & Gas Journal* quotes the lower (i.e. crude oil only) ministerial level.

The Ministerio de Energía y Minas also quotes (in million barrels) 'probable reserves' of around 661 crude and 294 NGL, and 'possible reserves' of 4 907 crude and 384 NGL.

For many years oil production was centred on the fields in the Costa (coastal) area in the northwest; from about 1960 onwards the Zocalo (continental shelf) off the northwest coast and the Selva (jungle) area east of the Andes came into the picture. In 2008 the Selva fields accounted for 68% of total oil output, the Costa fields for 21% and the Zocalo for nearly 11%. Production of crude oil has levelled off in recent years, but output of NGLs has recently been growing rapidly.

Qatar

Proved recoverable reserves (crude oil and NGLs, million barrels)	25 405
2008 production (crude oil and NGLs, thousand b/d)	1 378
R/P ratio (years)	50.4
Year of first commercial production	1949

In regional terms, Qatar's oil resources are relatively small, its strength being much more in natural gas. In the 1930s interest in its prospects was aroused by the discovery of oil in neighbouring Bahrain. The Dukhan field was discovered in 1939 but commercialisation was deferred until after World War II. During the period 1960-1970, several offshore fields were found, and Qatar's oil output grew steadily. It joined OPEC in 1961 and also became a member of OAPEC.

The level of proved recoverable oil reserves (25 405 million barrels) adopted for the present *Survey* is that stated by OPEC in its *Annual Statistical Bulletin 2008*. After quoting a static level of 15 207 for a number of years past, OPEC has revised its assessment of Qatar's oil reserves sharply upwards and incorporated comparable revisions to all years back to 2003 inclusive. These upward adjustments might be attributable to the belated incorporation of NGL reserves, but this procedure would not be consistent with OPEC's normal policy of quoting 'crude oil only' levels of reserves.

Currently BP and *Oil & Gas Journal* (as at 1 January 2010) broadly concur with OPEC's assessment, but *World Oil* is considerably lower at 20 000 million barrels, whilst in its 2008 *Annual Report* OAPEC retained a level of 15 210.

Qatar is a major producer of NGLs, with an output of about 535 000 b/d in 2008. Exports of crude oil and NGLs are consigned very largely to Japan, the Republic of Korea and other Asia/Pacific countries.

Romania

Proved recoverable reserves (crude oil and NGLs, million barrels)	411
2008 production (crude oil and NGLs, thousand b/d)	92
R/P ratio (years)	12.2
Year of first commercial production	1857

Despite being one of Europe's oldest oil producers, Romania still possesses substantial oil resources. The Romanian WEC Member Committee, quoting the National Agency for Mineral Resources, reports recoverable reserves of 54 million tonnes of crude plus 0.54 million tonnes of NGLs. The estimated additional recoverable reserves reported comprise 9 million tonnes of 'probable' reserves and 6 million tonnes in the 'possible' category, together with minor tonnages of NGLs.

The principal region of production has long been the Ploesti area in the Carpathian Basin to the northwest of Bucharest, but a new oil province has come on the scene in recent years with the start-up of production from two offshore fields (West and East Lebada) in the Black Sea. Within the figure of proved recoverable reserves given above, 2.2 million tonnes of crude oil is reported to be located in offshore waters. In national terms, oil output (including NGLs) has been gradually contracting since around 1995. Cumulative production of crude oil stood at some 746 million tonnes (approximately 5.6 billion barrels) at the end of 2008.

Russian Federation

Proved recoverable reserves (crude oil and NGLs, million barrels)	79 000
2008 production (crude oil and NGLs, thousand b/d)	9 886
R/P ratio (years)	21.8
Year of first commercial production	NA

The Russian oil industry has been developing for well over a century, much of that time under the Soviet centrally planned and state-owned system, in which the achievement of physical production targets was of prime importance. After World War II, hydrocarbons exploration and production development shifted from European Russia to the east, with the opening-up of the Volga-Urals and West Siberia regions.

As the Russian WEC Member Committee was unable to supply up-to-date assessments of hydrocarbon reserves, for reasons of confidentiality, the level of proved recoverable reserves adopted for the present *Survey* is based on the estimate of 79 000 million barrels published by BP in its *Statistical Review of World Energy*, June 2009. *World Oil* has quoted Russian oil reserves as 76 billion barrels for end-2006 through end-2008. *Oil & Gas Journal* has retained its estimate of 60 billion barrels for both end-2008 and end-2009, and OAPEC has now swung into line with OGJ for all years from 2004 to 2008.

Production levels in Russia advanced strongly from the mid-1950s to around 1980 when output levelled off for a decade. After a sharp decline in the first half of the 1990s, oil production levelled off again, at around 305 million tonnes/yr, until an upward trend starting in 2000 brought the total up to 488.5 million tonnes (nearly 9.9 million b/d) in 2008. Russia exports more than half of its oil production.

Saudi Arabia

Proved recoverable reserves (crude oil and NGLs, million barrels)	264 063
2008 production (crude oil and NGLs, thousand b/d)	10 846
R/P ratio (years)	66.5
Year of first commercial production	1938

NOTE: Saudi Arabia data include its share of the Neutral Zone, together with production from the Abu Safa oilfield (jointly owned with Bahrain).

The Kingdom has been a leading oil producer for more than 40 years and currently has by far the world's largest proven reserves of oil: at end-2008 these represented about 21% of the global total. The first major commercial discovery of oil in Saudi Arabia was the Dammam field, located by Aramco in 1938; in subsequent years the company discovered many giant fields, including Ghawar (1948), generally regarded as the world's largest oil field, and Safaniyah (1951), the world's largest offshore field.

Whilst not displaying an exact consensus, current published assessments of Saudi Arabia's proved oil reserves at end-2008 fall within a narrow bracket: namely (in billions of barrels), *World Oil* 262.325, OPEC (as used in this *Survey*) 264.063, BP 264.100, OAPEC 264.250 and *Oil & Gas Journal* 266.710 (262.400 at 1/1/10). The latest OPEC level corresponds with the (slightly rounded) figure given in the Saudi Arabian Monetary Agency’s *Annual Report 2008*.

Saudi Arabia was a founder member of OPEC and also of OAPEC. It exports about 80% of its crude oil output; major destination regions are Asia, North America and Western Europe.

It was reported in March 2009 that Chevron would shortly begin large-scale testing of a heavy-oil extraction technique in the partitioned Neutral Zone between Saudi Arabia and Kuwait. The American company has recently been granted a 30-year extension to its Neutral Zone operating licence by the Saudi Government.

Sudan

Proved recoverable reserves (crude oil and NGLs, million barrels)	6 700
2008 production (crude oil and NGLs, thousand b/d)	480
R/P ratio (years)	38.1
Year of first commercial production	1992

Several oil fields, including Heglig and Unity, were discovered in south-central Sudan in the early 1980s but terrorist action forced the companies concerned to withdraw. Other foreign companies started to undertake exploration and development activities some 10 years later. The principal published sources currently fall into two groups: *World Oil*, OPEC and BP all quote 6 700 million barrels for end-2008 proved reserves, whilst *Oil & Gas Journal* and OAPEC prefer a lower level (5 000 million barrels). For the present *Survey*, the *World Oil* figure has been adopted, in line with the 2007 edition.

Commercial production from the Heglig field began in 1996, since when Sudan has developed into an oil producer and exporter of some significance, a key factor being the construction of a 250 000 b/d export pipeline to the Red Sea. Sudan's oil production in 2008 averaged 480 000 b/d.

Syria (Arab Republic)

Proved recoverable reserves (crude oil and NGLs, million barrels)	2 459
2008 production (crude oil and NGLs, thousand b/d)	351
R/P ratio (years)	19.1
Year of first commercial production	1968

After many years (1930-1951) of unsuccessful exploration, oil was eventually found in 1956 at Karachuk. This and other early discoveries mostly consisted of heavy, high-sulphur crudes. Subsequent finds, in particular in the Deir al-Zor area in the valley of the Euphrates, have tended to be of much lighter oil.

For the 2007 SER, the Syrian WEC Member Committee reported that proved recoverable reserves at end-2005 were 391 million m^3 (2 459 million barrels). This level has been retained for the present *Survey*, as it is in line with the majority of the (obviously very rounded) estimates given by published sources: *Oil & Gas Journal*, OPEC and BP all show 2 500; *World Oil* quotes 2 800, while OAPEC is the only outlier at 4 150 (all figures in millions of barrels).

National oil output has declined in recent years; according to the National Bureau of Statistics, crude oil production averaged 348 000 b/d in 2008, a decrease of 17.3% compared with 2005. Syria is a member of OAPEC: exports accounted for about 40% of its crude oil production in 2007, with its principal customers being Germany, Italy and France.

Thailand

Proved recoverable reserves (crude oil and NGLs, million barrels)	453
2008 production (crude oil and NGLs, thousand b/d)	325
R/P ratio (years) (see below)	5.3
Year of first commercial production	1959

Resources of crude oil and condensate are not very large in comparison with many other countries in the region. The data reported by the Thai WEC Member Committee for the present *Survey* show that, after cumulative production to the end of 2008 of 463 million barrels of crude oil, Thailand's remaining proved oil reserves were some 182 million barrels of crude, plus 271 million barrels of condensate. Approximately 70% of the crude reserves and virtually all of the condensate reserves are located in Thailand's offshore waters. Data on reserves of other NGLs were not provided; consequently the calculated reserves/production ratio shown above is based on crude-plus-condensate production of 232 000 b/d in 2008.

Further recoverable amounts (in millions of barrels) reported by the Member Committee consist of 422 probable reserves of crude oil and 337 of condensate, plus 176 possible reserves of crude and 134 of condensate. The total of recoverable reserves of crude oil of some 780 million barrels is closely matched by the corresponding total for condensate (742 million barrels).

Total output of oil (crude oil, condensate and other NGLs) has more than doubled since 1999, with an average of 325 000 b/d in 2008. Exports have declined since 2006 to an average of about 40 000 b/d.

Trinidad & Tobago

Proved recoverable reserves (crude oil and NGLs, million barrels)	606
2008 production (crude oil and NGLs, thousand b/d)	149
R/P ratio (years)	11.1
Year of first commercial production	1908

The petroleum industry of Trinidad has passed its centenary, several oil fields that are still in production having been discovered in the first decade of the 20th century. Its remaining recoverable reserves are small in regional terms. The latest available assessment is 606 million barrels, as stated by the Minister of Energy and Energy Industries in 2008. Whilst *World Oil* quotes a similar figure, *Oil & Gas Journal* shows 728 and BP 800.

In his presentation, the Minister also stated that Trinidad's probable reserves of oil were 335 million barrels and possible reserves a further 1 561 million barrels, making the republic's 3P oil reserve just over 2.5 billion barrels.

The oil fields that have been discovered are mostly in the southern part of the island or in the corresponding offshore areas (in the Gulf of Paria to the west and off Galeota Point at the southeast tip of the island).

Production of crude oil and condensates fell sharply in 2007 and to a lesser extent in 2008; output is now down to about 114 000 b/d, over 30 000 b/d less than in 2005. However, output of gas plant liquids continues to grow, reaching nearly 35 000 b/d in 2008, almost all of which was exported.

Turkmenistan

Proved recoverable reserves (crude oil and NGLs, million barrels)	600
2008 production (crude oil and NGLs, thousand b/d)	205
R/P ratio (years)	8.0
Year of first commercial production	1911

This republic has been an oil producer for nearly a century, with a cumulative output of more than 5 billion barrels. According to *Oil & Gas Journal*, echoed by OAPEC and BP, its proved reserves are some 600 million barrels. Known hydrocarbon resources are located in two main areas: the South Caspian Basin to the west and the Amu-Darya Basin in the eastern half of the country.

After production growth averaging nearly 12% per annum from 1995 to 2003, oil output (including NGLs) fell by an overall 8% during the three years that followed, but has since recovered the lost ground, reaching a post-1985 high of 205 000 b/d in 2008.

Uganda

The independent oil company Tullow Oil is seeking to develop (in conjunction with two prospective partners) a number of promising oil fields that have been discovered in the vicinity of Lake Albert. Production from the Kasamene field, to serve industrial consumers within Uganda, is expected to commence by the end of 2011. Full exploitation of the deposits might require the construction of an export pipeline to the Indian Ocean coast, although other possibilities are being examined.

United Arab Emirates

Proved recoverable reserves (crude oil and NGLs, million barrels)	97 800
2008 production (crude oil and NGLs, thousand b/d)	2 980
R/P ratio (years)	89.7
Year of first commercial production	1962

The United Arab Emirates comprises Abu Dhabi, Dubai, Sharjah, Ras al-Khaimah, Umm al-Qaiwain, Ajman and Fujairah. Exploration work in the three last-named has not found any evidence of oil deposits on a commercial scale. On the other hand, the four emirates endowed with oil resources have, in aggregate, proved reserves on a massive scale, in the same bracket as those of Iran, Iraq and Kuwait. Abu Dhabi has by far the largest share of UAE reserves and production, followed at some distance by Dubai. The other two oil-producing emirates are relatively minor operators.

The UAE's proved oil reserves at end-2008 are quoted by OPEC as 97.8 billion barrels, a level unchanged since 1995. According to OPEC, Abu Dhabi accounts for 94.3% of proved reserves, Dubai for 4.1%, Sharjah for 1.5% and Ras al-Khaimah for 0.1%. With the exception of *World Oil*, which quotes 96 billion barrels, all the other major published sources concur exactly with the level that OPEC has retained.

According to the 2008 OPEC *Annual Statistical Bulletin*, output of crude oil averaged 2.57 million b/d in 2008, of which the bulk was exported, almost all to Japan and other Asia/Pacific destinations. The UAE has been a member of OPEC since 1967 and is also a member of OAPEC.

United Kingdom

Proved recoverable reserves (crude oil and NGLs, million barrels)	3 060
2008 production (crude oil and NGLs, thousand b/d)	1 526
R/P ratio (years)	5.5
Year of first commercial production	1919

Proved recoverable reserves, as reported by the UK WEC Member Committee, are based on a report by the Department of Energy and Climate Change (DECC) entitled *UK Oil and Gas Reserves and Resources* (September 2009). Proved recoverable reserves (termed ‘proven reserves’ by DECC) amounted to 408 million tonnes (approximately 3 060 million barrels) at end-2008. This figure compares with the United Kingdom's cumulative oil production of some 3 315 million tonnes (approaching 25 billion barrels).

In addition, there are estimated to be 361 million tonnes (2.7 billion barrels) of 'probable reserves', with 'a better than 50% chance of being technically and economically producible', and a further 360 million tonnes of 'possible reserves', with 'a significant but less than 50% chance of being technically and economically producible'.

Compared with the assessments for end-2005 quoted in the 2007 SER, there has been a net reduction of 108 million tonnes in proven reserves, notwithstanding production of more than twice this amount during the intervening three years. Probable reserves have increased by 61 million tonnes, whilst possible reserves have fallen by 91 million tonnes. Overall, the sum of the UK’s proven, probable and possible reserves has decreased by 137 million tonnes, or 10.8%. DECC’s assessment of the ‘ultimate recovery’ of UK oil stood at 4 444 million tonnes (33.3 billion barrels) at the end of 2008, an increase of 88 million tonnes (660 million barrels) over the end-2005 estimate. As well as the effect of production and new field developments, the changes in reserves reflect revisions in established fields, which may result in a reallocation of reserves between categories, e.g. possible to probable, or probable to proven.

United States of America

Proved recoverable reserves (crude oil and NGLs, million barrels)	28 396
2008 production (crude oil and NGLs, thousand b/d)	6 734
R/P ratio (years)	11.5
Year of first commercial production	1859

The United States has one of the largest and oldest oil industries in the world. Although its remaining recoverable reserves are dwarfed by some of the Middle East producers, it is the third largest oil producer, after Saudi Arabia and the Russian Federation.

Reporting on behalf of the US Energy Association, (the WEC Member Committee for the USA), the Energy Information Administration of the US Department of Energy states that proved oil reserves at end-2008 were 19 121 million barrels of crude oil and 9 275 million barrels of NGLs. Compared with the levels at end-2005, crude reserves were 12.1% lower and those of NGLs up by 13.6%.

The 2 636 million barrel net decrease in crude reserves was the result of a reserves increase of 2 438 from extensions and discoveries in old and new fields, minus net revisions and adjustments of 59, minus accrued production of crude totalling 5 015.

The comparable figures for NGLs (also in millions of barrels) were a reserves increase of 3 200 from extensions and discoveries, plus 392 net revisions, etc., less 2 482 accrued production of NGLs, giving a net increase of 1 110 in proved reserves.

Crude oil production in 2008 was 4 950 000 b/d and that of NGLs (including 'pentanes plus') was 1 784 000 b/d. The USA exported 29 000 b/d of crude oil in 2008, all to Canada.

Uzbekistan

Proved recoverable reserves (crude oil and NGLs, million barrels)	594
2008 production (crude oil and NGLs, thousand b/d)	111
R/P ratio (years)	14.6
Year of first commercial production	NA

Although an oil producer for more than a century, large-scale developments in the republic mostly date from after 1950. The current assessment published by *Oil & Gas Journal* (matched by other publications) shows proved reserves as 594 million barrels, a level unchanged since 1996. Oil fields discovered so far are located in the southwest of the country (Amu-Darya Basin) and in the Tadzhik-Fergana Basin in the east.

Since the late 1990s total oil output has followed a downward trend, falling by 80 000 b/d, or 42%, in the space of ten years. All of Uzbekistan's production of crude and condensate is processed in domestic refineries or used directly as feedstock for petrochemicals.

Venezuela

Proved recoverable reserves (crude oil and NGLs, million barrels)	99 377
2008 production (crude oil and NGLs, thousand b/d)	2 566
R/P ratio (years)	>100
Year of first commercial production	1917

The oil resource base is truly massive, and proved recoverable reserves are by far the largest of any country in the Western Hemisphere. Starting in 1910, hydrocarbons exploration established the existence of four petroliferous basins: Maracaibo (in and around the lake), Apure to the south of the lake, Falcón to the northeast and Oriental in eastern Venezuela. The republic has been a global-scale oil producer and exporter ever since the 1920s, and was a founder member of OPEC in 1960.

The level adopted for end-2008 proved recoverable reserves of crude oil and natural gas liquids is 99 377 million barrels, as given by *Oil & Gas Journal* and (in slightly rounded form) by OAPEC and BP.

OPEC, in its *Annual Statistical Bulletin 2008*, moved onto a different basis, quoting Venezuela's total proven crude oil reserves as 172 323 million barrels, including 'proven reserves of the Magna Reserve Project in the Orinoco Belt', amounting to 94 168 million barrels – see Chapter 4 of this *Survey* for coverage of Venezuela's Orinoco Oil Belt.

According *to Petróleo y Otros Datos Estadísticos 2006*, published in October 2008 by the Ministerio del Poder Popular para la Energía y Petróleo, about 61% of national oil output in 2006 came from the Oriental Basin, 36% from the Maracaibo, 3% from the Apure and a minimal proportion from the Falcón Basin.

Vietnam

Proved recoverable reserves (crude oil and NGLs, million barrels)	4 700
2008 production (crude oil and NGLs, thousand b/d)	317
R/P ratio (years)	40.5
Year of first commercial production	1986

During the first half of the 1980s oil was discovered offshore in three fields (Bach Ho, Rong and Dai Hung), and further discoveries have since been made.

Published estimates of Vietnam's oil reserves vary widely. The level adopted in the present *Survey* for proved recoverable reserves (4 700 million barrels) has been taken from BP's *Statistical Review of World Energy*, 2009. *World Oil* has raised its assessment substantially in recent years and now quotes the same figure as BP. OPEC is considerably lower with an estimate of 3 410 million barrels, whilst *Oil & Gas Journal* is in an entirely different league, quoting only 600 million barrels, which implies the very low R/P ratio of 5.5.

Production of crude oil began in 1986 and rose steadily until 2004, but subsequently has fallen to only about 300 000 b/d, all of which is presently exported. Output of NGLs is of minor proportions, at around 15 000 b/d.

Yemen

Proved recoverable reserves (crude oil and NGLs, million barrels)	2 670
2008 production (crude oil and NGLs, thousand b/d)	317
R/P ratio (years)	23.0
Year of first commercial production	1986

After many years of fruitless searching, exploration in the 1980s and 1990s brought a degree of success, with the discovery of a number of fields in the Marib area, many yielding very light crudes. Oil discoveries have been made in two other areas of the country (Shabwa and Masila) and Yemen has evolved into a fairly substantial producer and exporter of crude.

For the purposes of the present *Survey*, the latest assessment by *World Oil* – 2 670 million barrels - has been adopted. This level is echoed by BP in its *Statistical Review of World Energy* 2009, albeit in rounded form; *Oil & Gas Journal* and OAPEC quote a (highly rounded) figure of 3 billion barrels.

Oil production peaked in 2002 and has since followed a consistently downward path. Total output in 2008 was 317 000 b/d (including 24 000 b/d of gas-plant LPG). About 70% of Yemen's crude production is exported, largely to Singapore, Japan, Korea Republic and other Asia/Pacific destinations

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3. Oil Shale

COMMENTARY[1]

Introduction

Oil shales ranging from Cambrian to Tertiary in age occur in many parts of the world. Deposits range from small occurrences of little or no economic value to those of enormous size that occupy thousands of square kilometres and contain many billions of barrels of potentially extractable shale oil. Total world resources of shale oil are conservatively estimated at 4.8 trillion barrels (Table 3.1). However, petroleum-based crude oil is cheaper to produce today than shale oil because of the additional costs of mining and extracting the energy from oil shale.

Because of these higher costs, only a few deposits of oil shale are currently being exploited - in Brazil, China, Estonia, Germany and Israel. However, with the continuing decline of petroleum supplies, accompanied by increasing costs of petroleum-based products, oil shale presents opportunities for supplying some of the fossil energy needs of the world in the years ahead.

Definition of Oil Shale

Most oil shales are fine-grained sedimentary rocks containing relatively large amounts of organic matter (known as 'kerogen') from which

[1] This Commentary is based on a paper first published by the Energy Minerals Division of the American Association of Petroleum Geologists, 27 February 2000. It has been edited for inclusion in this *Survey*.

significant amounts of shale oil and combustible gas can be extracted by destructive distillation. Included in most definitions of 'oil shale', either stated or implied, is the potential for the profitable extraction of shale oil and combustible gas or for burning as a fuel.

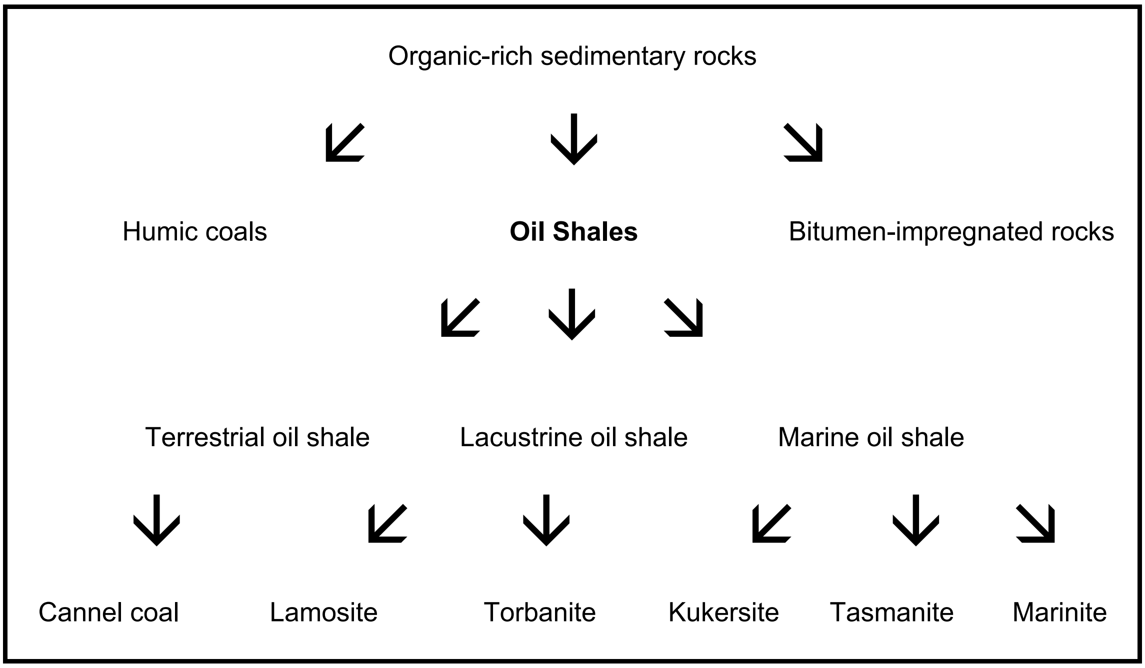
The organic matter in oil shale is composed chiefly of carbon, hydrogen, oxygen, and small amounts of sulphur and nitrogen. It forms a complex macromolecular structure that is insoluble in common organic solvents (e.g. carbon disulphide). The organic matter (OM) is mixed with varied amounts of mineral matter (MM) consisting of fine-grained silicate and carbonate minerals. The ratio of OM:MM for commercial grades of oil shale is about 0.75:5 to 1.5:5. Small amounts of bitumen that are soluble in organic solvents are present in some oil shales. Because of its insolubility, the organic matter must be retorted at temperatures of about 500^{o}C to decompose it into shale oil and gas. Some organic carbon remains with the shale residue after retorting but can be burned to obtain additional energy. Oil shale differs from coal whereby the organic matter in coal has a lower atomic H:C ratio, and the OM:MM ratio of coal is usually greater than 4.75:5.

Origin of Oil Shale

Oil shales were deposited in a wide variety of environments, including freshwater to saline ponds and lakes, epicontinental marine basins and related subtidal shelves. They were also deposited in shallow ponds or lakes associated with coal-forming peat in limnic and coastal swamp depositional environments. It is not surprising, therefore, that oil shales exhibit a wide range in organic and mineral composition. Most oil shales were formed under dysaerobic or anaerobic conditions that precluded the presence of burrowing organisms that could have fed on the organic matter. Many oil shales show well-laminated bedding attesting to a low-energy environment free of strong currents and wave action. In the oil shale deposits of the Green River Formation in Colorado and Utah, numerous beds, and even individual laminae, can be traced laterally for many kilometres. Turbiditic sedimentation is evidenced in some deposits as well as contorted bedding, microfractures, and faults.

Most oil shales contain organic matter derived from varied types of marine and lacustrine algae, with some debris of land plants, depending upon the depositional environment and sediment sources. Bacterial processes were probably important during the deposition and early diagenesis of most oil shales. Such processes could produce significant quantities of biogenic methane, carbon dioxide, hydrogen sulphide, and ammonia. These gases in turn could react with dissolved ions in the sediment waters to form authigenic carbonate and sulphide minerals such as calcite, dolomite, pyrite, and even such rare authigenic minerals as buddingtonite, an ammonium feldspar.

Figure 3.1 Classification of organic-rich rocks (Source: from Hutton, 1987)



Classification of Oil Shales

Oil shales, until recent years, have been an enigmatic group of rocks. Many were named after a locality, mineral or algal content, or the type of product the shale yielded. The following are some names that have been applied to oil shales, a few of which are still in use today:

- algal coal
- alum shale
- bituminite
- boghead coal
- cannel coal
- gas coal
- kerosene shale
- kukersite
- schistes bitumineux
- stellarite
- tasmanite
- torbanite
- wollongongite

A.C. Hutton (1987) developed a workable scheme for classifying oil shales on the basis of their depositional environments and by differentiating components of the organic matter with the aid of ultraviolet/blue fluorescent microscopy (Fig. 3.1). His classification has proved useful in correlating components of the organic matter with the yields and chemistry of the oil obtained by retorting.

Hutton divided the organic-rich sedimentary rocks into three groups. These groups are (1) humic coals and carbonaceous shales, (2) bitumen-impregnated rock (tar sands and petroleum reservoir rocks), and (3) oil shale. On the basis of the depositional environment, three basic groups of oil shales were recognised: terrestrial, lacustrine, and marine. Terrestrial oil shales include those composed of lipid-rich organic matter such as resins, spores, waxy cuticles, and corky tissue of roots and stems of vascular terrestrial plants commonly found in coal-forming swamps and bogs. Lacustrine oil shales are those containing lipid-rich organic matter derived from algae that lived in freshwater, brackish, or saline lakes. Marine oil shales are composed of lipid-rich organic matter derived from marine algae, acritarchs (unicellular microorganisms of questionable origin), and marine dinoflagellates (one-celled organisms with a flagellum).

Hutton (1987) recognised three major macerals in oil shale: telalginite, lamalginite, and bituminite. Telalginite is defined as structured organic matter composed of large colonial or thick-walled unicellular algae such as Botryococcus and Tasmanites. Lamalginite includes thin-walled colonial or unicellular algae that occur as distinct laminae, but displays little or no recognisable biologic structures. Under the microscope, telalginite and lamalginite are easily recognised by their bright shades of yellow under ultraviolet/blue fluorescent light. The third maceral, bituminite, is another important component in many oil shales. It is largely amorphous, lacks recognisable biologic structures, and displays relatively low fluorescence under the microscope. This material has not been fully characterised with respect to its composition or origin, although it is often a quantitatively important component of the organic matter in many marine oil shales. Other organic constituents include vitrinite and inertinite, which are macerals derived from the humic matter of land plants. These macerals are usually found in relatively small amounts in most oil shales.

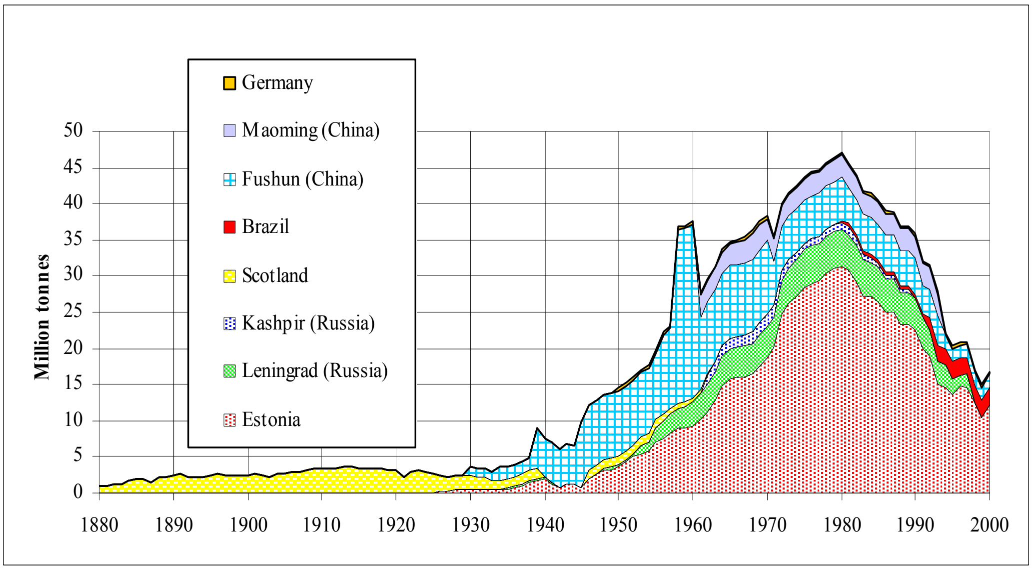
History of the Oil Shale Industry

The use of oil shale can be traced back to ancient times. By the 17th century, oil shales were being exploited in several countries. One of the interesting oil shales is the Swedish alum shale of Cambrian and Ordovician age that is noted for its alum content and high concentrations of metals including uranium and vanadium. As early as 1637, the alum shales were roasted over wood fires to extract potassium aluminium sulphate, a salt used in tanning leather and for fixing colours in fabrics. Late in the 1800s, the alum shales were retorted on a small scale for hydrocarbons. Production continued through World War II but ceased in 1966 because of the availability of cheaper supplies of petroleum crude oil. In addition to hydrocarbons, some hundreds of tonnes of uranium and small amounts of vanadium were extracted from the Swedish alum shales in the 1960s (Andersson et al., 1985).

An oil shale deposit at Autun, France, was exploited commercially as early as 1839. The Scottish oil shale industry began about 1859, the year that Colonel Drake drilled his pioneer well at Titusville, Pennsylvania. As many as 20 beds of oil shale were mined at different times. Mining continued throughout the 1800s and by 1881 oil shale production had reached 1 million tonnes per year. With the exception of the World War II years, between 1 and 4 million tonnes of oil shale were mined each year in Scotland from 1881 until 1955, when production began to decline, before ceasing in 1962. Canada produced some shale oil from deposits in New Brunswick and Ontario in the mid-1800s.

Common products made from oil shale from these early operations were kerosine and lamp oil, paraffin wax, fuel oil, lubricating oil and grease, naphtha, illuminating gas, and the fertiliser chemical, ammonium sulphate. With the introduction of the mass production of automobiles and trucks in the early 1900s, the supposed shortage of gasoline encouraged the

Figure 3.2 Oil shale mined from deposits in Brazil, China, Estonia, Germany, Russia and Scotland, 1880-2000 (Source: USGS)



exploitation of oil shale deposits for transportation fuels. Many companies were formed to develop the oil shale deposits of the Green River Formation in the western United States, especially in Colorado. Oil placer claims were filed by the thousand on public lands. The Mineral Leasing Act of 1920 removed oil shale and certain other fossil fuels and minerals on public lands administered by the Federal Government from the status of locatable to leaseable minerals. Under this Act, the ownership of the public mineral lands is retained by the Federal Government and the mineral, e.g. oil shale, is made available for development by private industry under the terms of a mineral lease.

Several oil shale leases on Federal lands in Colorado and Utah were issued to private companies in the 1970s. Large-scale mine facilities were developed on the properties and experimental underground 'modified in situ' retorting was carried out on one of the lease tracts. However, all work eventually ceased and the leases were relinquished to the Federal Government. Unocal operated the last large-scale experimental mining and retorting facility in the western United States from 1980 until its closure in 1991. The company produced 4.5 million barrels of oil from oil shale averaging 34 gallons of shale oil per ton of rock over the life of the project. After many years in the doldrums, interest in oil shale was rekindled in 2004 (see the Country Note on the USA).

The tonnages mined in six oil shale producing countries for the period 1880 to 2000 are shown in Fig. 3.2. By the late 1930s, total yearly production of oil shale for these six countries had risen to over 5 million tonnes. Although production fell in the 1940s during World War II, it continued to rise for the next 35 years, peaking in 1979-1980 when in excess of 46 million tonnes of oil shale per year was mined, two-thirds of which was in Estonia. Assuming an average shale oil content of 100 l/tonne, 46 million tonnes of oil shale would be equivalent to 4.3 million tonnes of shale oil. Of interest is a secondary period of high production reached by China in 1958-1960 when as much as 24 million tonnes of oil shale per year were mined at Fushun.

The oil shale industry as represented by the six countries in Fig. 3.2 maintained a combined yearly production of oil shale in excess of 30 million tonnes from 1963 to 1992. From the peak year of 1981, yearly production of oil shale steadily declined to a low of about 15 million tonnes in 1999. Most of this decline is due to the gradual downsizing of the Estonian oil shale industry. This decline was not due to diminishing supplies of oil shale but to the fact that oil shale could not compete economically with petroleum as a fossil energy resource. On the contrary, the potential oil shale resources of the world have barely been touched.

Oil Shale Resources

Although information about many oil shale deposits is rudimentary and much exploratory drilling and analytical work needs to be done, the potential resources of oil shale in the world are enormous. An evaluation of world oil shale resources is made difficult because of the numerous ways by which the resources are assessed. Gravimetric, volumetric, and heating values have all been used to determine the oil shale grade. For example, oil shale grade is expressed in litres per tonne or gallons per short ton, weight percent shale oil, kilocalories of energy per kilogram of oil shale or Btu, and others. If the grade of oil shale is given in volumetric measure (litres of shale oil per tonne), the density of the oil must be known to convert litres to tonnes of shale oil.

By-products can add considerable value to some oil shale deposits. Uranium, vanadium, zinc, alumina, phosphate, sodium carbonate minerals, ammonium sulphate, and sulphur add potential value to some deposits. The spent shale obtained from retorting may also find use in the construction industry as cement. Germany and China have used oil shale as a source of cement. Other potential by-products from oil shale include specialty carbon fibres, adsorbent carbons, carbon black, bricks, construction and decorative building blocks, soil additives, fertilisers, rock wool insulating materials, and glass. Many of these by-products are still in the experimental stage, but the economic potential for their manufacture seems large.

Many oil shale resources have been little explored and much exploratory drilling needs to be done to determine their potential. Some deposits have been fairly well explored by drilling and analyses. These include the Green River oil shale in western United States, the Tertiary deposits in Queensland, Australia, the deposits in Sweden and Estonia, the El-Lajjun deposit in Jordan, perhaps those in France, Germany and Brazil, and possibly several in Russia. It can be assumed that the deposits will yield at least 40 litres of shale oil per tonne of shale by Fischer assay. The remaining deposits are poorly known and further study and analysis are needed to adequately determine their resource potential.

By far the largest known deposit is the Green River formation in the western United States, which contains a total estimated in-place resource of some 3 trillion barrels. In Colorado alone, the total in-place resource reaches 1.5 trillion barrels of oil. The Devonian black shales of the eastern United States are estimated at 189 billion barrels. Other important deposits include those of Australia, Brazil, China, Estonia, Jordan, and Morocco.

The total world in-place resource of shale oil is estimated at 4.8 trillion barrels. This figure is considered to be conservative in view of the fact that oil shale resources of some countries are not reported and other deposits have not been fully investigated. On the other hand, several deposits, such as those of the Heath and Phosphoria Formations and portions of the Swedish alum oil shale, have been degraded by geothermal heating. Therefore, the resources reported for such deposits are probably too high and somewhat misleading.

Recoverable Resources

The amount of shale oil that can be recovered from a given deposit depends upon many factors. As alluded to above, geothermal heating, or other factors, may have degraded some or all of a deposit, so that the amount of recoverable energy may be significantly decreased. Some deposits or portions thereof, such as large areas of the Devonian black shales in the eastern United States, may be too deeply buried to mine economically in the foreseeable future. Surface land uses may greatly restrict the availability of some oil shale deposits for development, especially those in the industrial western countries. The obvious need today is new and improved methods for the economic recovery of energy and by-products from oil shale. The bottom line in developing a large oil shale industry will be governed by the price of petroleum-based crude oil.

The high petroleum price of recent times has prompted governments around the world to re-examine their energy supplies and to consider national security issues. Whereas at one time an indigenous energy resource such as oil shale would have been left undeveloped, it is now becoming attractive and feasible to further R&D programmes.

This current high level of interest in the development of oil shale has contributed to an increase in the number of international conferences on the subject.

In June 2009, Eesti Energia, in association with Tallinn University of Technology, the University of Tartu and the Colorado School of Mines (CSM) held an International Oil Shale Symposium in Tallinn, Estonia and in October 2010, the 30th Oil Shale Symposium, the CSM's own annual forum, will take place.

As part of the Euro-Mediterranean Energy Market Integration Project (MED-EMIP) on Regional Cooperation for Clean Utilization of Oil Shale, a series of meetings, workshops and a site visit were held between April 2009 and April 2010. With funding from the European Union, the project plans to strengthen energy security and sustainability in Turkey and the countries of the eastern and southern Mediterranean. MED-EMIP has five initiatives, one of which is a Program for the Cleaner Development of Oil Shale in Egypt, Jordan, Morocco, Syria and Turkey. A signing ceremony to establish an Oil Shale Cooperation Center took place in Jordan in April 2010. It will be headquartered in Amman.

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TABLES

Table 3.1 Shale oil: resources and production at end-2008

	In-place resources		Production in 2008	
	million barrels	**million tonnes**	**thousand b/d**	**thousand tonnes**
Egypt (Arab Republic)	5 700	816		
Congo (Democratic Rep.)	100 000	14 310		
Madagascar	32	5		
Morocco	53 381	8 167		
South Africa	130	19		
Total Africa	**159 243**	**23 317**		
Canada	15 241	2 192		
United States of America	3 706 825	536 931		
Total North America	**3 722 066**	**539 123**		
Argentina	400	57		
Brazil	82 000	11 734	3.8	200
Chile	21	3		
Total South America	**82 421**	**11 794**	**3.8**	**200**
Armenia	305	44		
China	354 430	47 600	7.6	375
Kazakhstan	2 837	400		
Mongolia	294	42		
Myanmar (Burma)	2 000	286		
Thailand	6 401	916		
Turkey	1 985	284		
Turkmenistan	7 687	1 100		
Uzbekistan	8 386	1 200		
Total Asia	**384 325**	**51 872**	**7.6**	**375**
Austria	8	1		
Belarus	6 988	1 000		
Bulgaria	125	18		
Estonia	16 286	2 494	6.3	355
France	7 000	1 002		
Germany	2 000	286		

Table 3.1 Shale oil: resources and production at end-2008

	In-place resources		Production in 2008	
	million barrels	million tonnes	thousand b/d	thousand tonnes
Hungary	56	8		
Italy	73 000	10 446		
Luxembourg	675	97		
Poland	48	7		
Russian Federation	247 883	35 470		
Spain	280	40		
Sweden	6 114	875		
Ukraine	4 193	600		
United Kingdom	3 500	501		
Total Europe	**368 156**	**52 845**	**6.3**	**355**
Israel	4 000	550		
Jordan	34 172	5 242		
Total Middle East	**38 172**	**5 792**		
Australia	31 729	4 531		
New Zealand	19	3		
Total Oceania	**31 748**	**4 534**		
TOTAL WORLD	**4 786 131**	**689 277**	**17.7**	**930**

Notes:

1. The figures for Turkmenistan refer to the Amu-Darya Basin, which also extends into Uzbekistan
2. Sources: Resources: J.R. Dyni, U.S. Geological Survey; Production: national sources and personal communication

COUNTRY NOTES

The following Country Notes on Oil Shale have been compiled by the Editors, drawing upon a wide variety of material, including papers authored by J.R. Dyni of the USGS, papers presented at oil shale symposia, national and international publications, and direct communications with oil shale experts.

Australia

The total demonstrated oil shale resource is estimated to be in the region of 58 billion tonnes, of which about 25 billion barrels of oil is recoverable. The deposits are spread through the eastern and southern states of the country (Queensland, New South Wales, South Australia, Victoria and Tasmania), although it is the eastern Queensland deposits that have the best potential for economic development.

Production from oil shale deposits in southeastern Australia began in the 1860s, coming to an end in 1952 when government funding ceased. Between 1865 and 1952 some 4 million tonnes of oil shale were processed.

During the 1970s and early 1980s a modern exploration programme was undertaken by two Australian companies, Southern Pacific Petroleum N.L. and Central Pacific Minerals N.L. (SPP/CPM). The aim was to find high-quality oil shale deposits amenable to open-pit mining operations in areas near infrastructure and deepwater ports. The programme was successful in finding a number of silica-based oil shale deposits of commercial significance along the coast of Queensland. Ten deposits clustered in an area north of Brisbane were investigated and found to have an oil shale resource in excess of 20 billion barrels (based on a cutoff grade of 50 l/t at 0% moisture), which could support production of more than 1 million barrels a day.

Between 1995 and February 2002 the Stuart Deposit (located near Gladstone) was developed, firstly by a joint venture between SPP/CPM and Suncor Energy Inc. of Canada and then by SPP/CPM, following its purchase of Suncor's interest. Further corporate restructuring took place when SPP became the holding company and CPM was delisted from the Australian stock exchange.

The Stuart project (found to have a total *in situ* shale oil resource of 2.6 billion barrels and a capacity to produce more than 200 000 b/d) and incorporating the Alberta-Taciuk Processor (ATP) retort technology had three stages: The Stage 1 demonstration plant (producing a relatively light 42^{o} API gravity crude with 0.4 wt% sulphur and 1.0 wt% nitrogen) was constructed between 1997 and 1999 and produced over 500 000 barrels. The plant was designed to process 6 000 tonnes per stream day of run-of-mine (wet shale) to produce 4 500 bpsd of shale oil products. Stage 2 was to be scaled up by a factor of 4 to a commercial-sized module processing 23 500 tpsd and producing 15 500 bpsd oil products. It was envisaged that multiple commercial ATP units would come on stream during 2010-2013 processing up to 380 000 tpsd and producing up to 200 000 bpsd of oil products for a period in excess of 30 years.

To meet the needs of the market, the raw oil required further processing which resulted in ultra low-sulphur naphtha and light fuel oil. Shale oil has been certified as a feedstock for jet fuel production by the world's leading accreditation agencies and a long-term contract for the sale of naphtha to Mobil Oil Australia was in place. The light fuel oil was shipped to Singapore and sold into the fuel oil blending market.

Having committed itself to ensuring that the Stuart oil shale project had a sustainable development, SPP put various schemes into operation to achieve its stated environmental goals. One in particular launched in 1998 was a reforestation carbon dioxide sink. Some 250 000 trees were planted on deforested lands in Central Queensland. In September 2000, the first carbon trade in Queensland was announced. It was between SPP and the state government and was based on the reforestation trials.

In February 2004 Queensland Energy Resources (QER) acquired the oil shale assets of SPP and ran final plant trials at the demonstration facility. However, no production ensued and the Environmental Protection Agency regulated operations until the plant was closed in mid-2004. The facility is now on 'care-and-maintenance in an operable condition'.

QER continues to assess the possibilities for the future commercial operation of the Stuart project.

QER spent the period 2005-2007 testing indigenous Australian oil shale at a pilot plant in the U.S. State of Colorado. QER successfully demonstrated that, by using the Paraho Process, it could operate an oil shale-to-liquids business in Queensland.

Following QER's acquisition of the Stuart oil shale project from SPP, the company planned to replace the rotating horizontal Alberta-Taciuk Processor (ATP) retort, with the vertical Paraho retort. During 2009 the company undertook refurbishment of the site and dismantled the ATP retort. In May 2010 QER announced that it 'would shortly begin construction' of a demonstration plant at Yarwun, north of Gladstone. Using Paraho II™ technology, the plant when complete is expected to process 2.5 tonnes of shale per hour and produce between 37 and 40 b/d of synthetic crude oil.

In August 2008 the Queensland Government announced that it had issued a 20-year moratorium on the development of QER's other oil shale resource, McFarlane. The McFarlane deposit, located some 15 km south of Proserpine in central Queensland, is considered a strategically important resource with the potential to supply in excess of 1.6 billion barrels of oil.

Following more than a quarter of a century of extraction of test material, QER announced during third quarter 2009 that it had reached agreement with the Queensland Government to back fill and rehabilitate the McFarlane box cut.

Brazil

The oil shale resource base is one of the largest in the world and was first exploited in 1884 in the State of Bahia. In 1935 shale oil was produced at a small plant in São Mateus do Sul in the State of Paraná and in 1950, following government support, a plant capable of producing 10 000 b/d shale oil was proposed for Tremembé, São Paulo.

Following the formation of Petrobras in 1953, the company developed the Petrosix process for shale transformation. Operations are concentrated on the reservoir of São Mateus do Sul, where the ore is found in two layers: the upper layer of shale (6.4 m thick), with an oil content of 6.4%, and the lower 3.2 m layer with an oil content of 9.1%. The company brought a pilot plant (8 inch internal diameter retort) into operation in 1982, its purpose being for oil shale characterisation, retorting tests and developing data for economic evaluation of new commercial plants. A 6 ft (internal diameter) retort demonstration plant followed in 1984 and was used for the optimisation of the Petrosix technology.

A 2 200 (nominal) tonnes per day, 18 ft (internal diameter) semi-works retort (the Iratí Profile Plant), originally brought on line in 1972, began operating on a limited commercial scale in 1981 and a further commercial plant - the 36 ft (internal diameter) Industrial Module retort - was brought into service in December 1991. Together the two commercial plants have a process capacity of some 7 800 tonnes of bituminous shale daily. The retort process (Petrosix) where the shale undergoes pyrolysis yields a nominal daily output of 3 870 barrels of shale oil, 120 tonnes of fuel gas, 45 tonnes of liquefied shale gas and 75 tonnes of sulphur.

The Ministry of Mines and Energy quotes end-1999 shale oil reserves as 445.1 million m^3 measured/indicated/inventoried and 9 402 million m^3 inferred/estimated, with shale gas reserves as 111 billion m^3 measured/indicated/ inventoried and 2 353 billion m^3 inferred/ estimated.

The policy relating to the development of the oil shale resource has changed in the light of the discoveries of huge oil reserves in deep and ultra-deep water, and latterly the pre-salt.

The oil shale facilities within Brazil are currently operating at near design capacity: 3 800 b/d of shale oil (480 t/d shale fuel oil, 90 t/d naphtha), 120 t/d fuel gas, 45 t/d LPG and 75 t/d sulphur.

The intention of Petrobras is to maintain the technological expertise and development of its indigenous capacity but without expansion. However, the company will assist in feasibility studies and development of oil shale projects in countries which also have rich reserves of oil shale. At the present time a comprehensive feasibility study for a 50 000 b/d plant in Utah, USA is in progress. Additionally, studies on the Wadi Maghar project in Jordan and the Timahdit project in Morocco are being undertaken and are forecast to be completed within 36 months.

Canada

Oil shales occur throughout the country, with as many as 19 deposits having been identified. However, the majority of the in-place shale oil resources remain poorly known. The most explored deposits are those in the provinces of Nova Scotia and New Brunswick. Of the areas in Nova Scotia known to contain oil shales, development has been attempted at two - Stellarton and Antigonish. Mining took place at Stellarton from 1852 to 1859 and 1929 to 1930 and at Antigonish around 1865. The Stellarton Basin is estimated to hold some 825 million tonnes of oil shale, with an *in situ* oil content of 168 million barrels. The Antigonish Basin has the second largest oil shale resource in Nova Scotia, with an estimated 738 million tonnes of shale and 76 million barrels of oil *in situ*.

Investigations into retorting and co-combustion (with coal for power generation) of Albert Mines shale (New Brunswick) have been conducted, including some experimental processing in 1988 at the Petrobras plant in Brazil. Interest has been shown in the New Brunswick deposits for the potential they might offer to reduce sulphur emissions by co-combustion of carbonate-rich shale residue with high-sulphur coal in power stations.

In mid-2006 Altius, a Canadian company based in Newfoundland was awarded a licence to explore for oil shale in the Albert Mines prospect in southeast New Brunswick. During 2008 and 2009 a drilling programme was undertaken within a licence area of 9 702 hectares. Although not yet quantified, it would appear that the oil shale resource is likely to be significant, with initial findings suggesting an API gravity of 32^{o} and a yield of 50 to 100 litres of oil per tonne. Evaluation studies are currently being carried out.

China

Between 2004 and 2006 China undertook its first national oil shale evaluation, which confirmed that the resource was both widespread and vast. According to the evaluation, it has been estimated that a total oil shale resource of some 720 billion tonnes is located across 22 provinces, 47 basins and 80 deposits. Some 70% of the deposits are in eastern and middle China, with the remainder largely in the Qinghai-Tibet area and the west.

The in-place shale oil resource has been estimated at some 48 billion tonnes (approximately 354 billion barrels).

The city of Fushun is known as the Chinese 'capital of coal'. Within the Fushun coalfield the West Open Pit mine is where, above the coal layer, oil shale from the Tertiary Formation is mined as a by-product.

During 2007, the Fushun Mining Group Co. was operating 180 retorts, each capable of processing 100 tonnes of oil shale per day. The shale ash by-product is utilised to produce building materials.

At the beginning of 2010 it was reported that a 6 000 t/d ATP retort, imported by Fushun and due to be in service by end-2009, had been delayed.

Many other retorts are either operating or being planned in the provinces of Gansu, Guangdong, Hainan, Heilongjiang and Jilin.

Development of the oil shale sector has been sustained partly because of the country's high level of oil imports, necessary to support indigenous demand and also to utilise a national resource in the face of high international oil prices. In 2008 Chinese shale oil production totalled some 7 600 b/d, a level predicted to be maintained in 2009. In 2010 it has been estimated that production will rise to some 10 000 b/d. Furthermore, several companies are involved in researching new retorting technologies for processing pulverised or particulate oil shale, with the possibility of constructing a pilot-scale demonstration plant.

It was reported during 2007 that the Bureau of Geological Survey of China was undertaking a review of the oil shale resource and its utilisation.

Egypt (Arab Republic)

Oil shale was discovered during the 1940s as a result of oil rocks self-igniting whilst phosphate mining was taking place. The phosphate beds in question lie adjacent to the Red Sea in the Safaga-Quseir area of the Eastern Desert. Analysis was at first undertaken in the Soviet Union in 1958 and was followed by further research in Berlin in the late 1970s. This latter work concentrated on the phosphate belt in the Eastern Desert, the Nile Valley and the southern Western Desert. The results showed that the Red Sea area was estimated to have about 4.5 billion barrels of in-place shale oil and that in the Western Desert, the Abu Tartour area contained about 1.2 billion barrels.

The studies concluded that the oil shale rocks in the Red Sea area were only accessible by underground mining methods and would be uneconomic for oil and gas extraction. However, the Abu Tartour rocks could be extracted whilst mining for phosphates and then utilised for power production for use in the mines. Additionally, although in both areas power could be generated for the in-place cement industry, the nature of the shale as a raw material would not be conducive to the manufacture of high-quality cement.

In view of the depletion of Egyptian fossil fuel reserves, a research project was implemented during 1994-1998 on the 'Availability of Oil Shale in Egypt and its Potential Use in Power Generation'. The project concluded that the burning of oil shale and its use as fuel for power production was feasible, but only became economic when heavy fuel oil and coal prices rose to significantly higher levels. Many recommendations of a technological and environmental nature were made and economic studies continue. A 20 MW oil shale pilot plant for power generation in Quseir was recommended as part of a first step towards the exploitation of Egyptian oil shale.

Assessment studies continue to be undertaken to establish the potential of the Egyptian resource.

The 4th Workshop on Regional Cooperation for Clean Utilization of Oil Shale, the final meeting of an EU-funded, Euro-Mediterranean Energy Market Integration Project was held in Sharm El-Sheikh in April 2010. In the same month a signing ceremony took place in Jordan for the establishment of an Oil Shale Cooperation Center. Egypt, Jordan, Morocco, Syria and Turkey, together with regional and international companies, will develop the Center with the aims of providing ‘a joint environmental and energy framework, common standards for studying and utilising oil shale resources and attracting investors to the sector’. The Center will be headquartered in Jordan.

Estonia

Oil shale was first scientifically researched in the 18th century. In 1838 work was undertaken to establish an open-cast pit near the town of Rakvere and an attempt was made to obtain oil by distillation. Although it was concluded that the rock could be used as solid fuel and, after processing, as liquid or gaseous fuel, the 'kukersite' (derived from the name of the locality) was not exploited until the fuel shortages created by World War I began to impact.

The Baltic Oil Shale Basin is situated near the northwestern boundary of the East European Platform. The Estonia and Tapa deposits are both situated in the west of the Basin, the former being the largest and highest-quality deposit within the Basin.

Since 1916 oil shale has had an enormous influence on the energy economy, particularly during the period of Soviet rule and then under the re-established Estonian Republic. At a very early stage, an oil shale development programme declared that kukersite could be used directly as a fuel in the domestic, industrial or transport sectors. Moreover, it was easily mined and could be even more effective as a combustible fuel in power plants or for oil distillation. Additionally kukersite ash could be used in the cement and brick-making industries.

Permanent mining began in 1918 and has continued until the present day, with capacity (both underground mining and open-cast) increasing as demand rose. By 1955 oil shale output had reached 7 million tonnes and was mainly used as power station/chemical plant fuel and in the production of cement. The opening of the 1 400 MW Balti Power Station in 1965 followed, in 1973, by the 1 600 MW Eesti Power Station again boosted production and by 1980 (the year of maximum output) the figure had risen to 31.35 million tonnes.

In 1981, the opening of a nuclear power station in the Leningrad district of Russia signalled the beginning of the decline in Estonian oil shale production. No longer were vast quantities required for power generation and the export of electricity. The decline lasted until 1995, since when production levels have varied but generally are less than half of those of the early 1980s.

The total Estonian in-place shale oil resource is currently estimated to be in the region of 16 billion barrels and at the present time continues to play a dominant role in the country's energy balance. However, many factors: economic, political and environmental are all having an effect.

In the years following independence, the oil shale industry was privatised and is now open to the forces of free market competition; in the past production of oil shale had been shown to be economically viable up to a crude oil price of US$ 30 but with prices in excess of this level, new mining projects have become feasible; the country's accession to the European Union has brought compliance with many directives, especially the emissions trading directive. Estonia has ratified the various climate change and pollution control protocols of recent years but must increasingly address the air and water pollution problems that nearly a century of oil shale mining has brought. Many investment programmes have been launched in an attempt to reduce the environmental effects of oil shale.

The historical ratio of underground mining to open-cast (approximately 50:50) is tending to move away from open-cast production as the bed depths increase - the exhausted open-cast areas are gradually being recultivated and reforested. The share of renewables in electricity production is to increase to 5.1% by 2010, the electricity market to be fully opened by 2013 and by 2016, the oil shale power industry to be brought in line with EU environmental requirements.

In the forthcoming years, three factors will bring major changes to Estonia’s power industry: the opening of Estlink, a submarine cable to Finland in 2006 has brought Estonia into contact with the Nordic electricity trading scheme; a second cable, Estlink-2 is planned to come into operation in 2014. Additionally, the closing of Lithuania’s Ignalina NPP at end-2009 will affect the balance of capacity in the Baltic region and, although not until 2025 at the earliest, Estonia may build its own NPP.

However, at the present time the Estonian oil shale industry remains of vital importance to the country and Eesti Energia (EE) is the largest oil shale processing entity in the world. EE continues to work on the technology of oil shale retorting including reducing the environmental impact. To this end the company provides consultancy services to other oil shale-rich countries.

In 2008 output of oil shale totalled 16.1 million tonnes, with consumption for electricity generation and generation of heat amounting to 11.5 and 0.6 million tonnes respectively A total of 3.3 million tonnes was used for the manufacture of shale oil, with a resultant output of 355 thousand tonnes.

In December 2009, after a construction period of 2½ years, a new 3 000 tonnes per day oil shale processing plant was officially opened. Located in Kohtla-Järve, the plant is designed to produce more than 100 000 tonnes of shale oil, 30 million m^3 of high-calorific gas and 150 GWh of steam.

Eesti Energia Technology Industries (operating as Enefit) is currently constructing a 2.26 million tonnes per year oil shale plant in Narva. The plant, planned to produce 290 000 t/yr of oil is due to start up in 2012. Three additional Enefit 280 units and an upgrader plant are scheduled to be started in 2013.

Ethiopia

The existence of oil shale deposits in Ethiopia has been known since the 1950s. Although surveys have been undertaken in the past, no projects were proceeded with owing to high mining costs and lack of funding.

In 2006 it was reported that the resource, estimated to be 3.89 billion tonnes, in the northern province of Tigray is considered to be suitable for open-cast mining.

In the Ethiopian Year 2000 (July 2007 - June 2008) the Geological Survey of Ethiopia undertook surveys in the Sese Basin, western Ethiopia to establish the nature and content of the oil shale (and coal) deposits. A certain amount of analysis has been carried out but further research is required.

France

Oil shale was irregularly exploited in France between 1840 and 1957 but at its highest (1950), output only reached 0.5 million tonnes per year of shale. During its 118 year life, the Government imposed taxes and duties on foreign oil, thus preserving the indigenous industry.

In 1978 it was estimated that the in-place shale oil resources amounted to 7 billion barrels.

In mid-2009 Toreador Resources Corporation reported that it had a four-phase plan to exploit the oil shale of the Paris Basin. Already owning the rights to approximately 650 000 acres plus some additional 150 000 acres (pending regulatory approval), the company expects Phase 1 core drilling to extend to late 2010 prior to Phase 2, study and analysis in 2011.

Germany

The German oil shale industry was developed in the middle of the 19th century and during the 1930s and 1940s the development of retorted oil contributed to the depleted fuel supplies during World War II.

In 1965 it was estimated that Germany's in-place shale oil resources amounted to 2 billion barrels.

Today the only active plant is located in Dotternhausen in southern Germany, where Rohrbach Zement began using oil shale in the 1930s. At the beginning of 2004, Holcim, a Swiss cement and aggregates company acquired Rohrbach Zement. The oil shale from this area has a low energy content, a low oil yield and a high ash content but by using a complex process the complete utilisation of both the oil shale energy and all its minerals can be accomplished and incorporated into the manufacture of cement and other hydraulic binding agents. A small part of the oil shale is directly used in a rotary kiln for cement clinker production as fuel and raw material. Most of the oil shale, however, is burnt in fluidised-bed units to produce a hydraulic mineral cement component while the heat of this process is used simultaneously to produce electricity. Currently only a minimal quantity of oil shale is produced for use at Dotternhausen.

India

Although oil shale, in association with coal and also oil, is known to exist in the far northeastern regions, the extent of the resource and its quality have not yet been determined.

Currently oil shale, recovered with coal during the mining process, is discarded as a waste product. However, the Indian Directorate General of Hydrocarbons has initiated a project designed to assess the reserve and its development. Phase I (September 2007 to October 2009) covers the geological mapping, sampling and analysis of three adjacent blocks in an area of approximately 250 km^2 in the states of Assam and Arunachal Pradesh. Phase II (November 2009 – October 2011) will include feasibility and environmental impact assessment studies. Additionally, preparation of the relevant legislation, a production sharing contract and the necessary criteria for the initial bidding round will be undertaken. It is envisaged that successful bids will be awarded during Phase III (November 2011 – June 2012).

Indonesia

Faced with declining reserves of oil and gas, Indonesia has accelerated its research into identifying, and possibly utilising, its oil shale resources.

The Center for Geo Resources is currently engaged on surveying and preparing an inventory of occurrences. To date, three main prospective oil shale areas have been found, two on the island of Sumatera and one on Sulawesi.

Israel

Sizeable deposits of oil shale have been discovered in various parts of Israel, with the principal resources located in the north of the Negev desert. Estimates of the theoretical reserves total some 300 billion tonnes, of which those considered to be open-pit mineable are put at only a few billion tonnes. The largest deposit (Rotem Yamin) has shale beds with a thickness of 35-80 m, yielding 60-71 l of oil per tonne. Generally speaking, Israeli oil shales are relatively low in heating value and oil yield, and high in moisture, carbonate, and sulphur content, compared with other major deposits.

Following tests in a 0.1 MW pilot plant (1982-1986), a 1 MW demonstration fluidised-bed pilot plant was established in 1989. In operation since 1990, the generated energy is sold to the Israeli Electric Corporation, the low-pressure steam to an industrial complex and a considerable quantity of the resulting ash used to make products such as cat litter which is exported to Europe.

Although during the early 1990s proposals for shale oil extraction were put forward, the crude oil price was not high enough to justify financial viability. With the current higher global crude oil price, the project has been seen to be economically possible.

During 2006, A.F.S.K. Hom-Tov, an Israeli company presented a scheme to the Ministry of National Infrastructures for the manufacture of synthetic oil from oil shale. The method would entail combining bitumen (from the Ashdod refinery, 80 km north of the proposed plant at Mishor Rotem in the Negev Desert) with the shale prior to processing in a catalytic converter. It has been suggested that the resultant oil, totalling up to 3 million tonnes/yr, could be piped back to Ashdod for refining. Additionally, the remaining shale rock, containing some residual fuel, could be utilised in a new power plant in the south of the country.

Oil shale is already being mined by companies accessing the phosphate reserves underlying the rock.

Whilst the Government is encouraging development of the oil shale resource, particularly *in situ* underground techniques, it is mindful of the environmental concerns.

Whilst the country investigates the possibilities of harnessing its large oil shale deposits for producing shale oil, some of the resource is utilised directly for the production of electricity. Since 1990 oil shale has supplied a 12 MW power plant in the Northern Negev.

Jordan

There are about 24 known occurrences, which result in Jordan having an extremely large proven and exploitable oil shale resource. Geological surveys indicate that the existing shale reserves cover more than 60% of the country and amount to in excess of 40 billion tonnes.

The eight most important deposits are located in west-central Jordan and of these, El Lajjun, Sultani, and the Jurf Ed-Darawish have been the most extensively explored. They are all classified as shallow and most are suitable for open-cast mining, albeit some are underlain by phosphate beds. One more deposit, Yarmouk, located close to the northern border is thought to extend into Syria and may prove to be exceptionally large, both in area and thickness. Reaching some 400 m in thickness, it would only be exploitable by underground mining.

The naturally bituminous marls of Jordan are generally of quite good quality. The oil content and calorific value vary quite widely between deposits but research has shown that 20-30% of the original thermal content remains in the retorted residue, thus providing a source of fuel for the production of heat or electricity. Additionally, it has been shown that the levels of sulphur and mineral content would not cause technological or environmental problems.

The Government has, over a prolonged period, undertaken a number of feasibility studies and test programmes. These have been carried out in co-operation with companies from Germany, China, Russia, Canada and Switzerland. They were all intended to demonstrate utilisation through either direct burning or retorting. All tests proved that burning Jordanian oil shale is very stable, emission levels are low and carbon burn-out is high. Furthermore, research on catalytic gasification was undertaken in the FSU, with positive results. Solvent extraction of organic matter was the subject of a joint study by the Jordanian Natural Resources Authority (NRA) and the National Energy Research Center.

The eventual exploitation of Jordan's fuel resource to produce liquid fuels and/or electricity, together with chemicals and building materials, would be favoured by three factors - the high organic matter content of Jordanian oil shale, the suitability of the deposits for surface-mining and their location - away from centres of population but having good transport links to potential consumers (i.e. phosphate mines, potash and cement works).

Whilst the price of crude oil was low there was no justification or financial commitment to develop Jordanian oil shale. The NRA proposed that it should continue to monitor both technological advances and the economic aspects of prospective projects. However, the Government now considers that owing to the rapid increase in demand for electricity, the prospective grid connections between countries in the region and significantly higher oil prices, the required investment is not only becoming feasible but should be pursued through joint ventures.

Jordan, with the help of other countries well-endowed with oil shale, continues to work towards the day when its vast oil shale resource can be exploited, both for the production of shale oil and also for electricity generation.

The Ministry of Energy and Mineral Resources reports that oil shale is expected to provide 11% of primary energy by 2015 and 14% by 2020.

In May 2010, Enefit (Eesti Energia) signed a concession agreement with the Jordanian Government granting the former the right to utilise part of the Attarat Um Ghudran deposit for 50 years. Located in central Jordan and estimated to contain 25 billion tonnes, the deposit is considered to be the largest in the country. Enefit, acting as project developer and technology provider in both the development and industrial stages, will initially undertake further geological research and an environmental impact assessment. After a maximum period of four years, a decision will be taken regarding the economic feasibility of the project. If commercial development ensues, it is planned that a 900 MW (maximum) capacity oil shale-fired power plant will begin operating in 2016 and a 38 000 b/d shale oil plant in 2017.

The Government also plans a third method to utilise the indigenous oil shale. In May 2009 the NRA signed an agreement with The Jordan Oil Shale Company (JOSCo), a wholly-owned subsidiary of Royal Dutch Shell. Under the terms of the project JOSCo will test the possibilities of processing the deep underground oil shale using its proprietary method of In Situ Conversion Process (ICP) technology. By means of slowly electrically heating of the *in situ* rock to 650-750^{o}C, the kerogen would be converted into oil and hydrocarbon gas. The products would then be extracted using conventional technology and refined into transportation fuels. The project which, following the initial assessment period, would be followed by appraisal, a small-scale pilot plant, full-scale design, a final investment decision, construction, and a period of heating would not see commercial production until the late 2020s.

The 4th Workshop on Regional Cooperation for Clean Utilization of Oil Shale, the final meeting of an EU-funded, Euro-Mediterranean Energy Market Integration Project was held in Egypt in April 2010. In the same month a signing ceremony took place in Jordan for the establishment of an Oil Shale Cooperation Center. Egypt, Jordan, Morocco, Syria and Turkey, together with regional and international companies, will develop the Center with the aims of providing 'a joint environmental and energy framework, common standards for studying and utilising oil shale resources and attracting investors to the sector'. The Center will be headquartered in Amman.

Kazakhstan

At the beginning of the 1960s successful experimentation was carried out on a sample of Kazakhstan's oil shale in the former Soviet Republic of Estonia. Both domestic gas and shale oil were produced. It was found that the resultant shale oil had a low-enough sulphur content for the production of high-quality liquid fuels.

Beginning in early 1998 and lasting until end-2001, a team funded by INTAS (an independent, international association formed by the European Community to preserve and promote scientific co-operation with the newly independent states) undertook a project aimed at completely reevaluating Kazakhstan's oil shales. The resultant report testified that Kazakhstan's oil shale resources could sustain the production of various chemical and power-generating fuel products.

The research undertaken concluded that the occurrence of oil shale is widespread, the most important deposits having been identified in western (the Cis-Urals group of deposits) and eastern (the Kenderlyk deposit) Kazakhstan. Further deposits have been discovered in both the southern region (Baikhozha and the lower Ili river basin) and the central region (the Shubarkol deposit).

In excess of 10 deposits have been studied: the Kenderlyk Field has been revealed as the largest (in the region of 4 billion tonnes) and has undergone the greatest investigation. However, studies on the Cis-Urals group and the Baikhozha deposit have shown that they have important concentrations of rare elements (rhenium and selenium), providing all these deposits with promising prospects for future industrial exploitation.

The in-place shale oil resources in Kazakhstan have been estimated to be in the region of 2.8 billion barrels. Moreover, many of the deposits occur in conjunction with hard and brown coal accumulations which, if simultaneously mined, could increase the profitability of the coal production industry whilst helping to establish a shale-processing industry.

The recommendations made to INTAS were that collaboration between the project's participants should continue and further research undertaken on a commercial basis with interested parties, as a precursor to the establishment of such an industry.

In September 2009 it was reported that a high-level bilateral economy, science and technology cooperation agreement had been signed by Estonia and Kazakhstan. Estonia expressed a willingness to share its expertise in the field of oil shale in order to help Kazakhstan develop its own resource.

Mongolia

Mongolia possesses large mineral deposits which, owing to the country's political isolation during most of the 20th century, remain largely undeveloped. Some mining operations were established prior to 1989 with the help of the Soviet Union and Eastern European countries but following the breakup of the USSR, Mongolia's move to a free economy and the Minerals Law being passed in 1997, the potential is being recognised.

Numbered amongst the indigenous minerals are oil shale deposits from the Lower Cretaceous Dsunbayan Group, located in the east of the country. Exploration and investigation of the deposits began as long ago as 1930 but it was only during the 1990s and with the help of Japanese organisations that detailed analyses began. Twenty six deposits were studied and found to be associated with coal measures. Historically, Mongolia's coal has been mined as a source of energy, with the shale being left untouched. However, the study ascertained that the oil shales are 'excellent' potential petroleum source rocks, particularly the Eidemt deposit.

During 2004, Narantuul Trade Company, the owner of the Eidemt deposit was investigating the possibilities of developing the field's potential with the aid of international cooperation.

It was reported in late-2006 that China University of Petroleum had signed a contract to undertake a feasibility study on the Khoot oil shale deposit.

Morocco

Exploitation of oil shale in Morocco occurred as long ago as 1939, when the Tanger deposit was the source of fuel for an 80 tonnes/day pilot plant which operated until 1945. A preliminary estimate of this resource has been put at some 2 billion barrels of oil in place.

During the 1960s two important deposits were located: Timahdit in the region of the Middle Atlas range of mountains (north central Morocco) and Tarfaya in the south west, along the Atlantic coast. The total resource has been estimated at 42 billion tonnes for the former and 80 billion tonnes for the latter. Oil in place has been estimated at 16.1 billion barrels for Timahdit and 22.7 billion barrels for Tarfaya.

Morocco's total resource is estimated at some 50 billion barrels in place, a level which ranks the country amongst the world leaders in respect of in-place shale oil.

During the 1970s and 1980s, the Office National des Hydrocarbures et des Mines (ONHYM), with the assistance of companies in the USA, Europe, Canada and Japan, undertook research and testing of more than 1 500 tonnes of Timahdit and 700 tonnes of Tarfaya oil shale. Within Morocco, some 2 500 metric tonnes of Timahdit oil shale were tested in an 80 tonne capacity pilot plant. In 1985-1986 the Moroccan experience led to ONHYM developing its own process called T3, a semi-continuous surface retorting method based on the utilisation of two identical retorts operating in tandem according to two modes: retorting mode and cooling mode.

The technical and economic feasibility studies have resulted in Morocco acquiring a large amount of information - a database which can be used for future projects. With the current need to look at developing alternative sources of liquid fuels, the ONHYM has stated that any pilot plant should be followed by a demonstration phase during which the commercial evaluation of by-products should also be undertaken.

In the light of a growing demand for electricity ONHYM has drawn up a strategy in order for the development of the oil shale resource to progress. It encompasses a legal and tax framework specific to oil shale; engagement with companies which have a recognised expertise in the oil shale sector; an exploration programme beyond the Timahdit and Tarfaya deposits and the establishment of an oil shale knowledge base within Morocco. To this end, several partnerships have already been drawn up, some of which have resulted in MOUs being signed. Petrobras and Total are re-evaluating the Timahdit oil shale deposits; both San Leon Energy and Xtract Energy are carrying out studies on the Tarfaya deposit and Enefit, an Eesti Energia company is assisting with the Tanger deposit.

The 4th Workshop on Regional Cooperation for Clean Utilization of Oil Shale, the final meeting of an EU-funded, Euro-Mediterranean Energy Market Integration Project was held in Egypt in April 2010. In the same month a signing ceremony took place in Jordan for the establishment of an Oil Shale Cooperation Center. Egypt, Jordan, Morocco, Syria and Turkey, together with regional and international companies, will develop the Center with the aims of providing 'a joint environmental and energy framework, common standards for studying and utilising oil shale resources and attracting investors to the sector'. The Center will be headquartered in Jordan.

Nigeria

Research has shown that the southeastern region of Nigeria possesses a low-sulphur oil shale deposit. The reserve has been estimated to be of the order of 5.76 billion tonnes with a recoverable hydrocarbon reserve of 1.7 billion barrels.

Russian Federation

In excess of 80 oil shale deposits have been identified in Russia.

The deposits in the Volga-Petchyorsk province, although of reasonable thickness (ranging from 0.8 to 2.6 m), contain high levels of sulphur.

Extraction began in this area in the 1930s, with the oil shale being used to fuel two power plants, but the operation was abandoned owing to environmental pollution. However, most activity has centred on the Baltic Basin where the kukersite oil shale has been exploited for many years. In 2002 the Leningradslanets Oil Shale Mining Public Company produced 1.12 million tonnes. Following June 2003 all shale mined was delivered to the Estonian Baltic power station with the resultant electricity delivered to UES (Unified Energy System of Russia). However, production ceased at the Leningradslanets Mine on 1 April 2005. It has been reported that the Russian-owned company, Renova, plans to build its own shale oil producing plant. Although design work has yet to begin, oil shale production restarted on 15 January 2007, with the 50 000 tonnes per month being stored. Leningradslanets exported 40 000 tonnes of oil shale to Estonia between May and August 2009.

Until 1998, the Slantsy electric power plant (located close to the Estonian border, 145 km from St Petersburg) was equipped with oil shale fired furnaces but in 1999 its 75 MW plant was converted to use natural gas. It continued to process oil shale for oil until June 2003, since when its main activities have been electrode coke annealing and the processing of coals and natural gas oil components.

In 1995 a small processing plant operated at Syzran with an input of less than 50 000 tonnes of shale per annum. Although the accompanying mine has now closed, a group of about 10 miners are producing in the region of 10 000 tonnes per year. Using the Syzran plant the oil shale is being processed for the manufacture of a pharmaceutical product. Investment is being sought for a new plant capable of processing 500 tonnes per day. The mine would be re-opened with the intention of perpetuating the production of pharmaceutical products. To this end a business plan has been issued.

Serbia

Over twenty oil shale deposits have been located in Serbia, most numerous in the southern half of the country. The total oil shale resource is estimated to be in the region of 4.8 billion tonnes with some 0.3 billion tonnes of shale oil thought to be recoverable. However, only sections of two of the deposits have received detailed study: Aleksinac in the basin of the same name and Goč-Devotin in the Vlase-Golemo Selo basin. Research has shown that the Aleksinac deposit contains some 2 billion tonnes of oil shale, recoverable by both surface and underground mining, and has an average oil content of approximately 10%.

Viru Keemia Grupp of Estonia is collaborating with the University of Belgrade to conduct further research and analysis of Serbia's resource.

Sweden

The huge shale resources underlying mainland Sweden are more correctly referred to as alum shale; black shale is found on two islands lying off the coast of south-eastern Sweden. The in-place shale oil resource is estimated to be 6.1 billion barrels.

The exploitation of alum shale began as early as 1637 when potassium aluminium sulphate (alum) was extracted for industrial purposes. By the end of the 19th century the alum shale was also being retorted in an effort to produce a hydrocarbon oil. Before and during World War II, Sweden derived oil from its alum shale, but this process had ceased by 1966, when alternative supplies of lower-priced petroleum were available; during the period 50 million tonnes of shale had been mined.

The Swedish alum shale has a high content of various metals including uranium, which was mined between 1950 and 1961. At that time the available uranium ore was of low grade but later higher-grade ore was found and 50 tonnes of uranium were produced per year between 1965 and 1969. Although the uranium resource is substantial, production ceased in 1989 when world prices fell and made the exploitation uneconomic.

Sustained commodity prices in recent years have resulted in a Canadian company, Continental Precious Minerals, conducting a drilling programme on the alum shale. The exploration of oil, uranium and various minerals are all possibilities and samples are being analysed by the Estonian Oil Shale Institute.

Syria (Arab Rep.)

Although the existence of oil shale has been known about for the past 60 years, it is only in the recent years of high oil prices that the widely-distributed deposits have received more detailed study.

The most significant and evaluated deposits have been located in the southern Yarmuk Valley, close to the border with Jordan, with the

Dar'a deposit having had the most detailed study. Further investigative research and evaluation, particularly in the northern areas of the country is being undertaken by the General Establishment of Geology and Mineral Resources.

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Thailand

Some exploratory drilling by the Government was made as early as 1935 near Mae Sot in Tak Province on the Thai-Burmese border. The oil shale beds are relatively thin, underlying about 53 km^2 in the Mae Sot basin and structurally complicated by folding and faulting.

Another deposit at Li, Lampoon Province is small, estimated at 15 million tonnes of oil shale and yielding 50-171 l of oil per tonne.

Some 18.6 billion tonnes of oil shale, yielding an estimated 6.4 billion barrels of shale oil, have been identified in the Mae Sot Basin, but to date it has not been economic to exploit the deposits. In 2000 the Thai Government estimated that total proved recoverable reserves of shale oil were 810 million tonnes.

The Thai Government has instituted a 4-year project to study the feasibility of developing and utilising the Mae Sot oil shale deposit. The Department of Mineral Fuels and the Electricity Generating Authority in its 2008-2011 study will look at all aspects of exploration and development. In the first instance the potential for both direct use (electricity generation) and indirect use (extraction of shale oil) will be evaluated but there will also be an investigation as to the suitability of using the retort ash in the building industry.

Turkey

Although oil shale deposits are known to exist over a wide area in middle and western Anatolia, they have received relatively little investigation. The total reserve of oil shale has been estimated to be in the region of 3-5 billion tonnes, with proved reserves put at 2.2 billion tonnes. Of this latter figure, the geologic reserve is put at 0.5 billion tonnes and the possible reserve at 1.7 billion tonnes. Four major deposits: Himmetoğlu, Seyitömer, Hatildağ and Beypazari have been studied in detail and found to vary quite widely in quality. Study is required of each individual reserve to establish the suitability of use. However, it is already considered that in general Turkish oil shale would be most profitably used to supplement coal or lignite as a power station fuel, rather than for the recovery of shale oil.

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United States of America

It is estimated that nearly 77% of the world's potentially recoverable shale oil resources are concentrated in the USA. The largest of the deposits is found in the 42 700 km^2 Eocene Green River Formation in northwestern Colorado, northeastern Utah and southwestern Wyoming. The richest and most easily recoverable deposits are located in the Piceance Basin in western Colorado and the Uinta Basin in eastern Utah. The shale oil can be extracted by surface and *in situ* methods of retorting: depending upon the methods of mining and processing used, as much as one-third or more of this resource might be recoverable. There are also the Devonian-Mississippian black shales in the eastern United States. The Green River deposits account for 83% of U.S. shale oil resources, the eastern black shales for 5%.

Oil distilled from shale was burnt and used horticulturally in the second half of the 19th century in Utah and Colorado but very little development occurred at that time. It was not until the early 1900s that the deposits were first studied in detail by the U.S. Geological Survey (USGS). In 1915 and the early 1920s the Government established the Naval Petroleum and Oil Shale Reserves, which for much of the 20th century served as a contingency source of fuel for the nation's military. These properties were originally envisioned as a way to provide a reserve supply of oil to fuel U.S. naval vessels.

Oil shale development had always been on a small scale but the project that was to represent the greatest development of the shale deposits was begun immediately after World War II in 1946 - the former U.S. Bureau of Mines established the Anvils Point oil shale demonstration project in Colorado. However, processing plants had been small and the cost of production high. It was not until the USA had become a net oil importer, together with the oil crises of 1973 and 1979, that interest in oil shale was reawakened. In the latter part of the 20th century military fuel needs changed and the strategic value of the shale reserves began to diminish.

In the 1970s ways to maximise domestic oil supplies were devised and the oil shale fields were opened up for commercial production. Oil companies led the investigations: leases were obtained and consolidated but one by one these organisations gave up their oil shale interests. Unocal was the last to do so in 1991.

Recoverable resources of shale oil from the marine black shales in the eastern United States were estimated in 1980 at 189 billion barrels, although the in-place resource is much larger. These deposits differ significantly in chemical and mineralogical composition from Green River oil shale. Owing to its lower H:C ratio, the organic matter in eastern oil shale yields only about one-third as much oil as Green River oil shale, as determined by conventional Fischer assay analyses. However, when retorted in a hydrogen atmosphere, the oil yield of eastern oil shale increases by as much as 2.0-2.5 times the Fischer assay yield.

Green River oil shale contains abundant carbonate minerals including dolomite, nahcolite, and dawsonite. The last two named minerals have potential by-product value for their soda ash and alumina content, respectively. The eastern oil shales are low in carbonate content but contain notable quantities of metals, including uranium, vanadium, molybdenum, and others which could add significant by-product value to these deposits.

After many years of inactivity, interest was revived in the oil shale sector in 2004. A committee was formed by the Office of Naval Petroleum and Oil Shale Reserves and prepared two reports: 1) Strategic Significance of America's Oil Shale Resource, vol. I, Assessment of Strategic Issues and vol II, Oil Shale Resources, Technology and Economics and 2) America's Shale Oil, A Roadmap for Federal Decision Making.

The increasing price of petroleum has encouraged the Government to initiate steps toward the commercial development of the Green River oil shale deposits through the issuance of RD&D oil shale leases. In 2005, nominations for 160-acre (65 hectare) tracts of public oil shale lands in Colorado and Wyoming were sought from private companies by the Bureau of Land Management (BLM). By September 2005, 19 applications for leases had been received - ten in Colorado, eight in Utah, and one in Wyoming. After a review of these nominations, five leases were granted in Colorado in late 2006; one lease in Utah received provisional approval (April 2007) and the Wyoming application was denied. All of the successful applicants for the Colorado leases proposed to develop *in situ* technologies for the recovery of shale oil, whereas the Utah lease applicant planned to use a surface retort. Industry interest in surface mining of oil shale in Colorado appeared to be minimal, in view of the problems of possible large-scale environmental degradation of the oil shale lands.

Since 1996 Shell Frontier Oil & Gas has been developing a new technique for extracting the oil by *in situ* heating of the rock in the Piceance Basin. Shell's patented *In Situ* Conversion Process (ICP), which is more environmentally benign and uses less water than conventional methods, involves heating the rock containing the kerogen until it yields a liquid hydrocarbon. In order to trap the oil prior to removal and refining, a barrier of ice between the heated rock and the surrounding area is created by the circulation of a chilled, compressed liquid refrigerant.

The total resource of Green River oil shale in the three-state area has recently been increased to 3 trillion barrels of in-place shale oil by the USGS (Johnson, et al., 2009). Although recoverable shale oil has been suggested to be as high as 25% of the total Green River resource, no definitive study has been made to substantiate this figure.

By way of enhancing the publicly-available body of knowledge, the USGS is preparing a database with information on the Green River Formation collected by the Bureau of Mines prior to its closure in 1996, and is also acquiring new data and maps. The Office of Naval Petroleum and Oil Shale Reserves announced early in 2007 that the U.S. could be producing oil from shale on a commercial basis in northwest Colorado by 2015.

The possibility of developing the vast oil shale resource of the U.S. remains the subject of much research and discussion. On the one hand, the *in situ* process technologies being developed by, for example, Shell and ExxonMobil, must be proved on a commercial scale and on the other, the new Federal Administration must release land, in order for commercial development to occur. In mid-2008 the BLM published proposed regulations to establish a commercial oil shale programme. The legislation was to provide a phased approach for the development on public lands in oil shale-rich western states. However, at the beginning of 2009, the new Administration announced that it was withdrawing the previous Administration's expanded RD&D leases and that, although offering a second round of RD&D leases, the oil shale programme would progress much more slowly.

In October 2009, the Secretary of the Department of the Interior offered a second round of 10-year RD&D Leases on public lands in Colorado, Utah and Wyoming. He also ordered that the terms of six leases of the first round entered into by the previous Administration should be investigated.

The Secretary stipulated that all prospective commercial development would have its environmental impact thoroughly assessed prior to being given permission to proceed. Furthermore, the first round permitted that, following successful demonstration of commercial quantities of oil shale in an initial 160 acres (65 hectares), the lease size could be extended to 4 960 acres (2 007 hectares), whereas the second round now stipulates that any extension may only be to a further 480 acres (194 hectares). The rules governing water and energy usage and socio-economic impact etc. have now been tightened. Additionally, the timing of any development plan, the acquisition of necessary permits, the deployment of infrastructure and the submission of progress reports have all been included as terms in the new leases (Johnson, et al., 2009, USGS).

4. Natural Bitumen and Extra-Heavy Oil

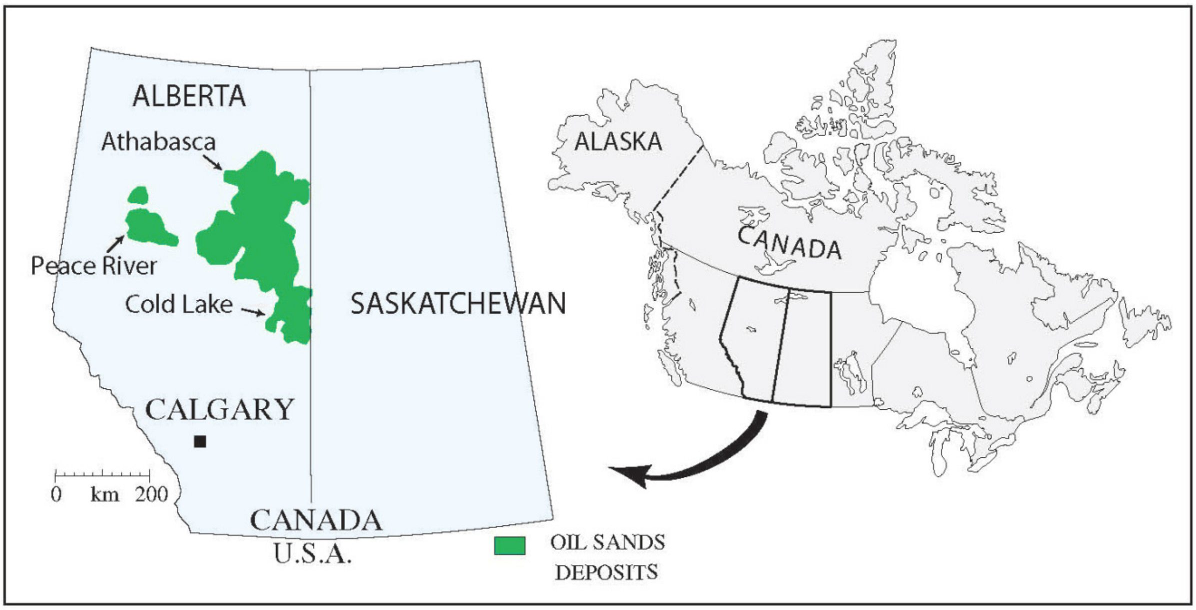
COMMENTARY

Introduction

Natural bitumen and extra-heavy oil are characterised by high viscosity, high density (low API gravity), and high concentrations of nitrogen, oxygen, sulphur, and heavy metals. These characteristics result in higher costs for extraction, transportation, and refining than are incurred with conventional oil. Despite their cost and technical challenges, major international oil companies have found it desirable to acquire, develop, and produce these resources in increasing volumes. Large in-place resource volumes provide a reliable long-term flow of liquid hydrocarbons and provide substantial payoff for any incremental improvements in recovery. High oil prices during 2007 and 2008 spurred new development and production which, in turn, have intensified concern about environmental effects of production increases.

Natural bitumen and extra-heavy oil are the remnants of very large volumes of conventional oils that have been generated and degraded, principally by bacterial action. Chemically and texturally, bitumen and extra-heavy oil resemble the residuum generated by refinery distillation of light oil. The resource base of natural bitumen and extra-heavy oil is immense and not a constraint on the expansion of production. These resources can make an important contribution to future oil supply if they can be extracted and transformed into usable refinery feedstock at sufficiently high rates and at costs that are competitive with alternative sources.

Figure 4.1 Location of the oil sands deposits of Canada
(Source: modified from McPhee and Ranger, 1998)



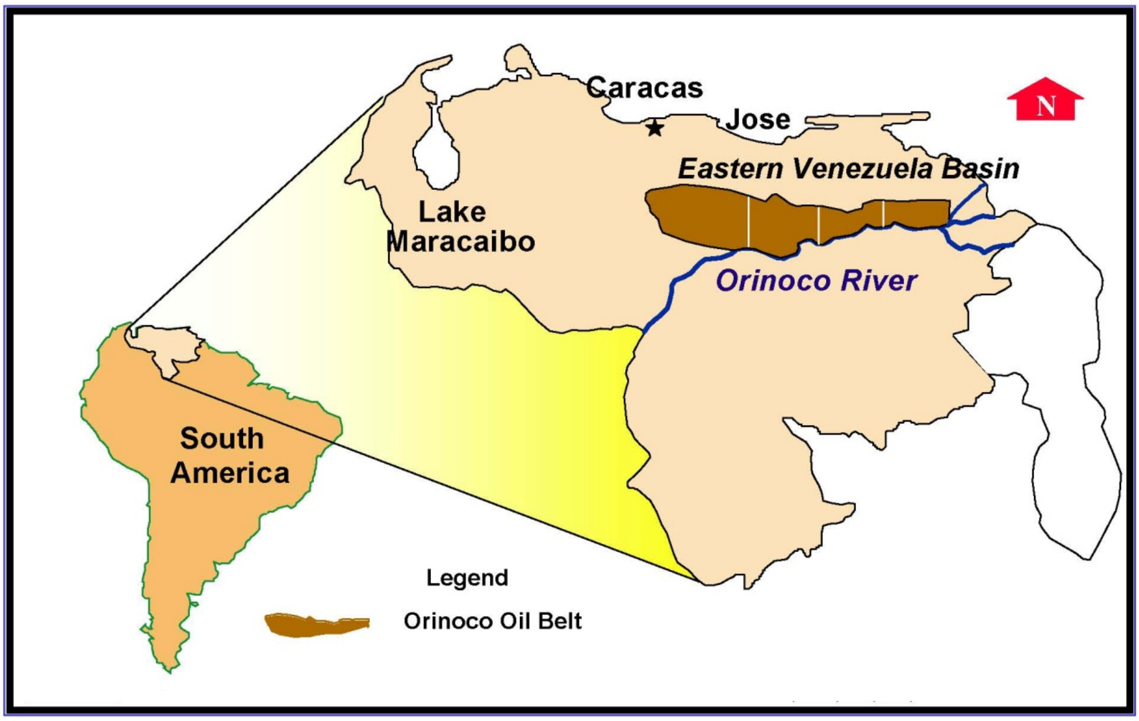
Production and upgrading technologies must continue to advance to address emerging environmental constraints.

Resource Quantities and Geographical Distribution

Resource quantities reported here are based upon a detailed review of the literature in conjunction with available databases, and are intended to suggest, rather than define, the resource volumes that could someday be of commercial value. Precise quantitative reserves and oil-in-place data for natural bitumen and extra-heavy oil on a reservoir basis are seldom available to the public, except in Canada. In cases where in-place resource estimates are not available, the in-place volume was calculated from an estimate of the recoverable volumes based on assumed recovery factors. For deposits in clastic rocks the original in-place volume was calculated as 10 times reported original recoverable volumes (cumulative production plus an estimate of the remaining recoverable volume) (Meyer and Schenk, 1986, 1988). For carbonate reservoir accumulations the original oil in place was calculated as 20 times the estimated original recoverable volume (Meyer, Fulton, and Deitzman, 1984). Geologic basin names used in the descriptions are standard and correspond to sedimentary basins shown on the map compiled by St. John, Bally, and Klemme (1984). The basins which are known to contain heavy oil and natural bitumen are described in Meyer, Attanasi, and Freeman (2007).

Natural Bitumen - is reported in 598 deposits in 23 countries (Table 4.1). No deposits are reported offshore. It occurs both in clastic and carbonate reservoir rocks and commonly in small deposits at, or near, the earth's surface. Natural bitumen deposits have been mined since antiquity for use as sealants and paving materials. In a few places such deposits are extremely large, both in areal extent and in resources they contain, most notably those in northern Alberta, in the Western Canada Sedimentary Basin. Although these oil sands extend eastward into Saskatchewan, resource estimates for this province have yet to be published. The three Alberta oil sand areas (Fig. 4.1), Athabasca, Peace River, and Cold Lake, together contain 1.73 trillion barrels of discovered bitumen in place (Energy Resources Conservation Board [ERCB], 2009a), representing two-thirds of that in the world and at this time are the only bitumen deposits being commercially exploited as sources of synthetic crude oil (SCO). More than 40% of the crude oil and bitumen produced in Canada in 2008 came from the Alberta natural bitumen deposits.

Figure 4.2 Location of the Orinoco Oil Belt in Venezuela
(Source: modified from Layrisse, 1999)



Outside of Canada, 367 natural bitumen deposits are reported in 22 other countries. The largest volumes of bitumen after Canada are in Kazakhstan and Russia, both well endowed with less costly conventional oil. In Kazakhstan, the largest numbers of bitumen deposits are located in the North Caspian Basin, and many of Russia's bitumen deposits are located in the Timan-Pechora and Volga-Ural basins. The North Caspian, Timan-Pechora, and Volga-Ural basins are geologically similar to the Western Canada Sedimentary Basin (Meyer, Attanasi, and Freeman, 2007). Very large resources occur in the basins of the Siberian Platform of Russia (Meyer and Freeman, 2006). Although many more deposits are identified worldwide as evidenced by oil seepages, no resource estimates are reported. The volumes of discovered and prospective additional bitumen in place amount to 2 511 billion barrels and 817 billion barrels, respectively.

Extra-heavy Oil - oil is recorded in 162 deposits world wide (Table 4.2). Extra-heavy oil deposits are located in 21 countries. There are 13 deposits offshore or partially offshore. The Orinoco Oil Belt (Fig. 4.2) in the Eastern Venezuela Basin accounts for about 90% of the discovered plus prospective extra-heavy oil in place, or nearly 1.9 trillion barrels. The Orinoco extra-heavy oil production capacity in 2008 was 640 000 b/d. The corresponding SCO plant upgrade capacity is 580 000 b/d and is located at the Jose refinery on the northeastern coast of Venezuela (U.S. Energy Information Administration [EIA], 2009a). Extra-heavy oil production accounts for more than 20% of Venezuela's oil production. Some fields are comprised only of extra-heavy reservoirs whereas other such reservoirs occur in fields producing mainly from conventional reservoirs. Table 4.2 shows an in-place discovered volume of 1 960 billion barrels and a total in-place volume of 2 150 billion barrels.

In total, Tables 4.1 and 4.2 report a total in-place extra-heavy oil and bitumen volume of 5 478 billion barrels. This volume is slightly *less but of the same order of magnitude as the estimated volume of original oil in place in the world's known conventional oil fields.* The commercially successful projects in the Orinoco Oil Belt and Alberta have proven production strategies and technologies that are being considered for smaller deposits elsewhere. The commercial value achieved is likely to lead to exploration that could result in additional deposits and verification of larger resource volumes at identified deposits.

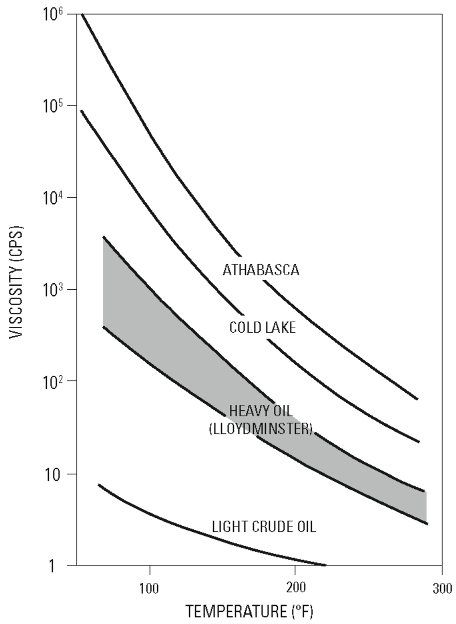


Figure 4.3 Response of viscosity to change in temperature for some Alberta oils
(Source: Raicar and Procter, 1984)

Economics of Production, Transportation and Refinery Technology

Production technologies: Canada

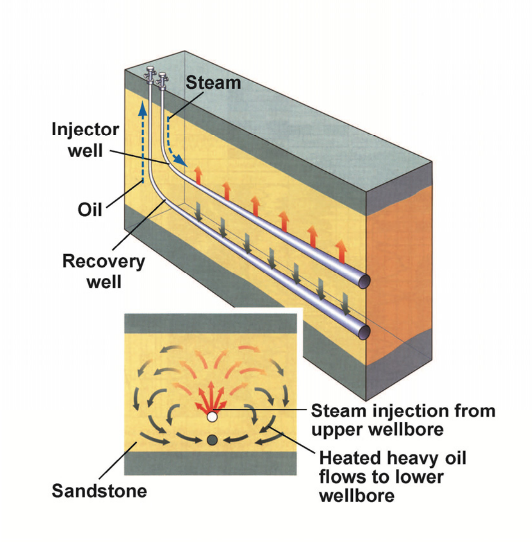
Natural bitumen deposits occurring to depths to 250 feet can be mined from the surface. The mined bitumen is then separated from the host sand by a hot water process. The bitumen mined at three of the four Athabasca operating mining/separation projects is upgraded onsite into a synthetic crude oil that is then transported by pipeline to conventional refineries. The fourth project, Albian Sands Energy, also in Athabasca, transports a mixture of bitumen and diluents to the Scotford upgrading facility about 270 miles south near Edmonton. In 2008, production amounted to 722 000 b/d for the four Alberta oil sand mining projects. Of the 170 billion barrels of bitumen estimated by the Alberta Energy Resources Conservation Board (ERCB) (2009a) to be recoverable from identified deposits, 34 billion barrels or 20% is accessible with current surface mining technology. In February 2009, the Alberta ERCB issued new environmental standards for reduction of tailing pond sizes and acceleration of their reclamation. Operators must modify procedures to meet the standards (ERCB, 2009b).

Some areas are too deep for surface mining. The bitumen can then be produced cold from some wells for short periods without utilising enhanced recovery methods. In cold heavy oil production with sand (or CHOPS) bitumen and sand are pumped to the surface through the well bore and then separated at the surface. The sand production creates channels or high permeability zones through which the bitumen flows most efficiently (Dusseault, 2001).

For most bitumen deposits cold production for extended periods is not possible. Heat and/or solvents may be injected into the reservoir to reduce the viscosity of bitumen. Steam injection raises the temperature of bitumen in the reservoir. Fig. 4.3 shows the dramatic reduction in fluid viscosity with increasing temperatures for the bitumen at Athabasca and Cold Lake (Alberta, Canada). Steam can be injected through vertical or horizontal wells. In the cyclic steam stimulation process, which is commonly applied at Cold Lake, steam is injected into the formation during the ‘soak’ cycle to heat the formation. A production cycle starts when the steam injection wells are converted to producers and ends when the dissipated heat is insufficient to lower bitumen viscosity. The cycles of soak and production are repeated until the response becomes marginal because of increasing water production and declining reservoir pressure. After as many as six cycles, the recovery technology may be converted to a continuous steam flood to enhance production rates (Dusseault, 2006).

Figure 4.4 Stacked pair of horizontal wells, SAGD natural bitumen recovery

(Source: Graphic copyright Schlumberger *Oilfield Review*, used with permission [Curtis, *et al*., 2002])



In the steam assisted gravity drainage or SAGD process (Fig 4.4), a horizontal steam-injection well is drilled about 5 metres above a horizontal production well. Injected steam creates a heated chamber, the heated bitumen is mobilised, and gravity causes the fluid to move downward to the producing well where it is pumped to the surface. Diluents may also be injected to assist in lowering viscosity of the reservoir fluids. The reservoir must exhibit a minimum threshold of vertical permeability for the SAGD process to be successful.

When the Alberta ERCB estimates recoverable bitumen resources, it assumes the following recovery factors for the original bitumen in place: cold production, 5%; cyclic thermal production at Cold Lake, 25%; SAGD at Peace River, 40%; and SAGD at Athabasca, 50% (2009a). The recovery efficiency of mining and extraction of the in-place bitumen is estimated at 82% (National Energy Board of Canada [NEB], 2006).

Production technologies: Venezuela

Compared to the Alberta oil sands, reservoirs in the Orinoco Oil Belt have higher reservoir temperatures, greater reservoir permeability, and higher gas-to-oil ratios, which gives the oil lower viscosity and greater mobility (Dusseault, 2001). In the Orinoco Oil Belt, extra-heavy oil production is cold and achieved through multi-lateral (horizontal) wells in combination with electric submersible pumps and progressing cavity pumps. These wells are precisely positioned in thin, but relatively continuous sands. Horizontal multilateral wells maximise the well bore contact with the reservoir. Efforts are also continuing to improve production of viscous oil through down-hole electrical resistance heating. The recovery factor for the cold production of extra-heavy oil in the Orinoco is estimated to be 8-12% of the in-place oil.

The Government of Venezuela has partitioned the heavy oil belt into six areas and subdivided the areas into blocks which have become the project units (EIA, 2009a). The plan is to start enhanced recovery methods after the cold production phase. Enhanced recovery might be steam and/or solvent injection or *in situ* combustion. New projects are required to include upgrading facilities, located near the coast.

Production economics: Canada

Fig. 4.5 shows the Canadian Energy Research Institute (CERI) estimates of bitumen and synthetic oil supply costs in end-2007 Canadian dollars for start of construction in 2008 and an assumed exchange rate of CDN$ 1 = US$ 0.95 (McColl, et al., 2008). The cost estimates (McColl, et al., 2008) assume a 10% real return on investment, 2.2% inflation and a gas price forecast ranging from CDN$ 6.50 to 9.00 per million British Thermal Units. The SAGD supply cost estimates are slightly lower than cyclic steam costs. The range of costs for the mining/extraction process is within the cost range of the thermal processes. CERI's

Figure 4.5 Estimates of operating cost (Opex) and supply costs by production method (Source: McColl, *et al.*, 2008)

			CDN$ (2007) * per barrel at plant gate	
Production method	**Quantity b/d**	**Product**	**Opex ****	**Supply cost *****
Cyclic steam (Cold Lake)	30 000	Bitumen	20	36-37
SAGD	30 000	Bitumen	19	34-35
Mining/extraction	100 000	Bitumen	13	36-37
Integrated/mining, extraction, and upgrading ****	100 000	SCO	23	72

* US$ / CDN$ = 0.95
** Opex is operating cost exclusive of taxes and fuel cost
*** Assumes CO_2 compliance cost of $ 15 per tonne for excess emissions over 100 000 tonnes/yr
**** Upgrading assumes 1 barrel SCO requires 1.15 barrels of bitumen

published supply cost estimates (McColl, et al., 2008) include all taxes and a CDN$ 15 charge per tonne of CO_2 in excess of 100 000 tonnes per year. The SAGD and cyclic steam stimulation capital investment costs are CDN$ 30 000-35 000 per sustainable daily barrel, so a project capable of producing 30 000 barrels per day would have a nominal investment cost from CDN$ 0.9 to just over 1.0 billion. Investment per daily barrel for the mining and extraction process is CDN$ 48 000. For a stand-alone upgrade plant of 100 000 barrels SCO per day, investment per daily barrel is CDN$ 46 000.

For thermal production methods, each barrel of bitumen produced requires 1.0-1.1 tcf of natural gas, based on a dry steam-to-oil ratio of 2.5:1. For mining/extraction configurations, gas requirements are 0.5 tcf per barrel of bitumen produced. Comparable CO_2 generation rates for thermal methods are 51.4-61.7 kg/bbl and 26.7 kg/bbl for mining and extraction, while a stand-alone upgrading configuration emits 51.4 kg/bbl (McColl, et al., 2008).

Concerns about the volumes of gas consumed and generation of CO_2 involved in the thermal recovery processes, along with availability of water and diluents, have been raised as critical environmental issues. The industry appears anxious to adopt technology to address these issues. Nexen and OPTI Canada's Long Lake SAGD project (startup 2009) upgrades bitumen to 39° API SCO on-site and uses the by-product asphaltenes to produce the synthesis gas for the SAGD steam generation, the cogeneration facility, and the upgrade plant. This design uses little if any outside gas and no diluents and provides the option of capturing a pure CO_2 stream for later sequestration. After years of laboratory and pilot testing, toe-to-heel-air injection (THAI[1]) *in situ* process is in the initial stages of full-scale commercial application at the May River Project (Petrobank Energy and Resources, 2010). This *in situ* combustion process uses little outside fuel or water to produce an upgraded oil product that is ready for pipeline transportation without diluents. However, the process requires an impermeable cap rock, a thick sand, and sufficient reservoir depth to permit operation at a high pressure.

Production economics: Venezuela

The unit supply cost for the Orinoco extra-heavy oil produced cold with multilateral wells is much lower than Canadian cold production costs of bitumen, because favourable fluid and reservoir conditions result in sustained high production rates per well. Current estimates of the supply costs for the Orinoco extra-heavy crude oil are as little as one-third of Canadian bitumen SAGD supply costs (Fig. 4.5).

[1] Any use of trade, firm, or product names is for descriptive purposes only and does not imply the endorsement of the U.S. Government

Transportation and Upgrading

Transportation

Unless there is on-site upgrading, transportation of the extra-heavy oil and bitumen requires that the oil be heated or, alternatively, blended with diluents (naphtha, gas condensates, or light oils) to reduce viscosity. Dilbit, a bitumen blend, consists of up to 67% bitumen and 33% natural gas liquids (or a 50/50 blend of bitumen and naphtha). The Synbit blend is half bitumen and half SCO. The total costs of transporting a given volume of produced raw bitumen are much greater than the costs of transporting the same volume of produced conventional oil because the additional volume of diluents, amounting to at least 50 to 100% by volume of bitumen, must also be transported. Additional costs are incurred if the diluents are recovered and shipped back to the producing field. In the Orinoco Oil Belt the produced extra-heavy oil is blended with lighter oils and transported to coastal upgrading plants.

Upgrading technology

In the crude oil distillation process the heavier the feedstock oil, the lower are yields of the valuable light fractions, and the greater is the residuum yield. The low yield of high-valued products explains why most refineries steeply discount the prices they pay for heavy oil relative to light oil. Upgrading bitumen and extra-heavy oil is profitable when the spread between the light and heavy oil prices is sufficient to cover the costs of upgrading.

In the upgrading process, extra-heavy oil or bitumen is passed through atmospheric and vacuum distillation processes that produce gas oil and residue and that also recover the diluents for recycling. The gas oil can be treated with hydrogen to reduce sulphur and nitrogen (producing hydrogen sulphide and ammonia). Gas oil is either hydrotreated (a catalytic reaction) or hydrocracked under mild conditions. Specific options for treating the residue (often called resid conversion) are (1) solvent deasphalting applied as pretreatment of the residue for removal of asphaltic materials (Speight, 1991), (2) visbreaking, which is a mild thermal cracking operation used to reduce the viscosity of the residue, producing a low grade gasoline, heavy gas oil distillates, and a residual tar, (3) coking, which is used to break the heaviest fractions of the residue into elemental carbon (coke) and lighter fractions, and (4) residue hydrocracking, which adds hydrogen to the residue to maximise SCO output as the residue is heated under high temperature and high pressures (Vartigan and Andrawis, 2006). Hydrogen for hydrocracking is purchased or generated by passing natural gas over steam (steam-methane reforming process). The high pressures and temperatures required of process equipment and the required hydrogen are sources of increased costs for residue hydrocracking (Speight, 1991). Carbon-rejection processes, such as coking, lead to penalties in the volume of SCO, whereas the hydrogen-addition processes, such as residue hydrocracking, lead to increased product volumes.

Figure 4.6 Commercial operations in the Orinoco Oil Belt
(Source: Energy Information Administration, 2009)

Area Name: **(Original project name):**	**Junin** **(Petrozuata)** [i]	**Carobobo** **(Cerro Negro)** [ii]	**Boyaca** **(Sincor)** [iii]	**Ayacucho** **(Hamaca)** [iv]
Startup	October 1998	November 1999	December 2000	October 2001
Extra-Heave Oil Production – b/d	120 000	120 000	200 000	200 000
API gravity	9.3º	8.5º	8.0-8.5º	8.7º
Synthetic Oil production – b/d	104 000	105 000	180 000	190 000
API gravity	19-25º	16º	32º	26º
Sulphur - % weight	2.5	3.3	0.2	1.2

i PDVSA 100%
ii PDVSA 83.34%; BP 16.66%
iii PDVSA 60%; Total 30.3%; Statoil 9.7%
iv PDVSA 70%; Chevron 30%

Bitumen upgrading: Canada

As of 2008, about 60% of the crude bitumen produced in Alberta was converted into various grades of SCO. The remaining 40% was blended with diluents (light oils, gas condensates or natural gas liquids) and shipped to refiners having the capability to accept the heavy oil blend (Canadian Association of Petroleum Producers, 2009).

The yield of SCO from the natural bitumen varies with the technology employed, consumption of the product for fuel in the upgrade, and the degree of residue upgrading. The Suncor, Syncrude, and Albian Sands projects mine natural bitumen and extract the oil from the mined sand. The Suncor project, for example, uses delayed coking for a yield of 0.81 barrels of SCO per barrel of natural bitumen input. The Syncrude project, which uses fluid coking combined with hydrocracking the gas oil fraction, has a yield of 0.85 barrels of oil per barrel of bitumen (Speight, 1990). The yield for the Albian Sands plant at Scotford, which applies hydrocracking to both gas oil and residue, is 0.9 (NEB, 2004).

Extra-heavy oil upgrading: Venezuela

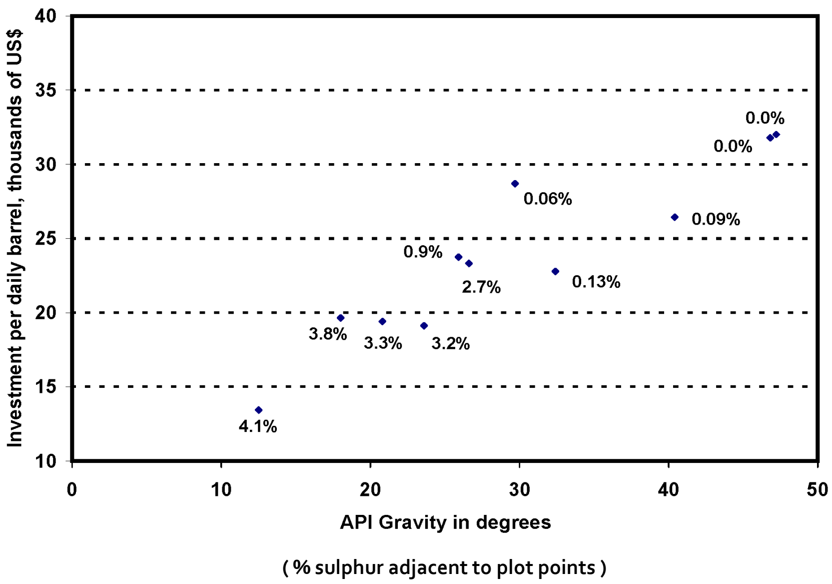
Fig. 4.6 shows the upgrade plant capacities and product specifications for the four commercially-operating Orinoco Oil Belt extra-heavy oil production projects. The limited availability of Venezuelan light crude oils for blending makes it economic to upgrade the Orinoco oil prior to export. Upgrade plants are located on the northeast coast of Venezuela. All the plants recover and return diluents to their fields. Each also uses delayed coking to upgrade residue and hydrotreatment for removal of sulphur and nitrogen from the coking process by-product naphtha. The Sincor project produces a low-sulphur light synthetic crude oil by hydrocracking the heavy gas oil generated from gasifying part of the coke from the coking process. The conversion efficiency of extra-heavy oil into synthetic crude varies from 87-95%. The variety of SCO qualities reflects the needs of the original operators. Upgrade plants producing the lower gravity (heavy) SCO shipped their products to captive refineries in the U.S. and Caribbean (Chang, 1998). Extra-heavy oil and bitumen use similar processes, so upgrading costs are comparable.

Upgrading costs and markets

In general the upgrade costs increase with the required quality of the SCO. Based on the CERI (McColl, et al., 2008) study, the supply cost of upgrading bitumen to an SCO of about 39° API and less than 0.3% sulphur is estimated to be CDN$ 32 per barrel, exclusive of the feedstock bitumen, assuming a plant capacity of 100 000 b/d SCO and a conversion efficiency of 86%.

Figure 4.7 Initial investment cost per daily barrel for upgrading bitumen to various grades of synthetic crude oil

(Source: based on Vartivarian and Andrawis, 2006, adjusted to late 2007 US$)



In an early study, Vartivarian and Andrawis (2006) published cost data coupled with upgrade plant process configurations designed to upgrade 8.6° API (4.8% sulphur) bitumen to various product SCO grades as measured by API gravity and sulphur content. These data have been adjusted to reflect U.S. cost increases from 2005 to late 2007 with adjusted data expressed as the required investment per daily barrel of SCO output. Fig. 4.7 shows (1) the wide range in initial investment costs per daily barrel of SCO output depending on product quality and (2) that, on the basis of the investment required per daily barrel of SCO, for a plant with a capacity of 80 000 b/d, the initial investment is in the billions of dollars even for the lowest-cost upgrade level.

Plants that upgrade extra-heavy oil and bitumen are chemical process plants that are subject to significant scale economies, that is, per barrel cost declines as size increases. Furthermore, when plant size is optimal for the market served, the plant generally must operate at high utilisation rates to be profitable. The most profitable upgrade plant design depends on the value placed on its synthetic crude product by refinery purchasers as well as the cost of inputs to the upgrade plant. SCO market value is determined by the availability of competing crude oils of the same or superior quality and the technical capability and excess capacity at local or operator-owned (captive) refineries to accept the crude and, in turn, to produce high-value products.

Downstream vertical integration is the economic term to describe a situation where a raw materials producer performs the next stages of processing, such as refining or smelting and even selling finished products. Alternatively, upstream vertical integration is a term that describes the situation when a processor or retailer starts a mining or extraction subsidiary in order to supply processing plants and retail outlets. One motivation for economic integration is to manage the risks inherent in raw materials markets by providing a means through a captive upgrading facility and perhaps a refinery to assure a market for the bitumen-derived products. Extra-heavy oil and bitumen production are high-cost sources of oil for the eventual production of high-value transportation fuels. The refiner’s price differential between heavy oil and light oil can be notoriously unstable so there is a real risk that the bitumen producers and upgrade plant operators may be unable to recover operating costs when light oil is in oversupply and light oil prices are in decline.

Technological innovations to meet environmental regulation

In North America, access to resources and the security of crude oil supply have motivated the utilisation of Canadian oil sands. Bitumen is now commercially produced in numerous large-scale projects with both mining and *in situ* recovery technologies. With the industry's maturation, a regulatory framework must be implemented to ensure that the private costs of producing and upgrading bitumen reflect the full cost to society of the resources used to produce SCO. Currently mining, *in situ* extraction of bitumen, and upgrading are more energy- and water-intensive than production of conventional oil and thus generate greater amounts of CO_2 per barrel of refinery feedstock. New technologies can offset and perhaps eliminate the differences.

For mining, new tailings pond performance standards (ERCB, 2009b) reduce the area and life of tailings ponds and accelerate the reclamation of pond and mined-out areas. Various additives to the tailings slurry may accelerate the settling process. An alternative bitumen and sand separation process results in dry tailings, which eliminate the tailings problem (Collison, 2008).

Three *in situ* extraction processes are in various developmental stages that promise to significantly reduce resources used and emissions generated by *in situ* bitumen extraction. In the VAPEX (vapor-assisted petroleum extraction) process, a solvent blend of propane, butane, naphtha, and methane is injected into the formation as a vapour by an upper horizontal well. The solvent mixes with bitumen to reduce its viscosity. Production occurs through a lower horizontal well. The process uses no water and produces no CO_2, but it is not yet commercial, because it is slow, and a practical system for recovery of the costly solvent has not been demonstrated. A hybrid solvent steam process (SAP) has enabled incremental reductions in the amount of steam required, energy consumption, and thus CO_2 emissions (National Petroleum Council [NPC], 2007).

In the Electro-Thermal Dynamic Stripping process (McGee, 2008) the bitumen's viscosity is reduced by heat generated from electrical energy delivered by electrodes inserted into the formation. No water or gas is used in the process. Scaled-up tests must develop ways to enhance well production rates and allow increased spacing of electrode and production wells.

The THAI process involves igniting bitumen at the toe of a horizontal production well and feeding the combustion front with compressed air injected by a vertical well. The heat reduces viscosity of the bitumen, allowing recovery through the production well. As the combustion front moves from the toe of the production well to the heel, a natural coking reaction uses precipitated asphaltenes as fuel, thus raising the API gravity of the produced oil. This process, owned by Petrobank Energy and Resources, has been field tested in a pilot configuration for several years at the Whitesands project.

Process development now focuses on increasing the well production rates to commercial levels and improving the quality of upgraded oil. Petrobank is applying the process to commercial-scale operations at the May River bitumen project and to a heavy oil deposit in Saskatchewan (Petrobank Energy and Resources Ltd., 2010). With the possible exception of an operation in Romania, other *in situ* process technologies have yet to be proven commercially successful.

Another experimental procedure is to introduce bacteria into the reservoir to upgrade the bitumen to light oil or natural gas. The challenge with this approach is to accelerate reaction times and create reservoir conditions amenable to high rates of extraction.

Summary and Implications

The volume of original oil in place in known deposits of natural bitumen and extra-heavy oil appears to be at least of the same order of magnitude as the volume of original oil in place at discovered conventional oil accumulations. Although occurrences of natural bitumen and extra-heavy oil are globally widespread, the massive deposits in Canada and Venezuela account for high percentages, (69% and 98%, respectively) of the discovered resources. Trade press reports prior to the decline in oil prices in 2008, indicated that the production technologies used in the Orinoco Oil Belt and Alberta bitumen deposits were being considered in connection with the development of other deposits. The Orinoco Oil Belt and the Alberta oil sands projects have demonstrated that these resources can be extracted and upgraded at rates that can make an important contribution to each country's petroleum supply and at costs that are competitive with high-cost conventional resources. The Venezuelan government has a stated goal of producing 6.86 million b/d from the Orinoco projects by 2021 (*Oil&Gas Journal*, 2010) and the Alberta ERCB estimates the production from Alberta's oil sands will be increased to 2.95 million b/d by 2018.

Innovations in *in situ* recovery are driven by the need to reduce resource and energy costs as well as emissions of greenhouse gases. New technologies also aim to eliminate plant upgrading by upgrading *in situ*. This generally requires raising reservoir temperatures higher than typically achieved by steam injection. The THAI process performs some upgrading. Theoretically, electrical heating might supply sufficiently high temperatures. The application of solvents and catalysts is also being evaluated. The introduction of bacteria in the reservoir to upgrade bitumen *in situ* is also an area of active research (NPC, 2007).

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DEFINITIONS

In Tables 4.1 and 4.2 the following definitions apply:

Discovered original oil in place: the volume of oil (natural bitumen/extra-heavy oil) in place reported for deposits or parts of deposits that have been measured by field observation. In the literature, estimates of the in-place volumes are often derived from the physical measures of the deposit: areal extent, rock grade, and formation thickness.

Prospective additional resources: the oil or bitumen in unmeasured parts of a deposit believed to be present as a result of inference from geological (and often geophysical) study.

Original oil in place: the amount of oil or bitumen in a deposit before any exploitation has taken place. Where original oil in place is not reported, it is most often calculated from reported data on original reserves (cumulative production plus reserves). Although admittedly inexact, this is a reasonable way to describe the relative abundance of the natural bitumen or extra-heavy oil.

Original reserves: reserves plus cumulative production. This category includes oil that is frequently reported as estimated ultimate recovery, particularly in the case of new discoveries.

Cumulative production: total of production to latest date.

Reserves: those amounts of oil commonly reported as reserves or probable reserves, generally with no further distinction, are quantities that are anticipated to be technically (but not necessarily commercially) recoverable from known accumulations. Only in Canada are reserves reported separately as recoverable by primary or enhanced methods. Russian A, B, and C1 reserves are included here. The term reserve, as used here, has no economic connotation.

Coking: a thermal cracking process that converts the heavy fraction of residue or heavy oils to elemental carbon (coke) and to lighter fractions of the residue, including naphtha or heavy gas oils.

Conventional oil: oil with an API gravity of greater than 20° (density below 0.934 g/cm^3). API gravity is the inverse of density and is computed as (141.5/sp g)-131.5 where sp g is the specific gravity of oil at 60 degrees Fahrenheit.

Cracking: a general term used for a process in which relatively heavy or more complex hydrocarbon molecules are broken down into lighter or simpler, lower-boiling temperature molecules.

Delayed coking: a coking process that recovers coke and produces heavy gas oils from the residuum following the initial distillation of the feedstock oil. The process uses at least two sets of large drums that are alternatively filled and emptied while the rest of the plant operates continuously. Drum temperatures are 415° to 450°C.

Extra-heavy oil: extra-heavy oil is commonly defined as oil having a gravity of less than 10° API and a reservoir viscosity of no more than 10 000 centipoises. In this chapter, when reservoir viscosity measurements are not available, extra-heavy oil is considered to have a lower limit of 4° API.

Flexi-coking: an extension of fluid coking, which includes the gasification of the coke produced in the fluid coking operation and produces a coke gas (Speight, 1986). Flexi-coking is a trademark name of an ExxonMobil proprietary process.

Fluid Coking: a continuous coking process where residuum is sprayed onto a fluidised bed of hot coke particles. The residuum is cracked at high temperatures into lighter products and coke. Coke is a product and a heat carrier. The process occurs at much higher temperatures than delayed coking but leads to lower coke yields and greater liquid recovery. Temperatures in the coking vessels are from 480° to 565°C (Speight, 1986). Fluid coking is a trademark name of an ExxonMobil proprietary process.

Gas oil: hydrocarbon mixture of gas and oils that form as product of initial distillation of bitumen or heavy oil feedstock.

Heavy oil: oil with API gravity from 10° to 20° inclusive (density above 1.000 g/cm^3).

Hydrocracking: a catalytic cracking process that occurs in the presence of hydrogen where the extra hydrogen saturates or hydrogenerates the cracked hydrocarbons.

Natural bitumen: natural bitumen is defined as oil having a viscosity greater than 10 000 centipoises under reservoir conditions and an API gravity of less than 10° API. In this chapter, when reservoir viscosity measurements are not available, natural bitumen is defined as having a gravity of less than 4° API. (Natural bitumen is immobile in the reservoir. Because of lateral variations in chemistry as well as in depth, and therefore temperature, many reservoirs contain both extra-heavy oil, and occasionally heavy oil, in addition to natural bitumen).

Oil Field: a geographic area below which are one or more discrete reservoirs from which petroleum is produced. Each reservoir may be comprised of one or more zones, the production from which is commingled. The production from the reservoirs may be commingled, in which case production and related data cannot be distinguished.

TABLES

TABLE NOTES

The data in the tables are estimates by Richard Meyer of the U.S. Geological Survey. They have been based upon a detailed review of the literature combined with available databases, and suggest (but do not define) the resource volumes that could someday be of commercial interest

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Table 4.1 Natural Bitumen: resources, reserves and production at end-2008

	Deposits	Discovered original oil in place	Prospective additional resources	Total original oil in place	Original reserves	Cumulative production	Reserves
	number			million barrels			
Angola	3	4 648		4 648	465		465
Congo (Brazzaville)	2	5 063		5 063	506		506
Congo (Democratic Rep.)	1	300		300	30		30
Madagascar	1	2 211	13 789	16 000	221		221
Nigeria	2	5 744	32 580	38 324	574		574
Total Africa	**9**	**17 966**	**46 369**	**64 335**	**1 796**		**1 796**
Canada	231	1 731 000	703 221	2 434 221	176 800	6 400	170 400
Trinidad & Tobago	14	928		928			
United States of America	204	37 142	16 338	53 479	24	24	
Total North America	**449**	**1 769 070**	**719 559**	**2 488 628**	**176 824**	**6 424**	**170 400**
Colombia	1						
Venezuela	1						
Total South America	**2**						
Azerbaijan	3	<1		<1	<1		<1
China	4	1 593		1 593	1		1
Georgia	1	31		31	3		3
Indonesia	1	4 456		4 456	446	24	422
Kazakhstan	52	420 690		420 690	42 009		42 009
Kyrgyzstan	7						
Tajikistan	4						
Uzbekistan	8						
Total Asia	**80**	**426 771**		**426 771**	**42 460**	**24**	**42 436**
Italy	16	2 100		2 100	210		210
Russian Federation	39	295 409	51 345	346 754	28 380	14	28 367
Switzerland	1	10		10			
Total Europe	**56**	**297 519**	**51 345**	**348 864**	**28 590**	**14**	**28 577**

Table 4.1 Natural Bitumen: resources, reserves and production at end-2008

	Deposits	Discovered original oil in place	Prospective additional resources	Total original oil in place	Original reserves	Cumulative production	Reserves
	number			million	barrels		
Syria (Arab Rep.)	1						
Total Middle East	**1**						
Tonga	1						
Total Oceania	**1**						
TOTAL WORLD	**598**	**2 511 326**	**817 273**	**3 328 598**	**249 670**	**6 462**	**243 209**

Source: R.F. Meyer, U.S. Geological Survey

Table 4.2 Extra-Heavy Oil: resources, reserves and production at end-2008

	Deposits	of which: deposits offshore	Discovered original oil in place	Prospective additional resources	Total original oil in place	Original reserves	Cumulative oil production	Reserves
	number	number			million barrels			
Egypt (Arab Rep.)	1		500		500	50		50
Total Africa	**1**		**500**		**500**	**50**		**50**
Mexico	2		60		60	6	5	1
Trinidad & Tobago	2		300		300			
United States of America	54	1	2 609	26	2 635	235	216	19
Total North America	**58**	**1**	**2 969**	**26**	**2 995**	**241**	**221**	**20**
Colombia	2		380		380	38	8	30
Cuba	1	1	477		477	48		48
Ecuador	3		919		919	92	50	42
Peru	2		250		250	25	18	7
Venezuela	33	2	1 922 007	189 520	2 111 527	72 556	14 702	57 854
Total South America	**41**	**3**	**1 924 033**	**189 520**	**2 113 553**	**72 759**	**14 778**	**57 981**
Azerbaijan	1		8 841		8 841	884	759	125
China	12		8 877		8 877	888	137	750
Uzbekistan	1							
Total Asia	**14**		**17 718**		**17 718**	**1 772**	**896**	**875**
Albania	2		373		373	37	3	34
Germany	1							
Italy	31	6	2 693		2 693	269	179	90
Poland	2		12		12			
Russian Federation	6		177		177	6		6
United Kingdom	2	2	11 850		11 850	1 085	1 009	76
Total Europe	**44**	**8**	**15 105**		**15 105**	**1 397**	**1 191**	**206**

Table 4.2 Extra-Heavy Oil: resources, reserves and production at end-2008

	Deposits	of which: deposits offshore	Discovered original oil in place	Prospective additional resources	Total original oil in place	Original reserves	Cumulative oil production	Reserves
	number	number	million barrels					
Iran (Islamic Rep.)	1	1						
Iraq	1							
Israel	2		2		2	<1		<1
Total Middle East	**4**	**1**	**2**		**2**	**1**		**1**
TOTAL WORLD	**162**	**13**	**1 960 327**	**189 546**	**2 149 873**	**76 220**	**17 086**	**59 133**

Source: R.F. Meyer, U.S. Geological Survey

COUNTRY NOTES

The Country Notes on Natural Bitumen and Extra-Heavy Oil have been compiled by the authors of the Commentary. Names of sedimentary basins and reference locations are from *Sedimentary Provinces of the World* by St. John, Bally and Klemme (1984). In the case of Canada, additional information supplied by the WEC Member Committee has been incorporated.

Albania

Two of Albania's oil fields contain extra-heavy oil accumulations, and both are located in the Durres Basin.

Angola

Two natural bitumen deposits are located in the Cuanza Basin in Bengo province. They contain about 4.5 billion barrels of oil in place, but have not been worked as an energy source. Their development could be an option after most of Angola's conventional oil resources have been produced.

Azerbaijan

The natural bitumen resources are small and will probably not be used as a source of energy in the near future. The deposits are located within the South Caspian Basin, and the best known is Cheildag (Waters, 1974). The large extra-heavy oil accumulation was discovered in 1904.

Canada

Resource information for the Alberta bitumen deposits is derived from the Alberta Energy Resources Conservation Board (ERCB, 2009), supplemented by estimates for Peace River (Harrison, 1984) and Athabasca (McPhee and Ranger, 1998, and Harrison, 1984).

Deposits are found in Lower Cretaceous sandstones and in the Mississippian and Devonian carbonates unconformably overlain by Lower Cretaceous strata. The oil sands occur along the up-dip edge of the Western Canada Sedimentary Basin. East of the Athabasca and Cold Lake deposits, in Alberta and Saskatchewan, large quantities of heavy and medium oil are found in the Lower Cretaceous sandstones, but occurrences of extra-heavy oil are few and of limited economic importance. At least one firm has announced plans to test whether the oil sands deposits extend into Saskatchewan.

Saskatchewan's oil sands reserves are not yet recognised as proved owing to a lack of an accepted geological survey. According to Oil Sands Quest there could be 50 to 60 billion barrels of bitumen in northwest Saskatchewan.

In 2009 the ERCB predicted that by 2018, bitumen production will increase to almost 2.95 million b/d, up from 1.3 million b/d (before upgrading) in 2008 – 55% of production. Mined output would increase to 1.56 million b/d from 720 000 b/d and *in situ* production to 1.39 million b/d from 580 000 b/d. Industry estimates that two tonnes of oil sands can produce 1.2 barrels of non-upgraded bitumen or 1 barrel of upgraded synthetic crude oil.

During 2009, many projects were delayed. Cost levels declined but some projects are still delayed, because of concern about potential CO_2 emissions constraints. Because production and upgrading costs for bitumen are high relative to conventional oil, the economic viability of the oil sands industry is dependent on a continuation of the recent level of prices of crude oil, at least until further cost-reducing technologies are devised and implemented.

According to the Province of Alberta, an estimated 1.7 to 2.5 trillion barrels of oil are trapped in a complex mixture of sand, water and clay. Bitumen already discovered amounts to 1.7 trillion barrels. The Province of Alberta indicates that additional oil is believed to exist owing to geological characteristics which could raise the total volume of bitumen in place to 2.5 trillion barrels.

According to ERCB, an estimated 315 billion barrels of bitumen is expected to be recovered from the oil sands with advances in technology. The ultimate potential (recoverable) figure has been adopted by the Government of Canada.

China

Four natural bitumen accumulations have been identified in the Junggar Basin with resources of about 1.6 billion barrels of bitumen. Ten of the 12 extra-heavy oil accumulations are located in the Bohai Gulf Basin with the other two located in the Huabei and the Tarim Basins.

Colombia

The two extra-heavy oil accumulations are part of a single field in Colombia in the Barinas-Apure Basin. There are numerous oil seepages and small bitumen deposits, especially in the Middle and Upper Magdalena Basins. None of these deposits appears to be sufficiently large to be an important commercial source of synthetic oil.

Congo (Brazzaville)

Heavy oil is found in reservoirs offshore Congo but no extra-heavy oil is known. The natural bitumen deposit at Lake Kitina in the Cabinda Basin has been exploited for road material. In 2008, Eni agreed to evaluate and produce bitumen in a concession that includes the Lake Kitina area (Tchikatanga area) and Lake Dionga area (Tchikatanga-Makola area). Estimated recoverable oil is about 500 million barrels.

Congo (Democratic Republic)

A natural bitumen deposit occurs in the Democratic Republic of Congo in the Cabinda Basin near the border with Cabinda. It has served as a source of road material, with nearly 4 000 tonnes (24 000 barrels) having been produced in 1958. This deposit is not likely to become a source of synthetic oil.

Cuba

Most of the oil produced from Cuba is heavy. Cuba contains numerous oil seepages but no significant natural bitumen accumulations. The extra-heavy oil accumulation is located partially offshore in the Florida-Bahamas Basin (also called the Greater Antilles Deformed Belt).

Ecuador

Ecuador is endowed with large amounts of heavy oil but only a small amount, all in the Putumayo Basin, is extra-heavy. Natural bitumen is restricted to scattered oil seepages.

Egypt (Arab Republic)

Many fields containing heavy oil are found in Egypt, but very little of this is extra-heavy. The single extra-heavy oil accumulation is undeveloped.

Georgia

The only significant natural bitumen deposit in Georgia is in the South Caspian Basin, at Natanebi. Neither heavy nor extra-heavy oil are known in Georgia, although conventional oil has been produced there for more than a century.

Germany

Heavy oil is produced from many fields in Germany, but extra-heavy oil has not been reported. Highly viscous natural bitumen is present in the Nordhorn deposit, in the Northwest German basin.

Indonesia

In Indonesia although many fields produce heavy oil there does not appear to be a large extra-heavy oil resource. Natural bitumen occurs in the well-known Buton Island deposit. This has long been utilised as a source of road asphalt.

Iran (Islamic Republic)

The principal extra-heavy oil accumulation is part of an offshore discovery. A number of Iranian fields produce heavy oil.

Iraq

Oil seepages have been known and utilised in Iraq throughout historical time, but are insufficient for serving as sources of synthetic oil. Although heavy oil fields are productive in the country, very little extra-heavy oil has been identified.

Israel

The extra-heavy oil that is known in Israel is located in the Dead Sea province. Natural bitumen occurs only as Dead Sea asphalt blocks, which occasionally rise to the surface.

Italy

Italy has 16 natural bitumen deposits and 31 extra-heavy oil deposits. The 269 million barrels of original reserves of extra-heavy oil in Italy are found in six separate basins, similar geologically to the Durres Basin of Albania. The most important of these is the Caltanisetta Basin, mostly offshore and including the Gela field. These fields are all found in the foredeep portion of the basins, where the sediments are thickest and most structurally disturbed. The viscous nature of the oil, the offshore environment, and the limited resources create challenges to economic development of these accumulations.

Kazakhstan

Although Kazakhstan possesses large resources of conventional and heavy oil, it contains little if any extra-heavy oil. It does have significant resources of natural bitumen in the North Caspian Basin. As with nearly all the large natural bitumen deposits, the geological setting, like that of the Western Canada Sedimentary Basin, is conducive to the development of natural bitumen. In the light of the very large resources of conventional oil and natural gas in this country, development of the bitumen as a source of synthetic oil is unlikely in the foreseeable future.

Kyrgyzstan

Little is known about these deposits except their location in the Fergana Basin. They have yet to be evaluated.

Madagascar

Bemolanga is the only natural bitumen deposit in Madagascar. In 2008 Total Oil acquired from Madagascar Oil a 60% interest (including operatorship) in the concession to develop the Bemolanga deposit. The partnership estimates 2.5 billion barrels is recoverable out of an in-place amount of 16 billion barrels, as evaluated by DeGolyer and MacNaughton. A large heavy-oil deposit, Tsimiroro, has been the subject of a number of unsuccessful production tests but no extra-heavy oil has been identified in the country.

Mexico

Mexico, with numerous heavy oil fields, contains very few extra-heavy oil reservoirs. The latter are small in resources and production. Oil seepages are common in the country, but no large natural bitumen deposits have been found.

Nigeria

Natural bitumen in place, possibly totaling as much as 38.3 billion barrels, is located in southwestern Nigeria, in the Ghana Basin. This extensive deposit has not yet been evaluated as a source of synthetic oil and its production will no doubt be delayed as long as Nigeria is a leading producer of conventional oil.

Peru

Peru contains numerous heavy oil deposits, mostly in the Oriente Basin. However, the recoverable oil from the two known extra-heavy oil accumulations is relatively small.

Poland

With current technology, the two extra-heavy oil reservoirs of Poland are marginally economic.

Russian Federation

Extra-heavy oil has been identified in the Russian Federation in small amounts in the Volga-Urals and North Caucasus-Mangyshlak Basins (S.I. Goldberg, written communication). As is the case with many countries, accurate and timely data are insufficient for making well constrained estimates.

Information relating to natural bitumen deposits indicates that very large resources are present in the east Siberia platform in the Tunguska Basin (Meyer and Freeman, 2006). This is harsh terrain and only the Olenek deposit has been studied in sufficient detail to permit the estimation of discovered bitumen in place. The Siligir deposit has been frequently cited in reports of world bitumen deposits, but the primary source for these citations has not been located. It may be assumed that the estimate of more than 51 billion barrels for the basin is conservative. This area is so remote, and Russia's conventional oil and gas resources so great, that it is not likely that attempts will be made in the near future to exploit this natural bitumen. Most of the other Russian bitumen deposits are located in the Timan-Pechora and Volga-Urals Basins, which are analogous geologically to the Western Canada Sedimentary Basin. However, these deposits are scattered and the recoverable portions are not quantitatively large. The deposits in the Tatar Republic have been studied extensively and efforts to exploit them may be conducted in the future.

Switzerland

The Val de Travers natural bitumen deposit in Switzerland is small, but representative of many such occurrences in Western European countries. Most of these have been known for centuries and a few have been mined, mainly for road material.

Syria (Arab Republic)

The Babenna natural bitumen in Syria was mined for many years for asphalt. It is one of numerous such deposits throughout the Middle East, those in Syria and Iraq being especially prominent since antiquity. They are not regarded as potential commercial sources of synthetic oil.

Tajikistan

Little is known about the four bitumen accumulations except that three are located in the Amu-Darya Basin and the fourth is located in the Fergana Basin.

Tonga

The Tonga natural bitumen accumulation was found as a seep but has yet to be evaluated.

Trinidad & Tobago

Trinidad & Tobago is rich in heavy oil, but only 300 million barrels of oil in place is extra-heavy. The country has more than 900 million barrels of oil in place in natural bitumen deposits, including Asphalt (Pitch) Lake. All these deposits are located in the Southern Basin, which is small, highly faulted, but highly productive of other hydrocarbons.

Asphalt (Pitch) Lake, at La Brea, which contains a semi-solid emulsion of soluble bitumen, mineral matter, and other minor constituents (mainly water), has been mined since at least 1815 but mostly for use as road-surfacing material. The lake contains 60 million barrels of bitumen, a sufficient supply for the foreseeable future. Production is between 10 000 and 15 000 tonnes per year (equivalent to 60 000 to 92 000 barrels per year), most of which is exported. In combination with asphalt from refined crude oil, the product is used for road construction. In addition, it can be used in a range of paints and coatings and for making cationic bitumen emulsions. Production of these emulsions of bitumen, water, and soap began in late 1996 and the emulsions are now used widely throughout the industrialised world in place of solvent-based bitumen emulsions.

United Kingdom

Offshore the United Kingdom has two extra-heavy oil deposits. One is a discovery in the West of Shetlands Basin, for which few data are available. The other is the producing Piper field in the North Sea Graben, which contains oil between 8.7º and 37º API gravity.

United States of America

The United States was endowed with very large petroleum resources, which are to be found in nearly all the various types of geologic basins.

The resources of extra-heavy oil and natural bitumen likewise are distributed in numerous geological settings. Geologically, about 80% of the discovered U.S. natural bitumen is deposited in basins similar to the Western Canada Sedimentary Basin. Such basins possess ideal conditions for occurrences of degraded oil. However bitumen deposits of the United States are much smaller, much less numerous, and more scattered. About 98% of the reported extra-heavy oil is found in basins that evolved along the rift-faulted, convergent continental margin of California where the island arcs which originally trapped the sediments against the land mass to the east have been destroyed.

Distillation of oil from Casmalia tar sands in California was first attempted in 1923. Many tar sands deposits in the United States have served as sources of road asphalt, but this industry disappeared with the advent of manufactured asphalt tailor-made from refinery stills. Largest deposits in the lower conterminous 48 states are in Utah. During the 1980s U.S. energy analysts studied criteria, both technical and economic, for supply of synthetic crude oil from tar sands and several tar sands pilot projects were started. With the decline in and stagnation of crude oil prices from the latter 1980s to about 2000, there was little interest in pursuing these projects. The recent sustained increases in oil prices have revived this interest.

The extra-heavy oil accumulations in California account for about 97% of the extra-heavy oil produced to date. These are typically reservoirs found in large fields, multiple reservoir fields, and fields that may have already installed a thermal recovery operation for production of heavy oil in underlying reservoirs or overlying reservoirs.

Uzbekistan

Little is known about the eight natural bitumen occurrences in Uzbekistan except that six occur in the Fergana Basin and two are located in the Amu-Darya Basin. The single occurrence of extra-heavy oil is reported as part of the Khaudag deposit in the Amu-Darya Basin (S.I. Goldberg, written communication). Its size is unknown.

Venezuela

A small amount of Venezuela's extra-heavy oil resource is found in the Maracaibo Basin, but the resources of worldwide significance lie in the Orinoco Oil Belt along the southern, up-dip edge of the Eastern Venezuela Basin. One natural bitumen deposit, Guanoco Lake, is found near the Caribbean coast on the north side of the Eastern Venezuela Basin. The deposit has been estimated to contain 62 million barrels of oil in place (Walters, 1974).

Four joint ventures for the exploitation of extra-heavy crude have been operating since 2001; as of 2006 they have an extra-heavy oil production capacity of 640 000 b/d. All the projects, in one way or another, involve production, transportation, and upgrading facilities. In 2007, Venezuela nationalised the production joint ventures that had been allowed to have foreign ownership. PDVSA (Petróleos de Venezuela, the state oil company) is now majority owner of the four operating projects.

Venezuela, through PDVSA, started a reserves certification programme to increase the proved reserves in the Orinoco Oil Belt. Twenty seven blocks have been selected for development, some of which are being studied by foreign, mostly state, oil companies working with PDVSA. After reserves in a particular block have been certified, the operator who prepared the evaluation may take a minority ownership in a joint venture with PDVSA. Each project must build an upgrade facility, usually in the northeastern coastal area. The scheme has attracted a number of national oil companies: Petrobras (Brazil), Petropars (Iran), CNPC (China) and ONGC (India). Eni and PDVSA have already established a joint venture to develop and upgrade oil from the Junin Block 5.

In the early 1980s Intevep, the research affiliate of PDVSA, developed a method of utilising some of the hitherto untouched potential of Venezuela's extra-heavy oil resource. The extra-heavy oil (7.5º-8.5º gravity API) is extracted from the reservoir and emulsified with water (70% natural bitumen, 30% water, <1% surfactants). The resulting product, called Orimulsion® can be pumped, stored, transported and burnt under boilers using conventional equipment with only minor modifications. Initial tests were conducted in Japan, Canada and the United Kingdom, and exports began in 1988. Orimulsion® is processed, shipped and marketed by Bitúmenes del Orinoco S.A. (Bitor), a PDVSA subsidiary.

Bitor operates an Orimulsion® plant at Morichal in Cerro Negro with a capacity of 5.2 million tonnes per year. In 2005 PDVSA announced it would cease Orimulsion® production because it was more profitable to sell the extracted oil as feedstock to extra-heavy oil upgraders. However, in 2006, PDVSA and CNPC (China National Petroleum Corporation) initiated the Sinovensa project, to supply two power plants in China and meet some of PDVSA's commitments to supply Orimulsion®. Sinovensa currently produces 80 000 b/d and expects to expand to 125 000 b/d.

5. Natural Gas

COMMENTARY

Introduction

This commentary consists of three sections:

- a description of the provenance, location and magnitude of proved reserves of natural gas, compiled by the Editors;
- a paper on Global Gas Supply and Demand to 2030, contributed by the International Gas Union;
- a brief position paper on Shale Gas, prepared by the Editors

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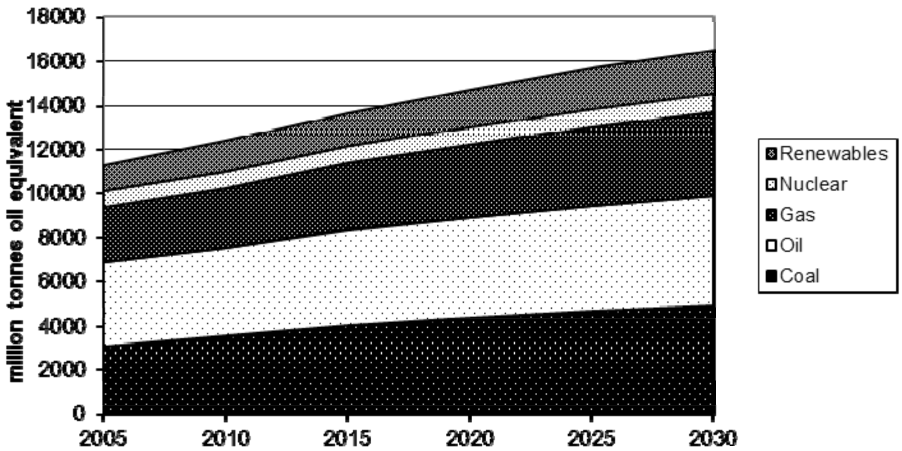
Figure 5.1 World primary energy consumption - Reference Case (Source: IGU)



Natural Gas Reserves

At the end of 2008, 103 countries were identified as possessing proved reserves of natural gas, with an aggregate volume of approximately 186 trillion standard cubic metres, or 6 550 trillion cubic feet. This global total is some 9 tcm (318 tcf) higher than the end-2005 figure reported in the 2007 *Survey*.

The world's largest reserves of natural gas are held by the Russian Federation, the Islamic Republic of Iran and Qatar, as has been the case for the last five editions of the SER. Fourth place is now taken by Turkmenistan which, according to the latest assessments published by Cedigaz, has overtaken Saudi Arabia in the world ranking list.

In absolute terms, the largest changes in proved gas reserves are observable in Turkmenistan (an increase of 5 540 bcm, attributable to a major reassessment), Iran, where reserves rose by a net volume of 2 870 bcm between end-2005 and end-2008, the USA (an increase of 1 156 bcm, largely due to a 51% rise between end-2007 and end-2008 in shale gas reserves – see the situation report below), and the Russian Federation, where three years' production, together with other factors, contributed to a contraction of 2 920 bcm in gas reserves.

Proved reserves of natural gas have been identified in every WEC region, with the highest volumes in the Middle East (41%), Europe (including the whole of the Russian Federation) (27%) and Asia (15%). OPEC's proved reserves were some 93 trillion cubic metres at the end of 2008, equivalent to just over 50% of the world total. The corresponding total for the members of the CIS was just over 60 tcm, representing 33% of global reserves.

Other published compilations of natural gas reserves provide some interesting comparisons with those assembled for the present *Survey.* On the basis of a common reference date (31 December 2008 or 1 January 2009), the six external surveys reviewed all arrive at global totals lying within a fairly narrow band, ranging from just over 177 trillion cubic metres as given by *Oil & Gas Journal* (also adopted by OAPEC) to the level of approximately 189 tcm quoted by Cedigaz. The other sources of comparable data show world proved reserves at intermediate levels: *World Oil* (182 tcm), OPEC (183 tcm), BP (185 tcm) and the Federal Instute for Geosciences and Natural Resources, Germany (BGR) (188 tcm). In its latest assessment (reserves as at 1 January 2010), *Oil & Gas Journal* raised its global total by some 10 tcm, half of which was due to a substantial increase in its estimate for Turkmenistan.

Figure 5.2 Regional share of natural gas in primary energy consumption - Reference Case (Source: IGU)

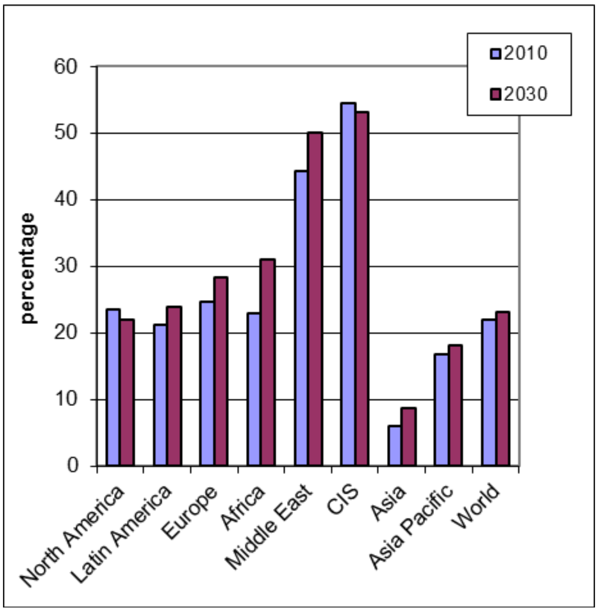
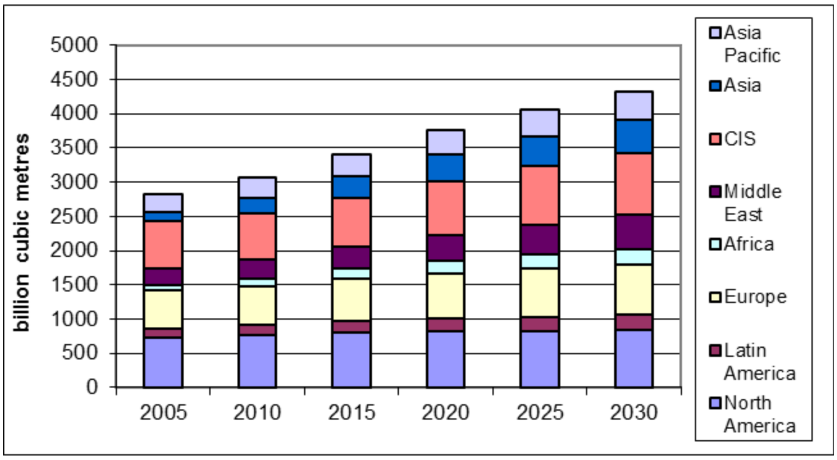


Figure 5.3 Natural gas demand by region - Reference Case (Source: IGU)



While WEC's overall total of 185.5 tcm is close to the mean level of the six assessments quoted above (184 tcm), the substantial measure of agreement on the world picture masks considerable (and in some instances, dramatic) differences in some individual countries. In addition to the obvious possibility of divergences of expert opinion, there are a number of other factors that can play a part. In the first place, although all the assessments in the comparison are ostensibly based on the end-2008 situation, it is undoubtedly true that for a variety of reasons some of the estimates quoted refer to an earlier point in time, frequently lagging by one year. Differences of definition or coverage can also lead to discrepancies: perhaps the commonest example in the case of proved gas reserves is the inclusion (intentional or otherwise) of probable reserves in the figures quoted. On the other hand, as gas reserves are invariably expressed in volumetric terms, they are not so subject to conversion factor differences as are oil reserves. Major discrepancies in individual reserve assessments are highlighted below in Country Notes.

The main portion of this Commentary is devoted to a paper contributed by the International Gas Union (IGU), a worldwide non-profit organisation which aims to promote the technical and economic progress of the gas industry. Its paper is an updated summary of part of a report presented at the 24th World Gas Conference, held in Buenos Aires in October 2009. The 25th World Gas Conference will take place in Kuala Lumpur, Malaysia from 4-8 June 2012.

The discussion of natural gas supply and demand is set in the context of the IGU's regions, which are not identical to the standard WEC geographical regions used elsewhere in this *Survey*. However, the differences are essentially marginal and do not invalidate the analysis.

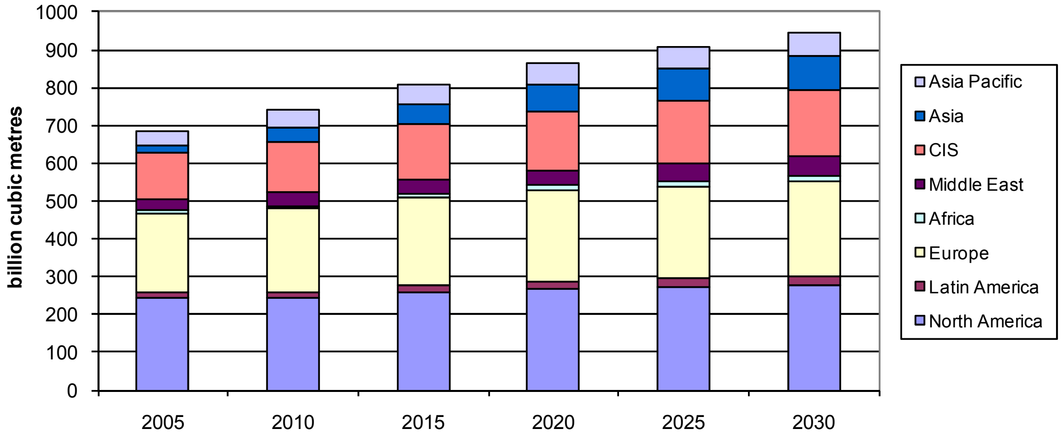
The Editors

GLOBAL SUPPLY AND DEMAND TO 2030

Analysis of the Global Market

Analysing the main trends in natural gas demand and supply in an energy world that is in transition is a challenging job. Moreover, the global financial and economic crisis starting in mid-2008 raised questions about the impact on gas demand and supply in the short-term, but also as to how long would the world remain in recession and what would be the implications for the future regional and global demand/supply balance. Uncertainty over the political response to climate change, as exemplified at

Figure 5.4 Natural gas demand, residential and commercial sector by region – Reference Case (Source: IGU)



Copenhagen in December 2009, also remains a critical influence in the energy mix.

The IGU analysis of the global gas market was conducted through regional experts, based on country data aggregated at regional level within an agreed global framework of assumptions. On the basis of this bottom-up analysis, the representatives of the gas industry in the working group performed a top-down check on the collected data, resulting in an IGU Reference Case.

The Reference Case showed that a global objective of starting to decrease CO_2 emissions will not be met, at least not before 2030. Natural gas, the cleanest and most efficient fossil fuel, could play a bigger role in helping to meet the environmental challenge and to foster the mitigation of climate change. In an alternative scenario, in which there was assumed to be a global agreement at Copenhagen in December 2009 to reduce emissions in the most economic way, it is clear that 'gas can make the difference'. Indeed, increasing the share of natural gas in the global fuel mix, combined with applying more renewable energy, could still start to bend the global CO_2 trend line down before 2020.

Primary Energy Demand

To frame gas supply into a wider energy context, an assessment was made of the development of the total primary energy consumption (Fig. 5.1).

Primary energy demand will increase at an average annual growth rate of 1.4% from 2010 to 2030. The share of natural gas will rise from 21% at the present time to 23% in 2030. The relative gas market share varies at the regional level. The share of gas in primary energy demand is expected to grow significantly in Europe, Africa, the Middle East and Asia.

Natural Gas Demand

- by Region – Reference Case

Natural gas demand is projected to increase by 1.6% per year between 2007 and 2030 to a total of 4.4 tcm. Compared to the previous IGU report of 2006 this projection is about 400 bcm lower. The biggest consuming regions are North America and CIS followed by Europe. The most dynamic regions are Asia (almost doubling from now to 2030), Africa and the Middle East (Fig. 5.3).

- by Category – Reference Case

The Residential and Commercial Sector: a moderate growth is expected from 0.7 tcm at present to well over 0.9 tcm in 2030. Although all regions show some growth in this sector, a significant increase is foreseen in Asia, mainly driven by the number of households to be provided with gas. The main driver for gas consumption is the number of households: in developing countries - mainly determined by population growth, whilst in developed countries - by the decreasing number of persons per dwelling. Furthermore, comfort levels and lifestyle are also driving factors.

Figure 5.5 Natural gas demand, industrial sector by region – Reference Case
(Source: IGU)

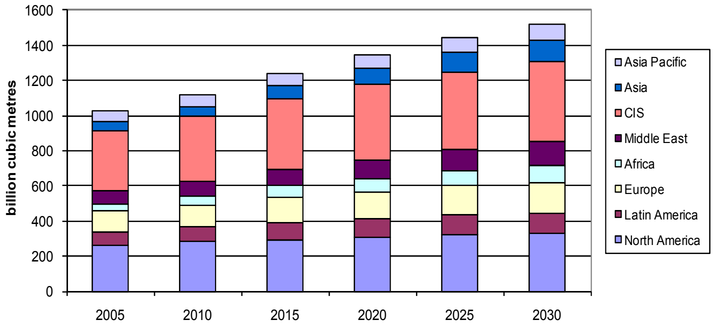
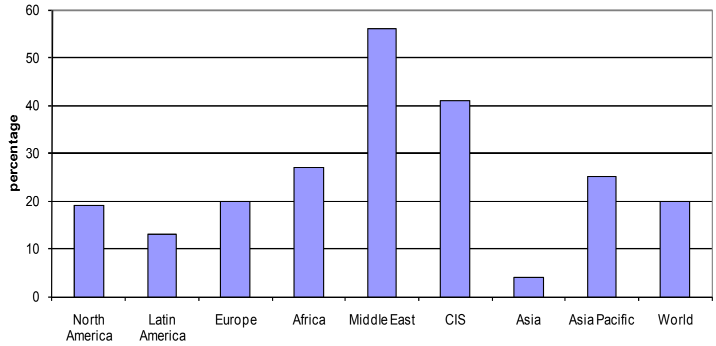


Figure 5.6 Regional share of natural gas in power generation, 2006 – Reference Case
(Source: IGU)



On the other hand gas demand is reduced by energy conservation and efficient use of resources. New, well-insulated houses with a low heat demand are increasingly using electricity for space heating, often in combination with heat pumps.

Renewable energy sources will provide an increasing share of the future energy demand in dwellings. The number of photovoltaic power generation systems as well as boilers using solar heat will grow significantly, although it will take more than a decade before a substantial share is achieved.

The Industrial Sector: this can benefit from the economic and environmental advantages of natural gas; low CO_2 emissions and efficient combustibility enable gas to increase its market share. Industrial gas demand is expected to grow from 1 tcm to 1.5 tcm in 2030.

Gas demand in the CIS has the potential to grow strongly, although a major area of uncertainty during this period is the timing of gas consumers' reactions to the rising cost of gas.

From a relative point of view, Asia has the highest growth figures. Industrial gas consumption will more than double within the time frame, mainly driven by economic development in China and India. Combined heat and power (CHP) will probably expand in almost all regions.

The Power Sector: the increase in global gas demand during recent years was driven mainly by the power sector. The current global gas share in power generation is more than 20%, based on the electricity generated. There are, however, strong regional differences - in the Middle East this share is around 60%, while in Asia only 4% is generated by gas (coal being the principal fuel). (Fig. 5.6).

The advantages of natural gas in power plants are evident: high efficiency, low pollutant emissions (including CO_2), flexibility in electricity generation, low investment costs and short lead-times for construction. Spreading gas networks and supply diversification through (long distance) pipelines and LNG schemes are increasing the availability of natural gas.

The global power sector is expected to grow to almost 1 400 bcm in 2020 and around 1 600 bcm in 2030. The main volume growth is forecast for Europe, the Middle East and Asia, while the gas demand for power generation in Africa will double in the coming two decades.

In the Reference Case there is very limited gas demand growth for power generation in North America. In the United States, consumption of natural gas for power is strongly influenced by the price of natural gas. Any reduction in natural gas for power consumption in the United States reflects the belief that coal will take the place of natural gas in future power generation. This is based on assumptions that the technology and economics will allow for large-scale carbon capture and sequestration, that the public will accept the massive construction of CO_2 pipelines and development of CO_2 storage (i.e.

Figure 5.7 Natural gas demand, power sector by region – Reference Case (Source: IGU)

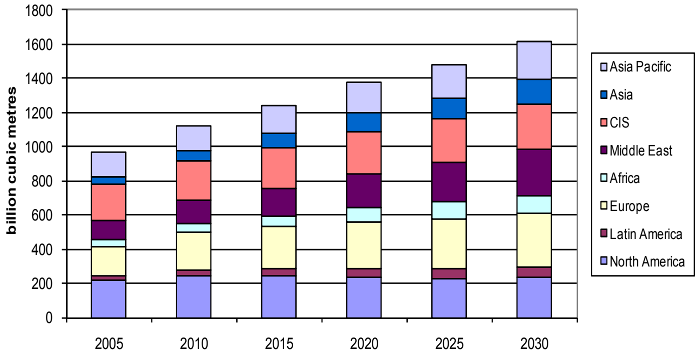
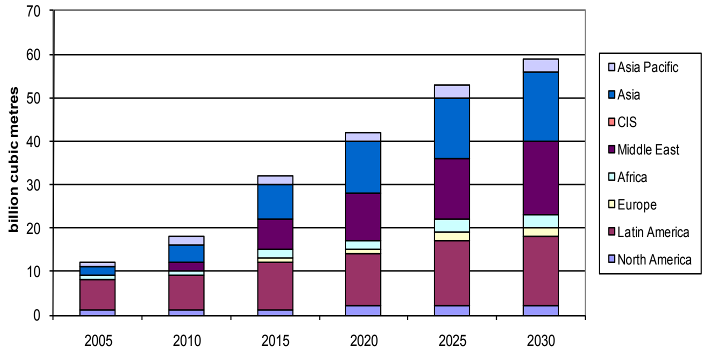


Figure 5.8 Natural gas demand, transport sector by region– Reference Case (Source: IGU)



sequestration), and that any carbon legislation that either caps or taxes emissions will be at a reasonable cost. Given these debatable assumptions, natural gas usage in the power sector could very well increase significantly above the Reference Case.

With a total projected volume of 1 600 bcm in 2030, the prospects for gas to power are impressive. However, at the same time numerous uncertainties arise. Nuclear power is more or less back on the agenda: is this a threat to the position of natural gas? How will the renewable energies develop: will they take over part of the electricity market? What will be the role of CO_2? An emission-trading scheme of CO_2 taxes will benefit natural gas, however the price of CO_2 is an uncertain factor. What will be the impact of Carbon Capture and Storage plants on gas demand in the power sector? The expected gas demand should be regarded against the background of these issues.

The Transport Sector: despite a large potential, gas consumption in the transport sector (natural gas vehicles) is expected to remain small, increasing from around 18 bcm currently to 60 bcm in 2030. Regionally this sector is currently most significant in Latin America, using about 8 bcm/yr. The main regions with growth in this sector are the Middle East and Asia.

Gas Supply

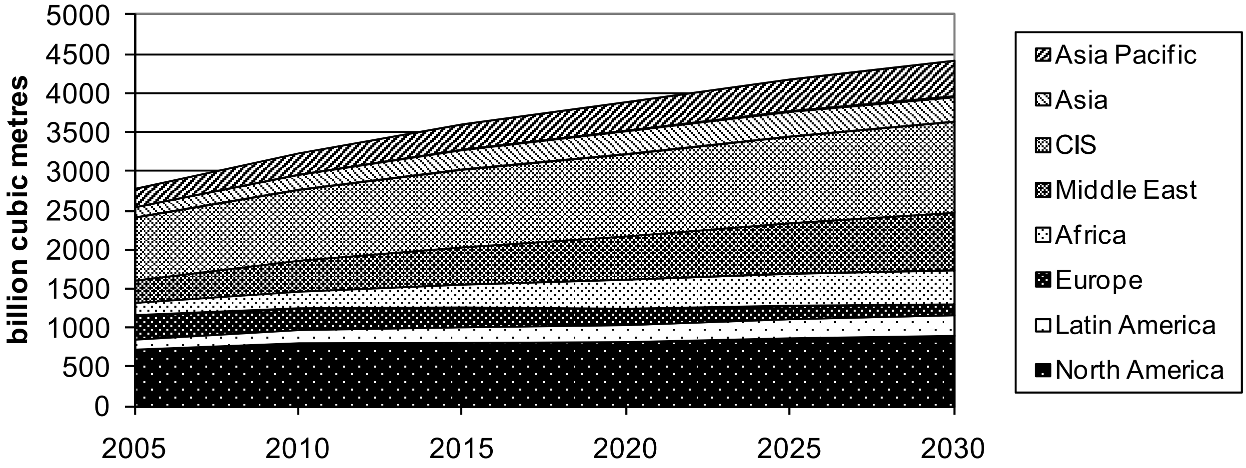
Natural gas reserves are sufficiently abundant to cover global gas demand for many decades. Moreover, technological developments and higher energy prices have increased the volumes of economic reserves as well as the diversification of sources.

Current developments in unconventional gas, especially shale gas in the United States, are spectacular and have led to upward revisions for the prospects in North America. The potential for unconventional gas in other regions is also significant.

For all regions, future gas supply has been estimated by local members of the IGU. These gas supplies were not forced to equate to regional gas demand but instead show the overall supply surplus or deficit that industry experts in every region think would occur under the common set of assumptions of the Reference Case. The difference between a region's gas demand and its gas supply indicates the need for imports from other regions and the possible volume that might be targeted as exports from the region.

Total natural gas production in *North America* will increase from 722 bcm in 2005 to 900 bcm in 2030. The largest producer of natural gas in the region is the United States, where depletion of the onshore lower 48 States' conventional reserves is offset by increased production from unconventional sources and from Alaska. Unconventional production increases from 244 bcm in 2006 to 374 bcm in 2030. The Alaska natural gas pipeline is expected to begin transporting natural gas in 2020 and should result in 46 bcm/yr of incremental natural gas supplies being delivered to the lower 48 States.

Figure 5.9 Natural gas production by region – Reference Case (Source: IGU)



Gas production in *Latin America & the Caribbean* almost doubles between now and 2030. Trinidad & Tobago has the highest average growth rate and Bolivia also grows strongly. Argentina is responsible for the largest share of natural gas production in Latin America; it accounts for 30% of all gas produced in the region and has a 5% average annual growth rate.

The indigenous production of natural gas in *Europe* (except for Norway) is in decline and from 2004 the UK has been a net importer. Domestic production in Germany, Italy and some eastern European countries is also declining, but production by Norway cannot keep up with this trend.

Currently half of the gas demand in Europe is covered by domestic production. The other half is imported from Russia (25%), Africa (20%, mainly Algeria) and the Middle East (5%). Although high energy prices may stimulate exploration and production, thus delaying the decline to some extent, European production is expected to drop to less than 20% of demand in 2030.

Gas production in *Africa* will double between now and 2030, growing to 450 bcm/yr, with Algeria, Egypt, Nigeria and Libya the main suppliers. Half of production will be exported to other regions. Africa contributes significantly to the global gas market and to the diversification of gas supply.

Because of the huge gas reserves and substantial investment in the exploration and production sector, production of natural gas in the *Middle East* is increasing significantly. Gas production will increase from 290 bcm in 2005 to 740 bcm in 2030. The largest producer in the Middle East is Iran, which produced 132 bcm in 2007 and held its place as fourth largest producer of natural gas in the world.

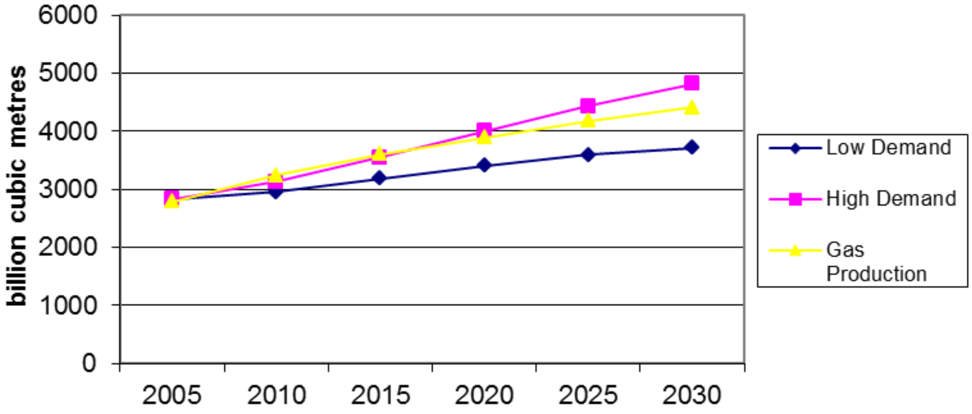
The main gas-producing countries in the *CIS* are Russia, Kazakhstan, Turkmenistan, Uzbekistan, and Azerbaijan. The rates of economic growth, demand in the domestic and export gas markets, the level of oil and gas prices, as well as success in attracting investment in the development of new gas fields, will affect future production levels. Depending on these factors, production may vary within a range of 1 070 bcm to 1 280 bcm by 2030.

The gas production in *Asia* is expected to grow to around 300 bcm in 2020 and then to stabilise at this level until 2030. China is the main supplier, followed by India and then Pakistan, Myanmar and Bangladesh.

In *Asia Pacific*, Indonesia is the main supplying country with substantial gas reserves, directly followed by Australia and Malaysia. Production has the potential to grow to 450 bcm/yr, which means almost twice as much as current levels.

Liquefied Natural Gas

Figure 5.10 Global gas balance (Source: IGU)



LNG production capacity increased by 50% during the five years prior to 2008. Against the background of global recession, growth slowed from 2008 on, for the first time in this decade. Nevertheless, production capacity will be about 380 bcm/yr during 2010.

High steel prices, high engineering costs and limited human resources (engineers) have caused an increase in the cost of LNG production, now estimated at around US$ 1 000 (and above) per tonne per year.

The expected global share of LNG is 400 bcm in 2015 and 750 bcm in 2030, corresponding to 17% of global gas demand.

Re-gasification capacity will be about twice as much as liquefaction capacity, creating downstream flexibility. LNG receiving terminal usage patterns differ by region: in the Pacific area, where LNG is generally used as a base gas source without large underground storage, seasonal demand fluctuations are absorbed by redundancy in LNG terminal capacities; in Europe and North America, with more underground storage facilities, higher utilisation rates are achieved.

Cost reduction in indigenous shale gas production in the USA has dramatically changed the future need for LNG in North America, with future supply to this region varying, depending on price differentials with shale gas as well as with other LNG markets.

Global exchanges of LNG cargoes will be accelerated, particularly from the Atlantic Basin to Pacific regions. Qatar, in particular, is expected to play a major role as the largest supplier of LNG. The global average shipping distance of LNG in 2008 was 7 100 km. It could be 8 000-8 500 km in 2010.

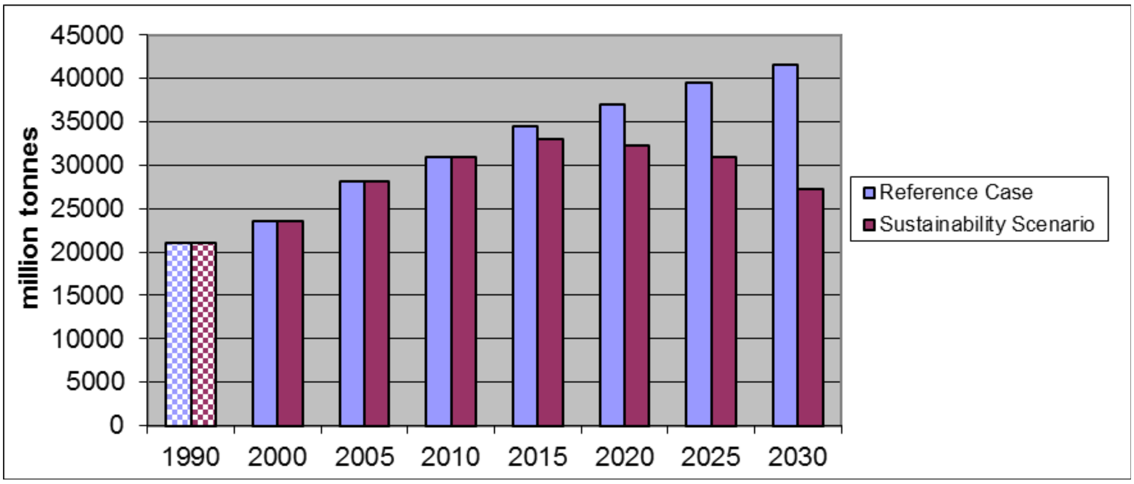
Long-term commitments in the LNG value chain are expected to continue, providing the foundation for a huge level of investment in LNG producing countries. However, long-term transactions can have flexible downstream arrangements. The share of genuine spot LNG cargoes will increase, but is not expected to grow as rapidly as the share of short-term contracts (several months or years)

Gas Balance

Adding all the gas market outlooks for each of the eight IGU regions allows for the creation of a global gas balance over a range of gas demand forecasts (Fig. 5.10).

In the Reference Case, gas production can cover gas demand. However in a high demand scenario, production would be tight. Increasingly, gas supply is also determined by price, with the North American market already exhibiting not only a demand-side response to gas prices, but also a supply-side (production) response. In the end, the gas price provides the balancing mechanism between supply and demand.

Figure 5.11 World CO_2 emissions - Reference Case and Sustainability Scenario (Source: IGU)



Sustainability Scenario

The Reference Case shows steadily increasing CO_2-emission levels. To investigate the possibility of bending down the CO_2 curve, a Sustainability Scenario was designed in which renewable energy sources increase their share to 15% of global primary energy demand in 2020 and 25% in 2030. To support this surge in renewable technology, flexible and reliable gas supplies are developed and gas demand rises to 4 800 bcm by 2030. This corresponds to 28% of the primary energy demand and is some 500 bcm more than gas consumption in the Reference Scenario. The resulting CO_2-emission levels are shown in Fig. 5.11.

The current trend of increasing CO2 emissions is halted and put into reverse: by 2030 the CO_2 level is well below current emissions. This scenario implies that gas supply must be increased by about 10% in 2030 in comparison with the Reference Case.

Conclusion

The world is a diverse place, but natural gas will be an important part of the energy mix in all regions. Overall, both for economic and environmental reasons, natural gas remains fundamental to achieving the optimum global energy solution.

Jaap Hoogakker
International Gas Union

SHALE GAS

History

Shale gas is one of the four categories of unconventional natural gas, the others being coalbed methane, gas from tight sandstones ('tight gas') and the not-yet-exploited methane hydrates. The U.S. Geological Survey (USGS) points out that shales have been extensively studied as source rocks but have only recently achieved importance as reservoir rocks. Consequently research into their reservoir characteristics has been 'extremely limited'. The USGS is currently carrying out a systematic study of the nature of shale gas reservoirs and of the mechanisms involved in the creation and preservation of such reservoirs through geological time.

The first commercial gas well in the USA, drilled in New York State in 1821, many years before Drake's pioneer oil well, was in fact a shale gas well. Subsequently, limited amounts of gas were produced from shallow, fractured shale formations (notably in the Appalachian and Michigan basins). Until quite recently, however, total U.S. shale gas production was negligible, being completely overshadowed by vastly greater volumes of natural gas produced from conventional reservoirs. The share of shale gas in U.S. natural gas production rose from 1.6% in 1996 to nearly 10% in 2008. There was a sharp jump in U.S. shale gas reserves in 2008, from 21.7 tcf at end-2007 to 32.8 tcf a year later. At end-2008, shale gas accounted for 13.4% of

U.S. proved reserves of natural gas, compared with 9.1% at end-2007.

One recent study estimates the resource endowment (gas in-place) of five major shale gas basins in the USA as 3 760 tcf, of which 475 tcf is considered to be recoverable, while two Canadian basins are estimated to hold 1 380 tcf, with about 240 tcf recoverable.

Although the existence of shale deposits across the world has been well-known for many years, most shales have not been regarded as potential sources of commercial quantities of natural gas as they have insufficient natural permeability to permit significant fluid flow to a well bore. The relatively few instances of commercial shale gas extraction in the past exploited the existence of natural fractures in the formations. The radical transformation that has occurred in recent years is not due to the discovery of new resources but to the development and application of new technology that in effect 'creates a permeable reservoir' and achieves high rates of production.

Technology

The transformation in shale gas production has been achieved very largely by a combination of horizontal drilling with hydraulic fracturing. In this procedure, a well is sunk to a depth somewhat less than that of a known shale gas deposit and then gradually deviated until the drill-bit is running horizontally through the shale bed. Once drilling has been terminated, the rock surrounding the horizontal bore is perforated in a number of locations and artificial fracturing induced by the injection of high-pressure water combined with special additives.

Resources

Shale gas resources, although believed to be widespread, have not as yet been quantified on a national basis for most countries, apart from the United States.

A status report (December 2009) by Kuuskraa and Stevens of Advanced Resources International, Inc. (ARI) states that 'all currently published resource estimates for world gas shales start with Rogner's 1997 "top-down" study of world hydrocarbon resources', in which the global Gas Shale Resource Endowment is put at 16 110 tcf (456 tcm). In the IEA's *World Energy Outlook* (2009), it is assumed that almost 40% of this endowment would be eventually recoverable, leading to a gas shale recoverable resource of around 6 350 tcf (180 tcm). Bottom-up assessments on a worldwide basis would be required in order to be able to test the validity of the original estimate.

While work on gas shale resources has, to date, been very largely concentrated in North America, and especially in the USA, other parts of the world are now receiving some attention, and preliminary assessments are beginning to emerge for some countries and geographical regions. For example, the ARI paper referred to above specifies three European basins as of particular importance – the Alum Shale in Sweden, the Silurian Shales in Poland and

Austria's Mikulov Shale. Together, these basins are estimated by ARI to have a shale gas resource of around 1 000 tcf (roughly 30 tcm), of which about 140 tcf (4 tcm) is considered to be recoverable.

Current Activity

A considerable amount of exploration activity is being undertaken with the objective of establishing the location of viable shale gas reservoirs, mostly by relatively small companies, although there are signs of increasing interest on the part of some of the international majors. Examples of such activity have been reported for the following countries:

Australia; Austria; Canada; China; France; Germany; Hungary; India; New Zealand; Poland; South Africa; Sweden; United Kingdom; and the United States.

Pros and Cons

The emergence of shale gas as a potentially major source of accessible energy has been accompanied by a flurry of publicity, both for and against its further development.

Among the advantages claimed for shale gas are:

- a potentially enormous resource base;
- lower carbon emissions than from other fossil fuels;
- applicability of the technology throughout the world;
- improved security of supply for gas-importing countries;
- extension of the life of some existing gasfields and opening-up of new provinces.

On the other hand, detractors and sceptics mention drawbacks such as:

- uncertainty over costs and affordability;
- doubts on the environmental acceptability of the technology;
- decline rates unclear or understated;
- potential shortages of equipment;
- local opposition to shale gas development.

It would seem that shale gas holds much promise, but that the eventual course of its development cannot be predicted at present. Helge Lund, chief executive of Statoil, was quoted by FT.com in March 2010 as saying 'it is far too early to conclude whether shale will make as much of an impact outside the US as it has done inside the US'.

The Editors

DEFINITIONS

Natural gas is a mixture of hydrocarbon and small quantities of non-hydrocarbons that exists either in the gaseous phase or is in solution in crude oil in natural underground reservoirs, and which is gaseous at atmospheric conditions of pressure and temperature.

Natural gas liquids (hydrocarbons that exist in the reservoir as constituents of natural gas but which are recovered as liquids in separators, field facilities or gas-processing plants) are discussed in Chapter 2 – Crude Oil and Natural Gas Liquids.

Proved amount in place is the resource remaining in known natural reservoirs that has been carefully measured and assessed as exploitable under present and expected local economic conditions with existing available technology.

Proved recoverable reserves are the volume *within* the proved amount in place that can be recovered in the future under present and expected local economic conditions with existing available technology.

Estimated additional amount in place is the volume *additional to* the proved amount in place that is of foreseeable economic interest. Speculative amounts are not included.

Estimated additional reserves recoverable is the volume *within* the estimated additional amount in place that geological and engineering information indicates with reasonable certainty might be recovered in the future.

Production - where available, gross and net (marketed) volumes are given, together with the quantities re-injected, flared and lost in shrinkage (due to the extraction of natural gas liquids, etc.).

Consumption - natural gas consumed within the country, including imports but excluding amounts re-injected, flared and lost in shrinkage.

R/P (reserves/production) ratio is calculated by dividing proved recoverable reserves at the end of 2008 by production (gross less re-injected) in that year. The resulting figure is the time in years that the proved recoverable reserves would last if production were to continue at the 2008 level.

As far as possible, natural gas volumes are expressed in standard cubic metres, measured dry at 15^{o} C and 1 013 mb, and the corresponding cubic feet (at 35.315 cubic feet per cubic metre).

NOTE:
The quantifications of reserves and resources presented in the tables that follow incorporate, as far as possible, data reported by WEC Member Committees. Such data will reflect the respective Member Committees' interpretation of the above Definitions in the context of the reserves/resources information available to them, and the degree to which particular countries' terminology and statistical conventions are compatible with the WEC specifications.

TABLES

TABLE NOTES

Table 5.2 shows the available data on known resources of natural gas, in terms of amount in place and recoverable reserves, for the categories proved (or measured), probable (or indicated) and possible (or inferred). The majority of the data are those reported by WEC Member Committees for the present *Survey*; they have been supplemented by comparable data derived from official publications.

For more detail regarding the provenance and coverage of individual countries' assessments, see the relevant Country Note.

Table 5.1 Natural gas: proved recoverable reserves at end-2008

	billion cubic metres	billion cubic feet
Algeria	4 504	159 069
Angola	161	5 700
Benin	1	40
Cameroon	150	5 300
Congo (Brazzaville)	91	3 200
Congo (Democratic Rep.)	1	35
Côte d'Ivoire	42	1 497
Egypt (Arab Rep.)	2 170	76 634
Equatorial Guinea	120	4 238
Ethiopia	25	883
Gabon	29	1 024
Ghana	24	848
Libya/GSPLAJ	1 540	54 385
Madagascar	2	71
Mauritania	28	1 000
Morocco	2	53
Mozambique	127	4 500
Namibia	20	700
Nigeria	5 292	186 887
Rwanda	57	2 000
Senegal	10	353
Somalia	6	200
South Africa	10	362
Sudan	85	3 002
Tanzania	24	846
Tunisia	92	3 257
Total Africa	**14 613**	**516 084**
Barbados	N	5
Canada	1 754	61 951
Cuba	71	2 500
Mexico	360	12 702
Trinidad & Tobago	481	16 997
United States of America	7 022	244 656
Total North America	**9 688**	**338 811**

Table 5.1 Natural gas: proved recoverable reserves at end-2008

	billion cubic metres	billion cubic feet
Argentina	399	14 074
Bolivia	710	25 074
Brazil	245	8 651
Chile	46	1 624
Colombia	124	4 384
Ecuador	9	315
Peru	335	11 820
Venezuela	4 983	175 975
Total South America	**6 851**	**241 917**
Afghanistan	50	1 750
Armenia	164	5 792
Azerbaijan	1 359	47 993
Bangladesh	344	12 148
Brunei	350	12 360
China	3 090	109 123
Georgia	8	300
India	1 074	37 928
Indonesia	3 186	112 500
Japan	51	1 808
Kazakhstan	3 000	105 945
Korea (Republic)	3	110
Kyrgyzstan	6	200
Malaysia	2 330	82 284
Myanmar (Burma)	590	20 836
Pakistan	840	29 671
Philippines	93	3 284
Taiwan, China	70	2 472
Tajikistan	6	200
Thailand	340	12 002
Turkey	6	220
Turkmenistan	8 400	296 646
Uzbekistan	1 745	61 625
Vietnam	217	7 663
Total Asia	**27 322**	**964 860**

Table 5.1 Natural gas: proved recoverable reserves at end-2008

	billion cubic metres	billion cubic feet
Albania	5	177
Austria	16	570
Belarus	3	100
Bulgaria	1	39
Croatia	36	1 287
Czech Republic	4	151
Denmark	66	2 347
France	7	250
Germany	126	4 458
Greece	2	70
Hungary	67	2 369
Ireland	10	350
Italy	70	2 472
Netherlands	1 245	43 967
Norway	2 215	78 223
Poland	75	2 632
Romania	102	3 602
Russian Federation	44 900	1 585 644
Serbia	48	1 700
Slovakia	15	530
Slovenia	N	N
Spain	3	90
Ukraine	787	27 804
United Kingdom	292	10 312
Total Europe	**50 095**	**1 769 144**
Bahrain	91	3 214
Iran (Islamic Rep.)	29 610	1 045 677
Iraq	3 170	111 949
Israel	24	848
Jordan	15	513
Kuwait	1 780	62 861
Oman	950	33 549
Qatar	25 172	888 949
Saudi Arabia	7 569	267 311
Syria (Arab Rep.)	300	10 595
United Arab Emirates	6 432	227 146
Yemen	555	19 600
Total Middle East	**75 668**	**2 672 212**

Table 5.1 Natural gas: proved recoverable reserves at end-2008

	billion cubic metres	billion cubic feet
Australia	819	28 910
New Zealand	46	1 612
Papua New Guinea	442	15 609
Total Oceania	**1 307**	**46 131**
TOTAL WORLD	**185 544**	**6 549 159**

Notes:

1. The relationship between cubic metres and cubic feet is on the basis of one cubic metre = 35.315 cubic feet throughout
2. Sources: WEC Member Committees, 2009/10; data reported for previous WEC *Surveys of Energy Resources*; Cedigaz; *Annual Report 2008*, OAPEC; *Annual Statistical Bulletin 2008,* OPEC; *Oil & Gas Journal*, December 2009; *World Oil*, September 2009; published national sources

Table 5.2 Natural gas: known resources at end-2008 (billion cubic metres)

		Proved (measured)	Probable (indicated)	Possible (inferred)
Argentina	amount in place	NA	NA	
	recoverable reserves	399	139	197
Czech Republic	amount in place	7	40	2
	recoverable reserves	4	NA	NA
Denmark	amount in place	140	included with proved	
	recoverable reserves	66	included with proved	29
Germany	amount in place	NA	NA	NA
	recoverable reserves	126	67	NA
Italy	amount in place	99		
	recoverable reserves	70	49	25
Kazakhstan	amount in place	NA	NA	NA
	recoverable reserves	3 000	3 500	10 200
Mexico	amount in place			
	recoverable reserves	360	425	479
Namibia	amount in place	25	51	82
	recoverable reserves	20	34	48
Norway	amount in place			
	recoverable reserves	2 215	181	512
Peru	amount in place			
	recoverable reserves	335	193	318
Romania	amount in place	696		
	recoverable reserves	102	47	11
Thailand	amount in place			
	recoverable reserves	340	353	216
Trinidad & Tobago	amount in place			
	recoverable reserves	481	223	167
United Kingdom	amount in place			
	recoverable reserves	292	309	306

Table 5.3 Natural gas: 2008 production

	billion cubic metres					billion cubic feet	R/P ratio
	Gross	Re-injected	Flared	Shrinkage	Net	Net	
Algeria	201.2	92.9	5.0	16.8	86.5	3 055	41.6
Angola	10.1	2.3	6.9	0.2	0.7	24	20.6
Cameroon	1.9		1.9		N	1	78.9
Congo (Brazzaville)	7.5	5.0	2.2	0.1	0.2	6	36.4
Côte d'Ivoire	1.3				1.3	46	32.3
Egypt (Arab Rep.)	54.8	2.0	0.8	3.7	48.3	1 706	41.1
Equatorial Guinea	8.3	0.5	0.8	0.3	6.7	236	15.4
Gabon	2.1	0.8	1.1	0.1	0.1	3	22.3
Libya/GSPLAJ	30.3	3.5	3.9	7.0	15.9	562	57.5
Morocco	0.1			N	0.1	2	20.0
Mozambique	3.3				3.3	117	38.5
Nigeria	64.6	11.1	17.9	3.9	31.7	1 121	98.9
Senegal	0.1				0.1	2	>100
South Africa	3.3				3.3	115	3.0
Tanzania	0.6			N	0.6	20	40.0
Tunisia	3.5		0.2	0.3	3.0	105	26.3
Total Africa	**393.0**	**118.1**	**40.7**	**32.4**	**201.8**	**7 121**	**52.3**
Barbados	N				N	1	7.0
Canada	208.7	19.2	1.9	20.1	167.5	5 916	9.3
Cuba	0.7		0.1	0.2	0.4	14	>100
Mexico	71.5		13.8	11.1	46.6	1 646	5.0
Trinidad & Tobago	42.1	1.4	1.1	0.3	39.3	1 388	11.8
United States of America	729.3	103.1	4.7	47.1	574.4	20 286	11.2
Total North America	**1 052.3**	**123.7**	**21.6**	**78.8**	**828.2**	**29 251**	**10.4**
Argentina	50.5	0.9	0.9	3.5	45.2	1 596	8.0
Bolivia	15.5	0.9	0.1	0.3	14.2	501	48.6
Brazil	21.6	3.9	2.2	1.3	14.2	503	13.8
Chile	2.0	0.1	0.2	0.1	1.6	58	24.2
Colombia	17.7	7.4	0.4	0.9	9.0	318	12.0
Ecuador	1.2	0.2	0.7		0.3	9	9.0
Peru	7.7	3.0	0.3	0.4	4.0	141	71.3
Venezuela	71.3	31.8	8.5	6.9	24.1	851	>100
Total South America	**187.5**	**48.2**	**13.3**	**13.4**	**112.6**	**3 977**	**49.2**

Table 5.3 Natural gas: 2008 production

	billion cubic metres					billion cubic feet	R/P ratio
	Gross	**Re-injected**	**Flared**	**Shrinkage**	**Net**	**Net**	
Afghanistan	N				N	1	>100
Azerbaijan	17.2	1.4	2.5	0.8	12.5	441	86.0
Bangladesh	17.9				17.9	632	19.2
Brunei	14.2	0.3		0.5	13.4	473	25.2
China	76.1				76.1	2 687	40.6
Georgia	N				N	1	>100
India	33.1		0.9		32.2	1 137	32.4
Indonesia	81.6	4.3	3.2	4.1	70.0	2 472	41.2
Japan	3.9				3.9	138	13.1
Kazakhstan	33.5	8.2	1.8	0.2	23.3	823	>100
Korea (Republic)	0.2		N		0.2	8	15.0
Kyrgyzstan	N				N	1	>100
Malaysia	75.1	11.5	1.3	5.0	57.3	2 024	36.6
Myanmar (Burma)	13.0		0.1	0.5	12.4	438	45.4
Pakistan	40.7	0.7		2.5	37.5	1 324	21.0
Philippines	3.4		0.2	0.3	2.9	104	27.4
Taiwan, China	0.4				0.4	13	>100
Tajikistan	N				N	1	>100
Thailand	31.0			2.2	28.8	1 016	11.0
Turkey	0.5			0.2	0.3	11	12.0
Turkmenistan	66.1				66.1	2 334	>100
Uzbekistan	63.7			0.3	63.4	2 239	27.4
Vietnam	7.5		0.6	0.3	6.6	233	28.9
Total Asia	**579.1**	**26.4**	**10.6**	**16.9**	**525.2**	**18 551**	**49.1**
Albania	N	N			N	1	>100
Austria	1.8				1.8	65	8.9
Belarus	0.3	0.3			N	1	>100
Bulgaria	0.3				0.3	11	3.3
Croatia	2.4			0.8	1.6	56	15.0
Czech Republic	0.2				0.2	6	20.0
Denmark	9.7	0.2	0.1		9.4	332	6.9

Table 5.3 Natural gas: 2008 production

	billion cubic metres					billion cubic feet	R/P ratio
	Gross	**Re-injected**	**Flared**	**Shrinkage**	**Net**	**Net**	
France	1.6			0.7	0.9	33	4.4
Germany	16.6		N	1.3	15.3	540	7.6
Greece	N			N	N	1	40.0
Hungary	2.8			0.2	2.6	92	23.9
Ireland	0.4				0.4	13	25.0
Italy	9.0				9.0	318	7.8
Netherlands	80.0				80.0	2 824	15.6
Norway	141.3	39.0	0.5	2.6	99.2	3 503	21.7
Poland	5.5			1.4	4.1	145	13.6
Romania	11.5	N	N	0.8	10.7	378	8.9
Russian Federation	652.3		15.8	15.2	621.3	21 941	68.8
Serbia	0.2			0.1	0.1	4	>100
Slovakia	0.2				0.2	7	75.0
Slovenia	N				N	N	
Spain	0.1				0.1	4	30.0
Ukraine	19.8				19.8	699	39.7
United Kingdom	75.2	0.6	0.7	5.7	68.2	2 409	3.9
Total Europe	**1 031.2**	**40.1**	**17.1**	**28.8**	**945.2**	**33 383**	**50.5**
Bahrain	15.2	2.6			12.6	446	7.2
Iran (Islamic Rep.)	180.4	27.4	16.8	19.9	116.3	4 107	>100
Iraq	14.8	0.9	6.0	6.0	1.9	67	>100
Israel	2.8		N	1.6	1.2	42	8.6
Jordan	0.3				0.3	9	50.0
Kuwait	14.2		0.5	1.0	12.7	450	>100
Oman	30.3	2.9	1.4	1.9	24.1	850	34.7
Qatar	90.9	4.8	3.6	5.5	77.0	2 718	>100
Saudi Arabia	86.4	0.2		5.8	80.4	2 841	87.8
Syria (Arab Rep.)	8.4	2.0	0.2	0.3	5.9	208	46.9
United Arab Emirates	80.1	23.1	1.0	5.8	50.2	1 774	>100
Yemen	17.5	16.3	0.5	0.7			>100
Total Middle East	**541.3**	**80.2**	**30.0**	**48.5**	**382.6**	**13 512**	**>100**

Table 5.3 Natural gas: 2008 production

	billion cubic metres					billion cubic feet	R/P ratio
	Gross	Re-injected	Flared	Shrinkage	Net	Net	
Australia	51.7		0.2	4.0	47.5	1 677	15.8
New Zealand	4.5	0.1	0.1	0.3	4.0	141	10.5
Papua New Guinea	0.1	N			0.1	4	>100
Total Oceania	**56.3**	**0.1**	**0.3**	**4.3**	**51.6**	**1 822**	**23.3**
TOTAL WORLD	**3 840.7**	**436.8**	**133.6**	**223.1**	**3 047.2**	**107 617**	**54.4**

Notes:

1. Sources: WEC Member Committees, 2009/10; Cedigaz; national sources

COUNTRY NOTES

The following Country Notes on Natural Gas provide a brief account of countries with significant gas resources. They have been compiled by the Editors, drawing upon a wide variety of material, including information received from WEC Member Committees, national and international publications.

The principal published sources consulted were:

- Annual Statistical Bulletin 2008, OPEC;
- BP Statistical Review of World Energy, 2009;
- Energy Balances of OECD Countries, 2009 Edition, International Energy Agency;
- Energy Balances of Non-OECD Countries, 2009 Edition, International Energy Agency;
- Energy Statistics of OECD Countries, 2009 Edition, International Energy Agency;
- Energy Statistics of Non-OECD Countries, 2009 Edition, International Energy Agency;
- Natural Gas in the World, 2009 Edition, Cedigaz;
- Oil & Gas Journal, various issues, PennWell Publishing Co.;
- Secretary-General's 35th Annual Report, A.H. 1428-1429/A.D. 2008, OAPEC;
- World Oil, September 2009, Gulf Publishing Company

Brief salient data are shown for each country, including the year of first commercial production of natural gas (where it can be ascertained).

Note that Reserves/Production (R/P) ratios have been calculated on the basis of gross production less quantities re-injected.

Algeria

Proved recoverable reserves (bcm)	4 504
Production (net bcm, 2008)	86.5
R/P ratio (years)	41.6
Year of first commercial production	1961

For the 2007 *Survey*, the Algerian WEC Member Committee reported a proved amount in place of 6 080 bcm, of which 4 504 bcm was classified as proved recoverable reserves. Gas reserves non-associated with crude oil accounted for 80% of proved recoverable reserves. An additional amount in place of 2 000 bcm, of which 960 bcm was deemed to be recoverable, was also reported by the Algerian Member Committee.

As there is virtual unanimity amongst the standard published sources with regard to the level of proved recoverable reserves quoted above, it has been retained for the present *Survey*.

Net production of natural gas in 2008 was the sixth highest in the world, after Russia, the USA, Canada, Iran and Norway. About 46% of gross production was re-injected, while much smaller proportions were flared or abstracted as NGLs. About 69% of net production was exported: 37% of gas exports were in the form of LNG, consigned to France, Spain, Turkey, Italy, Japan, Greece, India, Korea Republic, the UK, China and Taiwan, China. Exports by pipeline in 2008 went to Italy, Spain, Portugal, Tunisia, Morocco and Slovenia. Apart from oil and gas industry use, the main internal markets for Algerian gas are power stations, industrial fuel/feedstock and households.

Argentina

Proved recoverable reserves (bcm)	399
Production (net bcm, 2008)	45.2
R/P ratio (years)	8.0
Year of first commercial production	NA

The Argentinian Member Committee reports data provided by the Secretaría de Energía that indicate a further reduction in the republic's gas reserves. At the end of 2008, proved recoverable reserves stood at 399 bcm, 9.1% lower than the end-2005 level of 439 bcm adopted for the 2007 *Survey*. The same source states that 'probable reserves', not yet proven but considered to be eventually recoverable, now stand at 139 bcm, while possible reserves amount to a further 197 bcm. Potential additional recovery from known resources is put at some 245 bcm, representing an increase of around 33% on the total of reported recoverable reserves.

Gas extraction takes place in five sedimentary basins. In 2009 the largest share of production came from the Neuquina Basin which provided 56% of the total, followed by the Austral Basin with 20%, the Northwest Basin with 13% and the Golfo San Jorge with 11%; the contribution of the Cuyana Basin is minimal. Less than 2% of current gross production is re-injected. Marketed production (after relatively small amounts are deducted through flaring and shrinkage) is the highest in South America.

For many years, gas supplies have been augmented by imports from Bolivia, but this flow ceased in October 1999, as the focus of Bolivia's gas exports shifted to Brazil. In a further re-orientation of the South American gas supply structure, Argentina has become a significant exporter in its own right, with a number of pipelines supplying Chile and others to Uruguay and Brazil.

Consumption of indigenous and imported gas in 2007 was divided between the power generation market (35%), industrial fuel/feedstock (24%), residential/commercial uses (24%) and gas industry own use/loss (10%); about 7% was consumed as CNG in road transport.

Australia

Proved recoverable reserves (bcm)	819

Production (net bcm, 2008)	47.5
R/P ratio (years)	15.8
Year of first commercial production	1969

The latest data on natural gas reserves published by Geoscience Australia as a component of its report on the *Oil and Gas Resources of Australia 2008* (OGRA) relates to the situation as at 1 January 2009. At this point in time there was a total of 818.64 bcm of sales gas in Category 1 (comprising 'current reserves of those fields which have been declared commercial. It includes both proved and probable reserves'). This figure compares with the 1 January 2006 total of 906.54 bcm in this category (also referred to as 'remaining commercial reserves') quoted in OGRA 2005.

Estimated additional reserves recoverable of 3 821 bcm correspond with 'Non-commercial reserves' of sales gas in the Geoscience Australia publication cited above, which also provides an alternative assessment, using the McKelvey classification, resulting in 'Economic Demonstrated Resources' of 3 143 bcm and 'Subeconomic Demonstrated Resources' of 1 504 bcm.

Probably as a result of adopting differing definitions of 'proved reserves', other published sources tend to quote substantially higher levels for end-2008, ranging (in terms of bcm) from *Oil & Gas Journal*'s 849 to *World Oil*'s 4 649, and would appear in some cases to include either Category 2 (comprising ‘estimates of recoverable reserves which have not yet been declared commercially viable’) or to have adopted the McKelvey classification, in which 'economic demonstrated resources' include an element of extrapolation.

Australia's principal gas reserves are located in the Carnarvon, Gippsland, Browse and Bonaparte Basins.

About 45% of Australia’s natural gas production is exported in the form of LNG (almost all to Japan) from the North West Shelf fields.

The main gas-consuming sectors in Australia are public electricity generation, the non-ferrous metals industry and the residential sector.

Azerbaijan

Proved recoverable reserves (bcm)	1 359
Production (net bcm, 2008)	12.5
R/P ratio (years)	86.0
Year of first commercial production	NA

Azerbaijan is one of the world's oldest producers of natural gas. After years of falling production the outlook has been transformed by recent developments. Proved reserves of gas, as quoted by Cedigaz, have edged up from 1 350 at end-2005 to 1 359 bcm. *Oil & Gas Journal* and OAPEC opt for a lower level (849 bcm). Marketed production in 2008 was 12.5 bcm, of which much the greater part came from offshore fields in the Caspian Sea. About 15% of current gross production is reported to be flared or vented.

Bangladesh

Proved recoverable reserves (bcm)	344
Production (net bcm, 2008)	17.9
R/P ratio (years)	19.2
Year of first commercial production	1961

Whilst the published volumes of proved gas reserves are not particularly large, much of Bangladesh is poorly explored and the potential for further discoveries is thought to be substantial. For the present *Survey*, the Cedigaz assessment of 344 bcm for proved recoverable reserves has been adopted in preference to *Oil & Gas Journal*'s level of 142 bcm and that of 370 quoted by BP and OPEC.

Gas production has followed a rising trend for many years and approached 18 bcm in 2008. Natural gas contributes nearly three-quarters of Bangladesh's commercial energy supplies; its principal outlets are power stations and fertiliser plants.

Bolivia

Proved recoverable reserves (bcm)	710
Production (net bcm, 2008)	14.2
R/P ratio (years)	48.6
Year of first commercial production	1955

The level adopted for proved reserves at end-2008 reflects the view of Cedigaz: other published sources broadly concur. An earlier, and presumably now outdated, assessment issued by the state hydrocarbons company YPFB and published by the Instituto Nacional de Estadística in its *Anuario Estadistico 2008*, shows proved reserves at 1 January 2005 as 27 tcf (765 bcm) and probable reserves as 22 tcf (623 bcm).

Exports to Argentina used to be the major outlet for Bolivia's natural gas, but the focus of Bolivia's gas export trade shifted towards Brazil following the inauguration of two major export lines, one from Santa Cruz de la Sierra to south-east Brazil in 1999 and another in 2000 from San Miguel to Cuiaba. Exports to Brazil in 2008 were 10.9 bcm, while those to Argentina were only about 0.9 bcm.

Internal consumption of gas is still on a small scale (only about 2 bcm/yr), and confined almost entirely to electricity generation and industrial fuel markets, residential use being minimal at present. There is a small but rapidly growing market for CNG as a transport fuel.

Brazil

Proved recoverable reserves (bcm)	245
Production (net bcm, 2008)	14.2
R/P ratio (years)	13.8
Year of first commercial production	1954

Brazil's natural gas industry is relatively small at present compared with its oil sector. Proved reserves, as reported by the Brazilian WEC Member Committee, amounted to 245 bcm at end-2008 and are the fifth largest in South America. The corresponding level of probable reserves was 119 bcm. Together, proved + probable reserves of some 364 bcm equate to the category 'measured/indicated/inventoried' in the *Balanço Energético Nacional (BEN) 2009*, published by the Ministério de Minas e Energia in April 2010.

Additional recoverable amounts, classified as 'inferred/estimated' in the 2009 BEN, are put at very nearly 225 bcm.

About 28% of 2008 gross production of natural gas was either re-injected or flared. Marketed production is mostly used as industrial fuel or as feedstock for the production of petrochemicals and fertilisers. As a consequence of Brazil's huge hydroelectric resources, use of natural gas as a power station fuel had been minimal until fairly recently. The consumption picture has now changed, as imported gas (from Bolivia and Argentina) fuels the increasing number of gas-fired power plants that are being built in Brazil.

The use of CNG by road vehicles is now a significant feature of the gas market.

Brunei

Proved recoverable reserves (bcm)	350
Production (net bcm, 2008)	13.4
R/P ratio (years)	25.2
Year of first commercial production	NA

Natural gas was found in association with oil at Seria and other fields in Brunei. For many years this resource was virtually unexploited, but in the 1960s a realisation of the resource potential, coupled with the availability of new technology for producing and transporting liquefied natural gas, enabled a major gas export scheme to be devised. Since 1972 Brunei has been exporting LNG to Japan, and more recently to the Korean Republic. Occasional spot sales have been made to other destinations.

Despite annual exports of more than 9 bcm, Brunei's proved reserves as published by *Oil & Gas Journal* have remained virtually steady at just under 400 bcm since 1992. For the purpose of the present *Survey*, the somewhat lower level of 350 bcm preferred by Cedigaz, *World Oil* and BP has been adopted.

About 70% of Brunei's marketed production is exported as LNG, the balance being mostly used in the liquefaction plant, local power stations and offshore oil and gas installations.

Small quantities are used for residential purposes in Seria and Kuala Belait.

Canada

Proved recoverable reserves (bcm)	1 754
Production (net bcm, 2008)	167.5
R/P ratio (years)	9.3
Year of first commercial production	NA

Canada's gas reserves are the third largest in the Western Hemisphere. The Canadian WEC Member Committee reports that proved recoverable reserves are 1 754 billion cubic metres, based on 'remaining established reserves' of marketable natural gas at 31 December, 2008, as quoted by the Canadian Association of Petroleum Producers (CAPP) in its *2009 Statistical Handbook*. A high proportion (currently 88%) of Canada's proved recoverable reserves is non-associated with crude oil.

The remaining discovered amount of gas in place, of which the aforementioned recoverable quantity forms a part, is specified as 6 613 bcm. In addition to this quantity, a total of 9 467 bcm of undiscovered natural gas is estimated to be in place. The amount of gas recoverable from presently undiscovered reservoirs is not stated.

The provinces with the largest volumes of remaining established reserves are Alberta (with 65%), British Columbia (27.5%) and Saskatchewan (5%).

As with crude oil, the National Energy Board (NEB) has undertaken probabilistic estimates for the Mackenzie-Beaufort region, and it estimates that there could be 255 bcm of marketable natural gas at the mean probability. Additional resources in excess of 3 000 bcm could exist in Canada's north.

The Mackenzie Valley gas pipeline project, which would carry approximately 35 million m^3/d from three natural gas fields in the Mackenzie Delta in the Northwest Territories to southern markets, is in the regulatory hearing phase. The report of the Joint Review Panel for the Mackenzie River Project was published in March 2010.

Cumulative production of natural gas in Canada to the end of 2008 was 6 390 bcm. Gross production of Canadian natural gas is currently the third highest in the world. Marketed gas output in 2008 was 167.5 bcm, of which over 60% was exported to the United States. The largest users of gas within Canada are the industrial, residential and commercial sectors. A relatively small proportion is consumed in electricity generation, a sector dominated by Canada's hydropower.

China

Proved recoverable reserves (bcm)	3 090
Production (net bcm, 2008)	76.1
R/P ratio (years)	40.6
Year of first commercial production	1955

In the past discoveries of natural gas have been fewer than those of crude oil, which is reflected in the fairly moderate level of proved reserves. Gas reservoirs have been identified in many parts of China, including in particular the Sichuan Basin in the central region, the Tarim Basin in the northwest and the Yinggehai (South China Sea). China's gas resource base is thought to be enormous: estimates by the Research Institute of Petroleum Exploration and Development, quoted by Cedigaz, put total resources at some 38 000 bcm, of which 21% is located offshore. Most of the onshore gas-bearing basins are in the central and western parts of China.

So long as China's reserves remain a state secret, it is necessary to have recourse to published sources. For the purposes of the present *Survey*, Cedigaz estimates have been retained, involving an increase from 2 350 bcm at end-2005 to 3 090 bcm at end-2008. Other published assessments of China's gas reserves at end-2008 range from 2 265 to 2 460 bcm, with no two estimates being the same.

The major outlets for natural gas within China are as industrial fuel/feedstock (44%), the residential/commercial sector (25%), and oil/gas industry own use/loss (16%). Natural gas has relatively small shares in the generation of electricity and bulk heat, the bulk of which is the province of coal.

Colombia

Proved recoverable reserves (bcm)	124
Production (net bcm, 2008)	9.0
R/P ratio (years)	12.0
Year of first commercial production	NA

The early gas discoveries were made in the northwest of the country and in the Middle and Upper Magdalena Basins; in more recent times, major gas finds have been made in the Llanos Basin to the east of the Andes.

Proved reserves at end-2008 are reported by the Colombian WEC Member Committee as 4 384 bcf (124 bcm), in line with Cedigaz and *World Oil*. Other published assessments cluster around 110 bcm.

At present a high proportion of Colombia's gas output (42% in 2008) is re-injected in order to maintain or enhance reservoir pressures. The major outlets for natural gas are own use by the petroleum industry (23% of total gas consumption in 2007), chemicals, cement and other industrial users (27%) and power plants (25%). Residential/commercial consumers accounted for 20%, while CNG use in road transport is still of modest proportions.

Denmark

Proved recoverable reserves (bcm)	66
Production (net bcm, 2008)	9.4
R/P ratio (years)	6.9
Year of first commercial production	1984

The Danish WEC Member Committee reports data provided by the Danish Energy Authority (DEA), which does not use the terms ‘proved’, ‘probable’, ‘possible’ and ‘additional’ reserves, but employs the categories 'ongoing', 'approved', 'planned' and 'possible' recovery. The DEA expresses natural gas volumes in normal cubic metres (Nm^3), measured at 0^oC and 1 013 mb. For the purpose of the present *Survey*, all such data have been converted into standard cubic metres, measured at 15^oC and 1 013 mb.

The figure reported for proved recoverable reserves (66 bcm) has been derived from the sum of DEA’s 'ongoing and approved' reserves (63 billion Nm^3).

The amount of additional reserves recoverable from known resources (29 bcm) has been derived directly from the DEA publication *Denmark’s Oil and Gas Production 08*, as the sum of 2 billion Nm^3 'planned' and 25 billion Nm^3 'possible' recovery from producing and other (non-producing) fields. The amount recoverable from undiscovered resources (18 bcm) is based on the DEA’s figure of 17 Nm^3 for possible recovery from (future) discoveries.

Of the reported proved recoverable reserves, 47% is non-associated with crude oil.

In 2008 Denmark exported a total of 54% of its natural gas production, to Germany, the Netherlands and Sweden. The major inland consumers of Danish gas are CHP plants, manufacturers and the residential/commercial sector.

Egypt (Arab Republic)

Proved recoverable reserves (bcm)	2 170
Production (net bcm, 2008)	48.3
R/P ratio (years)	41.1
Year of first commercial production	1964

Egypt’s proved reserves of natural gas are the third largest in Africa, after Nigeria and Algeria. A succession of gas discoveries has boosted Egypt's reserves in recent years. In December 2008, the Chairman of the Egyptian Natural Gas Holding Company (EGAS) stated that by June of that year gas reserves had reached 76 tcf (equivalent to around 2 150 bcm). This implies an increase of 9.1 tcf (258 bcm) over the end-2005 level of 66.9 tcf reported for the 2007 *Survey*.

In the absence of any recent information from the Egyptian WEC Member Committee, recourse has been made to published material. There is general agreement amongst the standard published sources on a level of around 2 170 bcm, as reported by Cedigaz in November 2009. The only exception is *Oil & Gas Journal*, which has quoted 58 500 bcf (1 657 bcm) for each year since 1 January 2003.

Since the end of 2000, Egypt's gas reserves have exceeded those of its neighbour Libya. About 92% of its reported reserves are non-associated with crude oil. The major producing area is the Mediterranean Sea region (mostly from offshore fields), although output of associated gas from a number of fields in the Western Desert and the Red Sea region is also important.

Marketed production has grown steadily in recent years and is now the second largest in Africa. The main outlets at present are power stations, fertiliser plants and industrial users such as the iron and steel sector and cement works.

Germany

Proved recoverable reserves (bcm)	126
Production (net bcm, 2008)	15.3
R/P ratio (years)	7.6
Year of first commercial production	NA

Although it is one of Europe's oldest gas producers, Germany's remaining proved reserves are sizeable, and (apart from the Netherlands) they still rank as the largest onshore reserves in Western Europe. The principal producing area is in north Germany, between the rivers Weser and Elbe; westward from the Weser to the Netherlands border lies the other main producing zone, with more mature fields. Cumulative production of natural gas to the end of 2008 is reported by the German WEC Member Committee to have been 945.5 bcm.

The proved recoverable reserves of 126.2 bcm advised by the Member Committee draw upon a report covering 2008, prepared by the Landesamt für Bergbau, Energie und Geologie, Hannover. Almost all of Germany’s proved gas reserves are non-associated with crude oil. While Cedigaz, *World Oil*, OPEC and BP all quote similar levels to that reported to the WEC, *Oil & Gas Journal* gives 175 bcm. The Member Committee also reports just over 67 bcm of 'probable reserves' as being recoverable.

Indigenous production provides only about 17% of Germany's gas supplies; the greater part of demand is met by imports from the Russian Federation, Norway, the Netherlands, Denmark and the UK.

India

Proved recoverable reserves (bcm) at 1 April 2009	1 074
Production (net bcm, 2008)	32.2
R/P ratio (years)	32.4
Year of first commercial production	1961

A sizeable natural gas industry has been developed, largely on the basis of the offshore Mumbai gas and oil/gas fields. Proved reserves at 1 April, 2009 are stated by the Ministry of Petroleum & Natural Gas to have been 1 074 bcm, a decrease of 2.5% on the level advised by the Indian WEC Member Committee for the 2007 *Survey*.

Strong growth in India's offshore reserves raised them from 584 bcm (63% of total reserves) at 1 April 2004 to 761 bcm (69%) at 1 April 2005. They now stand at 787 bcm, and are equivalent to 73% of India's total proved gas reserves.

India has been importing LNG since 2004. The total of such imports in 2008, according to Cedigaz, was 10.8 bcm, of which 74% was supplied by Qatar; cargoes from nine other sources provided the balance.

Indigenous and imported natural gas is principally used for electricity generation, as feedstock for fertiliser and petrochemical manufacture, and as industrial fuel. The recorded use in the residential and agricultural sectors is very small, but automotive use of CNG is growing rapidly.

Indonesia

Proved recoverable reserves (bcm)	3 186
Production (net bcm, 2008)	70.0
R/P ratio (years)	41.2
Year of first commercial production	NA

The Directorate General of Oil and Gas (DGOG), quoted in the *Handbook of Energy and Economic Statistics of Indonesia 2009* issued by the Ministry of Energy and Mineral Resources (ESDM), states proved gas reserves as 112.5 tscf (3 186 bcm), 15.7% higher than the level advised for the 2007 *Survey of Energy Resources*. After the noticeable convergence in published assessments of Indonesia's proved reserves that was observed at the time of preparation of the 2007 SER, the corresponding estimates for end-2008 once again exhibit a certain amount of divergence, with *World Oil* quoting 2 708 bcm, and other sources ranging from *Oil & Gas Journal* and OAPEC on 3 002 to Cedigaz with 3 280 bcm.

The DGOG also reports potential reserves of 57.6 tscf (1 614 bcm).

Indonesia's gas production is the highest in Asia. The main producing areas are in northern Sumatra, Java and eastern Kalimantan.

Exports of LNG from Arun (Sumatra) and Bontang (Kalimantan) to Japan began in 1977-1978. Indonesia has for many years been the world's leading exporter of LNG. Shipments in 2008 were chiefly to Japan (70%), but also to the Republic of Korea and Taiwan, China (15% each). Indonesia exports nearly half of its marketed production, including (from early 2001) supplies by pipeline to Singapore (6.65 bcm in 2008).

The principal domestic consumers of natural gas (apart from the oil and gas industry) are power stations, fertiliser plants and industrial users; the residential, commercial and transportation sectors have relatively small shares.

Iran (Islamic Republic)

Proved recoverable reserves (bcm)	29 610
Production (net bcm, 2008)	116.3
R/P ratio (years)	> 100
Year of first commercial production	1955

Iran's proved reserves are second only to those of the Russian Federation, (although now closely approached by those of Qatar). They account for about 16% of the world total, and exceed the combined proved reserves of North America, South America and Europe (excluding the Russian Federation).

The Iranian WEC Member Committee reported in September 2009 that at the end of 2007 proved reserves of natural gas were 29 610 bcm, 10.7% higher than the end-2004 level reported for the 2007 *Survey of Energy Resources*. The Member Committee also reported that some 85% of proved recoverable reserves was non-associated with crude oil, and that the remaining proved amount of gas in place (hosting the quoted recoverable reserves) was 50.89 tcm.

There appears to be a high degree of consensus amongst the major published sources regarding Iran's proved recoverable gas reserves.

For many years only minute quantities of associated gas output were utilised as fuel in the oil fields or at Abadan refinery: by far the greater part was flared. Utilisation of gas in the industrial, residential and commercial sectors began in 1962 after the construction of a pipeline from Gach Saran to Shiraz. Iran's principal gas-consuming sectors in 2007 were residential/commercial users (39% of total consumption), electricity generation (30%), and industry (24%).

In 2008, almost 65% of Iran's gross production of 180 bcm of gas was marketed; about 15% was re-injected into formations in order to maintain or enhance pressure; about 9% was flared or vented and 11% lost through shrinkage and other factors. The marketed production volume of about 116 bcm was augmented by 6.9 bcm of imported gas (mainly from Turkmenistan), whilst 5.8 bcm was exported to Turkey.

Iraq

Proved recoverable reserves (bcm)	3 170
Production (net bcm, 2008)	1.9
R/P ratio (years)	>100
Year of first commercial production	1955

Gas resources are not particularly large by Middle East standards: proved reserves (as reported by OAPEC) account for less than 5% of the regional total. Most other published sources quote the same figure, the one exception being *World Oil*, which gives Iraq's proved reserves as 2 577 bcm.

According to data reported by Cedigaz, Iraq also possesses 5 009 bcm of probable and possible reserves, and states that 70% of Iraq's proved reserves consist of associated gas, with non-associated gas accounting for 20% and dome gas for the balance. A high proportion of gas output is thus associated with oil production: some of the associated gas is flared.

Between 1986 and 1990 Iraq exported gas to Kuwait. Currently all gas usage is internal, as fuel for electricity generation, as a feedstock and fuel for the production of fertilisers and petrochemicals, and as a fuel in oil and gas industry operations.

Kazakhstan

Proved recoverable reserves (bcm)	3 000
Production (net bcm, 2008)	23.3
R/P ratio (years)	>100
Year of first commercial production	NA

Kazakhstan has substantial resources of natural gas and may well become a major player on the world stage. The chief discovery so far has been the giant Karachaganak field, located in the north of Kazakhstan, near the border with the Russian Federation. Another major field is Tengiz, close to the north-east coast of the Caspian Sea.

The levels of natural gas reserves adopted for the present *Survey* are as reported by the WEC Member Committee for Kazakhstan, namely proved reserves of 3 tcm, probable reserves of 3.5 tcm and possible reserves of 10.2 tcm, based upon a 2007 feasibility study. Lower levels are however given by published compilations of reserves data: BP 1 820 bcm, Cedigaz 1 950, *Oil & Gas Journal* 2 407 and OAPEC 2 832.

The Member Committee reports that the country's economic reserves of gas are unevenly distributed, with 98% located in four western oblasts of Mangistau, Atyrau, Aktobe and West Kazakhstan, and the remaining 2% in the Kyzylorda, Zhambyl and Karaganda oblasts.

An alternative view of Kazakhstan's proved recoverable reserves of gas is taken by BP, one of the principal oil companies operating in the republic. In the June 2009 edition of the *BP Statistical Review of World Energy*, Kazakhstan's proved reserves are given as 1 820 bcm at end-2008; moreover, the previous edition of the *Statistical Review* had implied a retrospective scaling-down of BP's end-2006 estimate from 3 000 to 1 900 bcm. Thus it would appear that BP may in recent times have had a change of mind as to the magnitude of Kazakhstan's recoverable reserves of gas.

Kuwait

Proved recoverable reserves (bcm)	1 780
Production (net bcm, 2008)	12.7
R/P ratio (years)	>100
Year of first commercial production	1960

Note: Kuwait data include its share of Neutral Zone.

Gas reserves (as quoted by OAPEC and other published sources) are relatively low in regional terms and represent only about 2% of the Middle East total. With the exception of *World Oil*, which quotes 1 877 bcm, all the main publications give end-2008 levels falling inside a very narrow range (1 780-1 800).

All of Kuwait's natural gas production used to be associated with crude oil, so that its availability has been basically dependent on the level of oil output. However, official announcements during 2006 of two major discoveries of non-associated gas have changed the picture. In March it was announced that almost 35 tcf (circa 1 000 bcm) of gas had been discovered in the 'southern north' part of Kuwait; this was followed in June by news of an extractable amount of almost 5 tcf (ca. 140 bcm) in the west of the country.

In February 2010, Shell announced the signing of an agreement with the Kuwait Oil Company under which Shell will provide technical support to KOC in the development of the Jurassic Gas fields of non-associated gas in the northern part of the country.

After allowing for a limited amount of flaring and for shrinkage due to the extraction of NGLs, Kuwait's gas consumption is currently 12-13 bcm/yr, nearly one-third of which is used for electricity generation and desalination of seawater.

Libya/GSPLAJ

Proved recoverable reserves (bcm)	1 540
Production (net bcm, 2008)	15.9
R/P ratio (years)	57.5
Year of first commercial production	1970

Proved reserves - the fourth largest in Africa - have been largely unchanged since 1991, according to OAPEC and other published sources, which – in a rare instance of unanimity – all quote the same figure. Utilisation of the resource is on a comparatively small scale: net production in 2008 was only about one-third that of Egypt.

Since 1970 Libya has operated a liquefaction plant at Marsa el Brega, but LNG exports (in recent years, solely to Spain) have fallen away to only 0.5 bcm/yr.

Local consumption of gas is largely attributable to power stations, petrochemical/fertiliser plants and oil/gas industry use.

Malaysia

Proved recoverable reserves (bcm)	2 330
Production (net bcm, 2008)	57.3
R/P ratio (years)	36.6
Year of first commercial production	1983

Exploration of Malaysia's offshore waters has located numerous fields yielding natural gas or gas/condensates, mainly in the areas east of the peninsula and north of the Sarawak coast. Proved reserves (as quoted by Cedigaz) now stand at 2 330 bcm and rank as the fifth highest in Asia. Other published reserve assessments, whilst not identical, have moved much closer to Cedigaz. They now range from *Oil & Gas Journal*'s 2 350 bcm, via BP at 2 390, to OPEC's 2 475 and *World Oil*'s 2 506.

Malaysia became a major gas producer in 1983, when it commenced exporting LNG to Japan. This trade has continued ever since, supplemented in recent years by LNG sales to the Republic of Korea and Taiwan, China and by gas supplies via pipeline to Singapore. In 2008, the first deliveries of Malaysian LNG were made to China.

Domestic consumption of gas has become significant in recent years, the major market being power generation. The other principal outlet for natural gas, apart from own use within the oil/gas industry, is as feedstock/fuel for industrial users. Small amounts of CNG are used in transport, reflecting an official programme to promote its use.

Mexico

Proved recoverable reserves (bcm)	360
Production (net bcm, 2008)	46.6
R/P ratio (years)	5.0
Year of first commercial production	NA

The Mexican WEC Member Committee reports that proved recoverable reserves at end-2008 were equivalent to 12 702 bcf (360 bcm), reflecting the level of remaining proved reserves of dry natural gas given by Petróleos Mexicanos (Pemex) in *Las reservas de hidrocarburos de Mexico 2009*. Published sources appear to be divided into two camps: OAPEC and *Oil & Gas Journal* show proved reserves as 373, which was Pemex's end-2007 level for proved reserves of dry gas, while *World Oil*, BP and the

Federal Institute for Geosciences and Natural Resources (BGR), Germany quote what appears to be proved reserves of *wet* natural gas, before allowance for the extraction of NGLs, etc.

Within the total amount of proved reserves, 38% are located in the southern region, 29% in the northern region, 19% in the marine southwest region and 14% in the marine northeast region. Of total proved reserves, 41% is located in offshore waters. Pemex also quotes estimates of two further resource categories: 'probable reserves' of 15 004 bcf (425 bcm) and 'possible reserves' of 16 916 bcf (479 bcm). Mexico's proved gas reserves are 12.7% lower than at end-2005, largely due to production of gas during the intervening three years, whilst probable and possible reserves show little change over this period.

Production of natural gas has been on a rising trend since the turn of the century. The greater part of Mexico's gas production is associated with crude oil output, mostly in the southern producing areas, both onshore and offshore.

The largest outlet for gas is as power station fuel (49% of total inland disposals in 2007). The energy industry consumed 26%, industrial fuel/feedstock 23%, and residential/commercial users about 2%. Mexico habitually exports relatively small amounts of gas to the USA and imports considerably larger quantities.

Myanmar (Burma)

Proved recoverable reserves (bcm)	590
Production (net bcm, 2008)	12.4
R/P ratio (years)	45.4
Year of first commercial production	NA

Myanmar has long been a small-scale producer of natural gas, as of crude oil, but recent years have witnessed a substantial increase in its output, principally for export. There appear to be widely differing views on the level of its proved reserves: for the purpose of the present *Survey*, the level of 590 bcm published by Cedigaz has been utilised; *World Oil*'s figure equates to 412 bcm and that in *Oil & Gas Journal* to only 283, whereas BP quote 490 and OPEC 590.

Until 2000, gas production tended to oscillate around a slowly rising trend. With the commencement of exports of natural gas to Thailand from two offshore fields, first Yadana and subsequently Yetagun, Myanmar's gas industry has entered a new phase. As offtake by Thailand's 3 200 MW Ratchaburi Power Plant has built up, gas production in Myanmar has moved onto a significantly higher plane.

Namibia

The Namibian WEC Member Committee observes that the Kudu gas field was discovered as long ago as 1974, but had never been developed because of a lack of gas infrastructure. Recently licence-holders Tullow Kudu Ltd., CEICO E & P Co. Ltd. and the National Petroleum Corporation of Namibia (Pty) Ltd. have applied for a 25-year Production Licence based on the transport of the gas by CNG shuttle tankers to power plants and industrial gas markets in Namibia and South Africa.

In March 2010 it was reported that the Russian gas company Gazprom and the National Petroleum Corporation of Namibia (Namcor) were about to take a jointly-held 54% stake in the Kudu field, with Tullow's share being reduced from 70% to 31% and that of Japan's Itochu Corporation from 20% to 15%.

Netherlands

Proved recoverable reserves (bcm)	1 245
Production (net bcm, 2008)	80.0
R/P ratio (years)	15.6
Year of first commercial production	NA

The Netherlands Institute of Applied Geoscience (TNO) reports proved recoverable reserves as 1 245 bcm at 1 January 2009, towards the lower end of the range of end-2008 volumes given by the standard published sources (1 222-1 416 bcm). Nevertheless, Dutch reserves still represent one of the largest national gas resources in Western Europe. The giant Groningen field in the northwest of the Netherlands accounts for 83% of the country's proved reserves, with offshore fields providing another 10%.

TNO reports that there are 420 proven natural gas accumulations in the Netherlands, with 180 onshore and 240 offshore; in all, some 230 wells are currently producing gas. The 125 gas wells that remain undeveloped have reserves amounting to 81 billion Sm^3; 53 of these wells are scheduled to start production in 2009-2013, while the other 72 may or may not be brought into production at some later time.

In addition to its 1 326 billion Sm^3 of developed and undeveloped reserves, the Netherlands possesses some 19 billion Sm^3 of 'UGS cushion gas' – the reserves remaining in three gas fields which have been converted into underground gas storage facilities. Such cushion gas would not be produced until after the fields had ceased to be used as storage facilities, which TNO does not expect to happen before 2040.

Gas production has tended to fluctuate in recent years, largely reflecting weather conditions in Europe, thus demonstrating the flexibility that enables the Netherlands to play the role of swing producer.

Over half of Netherlands gas output is exported, mainly to Germany, but also to the UK, Italy, France, Belgium and Switzerland. The principal domestic markets are electricity and heat generation (34% of total consumption in 2007), industrial fuel and feedstock (23%) and the residential sector (20%).

New Zealand

Proved recoverable reserves (bcm)	46
Production (net bcm, 2008)	4.0
R/P ratio (years)	10.5
Year of first commercial production	1970

The proved recoverable reserves reported in petajoules by the New Zealand WEC Member Committee for the present *Survey* correspond with the 45.6 bcm of remaining 'proven and probable' reserves (or P50 values) given in the Ministry of Economic Development's publication *New Zealand Energy Data File 2009*. The Ministry compiles these data on the basis of information provided by field operators. Remaining P50 reserves have been assessed within the context of 'ultimate recoverable reserves' of around 188 bcm. About 54% of New Zealand's remaining P50 reserves are located in the Pohokura field.

The Maui offshore gas/condensate field (discovered in 1969) is the largest hydrocarbon deposit so far located in New Zealand, but now accounts for only 17% of the remaining P50 gas reserves. Maui came into commercial production in 1979 when a pipeline to the mainland was completed. Three plants were commissioned in the 1980s to use indigenous gas, producing (respectively) methanol, ammonia/urea and synthetic gasoline. By 2008, Maui's share of New Zealand gas production had fallen to only just over 30%.

The *Energy Data File* shows recoverable gas reserves from non-producing fields as amounting to 5.9 bcm in five fields, all of which have Petroleum Mining Permits.

An extensive transmission and distribution network serves industrial, commercial and residential consumers in the North Island. Minor amounts of CNG are used as an automotive fuel.

Nigeria

Proved recoverable reserves (bcm)	5 292
Production (net bcm, 2008)	31.7
R/P ratio (years)	98.9
Year of first commercial production	1963

Published assessments of Nigeria's proved reserves of natural gas at the end of 2008 all fall within a narrow band (5 215 to 5 292 bcm). The level adopted for the present *Survey* is that quoted by Cedigaz, which is closely matched by OPEC (5 249), *World Oil* (5 216) and OAPEC/BP/*Oil & Gas Journal* at around 5 215 (OGJ quotes 5 246 for gas reserves as at 1 January 2010).

Nigeria's proved reserves are the largest in Africa, ahead of those of Algeria, but historically its degree of gas utilisation has been very low. Much of the associated gas produced has had to be flared, in the absence of sufficient market outlets. Efforts are being made to develop gas markets, both locally and internationally, and to reduce flaring to a minimum. There are projects to replace non-associated gas by associated gas in supplies to power stations and industrial users. In 2008, about 28% of Nigeria's gross gas production of 64.6 bcm was flared or vented.

The Bonny LNG plant (commissioned in the second half of 1999) exported 20.65 bcm of natural gas as LNG during 2008, chiefly to Spain and France, with smaller quantities going to Portugal, Japan and Taiwan, China, together with several other countries. In another major export initiative, the West African Gas Pipeline (WAGP) has been constructed to transmit Nigerian associated gas to power plants in Benin, Togo and Ghana. Regular supplies to the Volta River Authority's gas-fired power station (4 x 110 MW) at Aboadze, near Takoradi, began in March 2010.

Norway

Proved recoverable reserves (bcm)	2 215
Production (net bcm, 2008)	99.2
R/P ratio (years)	21.7
Year of first commercial production	1977

Resource data have been sourced primarily from the Norwegian Petroleum Directorate (NPD). Proved reserves are the highest in Europe (excluding the Russian Federation). The bulk of gas reserves are located in the North Sea, the rest having been discovered in the Norwegian Sea and the Barents Sea.

The level of proved recoverable reserves reported by the NPD amounts to 2 215 bcm at end-2008; *World Oil* quotes the same level but *Oil & Gas Journal* and OAPEC give 2 313, probably reflecting the official end-2007 level. On the other hand, Cedigaz and OPEC give 2 985 bcm, which appears to include the NPD's categories 'contingent resources' and 'potential from improved recovery'. BP shows a somewhat lower figure (2 910), which may be on a similarly extended basis to that adopted by Cedigaz and OPEC, but exclude the potential from improved recovery.

For end-2008, NPD put contingent resources in fields at 181 bcm, those in discoveries at 512 bcm and potential from improved recovery at 77 bcm. In addition, NPD estimated that the recoverable potential of undiscovered gas was 1 875 bcm.

In the NPD's terminology, 'reserves' cover 'remaining recoverable, saleable petroleum resources in petroleum deposits that the licensees have decided to develop, and for which the authorities have approved the plan for development and operation (PDO) or granted a PDO exemption'. 'Contingent resources' are defined as 'discovered quantities of petroleum for which no development decision has yet been made'. 'Undiscovered resources' are 'petroleum volumes which are expected to be present in defined exploration models, confirmed and unconfirmed, but which have not yet been proven through drilling'.

Norway's gas production has consistently recorded year-on-year increases since 1993. A high proportion (nearly 28% in 2008) of output is re-injected; 96% of marketed production is exported. In 2008 supplies went to ten European countries, principally Germany, the UK, France, Belgium, the Netherlands and Italy. Apart from gas industry own use and some feedstock usage, Norway's internal consumption of gas is at relatively low levels in all sectors.

Oman

Proved recoverable reserves (bcm)	950
Production (net bcm, 2008)	24.1
R/P ratio (years)	34.7
Year of first commercial production	1978

Oman is one of the smaller gas producers in the Middle East, with moderate proved reserves which have increased by about 14% since 2005, on the basis of OAPEC data. The levels of reserves quoted in other published sources are fairly widely dispersed, ranging from Cedigaz and OPEC's 690 bcm to BP's 980, with *Oil & Gas Journal* and *World Oil* at 849 and OAPEC towards the top end of the scale at 950. For the sake of consistency with previous editions, the present *Survey* uses the level published by OAPEC.

Oman has developed its utilisation of gas to such an extent that oil has long been displaced as the Sultanate's leading energy supplier. Currently, the principal outlet for marketed gas is the power generation/desalination complex at Ghubrah. Other industrial consumers include mining and cement companies.

The Oman LNG project began operating in early 2000, with the first shipment being made to the Republic of Korea, which remains a principal customer. Regular shipments of LNG are also made to Japan, whilst during 2008 additional supplies (including spot cargoes) were delivered to Spain, India and Taiwan, China.

Pakistan

Proved recoverable reserves (bcm)	840
Production (net bcm, 2008)	37.5
R/P ratio (years)	21.0
Year of first commercial production	1955

The levels of natural gas resources and reserves quoted in the present *Survey* have been provided by the WEC Member Committee for Pakistan. Proved recoverable reserves at end-2008 were 29 671 bcf (840 bcm), derived by subtracting cumulative production of 23 889 bcf (677 bcm) from original recoverable reserves (= estimated 'ultimate recovery') of 53 560 bcf (1 517 bcm). There is now general agreement among the standard published sources on the current level of Pakistan's proved recoverable reserves of natural gas.

Pakistan's major gas-producing fields are Sui in Balochistan and Qadirpur, Mari, Zamzama, Sawan and Bhit in Sindh. Less than 2% of natural gas output was associated with oil production in 2008-09. The major markets for gas (excluding own use) in that year were power generation (32%), industrial users (26%), fertiliser plants (16%), households and commercial consumers (20%) and transport (7%). Rapidly growing quantities of CNG are consumed as an automotive fuel.

Papua New Guinea

Proved recoverable reserves (bcm)	442
Production (net bcm, 2008)	0.1
R/P ratio (years)	> 100
Year of first commercial production	1991

The Hides gas field was discovered in 1987 and brought into production in December 1991. Other resources of non-associated gas have been located in PNG, both on land and offshore. For the present *Survey*, the level of 442 bcm given by Cedigaz for PNG's proved gas reserves has been adopted. The other major published assessments concur, with the exception of *Oil & Gas Journal*, which opts for 226 bcm, both at 1 January 2009 and at 1 January 2010.

Up to the present, the only marketing outlet for Hides gas has been a 42 MW gas-turbine power plant serving the Porgera gold mine; offtake averages 14-15 million cubic feet/day. Associated gas produced in the Kutubu area is mostly re-injected into the formation.

The PNG LNG project, which is planned to start producing 6.6 million tonnes of LNG from 2014, is moving ahead, with the project operator ExxonMobil stating in March 2010 that all financing arrangements were complete.

Peru

Proved recoverable reserves (bcm)	335
Production (net bcm, 2008)	4.0
R/P ratio (years)	71.3
Year of first commercial production	NA

In terms of natural gas reserves, Peru is situated in the middle rank of South American countries, alongside Argentina, Bolivia and Brazil. The latest information available regarding Peru's gas reserves is contained in the *Anuario Estadistico de Hidrocarburos 2008*, published by the Peruvian Ministerio de Energia y Minas in 2009. This shows proved reserves at end-2007 as 11 821 bcf (335 bcm), probable reserves as 6 832 bcf (193 bcm) and possible reserves as 11 218 bcf (318 bcm). The principal international data sources quote very similar figures for Peru's proved reserves, with the exception of Cedigaz, which shows 415 bcm.

Gas output used to be mostly associated with oil production, but the coming on-stream of

Pluspetrol's non-associated gas production in the Selva Sur has radically altered the situation, such that only 15% of gross production in 2008 was associated with oil production. An appreciable proportion of production (40% in 2008) is re-injected. Flaring and shrinkage are reported to be on a small scale.

Marketed production of gas averaged about 0.4 bcm/yr from around 1990 until 2003, but since then has risen sharply year-on-year, reflecting the burgeoning of Pluspetrol's Selva Sur output. Electricity generation accounts for over 70% of Peru's gas consumption.

Qatar

Proved recoverable reserves (bcm)	25 172
Production (net bcm, 2008)	77.0
R/P ratio (years)	>100
Year of first commercial production	1963

Qatar's gas resources far outweigh its oil endowment: its proved reserves of gas of over 25 trillion m^3 are only exceeded within the Middle East by those reported by Iran, and account for nearly 14% of global gas reserves. In its Secretary General's 2008 Annual Report, OAPEC quotes Qatar's end-2008 reserves of natural gas as 25 172 bcm. Other published sources are all closely in line with this level.

Although associated gas has been discovered in oil fields both on land and offshore, the key factor in Qatar's gas situation is non-associated gas, in particular that in the offshore North Field, one of the largest gas reservoirs in the world. For the 2007 SER, the WEC Member Committee reported that non-associated gas accounted for almost 99% of Qatar's gas reserves.

Production of North Field gas began in 1991 and by 2008 Qatar's total annual gross production had risen to about 91 bcm; approximately 5% was re-injected, 4% flared and 6% lost through shrinkage. The gas consumed locally is principally for power generation/desalination, fertiliser and petrochemical production and gas industry own use.

Since the end of 1996, Qatar has become a substantial exporter of LNG; in 2008, shipments were nearly 40 bcm of gas, of which 29% was consigned to the Republic of Korea, 28% to Japan, 20% to India, 13% to Spain and 10% to other countries.

Romania

Proved recoverable reserves (bcm)	102
Production (net bcm, 2008)	10.7
R/P ratio (years)	8.9
Year of first commercial production	NA

The Romanian WEC Member Committee reports proved recoverable reserves of 102 bcm, a further reduction on the 121 bcm reported for the 2007 *Survey* and the 163 bcm advised for the 2004 edition. Published assessments of Romania's proved gas reserves vary by a factor of ten, ranging from *World Oil* and *Oil & Gas Journal* at 62-63 bcm to Cedigaz and BP at around 630 bcm. The proportion of proved recoverable reserves that is non-associated with crude oil is reported to be 90%.

Additional recoverable amounts reported by the Member Committee comprise probable reserves of 47 bcm and possible reserves of 11 bcm. The remaining discovered amount of gas in place is put at 696 bcm, which may be compared with past cumulative Romanian production of 1 317 bcm.

After peaking in the mid-1980s, Romania's natural gas output has been in gradual secular decline, falling to around 11 bcm in recent years, only about one-third of its peak level. Indigenous production currently supplies about two-thirds of Romania's gas demand; the principal users are power stations, CHP and district heating plants, the steel and chemical industries and the residential/commercial sector.

Russian Federation

Proved recoverable reserves (bcm)	44 900
Production (net bcm, 2008)	621.3
R/P ratio (years)	68.8
Year of first commercial production	NA

The gas resource base is by far the largest in the world: Russia's proved reserves are quoted as 44 900 bcm by Cedigaz. Other major published sources quote figures ranging from 43 300 to 47 572.

The majority of the Federation's reserves are located in West Siberia, where the existence of many giant, and a number of super-giant, gas fields has been proved. The Federation's net natural gas production of 621.3 bcm in 2008 accounted for just over 20% of the world total.

Russia is easily the largest exporter of natural gas in the world: in 2008, according to Cedigaz, its exports reached about 239 bcm, of which about 154 bcm went to European countries and the balance to former republics of the Soviet Union.

Saudi Arabia

Proved recoverable reserves (bcm)	7 569
Production (net bcm, 2008)	80.4
R/P ratio (years)	87.8
Year of first commercial production	1961

Note: Saudi Arabia data include its share of Neutral Zone.

Most of Saudi Arabia's proved reserves and production of natural gas are in the form of associated gas derived from oil fields, although a number of sources of non-associated gas have been discovered. In total, proved reserves of gas rank as the third largest in the Middle East. Other published sources' assessments are generally similar.

Output of natural gas has advanced fairly steadily for more than a quarter of a century. A significant factor in increasing Saudi Arabia's utilisation of its gas resources has been the operation of the gas-processing plants set up under the Master Gas System, which was inaugurated in the mid-1980s. These plants produce large quantities of ethane and LPG, which are used within the country as petrochemical feedstock; a high proportion of LPGs is exported. The main consumers of dry natural gas (apart from the gas industry itself) are power stations, desalination plants and petrochemical complexes.

Thailand

Proved recoverable reserves (bcm)	340
Production (net bcm, 2008)	28.8
R/P ratio (years)	11.0
Year of first commercial production	1981

Thailand's WEC Member Committee reports proved recoverable reserves at end-2008 as 12.002 tcf (equivalent to 340 bcm), implying an 11.7% increase on the level advised for the 2007 SER. In contrast to the disparity exhibited by published assessments of Thailand's proved gas reserves for end-2005, there is now a much greater measure of agreement, with the estimates ranging from BP's 300 to *World Oil* and *Oil & Gas Journal* at 317 (note that the latter source quotes 342 for 1 January 2010).

Recoverable reserves at lower levels of confidence than the proved amount are reported as 12.482 tcf (353 bcm) of probable reserves and 7.630 tcf (216 bcm) of possible reserves. Since the commencement of its natural gas production in 1981, Thailand has produced 12.890 tcf (365 bcm).

Since its inception nearly 30 years ago, Thailand's natural gas output has grown almost unremittingly year after year. Much the greater part of Thailand's gas output is used for electricity generation; industrial use for fuel or chemical feedstock is relatively small, whilst transport use (CNG) is increasing rapidly.

Thailand began to import natural gas from Myanmar in 1999; in 2008 the volume involved was 8.55 bcm.

Trinidad & Tobago

Proved recoverable reserves (bcm)	481
Production (net bcm, 2008)	39.3
R/P ratio (years)	11.8
Year of first commercial production	NA

The latest available estimates of Trinidad's reserves of natural gas are the result of an audit carried out for the Ministry of Energy and Energy

Industries during the first half of 2008, and relate to the situation at end-2007. Proved reserves are put at 16 997 bcf (481 bcm), probable reserves at 7 883 bcf (223 bcm) and possible reserves at 5 888 bcf (167 bcm). 'Exploration resources' are estimated at 31 253 bcf (885 bcm). Most published sources quote similar levels.

Marketed production of gas has increased rapidly during recent years, as exports from the Atlantic LNG plant (inaugurated in 1999) have built up. Local consumption is also on the increase, reflecting a government policy of promoting the utilisation of indigenous gas through the establishment of major gas-based industries: fertilisers, methanol, urea and steel. In 2007 the chemical and petrochemical industries accounted for about 60% of Trinidad's gas consumption, power stations for 18% and other industry (including iron and steel) for 12%; the balance of consumption is accounted for by use/loss within the gas supply industry.

Turkmenistan

Proved recoverable reserves (bcm)	8 400
Production (net bcm, 2008)	66.1
R/P ratio (years)	>100
Year of first commercial production	NA

Apart from the Russian Federation, Turkmenistan has the largest proved reserves of any of the former Soviet republics: for the present *Survey*, the significantly increased level of 8 400 bcm quoted by Cedigaz in its *Natural Gas in the World* survey (November 2009) has been adopted. Other published sources have also made radical revisions to their assessments, with BP quoting 7 940 bcm in June 2009 and *Oil & Gas Journal* giving 7 504 for 1 January 2010. These adjustments may be taken to represent provisional updating of Turkmenistan's reserves in the light of the discovery in March 2007 of Yolotan and Osman, ('two potentially massive gas fields', according to Cedigaz), in the southeast of the country, towards its border with Afghanistan.

Cedigaz has stated that Turkmenistan's total gas resources have been evaluated at 22.9 trillion cubic metres. Prior to 2007, many gas fields had been discovered in the west of the republic, near the Caspian Sea, but the most significant resources had been located in the Amu-Darya Basin, in the east.

Gas deposits were first discovered in 1951 and by 1980 production had reached 70 bcm/yr. It continued to increase throughout the 1980s, but by 1992 a serious contraction of the republic's export markets had set in and output fell sharply. Natural gas output recovered in 1999, and has since advanced to 66 bcm in 2008. Exports to Iran amounted to 6.5 bcm in 2008.

Ukraine

Proved recoverable reserves (bcm)	787
Production (net bcm, 2008)	19.8
R/P ratio (years)	39.7
Year of first commercial production	NA

For the 2007 SER, the Ukrainian WEC Member Committee reported proved recoverable reserves of 787 bcm as at end-2005, within a proved amount in place of 1 021 bcm. The available published sources (Cedigaz, *Oil & Gas Journal* and BP) all showed proved recoverable reserves between 1 100 and 1 121 bcm, appreciably higher than the reported figure. Although Cedigaz and BP have each reduced their estimates, these still substantially exceed the end-2005 level reported by the Ukraine Member Committee. However, pending further advice, it has been decided to retain the last reported level. Gas associated with crude oil was at that time stated to account for only about 3% of the proved reserves.

Over and above the proved quantities, the WEC Member Committee estimated that at end-2005 there was about 357 bcm of gas in place, of which around 169 bcm was likely to be recoverable.

Ukraine's output of natural gas has been virtually flat since 1994, although production since 2003 has been on a somewhat higher level. The republic is one of the world's largest consumers of natural gas: demand reached 137 bcm in 1990. Although consumption had fallen back to about 75 bcm by 2008, indigenous production met only 26% of local needs; the balance was imported from Russia and Turkmenistan. The consumption of gas is spread fairly evenly over electricity and heat plants, industrial fuel and feedstocks, and the tertiary sector.

United Arab Emirates

Proved recoverable reserves (bcm)	6 432
Production (net bcm, 2008)	50.2
R/P ratio (years)	> 100
Year of first commercial production	1967

Four of the seven emirates possess proved reserves of natural gas, with Abu Dhabi accounting for by far the largest share. Dubai, Ras-al-Khaimah and Sharjah are relatively insignificant in regional or global terms. Overall, the UAE accounts for about 8% of Middle East proved gas reserves.

After a lengthy period of stagnation in published estimates of Abu Dhabi’s proved reserves of natural gas at around 6 000 - 6 100 bcm, a tendency for a moderate upward shift can now be observed. BP (June 2009) quotes 6 430 bcm for total UAE at end-2008, and Cedigaz (in its November 2009 survey) has raised its estimate for Abu Dhabi from 5 650 bcm at 1 January 2007 to 6 030 bcm at both 1 January 2008 and 1 January 2009, thus bringing its comparable levels for total UAE up from 6 061 to 6 432 bcm. This latter level has been adopted for the present SER. The other main published sources (*Oil & Gas Journal*, OAPEC, OPEC and *World Oil*) all quote UAE reserves within a lower, very narrow band (6 071 - 6 091 bcm).

Two major facilities - a gas liquefaction plant on Das Island (brought on-stream in 1977) and a gas-processing plant at Ruwais (in operation from 1981) - transformed the utilisation of Abu Dhabi's gas resources. Most of the plants' output (LNG and NGLs, respectively) is shipped to Japan. In 2008, Abu Dhabi's other LNG customer was India.

Within the UAE, gas is used mainly for electricity generation/desalination, and in plants producing aluminium, cement, fertilisers and chemicals.

United Kingdom

Proved recoverable reserves (bcm)	292
Production (net bcm, 2008)	68.2
R/P ratio (years)	3.9
Year of first commercial production	1955

The UK is no longer Europe's leading offshore gas producer, having been overtaken by Norway in 2006. The data on gas resources and reserves adopted for the present *Survey* are based on those reported by the British Energy Association, the UK Member Committee of the WEC, on the basis of advice from the Department of Energy and Climate Change (DECC).

Proved recoverable reserves at end-2008 are reported to be 292 bcm, being the sum of 'gas from dry gas fields' (129 bcm), 'gas from condensate fields' (108) and 'associated gas from oil fields' (55). In this context DECC defines 'proven reserves' as those 'which on the available evidence are virtually certain to be technically and economically producible, i.e. have a better than 90% chance of being produced'.

'Probable' reserves (with a better than 50% chance of being technically and economically producible) are put at 309 bcm, whilst 'possible' reserves (with a significant, but less than 50%, chance) are estimated at 306 bcm.

It may be noted that Cedigaz quotes UK proved reserves of natural gas as 601 bcm, i.e. the sum of 'proved' and 'probable' reserves in DECC parlance. On the other hand, *Oil & Gas Journal*, OAPEC and BP report them as 343 bcm, reflecting DECC proved reserves as at end-2007, being the latest available at the time of their compilation.

Since the end-2005 estimates quoted in the 2007 *Survey*, DECC's assessment of the UK's proved gas reserves has fallen by 189 bcm, whilst net additions to probable reserves have amounted to 62 bcm and possible reserves have risen by a net 28 bcm. Despite production of natural gas amounting to some 218 bcm during

2006-2008, total proved + probable + possible reserves have fallen by less than 100 bcm.

In addition to the reserves discussed above, DECC estimates 'potential additional reserves' that exist in discoveries for which there are no current plans for development and which are currently not technically or commercially producible. DECC states that, on the basis of information gathered during the first quarter of 2009, these reserves are considered to lie within a range of 65 to 298 bcm, with a central estimate of 136 bcm, the last figure being little changed from the comparable level (141) released in September 2006. In the course of time, as additional data become available and development plans evolve, some of the 'potential additional reserves' gas is likely to be transferred to 'reserves'.

DECC has also produced estimates of 'undiscovered recoverable resources', based for the most part on an analysis of mapped leads. The latest update has produced a range of undiscovered gas resources from 319 to 1 043 bcm, with a central estimate of 540 bcm. It is pointed out by DECC that such figures provide only a broad indication of the ultimate remaining potential and that the central estimate is not necessarily the volume most likely to be discovered. The figures quoted do not include any estimates of unconventional gas resources such as coal-bed methane.

It should be noted that all UK gas reserves are reported in terms of recoverable quantities: the corresponding volumes of gas in place do not form part of the published data on gas resources. Moreover, the recoverable quantities exclude any gas that is flared, as well as gas consumed in production operations.

Natural gas production rose year-by-year during the 1990s, reflecting burgeoning consumption in the power generation sector and higher exports at the end of the decade, following the commissioning of the Interconnector pipeline between Bacton in the UK and Zeebrugge in Belgium, in October 1998. Total output peaked in 2000, since when it has followed a consistent downward trend.

United States of America

Proved recoverable reserves (bcm)	7 022
Production (net bcm, 2008)	574.4
R/P ratio (years)	11.2
Year of first commercial production	NA

The USA possesses the world's sixth largest proved reserves of natural gas, and accounts for almost 4% of the global total. The figure of 7 022 bcm tabulated above is derived from total proved reserves of dry natural gas at end-2008 (244 656 bcf), as reported by the US Energy Association, (the WEC Member Committee for the USA), quoting the Energy Information Administration (EIA) in its *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves 2008 Annual Report*. For the purposes of the present *Survey*, the original data in billion cubic feet at 14.73 psia and 60°F have been transformed into standard SER terms (1 013 mb and 15°C) by means of separate adjustments for pressure and temperature.

During the three years since the last edition of the *Survey of Energy Resources*, U.S. gas reserves have registered an increase of 40 271 bcf, or about 1 155 bcm. Total additions to reserves in 2005-2008 were 68.8% greater than the amount of gas produced during the same period.

U.S. natural gas proved reserves are now at their highest level since the EIA began reporting them in 1977. Their growth in recent years is largely attributable to the continued development of unconventional gas from shales, reflecting the oil industry's successful application of horizontal drilling and hydraulic fracturing to shale formations. In 2008, proved reserves of shale gas grew by over 50% and by year-end constituted 13.4% of total U.S. proved reserves of natural gas. Two-thirds of the USA's proved shale gas reserves are located in Texas.

U.S. proved reserves of coal-bed methane fell 5% in 2008, after rapid growth since the 1990s; it now accounts for 8.5% of total U.S. proved reserves of dry natural gas.

The 40.3 tcf net increase in total U.S. gas reserves during 2006-2008 was due partly to discoveries (field extensions, new field discoveries and new reservoir discoveries in old fields), totalling 81.9 tcf during the three-year period, partly to revisions and adjustments to estimates for old fields (+12.6 tcf) and partly to the net balance of sales and acquisitions (+4.3 tcf). These positive elements were partly offset by gas production during the three-year period totalling 58.5 tcf.

Total discoveries during 2008 amounted to 29.5 tcf, the largest component comprising field extensions, notably in Texas, Wyoming, Oklahoma, Colorado and Louisiana. The states with the largest gas reserves at end-2008 were Texas (31.7% of the USA total), Wyoming (12.7%), Colorado (9.5%) and Oklahoma (8.5%). Reserves in the Federal Offshore areas in the Gulf of Mexico accounted for 5.5% of the total. About 89% of proved reserves consist of non-associated gas.

Uzbekistan

Proved recoverable reserves (bcm)	1 745
Production (net bcm, 2008)	63.4
R/P ratio (years)	27.4
Year of first commercial production	NA

The republic's first major gas discovery (the Gazlinskoye field) was made in 1956 in the Amu-Darya Basin in western Uzbekistan. Subsequently, other large fields were found in the same area, as well as smaller deposits in the Fergana Valley in the east.

For the present *Survey*, the level of 1 745 bcm quoted by Cedigaz has been adopted for proved recoverable reserves; other published sources mostly specify 1 841 bcm, but BP shows 1 580.

Uzbekistan is a major producer of natural gas: its 2008 net output was, for example, greater than that of Egypt or the UAE. It exports gas to some of its neighbouring republics.

The principal internal markets for natural gas are the residential/commercial sector, power stations, CHP and district heating plants, and fuel/feedstock for industrial users. Some use is made of CNG in road transport.

Venezuela

Proved recoverable reserves (bcm)	4 983
Production (net bcm, 2008)	24.1
R/P ratio (years)	>100
Year of first commercial production	NA

Venezuela has by far the biggest natural gas resources in South America and possesses more than two-thirds of regional proved reserves. In the absence of any reserves data released by the Ministerio de Energía y Minas later than 4 708 bcm as at the end of 2006, the level for end-2008 quoted by Cedigaz and OPEC (4 983 bcm) has been adopted for the present *Survey*. Most other published sources tell much the same story: *Oil & Gas Journal*, OAPEC and BP 4 840 bcm, but *World Oil* opts for the rather lower figure of 4 304.

Substantial quantities of Venezuela's natural gas (amounting to almost 45% of gross output in 2008) are re-injected in order to boost or maintain reservoir pressures, while smaller amounts (12%) are vented or flared; about 10% of production volumes are subject to shrinkage as a result of the extraction of NGLs.

The principal outlets for Venezuelan gas are power stations, petrochemical plants and industrial users, notably the iron and steel and cement industries. Residential use is on a relatively small scale.

Yemen

Proved recoverable reserves (bcm)	555
Production (net bcm, 2008)	0
R/P ratio (years)	>100
Year of first commercial production	2009

Yemen has appreciable reserves of natural gas - currently quoted by OAPEC as 555 bcm, up from 479 bcm at end-2005. Cedigaz, *World Oil* and BP quote 490, while *Oil & Gas Journal* retains 479.

Commercialisation of Yemen's gas became a reality in October 2009 with the start-up of the first train at an LNG plant at Balhaf. The plant will consist of two trains, capable of delivering 6.7 million tonnes/yr of LNG. The second train is scheduled to come into operation during the first half of 2010. Natural gas is supplied from two gas-processing plants in the Marib gas field via a 320 km pipeline.

6. Part I: Uranium

COMMENTARY

Overview

As for almost all commodities, uranium market conditions abruptly changed with the onset of the financial and economic crises in 2008. At the close of 2009 spot prices were about 35% below their mid-2007 peak of US$ 350/kgU. Yet compared with other commodities, the uranium market weathered the storm fairly well. Uranium is generally better protected against aberrations than other markets. For one thing, short run reactor uranium requirements are relatively stable as existing nuclear power plants are usually the lowest-cost generators on the grid. Hence, stagnating or declining electricity demand does not usually affect nuclear generation. However, the level of global nuclear electricity generation has been slipping slightly during recent years owing to reactor closures, decommissioning and lengthy shutdowns for maintenance and repairs (e.g. the Kashiwazaki Kariwa units in Japan, owing to an earthquake). Lower nuclear generation, longer refuelling cycles and higher burn-ups caused annual global reactor uranium requirements to fluctuate between 59 000 tU and 66 000 tU over recent years.

Another factor in protecting against aberrations is that most uranium (about 85%) is supplied under long-term contracts, where the pricing is shielded from sudden market fluctuations. New contracts or contract renewals then tend to

Figure 6.1 Development of uranium spot market price
(Source: adapted from NEA/IAEA, 2010 and ESA, 2009*)

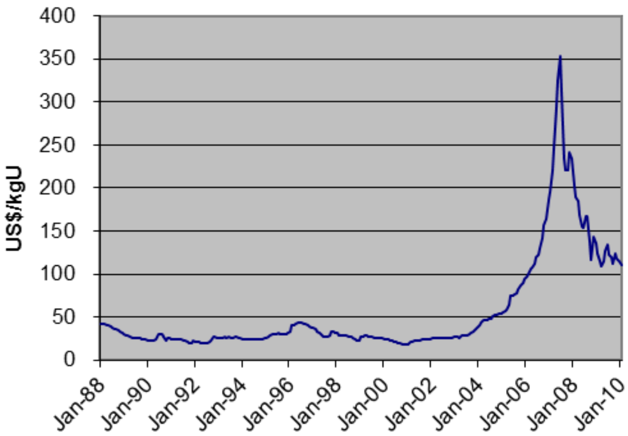
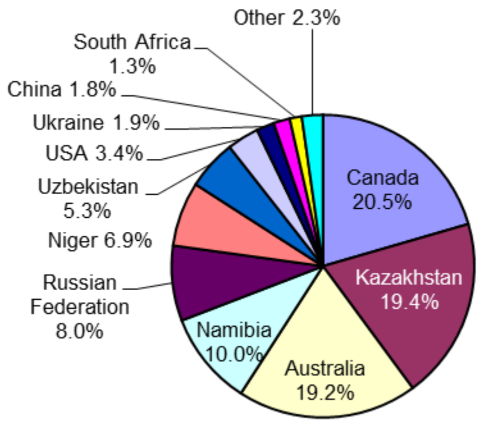


Figure 6.2 Top uranium producers in 2008 - total production 43 880 tU [51 885 tU_3O_8]
(Source: WNA, 2009a)



* Most uranium is traded under long-term contracts which may differ significantly from spot market prices. Spot prices indicate the tightness of the market in the short run. Between 2000 and 2009 contract prices varied less than 50%.

reflect the current spot price situation as well as other demand and supply factors. During the period 2006 to 2009 average long-term multiannual contract prices were about half the going spot market price.

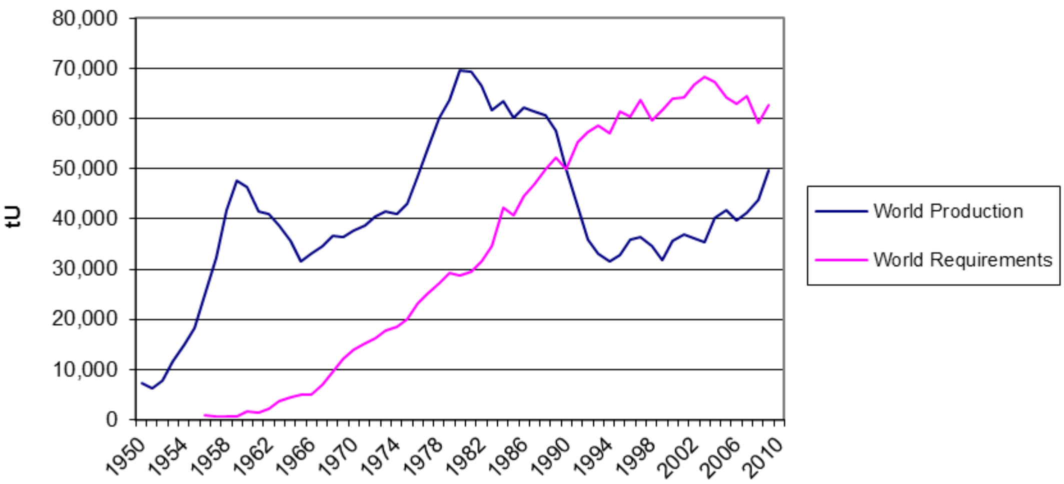
What brought down spot prices – in addition to the precipitous fall in energy, material and commodity prices - were those hedge funds and investors who since 2004 have traded in uranium and, to a certain extent, added fuel to the 2004-2008 spot price rally and who, as a result of the financial crisis, were forced to sell their uranium positions due to cash requirements.

Mine production continued to be short of annual reactor requirements and 30% to 35% of annual uranium demand continues to be supplied by secondary sources (reactor fuel derived from warheads, military and commercial inventories, re-enrichment of depleted uranium tails[1], as well as enriching at lower tail assays, reprocessed uranium and mixed oxide fuel). Secondary supplies therefore remain an important factor in the global uranium demand and supply balance. However, their future availability is uncertain and largely depends on further international nuclear disarmament agreements after 2013.

The longer-term market prospects for uranium remain bright. Between 2007 and 2009 construction started on 29 nuclear power plants representing 29.1 GW_e of new installed capacity, bringing the total number under construction to 55 reactors at the end of 2009, the largest number since 1992. The post-2000 trend of licence renewals or extensions for many operating reactors continued, especially in the USA. Licence extensions are usually accompanied by replacements of aged plant

[1] Natural uranium contains 0.71% of the fissile isotope U-235. The operation of light water reactors (globally the dominant reactor technology) requires a U-235 concentration of 3% to 5%. The enrichment process generates large amounts of depleted ‘uranium tails’ with varying U-235 concentrations depending on uranium prices and the cost and availability of enrichment facilities. The lower the tail concentration the more costly separation work is needed. Hence, typical tail concentrations are in the range of 0.25% to 0.35% U-235. At times of high uranium prices and excess enrichment capacity it can be economically viable to re-enrich these tails, e.g., by drawing down the U-235 share of the tails to 0.1%. Lowering the tail assays from 0.3% to 0.1% would reduce the demand for mined uranium by about 30%.

Figure 6.3 Global annual uranium production and reactor requirements*
(Source: adapted from NEA/IAEA, 2010)



** Production and reactor requirements are expressed in terms of tonnes (t) of contained uranium (U) rather than in terms of uranium oxide (U_3O_8). Data for 2009 are estimates*

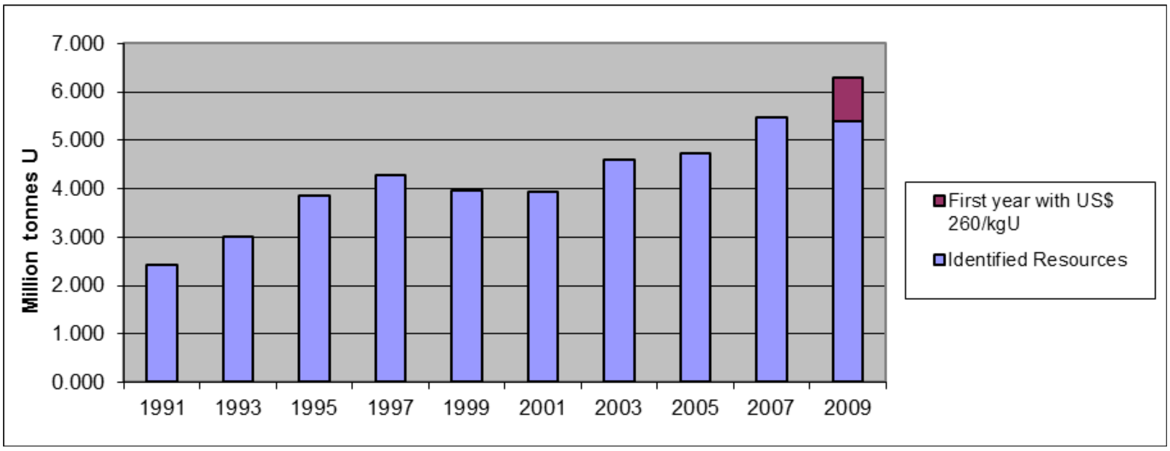
components, e.g., by more efficient or larger steam generators, turbines, pumps or generators, which can result in power uprates of up to 20%. Nuclear power phase-out policies were moderated in several European countries. Sweden will now allow its existing reactors to operate to the end of their economic lifetimes and to be replaced by new reactors once they are retired. Italy ended its ban on nuclear power and will now allow new construction. Belgium decided to postpone the first phase of its planned phase-out by ten years. Closure of its reactors had been scheduled to take place between 2015 and 2025. In Germany, following the change of Government, discussions started to postpone the phase-out. While all these developments are good news for uranium producers, even better news are the ambitious nuclear power expansion programmes in China, India, and, to a lesser extent, Russia. In addition, over 60 countries currently without nuclear power programmes have expressed their interest to the International Atomic Energy Agency in considering the introduction of nuclear power.

Reactor uranium requirements, therefore, are set to grow. To meet demand, stepped-up investment in uranium exploration and mine development must be made, especially if the supply of secondary sources declines after 2013, when the Russian downblending programme of highly enriched uranium to reactor fuel grade expires as planned that year.

The uranium market remains subject to political conditions. Most prominent still are the 1994 HEU Agreement (often referred to as the Megatons-to-Megawatts programme), which was implemented through a 1994 contract between the USA and Russia, and the antidumping suspension agreement between the USA and Russia plus five central Asian uranium-producing countries. Recent policy decisions have led to further market liberalisation, such as:

- the announcement by the State of Western Australia to lift the ban on uranium mining;
- the agreement between India and the USA on trade in nuclear materials, fuel and technology;
- the Nuclear Suppliers Group (NSG) also agreeing to allow its members to sell nuclear technology and fuel to India;
- the bilateral safeguards agreements between Australia and the Russian Federation and between Australia and China, which allows Australia to export uranium to these countries;

Figure 6.4 Development of Identified Uranium Resources at less than US$ 130/kgU and less than US$ 260/kgU production costs (Source: NEA/IAEA, 2010)



- changes in Zambia's legislation that now allows it to issue licences for uranium mining.

In general, the market has seen the formation of numerous new joint international ventures, as well as acquisitions and mergers, many of which aim to enhance exploration and mining activities.

Unwelcome surprises were the politically motivated market interventions causing friction between governments and overseas investors in Mongolia. Other recent notable government policy changes include modifications in the royalty structure in Kazakhstan and legislation targeted at environmental protection, e.g. with respect to mine site rehabilitation.

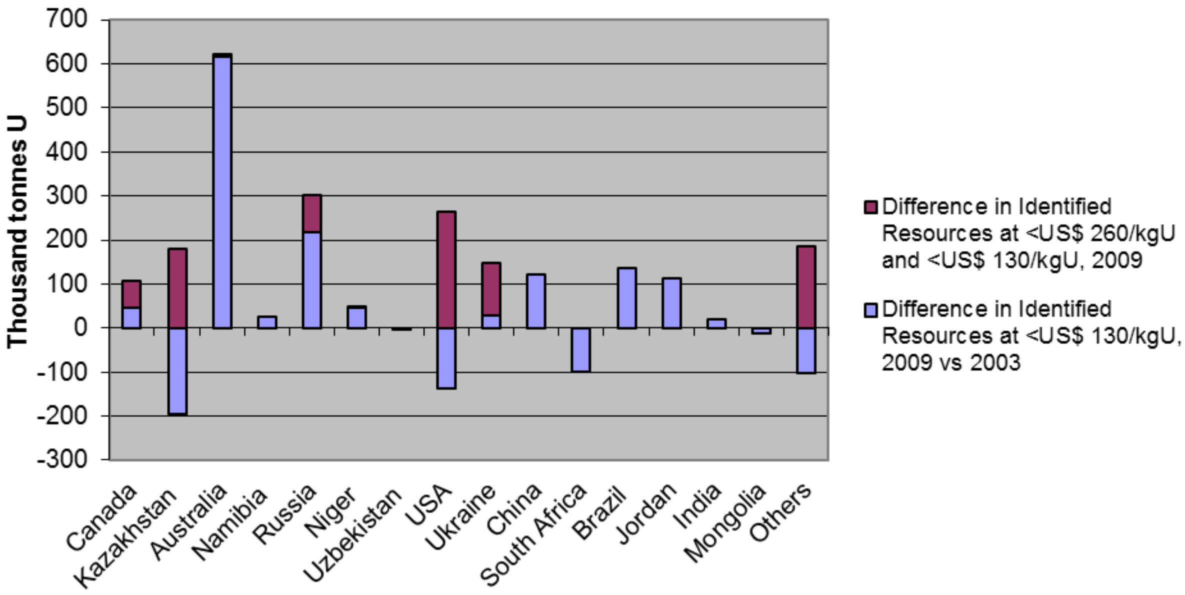
A notable change in the uranium market has been the arrival of new participants (hedge funds, forward markets, speculative stockpiles, etc.) with added transparency, liquidity and efficiency in a market that traditionally underperformed in these aspects, compared with other commodity markets. This and the appearance of new price indicators bring the uranium market closer to the trading practices of other energy commodities and minerals (ESA, 2009).

The market remained sensitive to uranium prices, with increasing prices not only stimulating uranium exploration and expansion of mining capacity but also attracting the attention of speculators. Starting in 2003, the recovery of uranium prices led to a steep rise in exploration activities as well as in preparations for the opening of new mines in many countries. For example, globally the number of companies actively involved in uranium exploration increased from a handful in 2003 to more than 400 in 2008 (ESA, 2009). Throughout 2009, announcements were made regarding production from new mines and plans for new uranium mining capacity or for increasing output from operating mines. However, postponements, putting operating capacity on stand-by or reducing output were also reported, often prompted by a lack of access to financial resources or expectations of improved market conditions in the years ahead. For example, the Australian uranium mining company BHP Billiton has withdrawn its takeover bid for Rio Tinto (ESA, 2009).

The market price increases between 2003 and 2007 not only reflected a more optimistic demand outlook, but also resulted from several technical failures in major producing mines in Australia, Canada and Kazakhstan adversely affecting global production capacities. The new paper market instruments and general availability of cheap money added further upward pressure on prices, very much in line with other energy and material prices.

After almost eight years of ascent to US$ 350/kgU, spot uranium prices fluctuated erratically around a general downtrend (Fig. 6.1) beginning in mid-2007, with spot prices

Figure 6.5 Change in Identified Uranium Resources by major country, 2009 vs 2003 and the impact of including the US$ 130/kgU to US$ 260/kgU category (Source: NEA/IAEA, 2010)



amounting to about US$ 115/kgU by the end of 2009 – in large part due to the overall uncertain economic and financial prospects, but also to much reduced ‘paper’ transactions with selling exceeding buying. Note: the decline of spot prices started in mid-2007 well before the financial and economic crises of 2008. Two factors were chiefly responsible for this turnaround - the return (or expected return) into service of large mining capacities that had previously encountered technical problems, and the market’s response to the additional capacities resulting from the accelerated investment in new mines and a general perception of now looser market conditions.

As the spot price slid below US$ 130/kgU, a number of higher-cost producers announced plans to put mining operations in a state of 'care and maintenance'. Mining capacities have also been shut down owing to technical problems, where costly fixes were not warranted at low uranium prices (e.g., Dominion mine) and producers decided to sit out the current price drought.

In the short to medium term, post-2008 uranium market price levels of above US$ 80/kgU should suffice to stimulate investment in upstream capacity. Some analysts expect that the next generation of uranium projects will have significantly higher costs than the mines that are currently in operation. Recent re-evaluations of uranium deposits resulted in a larger resource base, albeit at higher production costs. By 2030, uranium mining will need a price of US$ 150/kgU to justify bringing new projects on stream (CRU 2009). This projection is based on the examination of the operating and capital costs of uranium production at more than 70 mines and projects worldwide.

However, historically, rising uranium prices have triggered a significant increase in investment in uranium exploration (and mine development). The projected favourable market conditions, therefore, should stimulate exploration leading to further discoveries (including lower-cost deposits), as was the case during past periods of accelerated exploration activity (ESA 2009).

In summary, the drop in uranium spot prices since mid-2007 and the global economic and financial situation since mid-2008 affected uranium production differently for different mines across different regions. Some mining companies continued investing in new or additional production capacities while others reduced output or suspended production, depending on factors ranging from ownership structures (state or privately owned), marginal production costs and unforeseen technical challenges to the overall cash situation and longer-term market expectations, i.e., waiting for another turnaround in market prices.

Production

By end-2008, uranium had been produced commercially in 17 countries. In May 2009 Malawi became the 18th producer. Three further countries produce minute amounts as part of mine rehabilitation programmes. The eight leading countries, ranked in order of 2008 production, are Canada, Kazakhstan, Australia, Namibia, the Russian Federation, Niger, Uzbekistan, and the United States. Together these eight countries provided almost 93% of the world's uranium (Fig. 6.2 and Table 6.4). Compared with two years ago, Kazakhstan's output surpassed Australia, taking second place, while Namibia managed the same feat over Russia. Since the turn of the millennium, Kazakh mine output has increased by almost 400%. Its low-cost *in situ* leaching (ISL) extraction gives it a definite competitive advantage, especially in an environment of falling market prices. Preliminary data for 2009 indicate that Kazakhstan has also surpassed Canada and is now globally the top-ranked uranium producer. In 2008, Namibia increased its production by 50% from its two mines Rössing and Langer Heinrich - the highest growth rate that year. Output from the top producer throughout the decade, Canada, has been on the decline by an average of 2% per year and its market share in 2008 amounted to 21% compared with 30% in 2000.

Globally, freshly mined uranium grew steadily from 39 440 tU in 2006 to 43 880 tU in 2008. The 2008 production level is the highest since 1991, narrowing the gap between reactor requirements and uranium mined by 18 percentage points to 26% (Fig. 6.3). Prompted by the past and expected uranium market prices, several countries which historically produced uranium but discontinued for economic reasons (e.g. Argentina, Bulgaria, Chile, Finland, Spain) have begun to reconsider reopening closed mines or have stepped up exploration activities. Likewise, other countries previously not producing uranium have boosted efforts to explore the possibility of eventually launching uranium mining activities (e.g. Egypt, Indonesia, Iran or Nigeria). In the near-term future, therefore, a fair share of new mining capacity is likely to be at higher production costs than past capacity additions.

In terms of technology, conventional underground and open-pit mining accounted for 62% of global uranium production, ISL for 28%, and 10% was obtained as a by-product from other mining operations such as copper, gold and phosphate (WNA, 2009a).

The market continued to rely on secondary uranium sources to close the gap between reactor requirements and mined uranium. In 2008, secondary supplies continued to consist of strategic stockpiles and fissile material from nuclear weapons programmes of Russia and the USA, sold after HEU to LEU (highly enriched uranium to low enriched uranium) conversion as reactor fuel (about 50%), utility held stocks, re-enrichment of tails, reprocessed uranium and mixed oxide fuel closing.

Resources

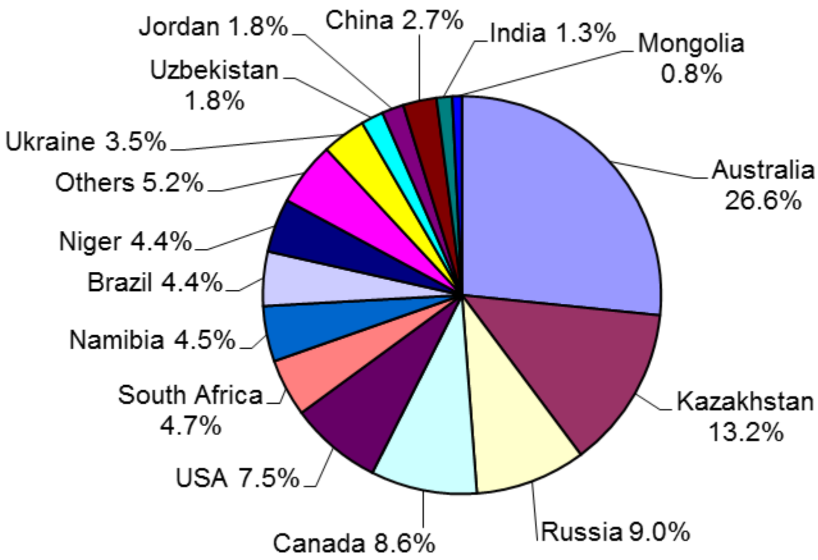
The latest details of uranium resources are reported in the publication *Uranium 2009: Resources, Production and Demand* (Red Book), a joint report of the OECD Nuclear Energy Agency and the International Atomic Energy Agency (NEA/IAEA, 2010). The resources reported by 47 countries are classified by the level of confidence in the estimates, and by production cost-categories. The Red Book uses three broad categorisations of uranium occurrences (i) Identified Resources (ii) Undiscovered Resources and (iii) Unconventional Resources.

Identified Resources consist of two subcategories: Reasonably Assured Resources (RAR) and Inferred Resources (IR) - both reported in terms of recoverable uranium for three production cost-classes, i.e. less than US$ 40/kgU, less than US$ 80/kgU and less than US$ 130/kgU. In the wake of recent spot price developments, the 2010 edition of the Red Book has reintroduced for the first time since 1988 the less than US$ 260/kgU category. RAR comprise deposits with known location, quantity, and quality based on specific measurements for which economic extraction is feasible with existing technologies and under current market conditions. IR refers to deposits less well delineated than RAR, usually 'based on direct geological evidence, in extensions of well-explored deposits, or in deposits in which geological continuity has been established but where specific data, including measurements of the deposits, and knowledge of the deposit's characteristics, are considered to be inadequate to classify the resource as RAR'.

Undiscovered Resources also consist of two categories: Prognosticated Resources and Speculative Resources, and refer to resources that are expected to exist on the basis of analogies from geological knowledge of previously discovered deposits and regional geological mapping. More specifically, Prognosticated Resources refer to those expected to occur in known uranium provinces, generally supported by some direct evidence. Speculative Resources refer to those expected to occur in geological provinces that may host uranium deposits. Both Prognosticated and Speculative Resources require significant amounts of exploration before their existence can be confirmed and grades and tonnages can be defined.

Unconventional Resources are generally very low-concentration occurrences or minor by-products from other mineral production, and would require new or innovative technology or substantially different levels of demand and market prices for their extraction.

Figure 6.6 Distribution of Identified Uranium Resources (RAR plus IR) at less than US$ 260/kgU production costs. Total at 1 January 2009: 6 306 000 tU
(Source: adapted from NEA/IAEA, 2010)



Identified Resources

While overall occurrence of a mineral may be of interest to geologists, the uranium market is primarily interested in the economically producible part thereof. Economically available resources, therefore, are a function of mineral concentration, exploration and mining technology, demand and market price. Higher prices may make lower-concentration occurrences economically attractive, higher demand stimulate innovation and innovation enable production from deposits not producible with current technology. Lower prices then reduce the economically producible portion of a resource. However, this does not mean that the physical occurrence no longer exists – it only means that its economically viable portion has become smaller (while the remainder awaits better market conditions).

Between 2003 and 2007 rising uranium prices triggered a significant increase in investment in uranium exploration and mine development. The stepped-up exploration activities worldwide resulted in new discoveries and re-evaluation of known deposits. Globally, Identified Resources grew by 37% from 2001 to 5.404 mtU* by 1 January 2009 but these are only slightly lower than the 2007 level of 5.468 mtU. With the higher cap on extraction costs of US$ 260/kgU, total Identified Resources are 6.306 mtU (Fig. 6.4 and Tables 6.2 and 6.3). The additional availability of 902 000 tU in the US$ 130-260/kgU category seems to confirm that the exploration rush has primarily resulted in high-cost discoveries.

Australia experienced the largest net increase in Identified Resources and accounted for almost one-third of the expansion since 2003 of 1.718 mtU, followed by Russia and Ukraine (Fig. 6.5). The fastest-growing producing country over that period, Kazakhstan, actually reported a decline of 0.196 mtU, up to US$ 130/kgU, which was almost offset by the addition of 0.180 mtU from the US$ 130-260/kgU category.

The top three producers also dominate the resource situation. Together Canada, Kazakhstan and Australia hold 50% of global economically recoverable uranium resources (current conditions and at production costs of less than US$ 130/kgU). Through the inclusion of the less than US$ 260/kgU category, Russia now ranks as the country with the third largest identified uranium resources, slightly ahead of Canada.

The inclusion of the US$ 130-260/kgU category boosted the uranium resource endowment, especially in the USA, Ukraine, Russia and Canada. In some cases, the increase in the highest cost category occurred at the expense of the lower categories. Two factors appeared to have played a role: the enormous material and commodity price escalation before mid-2008 shifted some resource into the next cost category, and the discoveries were generally of a higher-cost nature.

Finally, Fig. 6.6 shows the geographic distribution of Identified Resources.

* (Million (metric) tonnes of contained uranium)

Undiscovered Resources

Undiscovered Resources add another estimated 6.8 mtU at costs less than US$ 260/kgU (Table 6.3). This includes both resources that are expected to occur either in or near known deposits, and more speculative resources that are thought to exist in geologically favourable, yet unexplored areas. There are also an estimated further 3.6 mtU of speculative resources for which production costs have not been specified. Given the rather limited economic relevance of these occurrences in the short to medium run, many countries report undiscovered resources or update their assessments only at irregular intervals. The resource quantities have therefore remained essentially unchanged since 2003.

Unconventional Resources

In addition to the 16 mtU of conventional uranium resources, there are substantial amounts of unconventional occurrences. Past estimates of potentially recoverable uranium associated with phosphates, non-ferrous ores, carbonatite, black schist and lignite ranged between 10 mtU and 22 mtU. The technology to recover uranium (as a by-product) from phosphates is mature, with estimated costs of US$ 60–100/kgU, and was practiced predominantly in the USA (using phosphate rocks containing up to 120 ppm U) until the uranium price collapse in the late 1990s. Significant past production from phosphoric acid also took place in Belgium and Kazakhstan. With higher uranium prices recently, there is renewed interest in this area in Australia, Brazil, France, India, Jordan, Morocco, Tunisia and the USA.

The average concentration of uranium in sea water is 0.003 ppmv, equivalent to an overall occurrence of 4 000 mtU. The technology to extract uranium from sea water has only been demonstrated at laboratory scale, and extraction costs were estimated in the mid-1990s at US$ 260/kgU (Nobukawa, et al., 1994) and about US$ 210/kgU in 2009 (Tamada, 2009). Scaling up laboratory level production of a few tonnes to thousands has yet to be proven and may encounter unforeseen difficulties.

Thorium, which can also be used as a nuclear fuel resource, is three times as abundant in the earth's crust as uranium. It is widely distributed in nature and is an easily exploitable resource in many countries. Although existing estimates of thorium reserves plus additional resources total about 6 mtTh, such estimates are considered still conservative. They do not cover all regions of the world, and the essential absence of a market has limited thorium exploration (IAEA, 2007). Although thorium has been used as fuel on a demonstration basis, significant further work is needed before it can be considered on an equal basis with uranium.

The exploitation of unconventional uranium occurrences would require additional research and development efforts for which there is no imminent economic necessity, given the large conventional resource base and the option of reprocessing and recycling spent fuel. Niche opportunities may be explored in greater detail in the not-so-distant future. For example, uranium from coal ash from the Xiaolongtang power plant located in Yunnan Province, China, has been successfully recovered using heap leaching technology. The ash averages 160 ppmv uranium or some 0.16 kgU per tonne of ash. The uranium and thorium contents of coal vary greatly for different coal deposits and an assessment of their overall supply potentials has yet to be carried out.

Running out of Uranium?

The 6.3 mtU of Identified Resources suffices to fuel the global 2008 reactor requirements for about 98 years – a reserves-to-production ratio much larger than for most commercially traded minerals and commodities, including oil and natural gas. Even without considering the 10.4 mtU of undiscovered and speculative uranium resources, unconventional uranium occurrences or reprocessing of spent nuclear fuel, uranium availability *per se* does not pose a constraint to a possible expansion of nuclear energy. However what could prove a factor in limiting supply is timely investment in uranium exploration and new mining capacities, especially if the supply of secondary sources from military stockpiles were to decline at short notice.

Unlike the remnants of fossil fuels, spent nuclear fuel when it leaves the reactor still contains some 95% of its original energy content. Reprocessing and recycling of unspent uranium and the plutonium generated during its residence in the reactor can extend the availability of Identified Resources to several thousands of years, depending on reactor configuration and fuel cycle. This does not account for the potential development and commercialisation of Undiscovered and Unconventional Resources which would essentially decouple nuclear energy from any running-out-of-resources concerns, irrespective of the type of fuel cycle deployed (once-through or closed cycle with reprocessing and recycling).

Demand and Supply Outlook – the next two decades

Every year, the IAEA (IAEA, 2009) provides a range of projections on future nuclear electricity generation reflecting the inherent uncertainties in estimating future developments. In its 2009 projection for 2030, the range of nuclear electricity generation varies between 3 711 TWh and 5 930 TWh (2009: 2 560 TWh). The corresponding reactor uranium requirements would range between 105 000 tU and 140 000 tU by 2030.

The challenge before the uranium industry is the timely elimination of the current mining capacity gap relative to reactor requirements, caused by the appearance of military components of secondary supplies in the early 1990s, as well as capacity in support of new reactor requirements. Over the next 20 years this may call for a significant expansion of mine development by a factor of 2.5 to 3.5 above current capacity. Given that the lead times for turning uranium in the ground into a feed for the mill have become much longer than 30 years ago (due to lengthier regulatory and licencing processes, the need for environmental impact assessments and stakeholder involvement, further compounded by potential finance difficulties), global reactor requirements will continue to depend on secondary sources for another decade or so.

The level of supply of fissile material from weapons programmes is uncertain after 2013 (when the Megatons-to-Megawatts draws to an end) and depends on the details of the recent new negotiations between Russia and the USA. Supplies from re-enrichment of tails are expected to decrease in the near-term future as the Europe-Russia re-enrichment arrangement expires in 2010; global enrichment capacities will be better utilised owing to further growth in nuclear-generated electricity, thus reducing spare enrichment capacities. Re-enrichment still remains a potential option to extend the reach of uranium resources. The current global stockpile of depleted uranium amounts to some 1.5 million tonnes of metal and continues to grow (WNA, 2009b).

Presently, reprocessing of spent fuel generally lacks economic attractiveness, even at steeply elevated uranium prices. The situation is different for existing plants (sunk costs) in France and the UK, where reprocessing is seen as an integral part of a national waste disposal strategy, owing to substantially reduced volumes of high-level radioactive waste. Likewise, in cases where future reactor strategies include fast breeder reactors fuelled with plutonium (India, Russia and Japan), countries pursue reprocessing or even expand reprocessing capacity. Reprocessing is expected to continue contributing at the current level of 3 000 t of uranium equivalent per year. With the Rokkasho plant in Japan coming on line and China contemplating the establishment of non-military reprocessing capacities, the global uranium substitution potential could be around 6 000 tU supply equivalent per year by 2030.

In summary, in the absence of a major turnaround regarding reprocessing and recycling of spent fuel, the role of secondary sources is expected to decline from contributing one-third of global reactor requirements to between 5% and 10% by 2030. This means that mine production capacity currently estimated at 52 000 tU per year has to be ramped up to some 90 000 - 135 000 tU over the coming two decades. The challenge will be to mobilise the necessary investments for this expansion. Despite the current economic and financial crises, the fundamental market prospects for uranium remain bright. Overall market prospects are the primary driver of decisions to develop new or expand existing production capacities. Indeed as these prospects are bright, plans for increasing production capability exceed downward revisions caused by technical obstacles and financial difficulties. A number of countries, notably Australia, Canada and Kazakhstan, have reported plans for significant additions to planned future capability, which are expected to be operational well before 2015.

Conclusion

Like all commodity markets, uranium has encountered a good deal of turbulence and volatility. Unlike most commodities, investments in the nuclear sector are of a long-term nature with extended lead times and are thus less susceptible to short-term economic events. Despite a steep decline from the peak levels in 2007, uranium spot prices today are substantially higher than 10 years ago and are expected to remain at the levels necessary to attract investment in new mining capacity in line with future reactor requirements. Nuclear fuel resources are plentiful but they need the mobilisation of above-ground investment funds to unlock their below-ground potentials.

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DEFINITIONS

Uranium does not occur in a free metallic state in nature. It is a highly reactive metal that interacts readily with non-metals, and is an element in many intermetallic compounds.

This *Survey* uses the system of ore classification developed by the Nuclear Energy Agency (NEA) of the Organisation for Economic Cooperation and Development (OECD) and the International Atomic Energy Agency (IAEA). Estimates are divided into separate categories according to different levels of confidence in the quantities reported.

The estimates are further separated into categories based on the cost of uranium recovered at ore-processing plants. The cost categories are: less than US$ 40/kgU; less than US$ 80/kgU; less than US$ 130/kgU and less than US$ 260/kgU. Costs include the direct costs of mining, transporting and processing uranium ore, the associated costs of environmental and waste management, and the general costs associated with running the operation (as defined by the NEA). The resource data quoted in the present *Survey* reflect those published in the 2009 'Red Book'. Cost categories are expressed in terms of the US dollar as at 1 January 2009.

The WEC follows the practice of the NEA/IAEA and defines estimates of discovered reserves in terms of uranium recoverable from mineable ore and not uranium contained in the ore (i.e. to allow for mining and processing losses). Although some countries continue to report *in-situ* quantities, the major producers generally conform to these definitions.

All resource estimates are expressed in terms of tonnes of recoverable uranium (U), not uranium oxide (U_3O_8).

Note:

1 tonne of uranium	=	approximately 1.3 short tons of uranium oxide;
US$ 1 per pound of uranium oxide	=	US$ 2.60 per kilogram of uranium;
1 short ton U_3O_8	=	0.769 tU.

Reasonably Assured Resources (RAR) refer to recoverable uranium that occurs in known mineral deposits of delineated size, grade and configuration such that the quantities which could be recovered within the given production cost ranges with currently proven mining and processing technology can be specified. Estimates of tonnage and grade are based on specific sample data and measurements of the deposits and on knowledge of deposit characteristics. RAR have a high assurance of existence.

Inferred Resources (IR) refer to recoverable uranium (in addition to RAR) that is inferred to occur, based on direct geological evidence, in extensions of well-explored deposits and in deposits in which geological continuity has been established, but where specific data and measurements of the deposits and knowledge of their characteristics are considered to be inadequate to classify the resource as RAR.

Undiscovered Resources refer to uranium in addition to reasonably assured resources and inferred resources and covers the two NEA categories, 'Prognosticated Resources' (PR) and 'Speculative Resources' (SR): PR refer to deposits for which the evidence is mainly indirect and which are believed to exist in well-defined geological trends or areas of mineralisation with known deposits.

SR refer to uranium that is thought to exist mostly on the basis of indirect evidence and geological extrapolations in deposits discoverable with existing exploration techniques.

Annual production is the production output of uranium ore concentrate from indigenous deposits, expressed as tonnes of uranium.

Cumulative production is the total cumulative production output of uranium ore concentrate from indigenous deposits, expressed as tonnes of uranium, produced in the period from the initiation of production until the end of the year stated.

TABLES

Table 6.1 Uranium: Reasonably Assured Resources (RAR) as of 1 January 2009
(thousand tonnes of uranium)

	Recoverable at			
	< US$40/kgU	**< US$80/kgU**	**< US$130/kgU**	**< US$260/kgU**
Algeria			19.5	19.5
Central African Republic			12.0	12.0
Congo (Democratic Rep.)				1.4
Gabon			4.8	4.8
Malawi		8.1	13.6	13.6
Namibia		2.0	157.0	157.0
Niger	17.0	42.5	242.0	244.6
Somalia				5.0
South Africa	76.8	142.0	195.2	195.2
Tanzania				8.9
Zimbabwe				1.4
Total Africa	**93.8**	**194.6**	**644.1**	**663.4**
Canada	267.1	336.8	361.1	387.4
Mexico				1.3
United States of America		39.0	207.4	472.1
Total North America	**267.1**	**375.8**	**568.5**	**860.8**
Argentina		7.0	10.4	10.4
Brazil	139.9	157.7	157.7	157.7
Chile				0.8
Peru			1.3	1.3
Total South America	**139.9**	**164.7**	**169.4**	**170.2**
China	52.0	100.9	115.9	115.9
India			55.2	55.2
Indonesia			4.8	4.8
Japan			6.6	6.6
Kazakhstan	14.6	233.9	336.2	414.2
Mongolia		37.5	37.5	37.5

Table 6.1 Uranium: Reasonably Assured Resources (RAR) as of 1 January 2009
(thousand tonnes of uranium)

	Recoverable at			
	< US$40/kgU	**< US$80/kgU**	**< US$130/kgU**	**< US$260/kgU**
Turkey			7.3	7.3
Uzbekistan		55.2	76.0	76.0
Vietnam				1.0
Total Asia	**66.6**	**427.5**	**639.5**	**718.5**
Czech Republic		0.4	0.4	0.4
Finland			1.1	1.1
France				9.0
Germany				3.0
Greece				1.0
Italy			4.8	4.8
Portugal		4.5	6.0	6.0
Romania			3.1	3.1
Russian Federation		100.4	181.4	181.4
Slovakia				5.1
Slovenia			1.7	1.7
Spain		2.5	4.9	4.9
Sweden			4.0	4.0
Ukraine	2.5	38.7	76.0	142.4
Total Europe	**2.5**	**146.5**	**283.4**	**367.9**
Iran (Islamic Rep.)				0.7
Jordan		44.0	44.0	44.0
Total Middle East		**44.0**	**44.0**	**44.7**
Australia		1 163.0	1 176.0	1 179.0
Total Oceania		**1 163.0**	**1 176.0**	**1 179.0**
TOTAL WORLD	**569.9**	**2 516.1**	**3 524.9**	**4 004.5**

Notes:
1. Source: *Uranium 2009: Resources, Production and Demand*, 2010, OECD Nuclear Energy Agency/International Atomic Energy Agency

Table 6.2 Uranium: Inferred Resources (IR) as of 1 January 2009 (thousand tonnes of uranium)

	Recoverable at			
	< US$40/kgU	**< US$80/kgU**	**< US$130/kgU**	**< US$260/kgU**
Congo (Democratic Rep.)				1.3
Egypt (Arab Rep.)				1.9
Gabon				1.0
Malawi			1.5	1.5
Namibia			127.2	127.2
Niger		30.9	30.9	30.9
Somalia				2.6
South Africa	78.5	90.9	100.4	100.4
Tanzania				19.5
Total Africa	**78.5**	**121.8**	**260.0**	**286.3**
Canada	99.7	110.6	124.2	157.2
Greenland				85.6
Mexico				0.5
Total North America	**99.7**	**110.6**	**124.2**	**243.3**
Argentina		4.4	8.7	8.7
Brazil		73.6	121.0	121.0
Chile				0.7
Peru			1.4	1.4
Total South America		**78.0**	**131.1**	**131.8**
China	15.4	49.1	55.5	55.5
India			24.9	24.9
Indonesia				1.2
Kazakhstan	29.8	241.5	315.6	417.9
Mongolia		4.3	11.8	11.8
Uzbekistan		31.0	38.6	38.6
Vietnam				5.4
Total Asia	**45.2**	**325.9**	**446.4**	**555.3**

Table 6.2 Uranium: Inferred Resources (IR) as of 1 January 2009 (thousand tonnes of uranium)

	Recoverable at			
	< US$40/kgU	**< US$80/kgU**	**< US$130/kgU**	**< US$260/kgU**
Czech Republic		0.1	0.1	0.1
France			0.1	0.1
Germany				4.0
Greece				6.0
Hungary				8.6
Italy				1.3
Portugal			1.0	1.0
Romania			3.6	3.6
Russian Federation		57.7	298.9	384.9
Slovakia				5.2
Slovenia			7.5	7.5
Spain			6.4	6.4
Sweden			6.0	6.0
Ukraine	3.2	14.9	29.0	81.2
Total Europe	**3.2**	**72.7**	**352.6**	**515.9**
Iran (Islamic Rep.)				1.4
Jordan		67.8	67.8	67.8
Total Middle East		**67.8**	**67.8**	**69.2**
Australia		449.0	497.0	500.0
Total Oceania		**449.0**	**497.0**	**500.0**
TOTAL WORLD	**226.6**	**1 225.8**	**1 879.1**	**2 301.8**

Notes:

1. Source: *Uranium 2009*: *Resources, Production and Demand*, 2010, OECD Nuclear Energy Agency/International Atomic Energy Agency

Table 6.3 Uranium: Undiscovered Resources (Prognosticated [PR] and Speculative [SR]) as of 1 January 2009 (thousand tonnes of uranium [*in situ*])

	Prognosticated Resources recoverable at			Speculative Resources recoverable at			Total
	< US$80 /kgU	< US$130 /kgU	< US$260 /kgU	< US$130 /kgU	< US$260 /kgU	Cost range unassigned	Prognosticated + Speculative
Niger	14.5	24.6	24.6				24.6
South Africa	34.9	110.3	110.3			1 112.9	1 223.2
Zambia		22.0	22.0				22.0
Zimbabwe				25.0	25.0		25.0
Total Africa	**49.4**	**156.9**	**156.9**	**25.0**	**25.0**	**1 112.9**	**1 294.8**
Canada	50.0	150.0	150.0	700.0	700.0		850.0
Greenland				50.0	50.0	10.0	60.0
Mexico		3.0	3.0			10.0	13.0
United States of America	839.0	1 273.0	1 273.0	858.0	858.0	482.0	2 613.0
Total North America	**889.0**	**1 426.0**	**1 426.0**	**1 608.0**	**1 608.0**	**502.0**	**3 536.0**
Argentina		1.4	1.4				1.4
Brazil	300.0	300.0	300.0			500.0	800.0
Chile		1.5	1.5			3.2	4.7
Colombia		11.0	11.0	217.0	217.0		228.0
Peru	6.6	6.6	6.6	19.7	19.7		26.3
Venezuela						163.0	163.0
Total South America	**306.6**	**320.5**	**320.5**	**236.7**	**236.7**	**666.2**	**1 223.4**
China	3.6	3.6	3.6	4.1	4.1		7.7
India			63.6			17.0	80.6
Indonesia				16.1	16.1		16.1
Kazakhstan	321.6	498.5	500.0	270.5	300.0		800.0
Mongolia				1 390.0	1 390.0		1 390.0

Table 6.3 Uranium: Undiscovered Resources (Prognosticated [PR] and Speculative [SR]) as of 1 January 2009 (thousand tonnes of uranium [*in situ*])

	Prognosticated Resources recoverable at			Speculative Resources recoverable at			Total
	< US$80 /kgU	< US$130 /kgU	< US$260 /kgU	< US$130 /kgU	< US$260 /kgU	Cost range unassigned	Prognosticated + Speculative
Uzbekistan	56.3	85.0	85.0			134.7	219.7
Vietnam		7.9	7.9	100.0	100.0	130.0	237.9
Total Asia	**381.5**	**594.9**	**660.1**	**1 780.7**	**1 810.2**	**281.7**	**2 752.0**
Bulgaria			25.0				25.0
Czech Republic	0.2	0.2	0.2			179.0	179.2
Germany						74.0	74.0
Greece	6.0	6.0	6.0				6.0
Hungary		18.4	18.4				18.4
Italy						10.0	10.0
Portugal	1.0	1.5	1.5				1.5
Romania		3.0	3.0	3.0	3.0		6.0
Russian Federation		182.0	182.0			633.0	815.0
Slovenia		1.1	1.1				1.1
Ukraine		15.3	15.3		120.0	135.0	270.3
Total Europe	**7.2**	**227.4**	**252.5**	**3.0**	**123.0**	**1 031.0**	**1 406.5**
Iran (Islamic Rep.)		4.2	4.2		14.0		18.2
Jordan	67.8	84.8	84.8	84.8	84.8		169.6
Total Middle East	**67.8**	**89.0**	**89.0**	**84.8**	**98.8**		**187.8**
TOTAL WORLD	**1 701.5**	**2 814.8**	**2 905.0**	**3 738.2**	**3 901.7**	**3 593.8**	**10 00.5**

Notes:

1.Source: *Uranium 2009*: *Resources, Production and Demand*, 2010, OECD Nuclear Energy Agency/International Atomic Energy Agency

Table 6.4 Uranium: annual and cumulative production at end-2008 (tonnes of uranium)

	2008 Production	Cumulative production to end-2008
Congo (Democratic Rep.)		25 600
Gabon		25 403
Madagascar		785
Namibia	4 400	95 288
Niger	3 032	107 361
South Africa	565	156 312
Zambia		86
Total Africa	**7 997**	**410 835**
Canada	9 000	426 670
Mexico		49
United States of America	1 492	363 640
Total North America	**10 492**	**790 359**
Argentina		2 513
Brazil	330	2 839
Total South America	**330**	**5 352**
China	770	31 399
India	250	9 153
Japan		84
Kazakhstan	8 512	126 900
Mongolia		535
Pakistan	40	1 159
Uzbekistan	2 340	34 939
Total Asia	**11 912**	**204 169**
Belgium		686
Bulgaria	1	16 362
Czech Republic	275	110 427
Finland		30
Former Soviet Union (prior to 1992)		102 886
France	2	75 982
Germany		219 517

Table 6.4 Uranium: annual and cumulative production at end-2008 (tonnes of uranium)

	2008 Production	Cumulative production to end-2008
Hungary	1	21 052
Poland		660
Portugal		3 717
Romania	80	18 419
Russian Federation	3 521	139 735
Slovenia		380
Spain		5 028
Sweden		200
Ukraine	830	124 397
Total Europe	**4 710**	**839 478**
Iran (Islamic Republic)	6	17
Total Middle East	**6**	**17**
Australia	8 433	156 428
Total Oceania	**8 433**	**156 428**
TOTAL WORLD	**43 880**	**2 406 638**

Notes:

1.Source*: Uranium 2009: Resources, Production and Demand*, 2010, OECD Nuclear Energy Agency/ International Atomic Energy Agency

COUNTRY NOTES

The Country Notes on Uranium have been compiled by the Editors, drawing principally upon the following publication: *Uranium 2009: Resources, Production and Demand* (known as the Red Book); 2010; OECD Nuclear Energy Agency and International Atomic Energy Agency.

Information provided by WEC Member Committees and from other sources has been incorporated when available.

Algeria

Uranium exploration began in 1969, with an aerial radiometric survey in 1971 leading to the identification of numerous promising areas. However, follow-up investigations gradually petered out, and there has been no exploration or prospecting activity in recent years. *In situ* RAR at less than US$ 130/kgU have been assessed as 26 000 tonnes U, of which an estimated 75% is recoverable, but no production has ensued.

Argentina

Exploration for uranium started in the early 1950s, since when deposits have been discovered in a number of locations, mostly in the western part of the country and in the southerly province of Chubut in Patagonia. During the 1990s, a countrywide programme of exploration directed at the evaluation of areas with uranium potential was undertaken. Regional assessment of uranium potential continues, with selected areas of interest being studied in greater depth. Several Canadian companies have been involved in exploration activities in recent years.

Uranium was produced on a small scale from the mid-1950s, with cumulative production reaching just over 2 500 tonnes by the end of 1999. Since then, output has virtually ceased. The production centre at San Rafael in the province of Mendoza, which processed ore from the Sierra Pintada deposit, has been placed on a standby basis. In June 2004, the state agency CNEA, which since 1996 has owned and operated Argentina's uranium industry, presented a proposal to reactivate the San Rafael complex, but by early-2010 the plant had not yet resumed production.

Proved reserves of uranium, in terms of RAR recoverable at less than US$ 80/kgU, were 7 000 tonnes at the beginning of 2009, plus 3 400 tonnes at US$ 80-130/kgU. Further Identified Resources comprised 8 700 tonnes of IR recoverable at less than US$ 130/kgU. Undiscovered resources (at less than US$ 130/kgU) consisted of 1 400 tonnes of PR.

Australia

Exploration activities between 1947 and 1961 led to a number of uranium discoveries, including the deposits at Mary Kathleen (Queensland), Rum Jungle (Northern Territory) and Radium Hill (South Australia). A decrease in uranium requirements for defence purposes induced a virtual cessation in exploration between 1961 and 1966. Activity picked up again during the late 1960s, as civilian export demand accelerated, and numerous major deposits were located.

In 1983 the Government introduced the so-called 'three mines' policy, which permitted uranium exports only from the Nabarlek, Ranger and Olympic Dam mines. This restrictive measure, with its dampening effect on uranium exploration, lasted until 1996. Exploration expenditure and drilling activity rose in the latter half of the 1990s, but declined to historic lows in 2001 and 2002. Exploratory activity increased sharply in 2003-2006, and was concentrated on parts of the Northern Territory and South Australia.

Australia produced 8 433 tonnes of uranium in 2008, down by 2% on the previous year's output, bringing cumulative output since 1954 to more than 156 000 tonnes. During 2008, Kazakhstan edged Australia out of second place in terms of worldwide uranium production levels.

Three uranium production centres are in operation: Ranger (open-pit mine, with a production capacity of 4 660 tU/yr), Olympic Dam (underground mine at present, possibly also open pit in the future, current production capacity 3 930 tU/yr) and Beverley (*in situ* leaching, production capacity 848 tU/yr). A new centre with a production capacity of 2 290 tU/yr has been constructed at Jabiluka, but the facility has been on a standby and environmental maintenance basis since 2000. An ISL production centre (340 tU/yr) is planned for the Honeymoon deposit, and construction of the plant was reported to be under way during 2009.

Australia's total Reasonably Assured Resources (RAR) were 1 179 000 tU at the beginning of 2009, almost all recoverable at below US$ 80/kgU, and are by far the largest in the world for this category, accounting for nearly 30% of the global total. IR are assessed at 500 000 tU, again largely recoverable at less than US$ 80/kgU.

In May 2009 BHP Billiton commenced an application for environmental approval of the Yeelirrie uranium mining project in Western Australia. Four months later the company announced increased reserves of uranium ore at its Olympic Dam mine. However, in October of the same year damage to the ore haulage system in the main shaft at Olympic Dam was expected to result in a significant reduction in copper and uranium production 'for at least four to six months', according to BHP Billiton. In May 2010 the company envisaged that full production would be resumed by the end of the following month.

The resources of the Beverley Four Mile project in South Australia were reported in June 2009 to have nearly doubled. Production is scheduled to start up in 2010, but may be somewhat delayed by a legal dispute.

Brazil

Exploration activity over a period of some 40 years, ending in 1991, resulted in the discovery of occurrences and deposits of uranium in eight different areas of Brazil. Total Identified Resources are substantial, consisting of RAR of over 157 000 tonnes (recoverable at less than US$ 80/kgU) plus IR of 121 000 tonnes (recoverable at up to US$ 130/kgU). Undiscovered conventional resources are put at 300 000 tonnes of PR recoverable at under US$ 80/kgU and 500 000 tonnes of SR with no cost range assigned.

Although Brazil's RAR are considerable, and backed up by massive additional resources, its uranium output has never been on a commensurately large scale: cumulative production at end-2008 was well under 3 000 tonnes. Output in 2008 was 330 tU, an increase of 10% over the previous year's level.

After 2 years on standby, the 360 tU/yr Poços de Caldas production centre in Minas Gerais state was definitively shut down in 1997 and is now being decommissioned. It has been replaced by a new plant (Caetité) at Lagoa Real in the eastern state of Bahia. The Caetité plant has a current nominal production capacity of 340 tU/yr, but an expansion programme currently being undertaken will increase this to 670 tU/yr.

Another production centre, at Itataia in north-eastern Brazil, is scheduled to commence operations in 2012. Its annual uranium production capacity, as a by-product of phosphate output, is planned to be 680 tonnes.

Brazil's conventional resources are supplemented by unconventional resources, for which there are at present no plans for recovery. The quantities reported for an earlier *Survey* (2001) were as follows:

- carbonatite (containing 13 000 tonnes U);
- marine phosphates (28 000 tonnes U);
- quartz-pebble conglomerates (2 000 tonnes U).

Bulgaria

Uranium exploration activities commenced in 1935, with the first mining of uranium ore taking place some four years later. More intensive investigations starting in 1946 led to the discovery of numerous small-medium size deposits of low-grade ore in various parts of the country. A large number of mines were established, resulting in a cumulative production of 16 357 tonnes of uranium between 1946 and 1990, after which exploration and production activities ceased.

The IAEA/NEA's 2007 Red Book quotes Identified Resources as 19 809 tU (*in situ*) at the beginning of 2007, of which some 60% was underground-mineable and 40% amenable to ISL extraction. However, mining costs were not available and as the resource was spread over a large number of small deposits the quantities involved were deemed to be 'economically and technologically unprofitable'.

The only uranium resources currently quoted for Bulgaria in the Red Book 2009 are 25 000 tU of Prognosticated Resources, recoverable at less than US$ 260/kgU.

Canada

Canadian production began in 1942 when uranium was extracted from pitchblende ore from Port Radium, Northwest Territories, which had been mined since the 1930s for its radium content. During the post-war period, uranium deposits were discovered and developed in the Beaverlodge area of northern Saskatchewan and in the Elliot Lake area of Ontario. Demand for uranium increased in the 1960s as the use of nuclear power expanded. After the discovery of large high-grade deposits in the Athabasca Basin in the 1970s, Saskatchewan became Canada's main producer and output from Ontario was gradually phased out, ceasing altogether in 1996.

Canada was the world's largest producer of uranium, with over 20% of total world production in 2008, the bulk of which was destined for export. In 2008, Canada produced a total of 9 000 tU, all from northern Saskatchewan. This output comes from three production centres, two of which are operated by Cameco Corporation (Key Lake/McArthur River and Rabbit Lake) and the other by Areva Resources Canada Inc. (McClean Lake). The ore is mined from high-grade deposits (up to 23% uranium) which have grades that are one to two orders of magnitude greater than found elsewhere in the world.

Two additional mines in Saskatchewan - Cigar Lake and Midwest - had been scheduled to begin production, but their prospects are now uncertain. The Cigar Lake Mine is not expected to come into operation until at least 2012. Serious flooding of the underground development area in October 2006 and again in 2008 has delayed the start-up date, which had been scheduled for early-2008. It was announced in November 2008 that development of the Midwest deposit had been postponed.

Areva announced in December 2009 that its McClean Lake mill would be put on a care-and-maintenance basis from July 2010 until market conditions improve. Cameco's plans to increase production at Key Lake/McArthur River are under regulatory review.

In September 2009 the Fronteer Development Group announced a 'positive preliminary economic assessment' for its Michelin project in Labrador.

Canada currently holds 12% of the world's Identified Resources of uranium recoverable at less than US$ 80/kgU: at 1 January 2009 it had 336 800 tU of RAR and 110 600 tU of IR in this cost bracket. Undiscovered resources at below US$ 130/kgU were estimated to be 850 000 tU, of which PR accounted for 150 000 tU and SR for 700 000 tU.

Chile

Exploration activities have been carried out since the early 1950s, leading to the detection of numerous areas of interest and uranium occurrences. However, no production has so far ensued.

In situ RAR have been reported as 1 034 tonnes and IR as 896 tonnes, with no cost ranges assigned. The IAEA/NEA has allocated both amounts to the US$ 130-260/kgU category and assumed a recovery factor of around 78% in each case. Undiscovered resources comprise 1 500 tonnes of PR at up to US$ 130/kgU and 3 200 tonnes of SR, with an unassigned cost range.

In April 2008 a British exploration company, U3O8 Holdings, was reported to have discovered indications of uranium deposits in the south of Chile.

China

More than 50 years of exploration for uranium have resulted in the discovery of deposits in various parts of the country. The major resources are in Jiangxi and Guangdong provinces in the south-east, in Liaoning province to the northeast of Beijing and in the Xinjiang and Inner Mongolia Autonomous Regions of northern China.

The 2009 Red Book shows recoverable RAR (in thousands of tonnes) as 52.0 at less than US$ 40/kgU, 48.9 at US$ 40-80/kgU and 15.0 at US$ 80-130/kgU. The comparable figures for recoverable IR in the same cost-bands are 15.4, 33.7 and 6.4. All these levels are appreciably higher than the corresponding figures quoted in the 2007 Red Book.

Undiscovered resources (*in situ*) have been retained at the previous levels of 3 600 tonnes of PR at up to US$ 80/kgU and 4 100 tonnes of SR at up to US$ 130/kgU.

China's production of uranium in 2008 has been estimated to be around 770 tonnes, implying an increase of about 8% over the previous year's level.

Colombia

Ingeominas (the Colombian Institute of Geology and Mining) has granted a number of uranium mining concessions in recent years and exploration activities are getting under way.

Colombia is estimated to possess 11 000 tonnes of uranium in the PR category and 217 000 tU of SR, both amounts on an *in situ* basis, at less than US$ 130/kgU. No production of uranium has so far been recorded.

Congo (Democratic Republic)

Past production of uranium amounted to more than 25 000 tonnes, but presently Identified Resources are of comparatively modest proportions, with a total of 2 700 tonnes estimated to be recoverable at less than US$ 260/kgU.

In March 2009 the French company Areva signed an agreement with the DRC for cooperation on uranium prospecting and mining.

Czech Republic

After an early start in 1946, uranium exploration in the republic was systematic and intensive during a period of more than 40 years. From 1990, however, expenditure decreased sharply, with field exploration coming to an end early in 1994.

There are 23 uranium deposits, of which 20 have been mined-out or closed. The Rozná deposit is being mined but two others are not exploitable for reasons of environmental protection. The Straz production centre has been closed but some ISL extraction is continuing under a remediation regime. The Rozná mine had been scheduled for closure, but favourable uranium prices and a persistently good level of resources at the mine led the Government to decide in May 2007 that production should be continued as long as it remained profitable.

Output from Czechoslovakian mines began in 1946 and until 1990 was all exported to the Soviet Union. Production in 2008 amounted to 275 tonnes, giving a cumulative output of about 110 000 tonnes.

RAR are estimated to be 400 tU and IR 100 tU, both recoverable at up to US$ 80/kgU. Undiscovered resources (on an *in situ* basis) comprise about 200 tonnes of PR recoverable at up to US$ 80/kgU and 179 000 tonnes of SR, unassigned to a cost category.

Finland

Exploration for uranium took place during the period 1955-1989, resulting in the identification of four uranium provinces. Proved reserves (RAR at US$ 80-130/kgU) amount to 1 500 tonnes, of which 75% is regarded as recoverable. Unconventional resources are represented by possible by-product production of 3 000-9 000 tU from Talvivaara black shales and 2 500 tU from Sokli carbonatite.

Finland's past production of uranium has been limited to the minor quantity (circa 30 tU) produced by a pilot plant at the Paukkajanvaara mine in eastern Finland, which was operated from 1958 to 1961.

Recent years have witnessed a revival of interest in exploration for uranium, with a number of new licences being awarded by the Ministry of Trade & Industry in October 2006 and January 2007. In February 2010 Talvivaara Mining announced plans for recovering uranium oxide as a by-product of nickel and zinc production in eastern Finland.

France

Exploration for uranium commenced in 1946 and during the next 40 years a number of deposits were located. Exploration activities have now ceased and production is confined to small amounts obtained during remediation. Total output in 2008 was only 2 tonnes, bringing the cumulative tonnage to almost 76 000 tonnes. France's last uranium mine (Jouac) and last ore-processing plant (at Le Bernardan in the northwestern part of the Massif Central) ceased operations in 2001.

After a reclassification of uranium resources, RAR are now put at 9 000 tonnes, recoverable at US$ 130-260/kgU, and IR at a mere 100 tonnes, recoverable at less than US$ 130/kgU.

Gabon

Exploration by the French Commissariat à l'Energie Atomique (CEA) led to the discovery in 1956 of a substantial deposit of uranium ore near Mounana in southeastern Gabon. Further deposits in the Franceville Basin were located during 1965-1982. Exploratory activity continued until the late 1990s. Signs of a revival of interest in Gabon's uranium resources were evident in March 2006 when a press release announced that two Canadian corporations, Cameco and Pitchstone Exploration, had signed an agreement with Motapa Diamonds Inc. to jointly explore Motapa's uranium exploration licences in the Franceville Basin.

Uranium production from the Mounana production centre began in 1961 and built up to a peak of around 1 250 tpa by the end of the 1970s. Subsequently output followed a declining trend, ceasing altogether in early 1999. The last underground mine, exploiting the Okelobondo deposit (discovered in 1974), closed down in November 1997. An open-pit operation at the Mikouloungou deposit (discovered in 1965) was in production from June 1997 to March 1999, since when Gabon has ceased to be a uranium producer.

Gabon's cumulative production of over 25 000 tonnes of uranium indicates its historic significance as one of the leading minor producers.

Known conventional resources of uranium in Gabon amount to just under 6 000 tonnes, comprising 4 800 tonnes of RAR recoverable at less than US$ 130/kgU, and 1 000 tonnes of IR in the US$ 130-260 price bracket.

Germany

Prior to Germany's reunification in 1990, the GDR had been a major producer of uranium, with a cumulative output of some 213 000 tonnes. All uranium mines have now been closed. The only production reported in recent years has related to uranium recovered in clean-up operations in the former mining/milling areas, but by 2008 even this minor level of output had ceased.

Germany's Identified Resources of uranium total 7 000 tonnes, comprising 3 000 tonnes of RAR recoverable at US$ 130-260/kgU, and 4 000 tonnes of IR in the same price category. SR are put at 74 000 tonnes, with their cost range unassigned.

Greenland

Exploration for uranium was carried out for more than 30 years (1955-1986), with moderate success. IR at 1 January 2009 have been estimated by the NEA/IAEA Secretariat as 85 600 tU, recoverable at US$ 130-260/kgU. There is also estimated to be an *in situ* amount of 60 000 tU in the speculative category, most of which is deemed to be recoverable at less than US$ 130/kgU. No production of uranium has yet taken place.

Hungary

Uranium exploration commenced in the early 1950s, with the Mecsek deposit in southern Hungary being discovered in 1954. An underground mine came into production at Mecsek in 1956. Initially the raw ore produced was shipped to the USSR, but from 1963 onwards it passed through a processing plant at Mecsek before being shipped as uranium concentrates.

Mining and milling operations at the Mecsek site were shut down at the end of 1997. Cumulative production of uranium, including a relatively small amount derived from heap leaching, was about 21 000 tonnes. Since 1998, the only production has been of very small quantities (currently about 1 tonne per year) obtained as a by-product of water treatment activities.

An Australian company, Wildhorse Energy, was granted a uranium exploration licence in January 2007 for its Máriakéménd project in the Pécs region of southern Hungary, in the vicinity of the former Mecsek operation.

Hungary's estimated remaining resources of uranium, as reported to the IAEA/NEA, are 18 400 tonnes of PR at less than US$ 130/kgU.

India

Exploration for uranium began in 1949, since when deposits have been located in many parts of the country. Exploratory activity is continuing, principally in the States of Rajasthan, Andhra Pradesh, Karnataka and Meghalaya. Uranium has been produced at the Jaduguda mine in the eastern state of Bihar since 1967. In 2008, output from this and three other mines in the same area (Narwapahar, Bhatin and Turamdih) was about 250 tonnes.

RAR (less than US$ 130/kgU category) are reported in the 2009 Red Book as 55 200 tonnes. Other Identified Resources consist of nearly 25 000 tonnes classified as IR, also without an assigned cost range and allocated to the less than US$ 130/kgU category). Undiscovered conventional resources consist of 63 600 tonnes of PR and 17 000 tonnes of SR, both expressed on an *in situ* basis.

Unconventional resources have been estimated to amount to about 6 600 tonnes, recoverable from copper mine tailings in the Singhbhum district of the state of Jharkhand.

A number of new facilities - ion-exchange/acid leaching (IX/AL) plants and production centres - are being constructed.

Indonesia

The Nuclear Minerals Development Centre of the Indonesian National Atomic Energy Agency (BATAN) began exploring for uranium in the 1960s. Since 1996, exploratory work has tended to focus on the vicinity of Kalan in West Kalimantan. Exploration drilling has continued in recent years in a number of locations. No production of uranium has yet taken place.

At the beginning of 2009, Indonesia's RAR, recoverable at less than US$ 130/kgU, were estimated to be 4 800 tonnes; Inferred Resources (at up to US$ 260/kgU) were 1 200 tonnes. Over and above these amounts, *in situ SR* were put at about 16 000 tonnes, recoverable at under US$ 130/kgU.

Iran (Islamic Republic)

Exploratory work has been undertaken since the early 1970s and a number of prospects have been defined, mostly in central and southern Iran.

A small uranium production centre has been operating since 2006 at Bandar Abbas on the southern coast (using ore from Gachin) and another is under construction at Ardakan in central Iran (to use Saghand ore).

At the beginning of 2009 recoverable RAR amounted to about 700 tonnes, with IR assessed as 1 400 tonnes, both in the less than US$ 260/kgU cost category. Undiscovered conventional resources (*in situ*) consisted of 4 200 tonnes in the PR category (recoverable at less than US$ 130/kgU) plus 14 000 tonnes of SR at less than US$ 260/kgU.

Japan

Between 1956 and 1988, the Power Reactor and Nuclear Fuel Development Corporation (PNC) and its predecessor (Atomic Fuel Corporation) undertook domestic exploration for uranium, resulting in the discovery of deposits at two locations on the island of Honshu. Total discovered reserves, reported as RAR recoverable at up to US$ 130/kgU, were some 6 600 tonnes at the beginning of 2009.

Cumulative production of uranium in Japan amounts to only 84 tonnes, produced by a test pilot plant operated by PNC at the Ningyo-toge mine between 1969 and 1982, together with a small-scale vat leaching test facility from 1978 to 1987.

Jordan

Uranium exploration got under way during the 1980s, since when a number of significant occurrences have been observed.

RAR and IR, each in the less than US$ 80/kgU bracket, now stand at 44 000 and 67 800 tU respectively. The assessed level of Jordan's PR amounts to nearly 85 000 tU, 80% of which is deemed to fall into the less than US$ 80/kgU category.

The estimated level of by-product resources associated with phosphate rocks was reduced from 70 000 tU to 59 360 tonnes as at the beginning of 2007.

Production of uranium is expected to start in 2012, according to the IAEA/NEA.

Kazakhstan

Uranium exploration commenced in 1948 and since then a large number of ore deposits have been located, initially in the districts of Pribalkhash (in southeastern Kazakhstan), Kokchetau in the north of the republic, and Pricaspian near the Caspian Sea. Since 1970 extensive low-cost resources have been discovered in the Chu-Sarysu and Syr-Darya basins in south-central Kazakhstan.

Production started in 1957, with the early years' output being processed in Kyrgyzstan. Production centres in Kazakhstan were started up by the Tselinny Mining and Processing Company in 1958 (based on underground-mined ore) and by the Kaskor Company in 1959 (based on open-pit mining). Economic pressures forced the closure of the Kaskor plant in 1993 and of the Tselinny plant in 1995. Almost all subsequent uranium production has utilised ISL technology. A number of new ISL facilities will be constructed, including several based on joint ventures with foreign corporations.

As at the beginning of 2009, Kazakhstan's recoverable RAR were 336 200 tonnes (at up to US$ 130/kg), giving it a 9.5% share in global resources at that cost level. In addition, it possessed approaching half a million tonnes of uranium recoverable from other Identified Resources: 78 000 tonnes of RAR (at US$ 130-260/kgU) and 417 900 tonnes of IR recoverable at costs of less than US$ 260/kgU. Undiscovered resources (*in situ*) recoverable at costs below US$ 260/kgU were also massive: 500 000 tonnes of PR and 300 000 tonnes of SR.

Total output of uranium in 2008 was 8 512 tonnes, thus edging Australia out of the number 2 slot among the world's uranium producers. Kazakhstan's cumulative production (now quoted as from its commencement) reached almost 127 000 tonnes.

Provisional data published at the beginning of 2010 indicated that total 2009 uranium production in Kazakhstan had been approximately 13 900 tonnes, which would probably make it the world's leading producer in that year, ahead of Australia and Canada.

Malawi

Exploration during the 1980s led to the discovery of a uranium deposit at Kayelekera in northern Malawi. The Australian company Paladin Resources Ltd. is currently mounting a project for developing uranium production at Kayelekera, for which it was granted a Mining Licence in April 2007. A ceremony was held in

April 2009 to mark the official launch of the Kayelekera mine. Paladin announced expansion plans in October 2009.

The IAEA/NEA estimates Malawi's RAR as 8 100 tU recoverable at up to US$ 80/kgU plus 5 500 tonnes at US$ 80-130/kgU. IR at less than US$ 130/kgU amounts to 1 500 tU.

Mexico

Exploration for uranium came to an end in 1983. The IAEA/NEA Secretariat's current assessment of Mexico's Identified Resources recoverable at up to US$ 260/kgU comprises 1 300 tU of RAR plus 500 tU of IR. Additional undiscovered resources (*in situ*) amount to 13 000 tonnes, the bulk of which (10 000 tonnes) are speculative.

Unconventional resources contained in marine phosphates in Baja California amount to about 150 000 tU, as assessed in the early 1980s.

For a short period (1969-1971), molybdenum and by-product uranium were recovered from a variety of ores at a plant in Aldama, Chihuahua state. Uranium output totalled 49 tonnes: there are presently no plans for resuming production.

Mongolia

Identified Resources recoverable at up to US$ 80/kgU consist of 37 500 tU of RAR and 4 300 of IR. Additional IR are estimated to amount to 7 500 tU recoverable at US$ 80-130/kgU. There are enormous speculative resources of 1.39 million tonnes, estimated to be recoverable at less than US$ 130/kgU.

Despite the considerable size of its Identified Resources, Mongolia's recorded cumulative production of uranium amounts to only 535 tonnes. The tempo of exploratory activity has increased in recent years. A number of Canadian companies have become involved, either through purchasing prospective areas or by obtaining exploration licences. It was reported in September 2009 that Indian and Mongolian officials had agreed to cooperate in the development of uranium mining in the republic.

Namibia

Although uranium mineralisation had been detected in the Rössing Mountains in the Namib Desert in 1928, extensive exploration for uranium did not get under way until the late 1960s. The major discovery was the Rössing deposit, located to the north-east of Walvis Bay; other discoveries were made in the same area of west-central Namibia, notably the Trekkopje and Langer Heinrich deposits.

A large open-pit mine operated by Rössing Uranium Ltd (68.58% owned by Rio Tinto Zinc, 3% by the Government of Namibia, 15% by the Government of Iran, 10% by the Industrial Development Corporation of South Africa and the balance by individual shareholders) has been in production since 1976. Although Rössing Uranium had intended to close down its operations in 2007, a rise in the price of uranium led to a change of plan. The company is now investing US$ 120 million to extend the mine's life by ten years, and the facility might stay in operation beyond 2016/2017.

The Australian company Extract Resources is carrying out intensive drilling at its Rössing South concession and has reported good results from chemical assays.

UraMin Inc. was granted exploration licences for Trekkopje and the surrounding area in November 2006. Areva, which acquired UraMin in 2007, is working to bring a new production facility at the Trekkopje mine and its accompanying desalination plant into operation.

The Langer Heinrich deposit was acquired by an Australian company, Paladin Resources Ltd., in August 2002. Since then, the company has constructed a new mining and processing facility with a nominal production capacity of 1 000 tU per annum. The processing plant came into operation in December 2006. It was reported in June 2009 that Paladin Energy was going to proceed with the third stage of expansion at Langer Heinrich, with the objective of bringing annual output capacity up to 2 000 tU by September 2010. Further expansion plans were announced by Paladin in October 2009.

The Valencia deposit, lying in the vicinity of the Rössing and Langer Heinrich deposits, was declared uneconomic by Goldfields Namibia, following feasibility studies undertaken in the 1980s. In late-2005 the Canadian company Forsys Metals Corporation acquired the project. Forsys (now part of the Forrest Group, based in the Congo D.R.) is developing an open pit mine at Valencia. It was granted a mining licence in August 2008.

Namibia's RAR (at up to US$ 130/kgU) are now put at 157 000 tonnes and are equivalent to 4.5% of the global total for this category. IR in the same cost bracket are about 127 000 tonnes.

Together, the Rössing and the new mines attest to Namibia's position as the top uranium producer in Africa. Namibia is currently the 4th largest uranium producer in the world. Its output fell by nearly 8% in 2007 to a total of 2 832 tU, but leapt by 55% to 4 400 tU in 2008.

Niger

Exploration for uranium began in 1956, resulting in the discovery of a number of deposits in the Aïr region of north-central Niger. There are currently two uranium production centres, one near Arlit processing ore from the Ariege, Arlette, Tamou and Taza deposits and operated by Société des Mines de l'Aïr (Somaïr), and the other at Akouta processing ore from the Akouta and Akola deposits and operated by Compagnie Minière d'Akouta (Cominak).

Niger's participation in the producing companies is 36.6% in Somaïr, and 31% in Cominak. Somaïr has been producing uranium from open-pit operations since 1970, while Cominak has carried out underground mining since 1978. Somaïr has constructed a heap leaching unit to process 3 800 tonnes of low-grade ore per day, which has boosted its uranium production capacity by 700 tpa.

After the major reappraisal reported in the 2007 Red Book, the latest assessments show little change. RAR recoverable at up to US$ 80/kgU now stand at 42 500 tU, whilst RAR recoverable at US$ 80-130/kgU amount to 199 500 tU. IR recoverable at up to US$ 80/kgU are unchanged at 30 900 tU, as are PR of 14 500 tU in the less than US$ 80/kgU bracket and 10 100 tU at US$ 80-130/kgU.

In June 2007 a new company, Société des Mines d'Azelik, was established to mine the Azelik uranium deposits to the south of the Aïr Massif. The Teguidda mine is being developed, with production scheduled to begin in 2010 at 700 tU/yr.

Uranium exploration is being carried out by Somaïr and Cominak, as well as by two newcomers, Areva NC Niger and China National Uranium Corporation. In August 2008 Cameco announced that it had taken an 11% interest in GoviEx, a company with exploration assets in Niger. In May 2009 the President of Niger laid the foundation stone for Areva's Imouraren uranium mining complex, which is scheduled to commence production of 5 000 tU in 2013.

Niger's uranium production decreased by 5% in 2008, to a total of 3 032 tU. Niger remains the world's sixth largest producer of uranium, accounting for 6.9% of global output.

Pakistan

Extensive exploration for uranium has been carried out. Discoveries reported in the 1999 Red Book related to the Kamlial Formation in the Salt Range and the Maraghzar area in the Swat district, but no uranium resources have been reported to the IAEA. A number of previously discovered deposits have been mined out. Currently, production is estimated to be about 40 tU per annum. Cumulative output of uranium, all recovered using ISL technology, is now approaching 1 200 tonnes.

Peru

During the course of exploration carried out up to 1992, the Peruvian Nuclear Energy Institute (IPEN) discovered over 40 occurrences of uranium in the Department of Puno, in the southeast of the republic, but no production has taken place.

Identified Resources in the Macusani area in northern Puno are estimated to amount to 2 700 tonnes, of which 1 300 are classified as RAR and 1 400 as IR, both tonnages recoverable at less than US$ 130/kgU. Undiscovered resources (*in situ*) consist of 6 600 tonnes in the PR category (recoverable at less than US$ 80/kgU), plus 19 700 tonnes of SR (at less than US$ 130/kgU).

Portugal

The first traces of uranium were discovered as long ago as 1907, in association with radium deposits. From the mid-1950s to the mid-1990s, extensive exploration was undertaken, resulting in the discovery of numerous small-to-medium deposits. Starting in 1951, uranium was produced on a relatively small scale for fifty years, mostly at the Urgeiriça mill in north-central Portugal. Operations came to an end in 2001, after cumulative production of around 3 700 tonnes.

A revised resource assessment in the 2007 Red Book (retained in the 2009 edition) puts RAR (at up to US$ 80/kgU) at 4 500 tonnes, with a further 1 500 tonnes in the US$ 80-130/kgU cost bracket. IR are estimated at 1 000 tonnes, recoverable at less than US$ 130/kgU. Undiscovered conventional resources recoverable at the same price level comprise 1 500 tonnes of PR, of which two-thirds is classed as recoverable at less than US$ 80/kgU.

Romania

Since 1952, when Romania started to produce uranium, cumulative output has exceeded 18 000 tonnes. There are deposits in three principal areas: the Apuseni Mountains in the west, the Banat Mountains in the southwest and the Eastern Carpathians. Since 1978, all of Romania's production of uranium ore has been processed at the Feldioara mill in the centre of the country.

Uranium output in 2008 was about 80 tonnes, with RAR (up to US$ 130/kgU) at the beginning of 2009 estimated as 3 100 tonnes (recoverable). Other Identified Resources recoverable at the same cost level were 3 600 tonnes of IR; *in situ* undiscovered resources comprised 3 000 tonnes of PR together with an equal tonnage of SR.

Russian Federation

Uranium exploration has been undertaken since 1944. Over a hundred ore-bearing deposits have been located in 14 districts of the Federation: the Streltsovsk district, where underground mining takes place, the Transural and Vitim districts, where the deposits are suitable for ISL, and 11 other districts, where higher-cost resources have been discovered. Government funding for uranium exploration has grown strongly in recent years.

Mining and processing of uranium ore started in 1951 in the Stavropolsky region of European Russia, a source which had been exhausted by the late 1980s, after producing 5 685 tonnes, of which underground mining accounted for 69% and various leaching techniques for the balance. Between 1968 and 1980, the Sanarskoye deposit in the Transural district produced 440 tonnes of uranium, using ISL technology.

For more than a decade, the most important uranium producing area has been the Streltsovsk region near Krasnokamensk in the Chitinskaya Oblast of eastern Siberia. The state concern responsible for production in the

Krasnokamensk area is the Priargunsky Mining-Chemical Production Association; its production centre has a nominal production capacity of 3 500 tU per annum. Priargunsky accounts for more than 90% of national production. Lower-concentration deposits at the mine are increasingly exploited via block and heap leaching.

A number of schemes for the expansion of existing production centres or the construction of new facilities are under way or being planned.

Russia's RAR (estimated to be recoverable at up to US$ 130/kgU) of 181 400 tonnes represented just over 5% of the global total for that category at the beginning of 2009. The balance of Identified Resources recoverable at the same price level consisted of almost 300 000 tonnes of IR. Undiscovered resources (*in situ*) are also estimated to be extremely large: 182 000 tonnes of PR (all considered to be recoverable at less than US$ 130/kgU), plus 633 000 tonnes of SR with a cost range unassigned.

Total national output in 2008 was 3 521 tU, most of which was derived from ore obtained by underground mining, the balance being obtained from low-grade ore by heap- or *in situ* leaching. The Russian Federation was the world's fifth largest producer of uranium in 2008, accounting for 8% of global output.

Slovenia

Exploration of the Zirovski Vrh area began in 1961, followed some 20 years later by the commencement of mining and eventually by the production of yellowcake (uranium oxide concentrate) in 1985. Exploration expenditure ceased in 1990 and uranium production came to an end two years later, with cumulative output of 380 tU.

The estimated recoverable resources are fairly modest: RAR of 1 700 tU and IR of 7 500 tU, plus 1 100 tonnes of *in situ* PR, all recoverable at under US$ 130/kgU.

South Africa

Between the late 1940s and the early 1970s uranium exploration was pursued as an adjunct to exploration for gold, centred on the quartz-pebble conglomerates in the Witwatersrand Basin in the Transvaal. The 1973-1974 oil crisis triggered intensified exploration for uranium, leading to the country's first primary uranium mine (Beisa) being commissioned in 1981. Output as a by-product of gold mining had begun 30 years previously, and by 1959 26 mines in the Witwatersrand Basin were supplying 17 processing plants, resulting in an annual output of nearly 5 000 tonnes.

Between the late 1980s and the early 1990s, a substantial reduction in production capacity took place; subsequent closures brought the total of operational production centres at the beginning of 2002 down to two, each served by a single mine. The companies in production were Vaal River Operations at Klerksdorp, and Phalabora Mining Company in the Northern Province; uranium production by the latter company, as a by-product of copper mining, ceased during the year.

The country's RAR (at up to US$ 80/kgU), consisting to a considerable extent of quartz-pebble conglomerates, is reported as 142 000 tonnes at the beginning of 2009. Further resources are on a commensurately large scale: more than 53 000 tU of RAR recoverable at US$ 80-130/ kgU, over 100 000 tU of IR recoverable at up to US$ 130/kgU, 110 000 tU of PR in the same cost range, and more than 1.1 million tU in the speculative category (with no cost range assigned).

Total uranium output in 2008 was 565 tonnes. Cumulative output of uranium in South Africa now exceeds 156 000 tonnes.

South Africa's uranium production received a boost when sxr Uranium One's Dominium mine came into production during 2007; processing of underground ore had begun by the beginning of March, with the initial annual production rate planned to be 1 460 tU.

It was reported in August 2009 that First Uranium was ramping up production at its Ezulwini gold/uranium mine, after making its first shipment of yellowcake in June.

Spain

The first uranium discoveries were made in the western province of Salamanca in 1957 - 1958. Subsequently other finds were made further to the south and, in one instance, in central Spain. Production began in 1959 and by the end of 2002, a cumulative total of over 5 000 tonnes had been produced. Ore mining ceased in December 2000 and the production of uranium concentrates was terminated two years later. In January 2007 a Canadian company, Mawson Resources, applied for two exploration permits in the La Haba district of Extremadura in southwestern Spain, but in December 2009 the company announced its intention to withdraw from its licences in Spain.

At beginning-2009, the remaining RAR (at less than US$ 80/kgU) were about 2 500 tonnes. Further Identified Resources recoverable at US$ 80-130/kgU comprised 2 400 tonnes of RAR and 6 400 tonnes of IR.

Sweden

Exploration for uranium was carried out from 1950 until 1985, when low world prices for the metal brought domestic prospecting to a halt. Four principal uranium provinces were identified, two in south/central Sweden and two in the north. Interest in exploration has revived recently, with the Canadian corporation Mawson Resources Ltd obtaining several concession areas. In 2010 Mawson reported that it was drilling in a number of project locations.

Sweden's proved reserves are reported as 4 000 tonnes of RAR recoverable at less than US$ 130/kgU, with additional amounts recoverable comprising 6 000 tonnes of IR in the same cost bracket.

There are substantial unconventional resources of uranium in alum shale, but the deposits are of very low grade and recovery costs would exceed US$ 130/kgU. During the 1960s, a total of about 200 tonnes of uranium was recovered from alum shale deposits at Ranstad, in the Billingen district of Västergötland, southern Sweden. This mining complex has now been rehabilitated, the open pit being transformed into a lake and the tailings area treated to prevent the formation of acid.

Tanzania

It was reported in September 2009 that Mantra Resources of South Africa and Uranex NL of Australia had received environmental approval for their uranium mining project from Tanzania's National Environment Management Council.

The 2009 Red Book quotes Identified Resources recoverable at less than US$ 260/kgU as comprising RAR of 8 900 tU and IR of 19 500 tU.

Turkey

The first exploration work took place in 1956-1957, but did not locate any economic deposits. Subsequent activity, which is continuing at the present time, has identified a number of uranium occurrences. RAR at less than US$ 130/kgU have been assessed as 7 300 tonnes.

Ukraine

Since the start of exploration for commercial resources of uranium in 1944, a total of 21 deposits have been discovered, mostly located in south-central Ukraine, between the rivers Bug and Dnepr. The most important ore bodies are Vatutinskoye, Severinskoye and Michurinskoye, all in central Ukraine. Uranium has been produced since 1947, initially by the Prednieprovskiy Chemical Plant and since 1959 also by the Zheltiye Vody production centre. The first plant ceased producing uranium in 1990; the 2008 output of Zheltiye Vody was about 800 tonnes, making Ukraine the world's ninth largest producer of uranium, with 1.9% of global output.

All currently processed ore comes from underground operations at the Ingul'skii mine on the Michurinskoye deposit and from the Vatutinskii mine on the Vatutinskoye deposit. A new uranium production centre is planned to process Severinskoye ore, with a scheduled start-up date of 2015.

Ukraine's uranium resources were substantially revised for the 2007 edition of the Red Book, mainly through the incorporation of the Novokonstantinovskoye and Central deposits, which had not previously been taken into account. Further major revisions have been incorporated in the 2009 edition.

Recoverable RAR (at up to US$ 130/kgU) are now put at 76 000 tonnes, as compared with 135 000 tU at 1 January 2007. Further Identified Resources are represented by additional RAR of 66 400 tU in the US$ 130-260/kgU bracket and a total of over 81 000 tU of IR recoverable at under US$ 260/kgU.

Undiscovered resources (*in situ*) comprise 15 300 tonnes of PR recoverable at up to US$

130/kgU, plus 120 000 tonnes of SR at less than US$ 260/kgU and 135 000 tonnes of SR with no cost range assigned.

United States of America

Between 1947 and 1970 the US Atomic Energy Commission (AEC) promoted the development of a private-sector uranium exploration and production industry; in late 1957 the AEC concluded its own exploration and development activities. Private-sector efforts accelerated in the 1970s in a context of rising prices and anticipated growth in the demand for the metal to fuel civilian power plants.

This exploration activity revealed the existence of extensive ore deposits in the western half of the United States, particularly in the states of Wyoming, Nebraska, Utah, Colorado, Arizona and New Mexico and in the Texas Gulf Coastal Plain. Numerous production centres were erected over the years, but many have now been closed down and either dismantled or put on standby.

Current production is mainly reliant on ISL, although some uranium is obtained from solvent extraction and other operations, such as mine water treatment and environmental restoration. U.S. uranium output in 2008 amounted to 1 492 tonnes, the eighth highest in the world.

According to the 2009 edition of the IAEA/NEA's Red Book, the USA's RAR (at up to US$ 130/kgU) at the beginning of 2009 were about 207 000 tonnes, equivalent to 5.9% of the global total for that cost-range; RAR recoverable at US$ 130-260/kgU were nearly 265 000 tonnes. PR at up to US$ 80/kgU were 839 000 tonnes, with a further 434 000 tonnes at US$ 80-130/kgU. SR at up to US$ 130/kgU were 858 000 tonnes, with additional SR (with an unassigned cost range) amounting to 482 000 tonnes.

In November 2009 Energy Fuels applied for the final licence needed to construct its Piñon Ridge uranium/vanadium mill in Colorado, which if approved will be the first new U.S. uranium mill for more than 25 years. In April 2010 the licensing application was still under review.

Uzbekistan

Deposits of uranium ores have been found in at least 25 locations since the early 1950s, mostly lying in the central Kyzylkum area running from Uchkuduk in the northwest to Nurabad in the southeast. Although there was some production in the Fergana valley area, starting in 1946, commercial mining began in 1958 at Uchkuduk with the development of open-pit and underground operations. ISL recovery methods were brought into use from 1965 and gradually came to dominate the production scene. The last of the open-pit and underground mines were closed in 1994, after conventional mining had produced a cumulative total of nearly 56 000 tonnes, 65% of which had come from open-pit operations.

Uranium output in 2008 by the state-owned Navoi Mining and Metallurgical Complex

(NMMC), the sole producer, amounted to 2 340 tonnes - corresponding to 5.3% of global output. Production is exclusively ISL-based and takes place at eight locations. In operation during 2008 were three ISL production centres, which sent their output by rail to the NMMC processing plant at Navoi (nominal production capacity 3 000 tU/yr).

The IAEA/NEA Secretariat estimates the republic's recoverable RAR (at up to US$ 80/kgU) as 55 200 tonnes at the beginning of 2009. The balance of known conventional resources consisted of 20 800 tonnes of recoverable RAR (at US$ 80-130/kgU) and 38 600 tonnes of recoverable IR (at up to US$ 130/kgU). Undiscovered conventional resources (on an *in situ* basis) totalling some 220 000 tonnes, of which PR recoverable at up to US$ 130/kgU accounted for 85 000 tonnes, the balance (around 135 000 tonnes) being SR without a cost range assigned.

Vietnam

Exploration for uranium in selected parts of the republic began in 1955, and since 1978 a systematic regional programme has been undertaken. Virtually the entire country has now been explored, with a number of occurrences and anomalies subjected to more intensive investigation.

As at the beginning of 2009, Identified Resources recoverable at up to US$ 260/kgU comprised 1 000 tonnes of RAR and 5 400 tonnes of IR. Undiscovered *in situ* conventional resources recoverable at up to US$ 130/kgU consisted of 7 900 tonnes in the PR category, plus 100 000 tonnes of SR. Further SR (without a cost range assigned) amounted to 130 000 tonnes.

Unquantified amounts of unconventional resources have been reported to be present in deposits of coal, rare earths, phosphates and graphite.

No production of uranium has so far been achieved.

6. Part II: Nuclear

COMMENTARY

Recent Developments

The last five years have witnessed somewhat contradictory nuclear power trends, specifically a substantial increase in interest in the use of the technology and, at the same time, a slow but steady decline in its share of global electricity supply. And while 2008 was distinctive as the first year since 1955 in which no new reactors were connected to the grid, 2009 was the second straight year with a relatively high number of new construction starts. The eleven construction starts in 2009 were the highest since 1987 (Fig. 6.7). While the order books of vendors of heavy forging equipment are full, with backlogs of 50 months and more, utilities, especially in the United States, have remained reluctant to close the deals as scheduled. Projected construction costs of new nuclear reactors skyrocketed through mid-2008; yet despite high cost estimates and the financial and economic crisis that started in the second half of 2008, upward revisions in projections of future nuclear power growth continued in 2009 as well. In part, these upward revisions reflect continued high interest in starting new nuclear power programmes. Some 60 countries currently without nuclear have expressed to the IAEA interest in exploring or starting nuclear programmes.

The reasons for these apparently conflicting trends are several. First, the current financial and economic crisis has not affected the longer-term market fundamentals (or drivers of nuclear

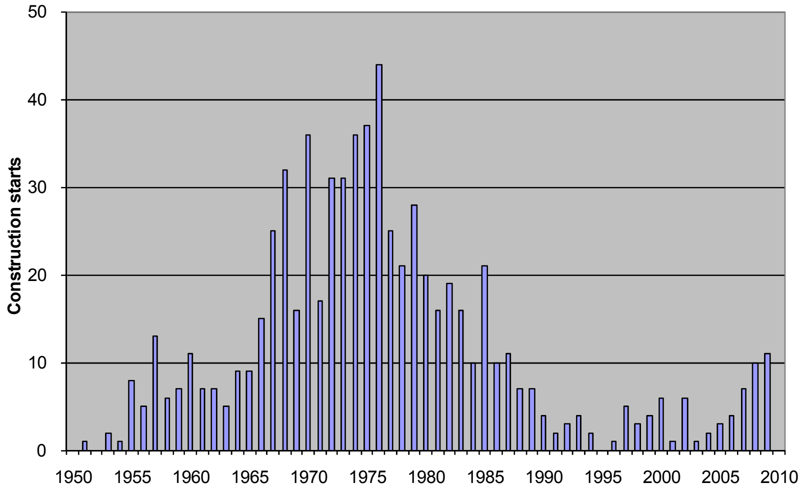


Figure 6.7 Construction starts of nuclear power plants (Source: IAEA, 2010a)

energy), most importantly growing energy demands due to population growth and economic development, an interest in stable and predictable generating costs, and concerns about energy security and environmental protection, especially climate change. Second, the financial and economic crisis has had a more pronounced impact on projects with short lead times. The prospect of lower demand growth in the near term reduces the pressure for near-term investment decisions, and the long lead times associated with nuclear projects allow for additional analysis and less rushed preparation. Put differently, the current crisis hit most nuclear projects in the early planning stages, years before key financing decisions would have to be made. Hence only a few nuclear expansion plans have been postponed or cancelled, and the order pipelines remain filled. Third, investment costs for non-nuclear generation options have also increased, and the relative economics of electricity generation options have been only marginally realigned, if at all.

This is not to say that the global financial and economic crisis left the nuclear power business unscathed. It was cited as a contributing factor in near-term delays or postponements affecting nuclear projects in some regions of the world. Vattenfall announced in June 2009 that it was putting decisions on nuclear new build in the UK on hold for 12–18 months, citing the economic recession and market situation. Financing uncertainty was cited in connection with the withdrawal of the utilities GDF SUEZ and RWE from the Belene project in Bulgaria. The Russian Federation announced that for the next few years, because of the financial crisis and lower projected electricity use, it would slow planned expansion from two reactors per year to one. Ontario, Canada, suspended a programme to build two replacement reactors at Darlington, partly because of uncertainty about the future of Atomic Energy of Canada Limited (AECL). The Canadian Government had reported that it planned to seek buyers for AECL to reduce budget deficits. In the USA, Exelon deferred major pre-construction work on a proposed new nuclear power plant in Texas, citing uncertainties in the domestic economy. Of 17 combined licence applications before the U.S. Nuclear Regulatory Commission (NRC), four were put on hold in the course of 2009 at the request of the applicants. In South Africa, Eskom extended the schedule for its planned next reactor by two years to 2018 (IAEA 2010b).

In contrast, China saw nine construction starts in 2009 after six in 2008. It appears that as utilities elsewhere dragged their feet in following through with nuclear plant and equipment orders, China seized the opportunity, moving ahead in the queue and negotiating attractive terms. As the year 2009 drew to a close, the United Arab Emirates announced the signing of a contract to purchase four 1 400 MW_e reactors from a South Korean consortium led by the Korea Electric Power Corporation. About a dozen countries currently without nuclear power are continuing preparations to start their first nuclear power plants by the early 2020s, while an even larger number are familiarising themselves with the prerequisite nuclear infrastructure requirements.

In short, while the prospects for nuclear power are brighter now than at the turn of the millennium, uncertainty remains as to whether and when all the high ambitions will be realised. Government policies and private sector risk perception remain decisive factors shaping the future of nuclear power.

Nuclear Power Plants in Operation and Under Construction

As of 1 January 2010, there were 437 nuclear power reactors in operation worldwide, with a total capacity of 370 GW_e (Table 6.5). This was slightly lower than at the beginning of 2009 owing to three retirements and only two new reactors coming on-line. The retirements were Hamaoko-1 and -2 in Japan and Ignalina-2 in Lithuania, which was retired at the end of the year in line with Lithuania's EU accession agreement. Ignalina-2 was the last nuclear plant to be closed by an accession agreement. The two new grid connections in 2009 were Tomari-3 (866 MW_e) in Japan and Rajasthan-5 (202 MW_e) in India. However the capacity additions of 1 068 GW_e did not fully compensate for the retirement of 2 506 GW_e.

During the first decade of the new millennium, annual electricity production from the global fleet of nuclear power plants ranged between 2 544 TWh and 2 661 TWh. The 2009 production of 2 558 TWh translates into a market share of 14%, i.e., every seventh kilowatt-hour produced in the world was generated by nuclear power. The market share has been declining slowly but consistently since the turn of the millennium, as overall electricity generating capacity has grown faster than nuclear power and also because of the temporary unavailability of several reactors, such as those at the 8.2 GW_e Kashiwazaki-Kariwa nuclear power plant in Japan, which was shut down in July 2007 after a major earthquake. After in-depth safety inspections and seismic upgrades, two of the seven units were restarted and connected to the grid in 2009.

There were eleven construction starts in 2009: Hongyanhe-3 and -4, Sanmen-1 and -2, Yangjiang-2, Fuqing-2, Fangjiashan-2, Haiyang-1 and Taishan-1 (all 1 000 MW_e) in China; Shin-Kori-4 (1 340 MW_e) in the Republic of Korea; and Novovoronezh 2-2 (1 085 MW_e) in the Russian Federation. Active construction resumed on Mochovce-3 and -4 (both 405 MW_e) in Slovakia. This compares with ten construction starts in 2008 and, in 2007, seven construction starts plus the resumption of active construction at one reactor. A total of 55 reactors, with a total design capacity of 50.9 GW_e, were therefore under construction at the end of 2009, the largest number since 1992.

Current expansion, as well as near-term and long-term growth prospects, remain centred on Asia. Of the eleven construction starts in 2009, ten were in Asia. As shown in Table 6.5, 36 of the 55 reactors under construction are in Asia (including the Middle East), as were 30 of the last 41 new reactors to have been connected to the grid. China's target is 40 GW_e of nuclear power capacity in 2020, compared to 8.4 GW_e today. Indian Prime Minister Manmohan Singh, in opening the International Conference on Peaceful Uses of Atomic Energy in New Delhi in September 2009, said India could potentially install 470 GW_e by 2050.

The recent trends of uprates and renewed or extended licences for many operating reactors continued in 2009. In the USA, the NRC approved eight more licence renewals of 20 years (for a total licensed life of 60 years) bringing the total number of approved licence renewals to 59. The UK Nuclear Installations Inspectorate approved renewed periodic safety reviews for two reactors, permitting an additional ten years of operation. Spain's Garoña nuclear power plant was granted a four-year licence extension, and operating licences for Canada's Bruce A and Bruce B nuclear power plants were renewed for an additional five years.

In Europe, nuclear power phase-out policies were moderated in several countries. Sweden will now allow its existing reactors to operate to the end of their economic lifetimes and to be replaced by new reactors once they are retired. Italy ended its ban on nuclear power and will now allow new construction. Belgium decided to postpone the first phase of its planned phase-out by ten years. Closure of its reactors had been scheduled to take place between 2015 and 2025. In Germany, following the change of Government, discussions to postpone the phase-out were started.

Economics

Generally, existing operating nuclear power plants continue to be highly competitive and profitable. The low share of fuel costs in total generating costs makes them the lowest-cost base load electricity supply option in many markets. Uranium costs account for only about 5% of total generating costs and thus protect plant operators against resource price volatility. Recently the prices of energy resources, materials used in power plants and commodities have been high, but generating costs of nuclear power plants have been barely affected, despite record-level uranium spot prices of US$ 350/kgU in 2007 (compared with US$ 20-30/kgU during 2000 to 2003).

On a levelised cost of electricity basis (LCOE), new nuclear build is generally competitive with other generating options. The 'front-loaded' cost structure of nuclear plants (i.e. the fact that they are relatively expensive to build but inexpensive to operate) has always been an investment risk factor and a financial challenge, especially in liberalised electricity markets. Amortisation periods of between 15 and 25 years, the bulkiness of the investment volume of a 1 000-1 700 MW_e nuclear project, and regulatory uncertainty are potential disadvantages to be weighed against a relatively low and predictable LCOE once the plant is completed and connected to the grid.

The 2005 OECD report *Projected Costs of Generating Electricity* (NEA and IEA, 2005), prepared by a diverse group of experts from vendors, utilities, research organisations and national and international governmental institutions, showed an investment cost range for nuclear power of US$ 1 000-2 500/kW$_e$, and found that nuclear power fared well compared to alternative generating options[1]. However, investment costs for all power plants began to climb steeply around 2006 and by 2008 had more than doubled, both for conventional coal technology and, especially, for nuclear power. This sharp increase coincided with the rapid rise in world market prices of energy and materials (e.g. cement and the full spectrum of metals). While the price increases for energy and materials were one element pushing investment costs higher, they alone do not explain the full investment cost increases. These are rather the result of a combination of several coinciding factors: (i) an above average demand for generating capacity in Asia, (ii) an ageing fleet of other kinds of power plants in North America and Europe that are competing for components and materials needed for refurbishments (driven by environmental considerations and the need for efficiency improvements due to high fuel prices), and (iii) a global power equipment manufacturing industry with little spare capacity, owing to relatively little expansion for more than a decade. Globally only a few manufacturers exist that are capable of producing heavy forging equipment such as reactor pressure vessels or steam generators. In 2008, lead times of 50 months or more had become commonplace. Backlogs started to accumulate with the licence extension of existing reactors, which often require the replacement of steam generators and other heavy components. Rising interest in new nuclear build and the accompanying pre-orders added further to the backlog. Full order books allow manufacturers to command higher margins and thus exert further upward pressure on prices.

For new designs, or for construction in new environments, investment costs may include first-of-a-kind (FOAK) costs – whether truly for the first construction of a design never built before (e.g. the European Pressurised Reactor [EPR] at Olkiluoto in Finland), construction in a region or country without nuclear power (e.g. UAE or Vietnam) or construction in countries where active nuclear power construction stopped decades ago (e.g. USA, Belgium, Switzerland or the UK). FOAK costs include a particularly high share of contingency costs to cover unforeseen events, given the lack of experience with the design, the environment or the country. They can add as much as 35% to overnight costs[2] (University of Chicago, 2004).

[1] The OECD study accounts for all generating options (coal, natural gas, nuclear and renewables) and considers electricity generating capacities in the pipeline or early planning stages using partly harmonised criteria (e.g., for load factors or discount rates); it otherwise reflects location-specific data and circumstances (e.g., construction times or design specificity). Numerous national studies published before 2006 use similar investment cost ranges (MIT 2003; Tarjanne and Loustarinen 2003; French Energy Secretariat 2003; University of Chicago, 2004; CERI 2004; TVA 2004). Nuclear power plants completed in Asia between 2000 and 2007 reported investment costs between US$ 1 800-2 400/kW$_e$.

[2] The term 'overnight capital costs' (OC) generally includes costs for equipment, procurement and construction, plus owner's and contingency costs, but

FOAK costs are uncertain and prone to rapid escalation, particularly since nuclear power's capital intensiveness makes costs highly sensitive to delays in construction. For example, the overnight cost (OC) estimate for Olkiluoto-3 in Finland, a FOAK third-generation EPR, has reportedly risen from € 3.2 billion to more than € 4 billion (at 2008 prices and exchange rates) owing to construction delays caused by FOAK costs related to quality issues, design revisions, approvals, and logistic challenges not experienced for a long time. The resulting FOAK costs were further compounded by the 2007-2008 price escalation of raw materials, mainly copper, nickel and steel, and labour. This does not include the higher interest costs during construction (IDC) and power replacement costs caused by the completion delay.

OC are lower for subsequent units, but some (decreasing) additional costs will persist until experience has been accumulated through the completion of several (about five to eight) essentially identical designs. Sharing existing sites and local infrastructure can considerably reduce OC (and IDC through generally shorter construction periods). For example, Progress Energy put the OC for a second AP-1000 at its Levy County site at US$ 3 376/kW$_e$, substantially lower than the first unit's US$ 5 144/kW$_e$, with an average cost of US$ 4 260/kW$_e$ for both units. And the OC of the Russian Federation's Kaliningrad-2 are US$ 2 150/kW$_e$, half the cost of Kaliningrad-1.

The Massachusetts Institute of Technology (MIT) published in 2009 an update of its 2003 cost study for the USA (Du and Parsons, 2009). Its updated OC estimate of US$ 4 000/kW$_e$ is very close to the mean of recent estimates for North America. The 2009 study concludes that, in the USA, the cost of capital will be higher for nuclear power than for coal- and natural gas-fired power because of the lack of recent experience and resulting uncertainty among investors. Without this 'risk premium', nuclear power's estimated LCOE would be comparable to the LCOEs for coal- and gas-fired power, even without fees or taxes on carbon dioxide emissions. U.S. policy currently provides for loan guarantees and production tax credits for a limited number of new nuclear power plants, and these act to offset the risk premium. But the study concludes that long-term expansion of nuclear power in the USA will require permanent elimination of the risk premium, which can only be done by demonstrated successful performance.

The recent OECD report *Projected Costs of Generating Electricity* (NEA and IEA, 2010) presents nuclear OC between US$ 1 560/kW$_e$ and US$ 5 860/kW$_e$ – a much wider range than in 2005 – which shows continued uncertainty about nuclear power OC. Altogether fourteen countries, all of which operate nuclear power

excludes interest during construction (IDC), escalation due to increased costs for project specific material, components and labour, as well as general inflation. OC are the costs if the plant were built overnight. However, OC quotes for plants to be built, say, in 2015 often do include anticipated cost escalation and inflation. Extrapolations based on two-digit annual escalation rates as observed between 2005 and mid-2008 can quickly double or triple OC.

Figure 6.8 Expected overnight cost of nuclear power plants (Source: NEA and IEA, 2010)

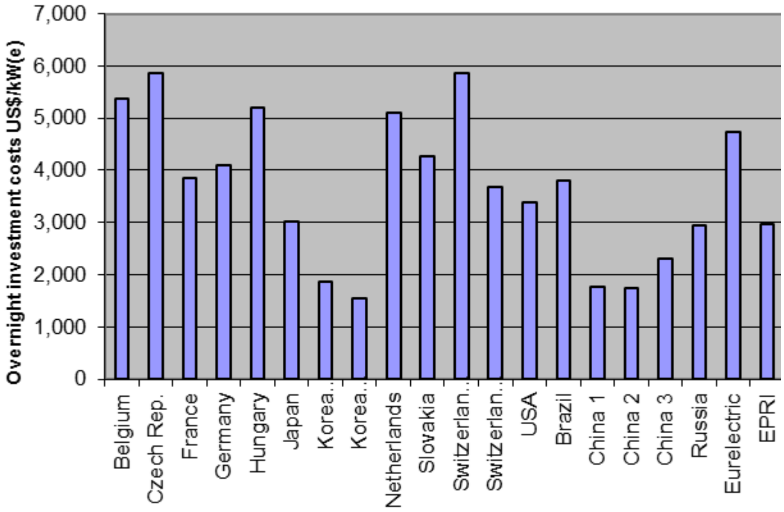
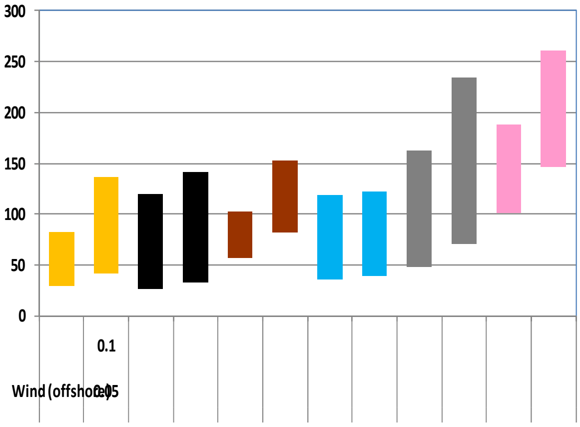


Figure 6.9 Levelised costs of electricity of different generating options at 5% and 10% discount rates (Source: NEA and IEA, 2010)



plants, and two industrial associations contributed data for a total of twenty prospective nuclear projects (Fig. 6.8). At the lower end of the OC estimates are China, Japan, Korea and Russia, i.e. countries with ongoing construction experience. At the higher end, OC often reflect FOAK costs.

However, what ultimately matters are not the investment costs but the LCOE over different generating options. As the OC of all electricity generating alternatives have increased substantially, and fossil fuel prices remain at elevated levels (except for domestic coal) compared to ten years ago, the LCOEs at a discount rate of 5% show nuclear power to be a competitive base load electricity provider (Fig. 6.9). At a discount rate of 10% the situation is different. Nuclear power is competitive in some markets; in others it would only be competitive if there were a financial benefit attached to its low greenhouse gas emissions.

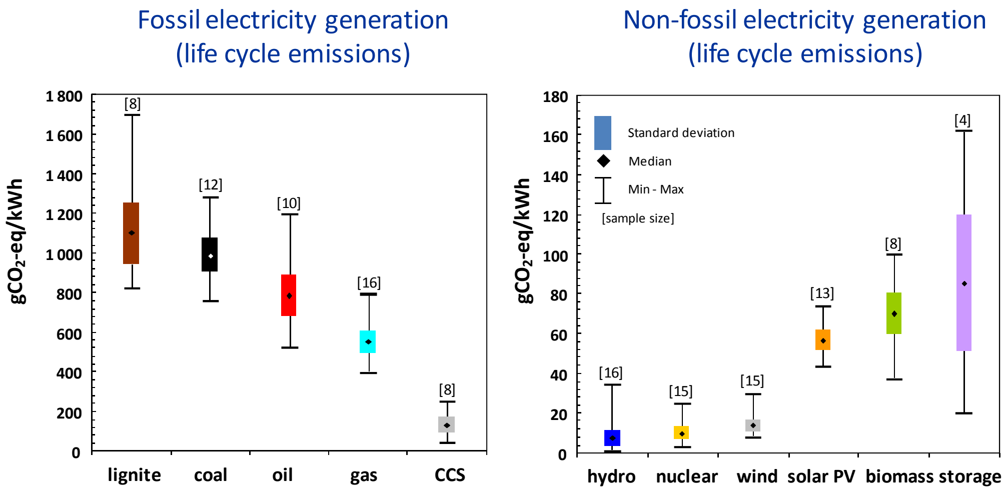
The generating costs in Fig. 6.9 cover a wide range, reflecting different local conditions, e.g., the differences between regulated and liberalised markets and different assumptions about the future costs of fuel and other factors. The main parameters influencing total cost are: construction cost, financial factors (interest and discount rates, return on equity), fuel prices, decommissioning costs (and, in the case of nuclear power, also spent fuel management costs) as well as energy and environmental policies.

The economics of nuclear power relative to fossil-fuelled generation, particularly coal, improves with carbon pricing. No such pricing is included in the generating cost projections of Fig. 6.9. To put the impact of carbon prices into perspective, consider that a price of US$ 50/t of CO_2 would increase the cost of coal-fired electricity by US$ 30-60/MWh depending on the combustion technology and type of coal. For natural gas, with a much lower carbon content per unit of fuel, the corresponding range is US$ 8-15/MWh.

Climate Change

The Copenhagen Accord of December 2009 defined dangerous anthropogenic interference with the climate system as an increase in global temperature of more than 2°C. According to the Fourth Assessment Report (AR4) of the Intergovernmental Panel on Climate Change (IPCC), avoiding such dangerous interference requires that global greenhouse gas (GHG) emissions peak within 15 years and then, by 2050, fall by 50-85% compared with 2000 levels. While efficiency improvements throughout the energy system, especially at the level of energy

Figure 6.10 Summary of life cycle GHG emissions for selected power generation technologies (Source: Weisser, 2007)



end-use, offer substantial GHG reduction potentials often at 'negative' costs[3], nuclear power, together with hydropower, wind power and carbon capture and storage (CCS) technologies, is one of the lowest emitters of GHGs in terms of grams of CO_2-eq/kWh generated on a life cycle basis (Fig. 6.10).

The low GHG emissions per kWh of renewables and nuclear power are reflected in the overall GHG intensities of electricity generation in countries with a high share of any of these technologies in their generating mixes. Fig. 6.11 contrasts the relative contributions of nuclear power, hydropower and other renewable technologies in 2006 with the average amount of CO_2 emitted per kWh. Countries with the lowest CO_2 intensity (less than 100g CO_2/kWh, below 20% of the world average) generate around 80% or more of their electricity from hydropower (Norway and Brazil), nuclear power (France) or a combination of these two (Switzerland and Sweden). At the other extreme, countries with high CO_2 intensity (800g CO_2/kWh and more) have none (Australia – no nuclear) or only limited (China and India – nuclear and hydropower) shares of these sources in their power generation mixes (IAEA, 2009a).

Fig. 6.12 takes a closer look at the GHG mitigation potentials of the principal low-carbon power generation technologies assessed by the IPCC. The mitigation potentials of nuclear power and renewables are based on the assumption that they displace fossil-based electricity generation. The figure shows the potential GHG emissions that can be avoided by 2030 by adopting the selected generation technologies. The width of each rectangle is the mitigation potential of that technology for the carbon cost range shown on the vertical axis. Each rectangle's width is shown in the small box directly above it. Thus, nuclear power has a mitigation potential of 0.94 Gt CO_2-eq at negative carbon costs plus another 0.94 Gt CO_2-eq for carbon costs up to US$ 20/t CO_2. The total for nuclear power is 1.88 Gt CO_2-eq, as shown on the horizontal axis. The figure indicates that nuclear power represents the largest mitigation potential at the lowest average cost in the energy supply sector, essentially electricity generation. Hydropower offers the second cheapest mitigation potential but it is the smallest of the five options considered here. The mitigation potential offered by wind energy is spread across three cost ranges, yet more than one-third of it can be utilised at negative cost. Bioenergy also has a significant total mitigation potential, but less than half of it could be harvested at costs below US$ 20/t CO_2-eq by 2030.

[3] Mitigation options with net negative costs ('no regrets' opportunities) are defined as those options whose benefits, such as reduced energy costs and reduced emissions of local and regional pollutants, equal or exceed their costs to society, excluding the benefits of avoided climate change.

Figure 6.11 CO_2 intensity and shares of non-fossil sources in the electricity sector of selected countries (Source: IAEA, 2009a)

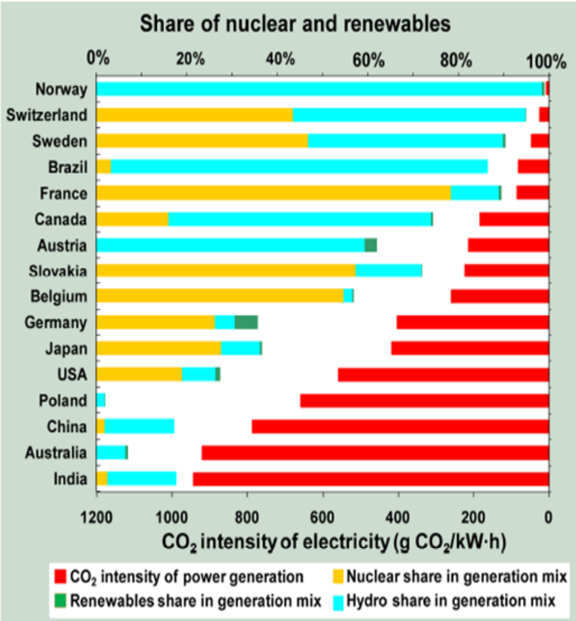
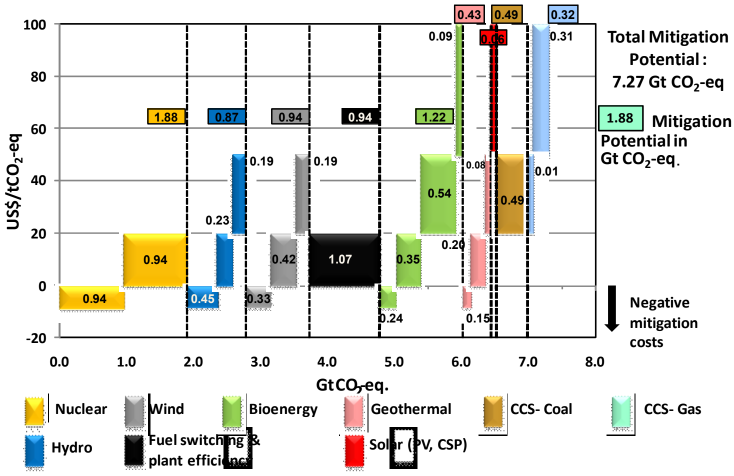


Figure 6.12 Mitigation potential in 2030 of selected electricity generation technologies in different cost ranges (Source: adapted from IPCC, 2007)



Projected growth for Nuclear Power

Each year the IAEA updates its low and high projections for global growth in nuclear power. In 2009, despite the financial and economic crisis that started in late 2008, both the low and high projections were revised upwards. In the updated low projection, global nuclear power capacity reaches 511 GW_e in 2030, compared to a capacity of 370 GW_e at the end of 2009. In the updated high projection it reaches 807 GW_e. These revised projections for 2030 are 8% higher than the projections made in 2008 (IAEA, 2009b).

The upward shift in the projections is greatest for the Far East, a region that includes China, Japan and the Republic of Korea. Modest downward shifts in the projections were made for North America and for Southeast Asia and the Pacific.

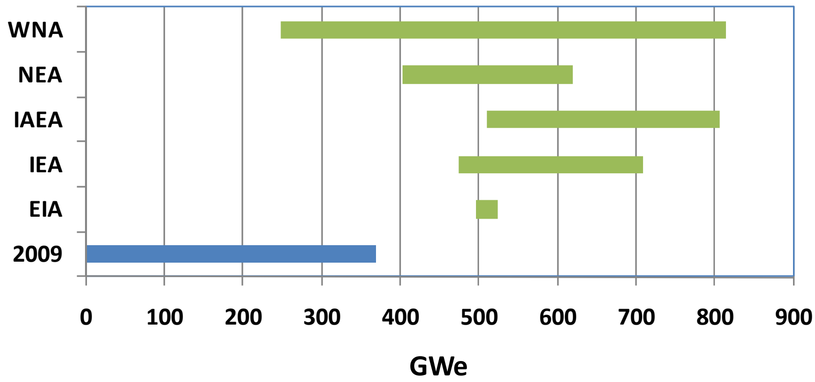
The financial crisis that started in late 2008 affected the prospects of some nuclear power projects, but its impact was different in different parts of the world. The regional pattern of revisions in the projections reflects, in part, the varying impacts of the financial crisis in different regions. The general upward revision in both the low and high projections reflects expert judgment that the medium- and long-term factors driving rising expectations for nuclear power had not changed substantially. The performance and safety of nuclear power plants continued to be good. Concerns persisted about global warming, energy supply security, and high and volatile fossil fuel prices. All studies still projected persistent energy demand growth in the medium and long term.

What had changed since the projections made in 2008 was that the commitments of governments, utilities and vendors to their announced plans, and the investments they were already making in those plans, were generally perceived as becoming firmer over time. That raised confidence. Another change was the Safeguards Agreement between India and the IAEA in August 2008. The Nuclear Suppliers Group subsequently exempted India from previous restrictions on nuclear trade, which should allow India to accelerate its planned expansion of nuclear power.

The IAEA's were not the only nuclear projections to have been revised in 2009. Updated projections were also published in 2009 by the US Energy Information Administration (EIA), the OECD International Energy Agency (IEA) and the World Nuclear Association (WNA). The EIA's range of projections became slightly narrower,

Figure 6.13 Comparison of nuclear power projections

(Sources: EIA, 2009; IEA, 2009; IAEA, 2009b; NEA, 2008; WNA, 2010)



the WNA's range became slightly broader, and the IEA's range was shifted very slightly upwards (both the low and high values increased). Note that the projections are based on different sets of assumptions about the principal drivers of future electricity demand and supply, including demographics, economic development, energy policies, environmental policies, prices, etc. Fig. 6.13 compares the ranges of the nuclear projections for 2030 from the EIA, IEA, IAEA, and WNA. Also included are the projections of the OECD Nuclear Energy Agency's 2008 World Nuclear Outlook.

Uranium Availability

Between 2003 and 2007 rising uranium prices triggered a significant increase in investment in uranium exploration and mine development. The stepped-up exploration activities worldwide resulted in new discoveries and re-evaluation of known deposits. As a result, identified resources recoverable at less than US$ 130/kgU grew by more than 37% from the amount estimated in 2001, to a current total estimate of 5.404 million tU. There are an additional 0.902 million tU of identified conventional resources recoverable at costs between US$ 130/kgU and US$ 260/kgU (NEA, 2010).

Uranium production in 2008 covered about 74% of the world's reactor requirements of 59 360 tU – the highest share since 1991. The remainder was covered by five secondary sources: stockpiles of natural uranium, stockpiles of enriched uranium, reprocessed uranium from spent fuel, mixed oxide (MOX) fuel with uranium-235 partially replaced by plutonium-239 from reprocessed spent fuel, and re-enrichment of depleted uranium tails (depleted uranium contains less than 0.7% uranium-235). At the estimated 2009 rate of consumption, the projected lifetime of the 6.306 million tU of identified conventional resources recoverable at less than US$ 260/kgU is about 100 years. This compares favourably with reserves of 30–50 years for other commodities (e.g. copper, zinc, oil and natural gas). With reprocessing and recycling, more years of power could be extracted from the same amount of uranium, and the projected lifetime of current identified conventional resources recoverable at less than US$ 130/kgU would rise to several thousand years. In short, uranium resources are plentiful and pose no constraint on future nuclear power development (IAEA, 2009a).

Technology

The majority of nuclear power plants operating around the world were designed in the late 1960s and 1970s and are no longer offered commercially today. Reactor designs increased gradually in size, taking advantage of economies of scale to be competitive. Many of the earliest reactors, which started commercial operation in the 1950s, were 50 MW_e or smaller. The current fleet ranges from less than 100 MW_e up to 1 500 MW_e. The average size of reactors in operation today is 850 MW_e.

Although the industry has historically and overwhelmingly pursued greater economies of scale, modest deployment of small (less than

300 MW_e) and medium-sized (between 300 MW_e and 700 MW_e) reactors continues. Small and medium-sized reactors (SMRs) allow for incremental capacity expansion, reduce economic risk exposure, especially at times of uncertain electricity demand prospects, and lower finance barriers. SMRs are being developed for: (a) use in small grids with limited interconnections, typically found in developing countries, (b) as a power or multipurpose energy source for isolated areas and (c) as less ‘bulky’, less risky investments in liberalised markets.

Reactor technologies available for use today are evolutionary improvements of previous designs and generally take into account the following design characteristics:

- a sixty-year service life;
- simplified maintenance - on-line or during outages;
- easier and quicker construction;
- inclusion of safety and reliability considerations at the earliest stages of design;
- modern technologies in digital control and the human-machine interface;
- safety system design, guided by risk assessment;
- simplicity, by reducing the number of rotating components;
- increased reliance on passive systems (gravity, natural circulation, accumulated pressure, etc.);
- additional severe accident mitigating equipment;
- complete and standardised designs with pre-licensing.

Close to a dozen reactor designs are currently offered by the major nuclear power plant vendors worldwide. These so-called ‘generation III’ and ‘generation III+’ designs are expected to provide the majority of new nuclear build for the coming two decades. They include:

- the ABWR (Advanced Boiling Water Reactor) is the only one of the leading designs already operating. Four are operating in Japan and another three units are under construction in Taiwan and Japan. The four operating units have outputs in the 1 300 MW_e range, but versions up to 1 500 MW_e are offered. The basic design was developed jointly by General Electric (GE), Toshiba and Hitachi. The ABWR design is currently licensed in three countries, the United States, Japan and Taiwan, China;
- the AP-1000 is an advanced pressurised water reactor (PWR) with a capacity of 1 100-1 200 MW_e designed by Westinghouse. Construction of the first AP-1000s started in 2009 at Sanmen in China. The design has also been

associated with the majority of projects under consideration in the USA and is being considered in the UK and other markets;

- the ESBWR (Enhanced Simplified BWR) is an evolutionary development of the ABWR concept by GE-Hitachi. To date, no orders have been placed for this 1 600 MW_e design, but the design has been tentatively earmarked for some potential new plants in the USA;

- the EPR (Evolutionary PWR) is a joint development by Areva of France and Siemens of Germany designed to comply with stringent safety requirements laid down in the 'European Utility Requirements' as well as with similar requirements issued by the U.S. Electric Power Research Institute (EPRI). Unit sizes will vary from 1 600 MW_e to 1 700 MW_e. The first such units are now under construction in Finland, France and China, although the first named has experienced significant 'first-of-a-kind' related delays. Several projects in early planning stages in the USA and the UK are considering the EPR design;

- the APWR (Advanced PWR) has been developed for the Japanese market by Mitsubishi Heavy Industries (MHI). The design of the 1 530 MW_e plant is an evolutionary improvement on currently operating designs. The construction of two units at Tsuruga is expected to start in the near future. MHI is also offering a version of the APWR in the US market, and has been selected for one potential project;

- the VVER-1200 (also known as AES-2006) has been designed by a group of Russian institutions including the Russian Research Center Kurchatov Institute, Rosenergoatom, Atomstroyexport and others (now all part of Atomenergoprom - a holding company for all of Russia's civil nuclear industry). It is the most advanced PWR of the VVER series with a power output of about 1 100-1 200 MW_e. Three VVER-1200 units are presently under construction in Russia. The latest VVER-1000 designs have also been exported to several countries, including China and India;

- the ACR-1000 (Advanced CANDU) is the latest pressurised heavy water moderated reactor (PHWR) design of the Canadian crown corporation Atomic Energy of Canada, Ltd. (AECL). AECL's reactor technology, known as CANDU, differs from other designs in that it uses natural uranium, thus avoiding the need for uranium enrichment. The ACR, however, will use slightly enriched fuel, the first CANDU design to do so. The ACR-1000 is an evolutionary 1 200 MW_e PHWR building on AECL's flagship CANDU 6 design. Preliminary orders for two ACRs by the Canadian Province of Ontario have been suspended over concerns about pricing and the future of AECL;

- the APR-1400 is the latest Korean PWR design led by Doosan Heavy Industries (DHI). The APR 1400 is an evolutionary further development which has its origins in the second generation CE System 80+ model of Combustion Engineering, now part of Westinghouse. Two of these 1 400 MW_e plants are under construction at the Republic of Korea's Shin-Kori site. In late 2009 a consortium led by the Korea Electric Power Corporation won a contract to build four APR-1400s in the United Arab Emirates. The contract also foresees plant operation being carried out over the 60 year plant lifetime by Korea Hydro and Nuclear Corporation;

- in addition to the designs listed above, there are further designs under development that could become commercially available around 2020-2025. Efforts are particularly targeted at the development of smaller designs suitable for markets with smaller grid sizes or markets where smaller capacity increments would minimise financial risk.

In the fastest growing markets for nuclear new build, China and India, two designs dominate:

- the CPR-1000 is currently the main design being built in China, with 14 units now under construction. The design is a further development of French pressurised water reactor technology transferred to China under a 1992 agreement with the then Framatome (now Areva). Technology transfer and a high localisation factor have been the cornerstones of China's nuclear power development strategy. Another major technology transfer agreement with Westinghouse provides for the construction of four AP-1000s; two units are already under construction. Subsequent AP-1000s are expected to be built largely by domestic component suppliers;

- India's PHWR designs are based on an early CANDU design exported from Canada in the 1960s. The latest unit now has a capacity of 540 MW_e, up from the 220 MW_e of earlier plants. The 2008 US-Indian nuclear cooperation agreement and the subsequent lifting of the ban on nuclear technology exports by the 45-nation Nuclear Suppliers Group ended India's 30-year-old isolation from access to imported nuclear technology. It is expected that India will soon play an important role in the nuclear technology market. Two VVER-1000s from Russia are already under construction at Kudankukam, and several more are in a planning stage.

Conversion, Enrichment and Fuel Fabrication

Total global conversion capacity is about 76 000 tonnes of natural uranium per year for uranium hexafluoride (UF_6) and 4 500 tU per year for uranium dioxide (UO_2). Current demand for UF_6 conversion is about 62 000 tU/yr. In 2009, Areva started construction on its new Comurhex II conversion facilities to replace the older facilities at Malvési and Pierrelatte, France. Comurhex II's design capacities for uranium tetrafluoride (UF_4) and UF_6 conversion are 15 000 tU each per year by 2012. In 2008, Cameco Corporation and Kazatomprom announced the establishment of a joint venture to develop a 12 000 tUF_6 conversion facility in Kazakhstan (IAEA, 2010b).

Total global enrichment capacity is currently about 60 million separative work units (SWUs) per year compared to a total demand of approximately 45 million SWUs per year. Three new commercial-scale enrichment facilities are under construction, Georges Besse II in France and, in the USA, the American Centrifuge Plant (ACP) and the National Enrichment Facility (NEF). All use centrifuge enrichment. Georges Besse II and ACP are intended to allow the retirement of existing gas diffusion enrichment plants. At Georges Besse II rotation of the first centrifuge cascade took place in December 2009. At NEF the first centrifuge was installed in September 2009. For the ACP, there is still some doubt about the readiness of the technology. The U.S. NRC began formal reviews for two additional facilities, Areva's proposed Eagle Rock Enrichment Facility in Idaho and Global Laser Enrichment's proposed laser enrichment facility in North Carolina (IAEA, 2010b).

Japan Nuclear Fuel Limited expects to begin commercial operation of improved centrifuge cascades at Rokkasho-mura around 2011 and expand capacity from 150 000 SWUs today to 1.5 million SWUs by 2020. Current enrichment capacity in China, using Russian centrifuges, is 1.3 million SWUs, and Russia and China recently agreed to add 0.5 million SWUs. Limited enrichment facilities for domestic needs exist in Argentina, Brazil, India and Pakistan. Ukraine joined Armenia, Kazakhstan and the Russian Federation as members of the International Uranium Enrichment Centre (IUEC). The IUEC was established in 2007 in Angarsk, Russian Federation, following calls by the IAEA's Director General and the Russian President to work towards multinational control of enrichment and create a network of international centres, under IAEA control, for nuclear fuel cycle services including enrichment.

Total global fuel fabrication capacity is currently about 13 000 tU/yr (enriched uranium) for light water reactor (LWR) fuel and about 4 000 tU/yr (natural uranium) for PHWR fuel. Total demand is about 10 400 tU/yr. Some expansion of current facilities is under way, for example in China, Republic of Korea and the USA. The current fabrication capacity for MOX fuel is around 250 tonnes of heavy metal (tHM), mainly located in France, India and the UK, with some smaller facilities in Japan and the Russian Federation. Additional MOX fuel fabrication capacity is under construction in the USA (to use surplus weapon-grade plutonium). Genkai-3 in Japan started operating with MOX fuel in November 2009, making it the first Japanese reactor to use MOX fuel. Worldwide, 31 thermal reactors currently use MOX fuel (IAEA, 2010b).

Table 6.6 summarises the current status of front-end fuel cycle facilities by country.

Back End of the Fuel Cycle

The total amount of spent fuel that has been discharged globally is approximately 320 000 tHM. Of this amount, about 95 000 tHM has already been reprocessed, and about 310 000 tHM is stored in spent fuel storage pools at reactors or in away-from-reactor (AFR) storage facilities. AFR storage facilities are being regularly expanded, both by adding modules to existing dry storage facilities and by building new ones. Six countries operate reprocessing facilities (Table 6.6) and recycle parts of the plutonium in the form of MOX for reuse in nuclear power plants. Some countries build up plutonium stockpiles for fuelling future fast-breeder programmes. Total global reprocessing capacity is about 5 000 tHM/yr. Completion of the new Rokkasho-mura reprocessing plant in Japan was postponed until 2010.

The Swedish Nuclear Fuel and Waste Management Company (SKB) selected Östhammar as the site for a final spent-fuel geological repository in June 2009, following a nearly 20-year process that narrowed the list of voluntary applicant sites to two in 2002. Subsequent site investigations concluded that the bedrock in Östhammar was more stable with less water than that in Oskarshamn, the other potential site. SKB plans to apply for a construction licence in 2010 with site works scheduled to start in 2013; disposal operations are to commence in 2023 (IAEA, 2010b).

Site investigations for repositories at Olkiluoto in Finland and in the Bure region in France continued on schedule with operation targeted for 2020 and 2025 respectively.

In the USA, the Government decided to terminate its development of a permanent repository for high-level waste at Yucca Mountain, while continuing the licensing process. It plans to establish a commission to evaluate alternatives.

In the UK a voluntary siting process has been initiated. Two boroughs in the neighbourhood of Sellafield have expressed an interest.

In 2009, completion of the decommissioning of the Rancho Seco nuclear power reactor in California brought the number of power reactors worldwide that had been fully dismantled to 15. Fifty-one shutdown reactors were in the process of being dismantled, 48 were being kept in a safe enclosure mode, 3 were entombed. For 6 more, decommissioning strategies had not yet been specified (IAEA, 2010b).

Human Resource Development

An important challenge for the nuclear power industry, government authorities, research and development organisations, and educational institutions is ensuring that there is a sufficient skilled workforce for all stages of the nuclear fuel cycle. Estimates of the human resource (HR) requirements associated with any of the nuclear growth projections cited above are not readily available, and data are scarce on the number of people today with the various skills needed in the nuclear industry and on the number in relevant education and training programmes. With increased interest in nuclear power, concerns have been expressed about possible shortages of the requisite personnel, although it has also been recognised that the situation varies across countries according to the strength of their nuclear power programmes.

Concerns about possible shortages have prompted initiatives by government and industry to attract students and expand education and training in nuclear-related fields. Where data are available, these initiatives appear to be successful. For example, Electricité de France (EDF) recruited four times as many professionals in 2008 as it had in 2006, and it expects to maintain this higher level of recruitment for several more years, supported partly by an internal 'skills renewal' project. Areva hired 12 000 engineers in 2008 and plans to recruit an additional 40 000 in the next four years. Both companies will benefit from a presidentially-initiated French Committee to Coordinate Training in Nuclear Science and Technology (C2FSTN), established in 2008. In the USA, nuclear engineering enrolment has increased by 46% in the past five years, assisted by Government funding and annual surveys of HR needs that have increased the visibility of nuclear careers. China is developing a five-year plan to recruit 20 000 new engineers for its nuclear power programme by 2020, and the Nuclear Power Corporation of India is expanding its existing recruitment programmes to more than double its workforce of engineers by 2017.

If the higher projections for nuclear power described above are realised, these efforts will have to be successful and replicated several times over. That challenge will be significant. The IAEA high projection, for example, would require bringing on-line an average of 22 new reactors each year through 2030. This is much higher than the average of 3 new reactors connected to the grid each year from 2000 through 2009, and one third higher even than the average of 16 new reactors each year during the 1970s. Still, even in the high projection, nuclear power capacity grows just 0.5% faster than overall electricity generation capacity. This means that human resource needs for nuclear power would be growing only slightly faster than those for electricity generation from coal, natural gas and renewables. The challenge faced by nuclear power is not exceptional (IAEA, 2010b).

Conclusions

Nuclear power is back on the agenda of many countries, essentially for three reasons: predictable and stable long-term generating costs, energy security, and its climate-change mitigation benefits. Its economic competitiveness depends on local conditions including available alternatives, market structures and government policy. Nuclear power is not the 'silver bullet' to solve all the energy challenges before us. Deployment of nuclear energy should be preceded by comparative analyses of all available options. It also requires a strong and long-term commitment on the part of governmental institutions and utilities as well as public acceptance. Good governance, transparency and stakeholder involvement in the decision process are therefore key for a decision to invest in the nuclear option.

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TABLES

Table 6.5 Nuclear Energy: capacity, generation and operating experience at 1 January 2010

	Reactors in operation		Reactors under construction		Net generation in 2009	Nuclear share of electricity generation in 2009	Total operating experience to end-2009	
	Units number	Capacity MW_e	Units number	Capacity MW_e	TWh	%	years	months
South Africa	2	1 800			11.6	4.8	50	3
Total Africa	**2**	**1 800**			**11.6**		**50**	**3**
Canada	18	12 577			85.1	14.8	582	2
Mexico	2	1 300			10.1	4.8	35	11
United States of America	104	100 683	1	1 165	796.9	20.2	3 499	9
Total North America	**124**	**114 560**	**1**	**1 165**	**892.1**		**4 117**	**10**
Argentina	2	935	1	692	7.6	6.9	62	7
Brazil	2	1 766			12.2	2.9	37	3
Total South America	**4**	**2 701**	**1**	**692**	**19.8**		**99**	**10**
Armenia	1	376			2.3	45.0	35	8
China	11	8 438	20	19 920	65.7	1.9	99	3
India	18	3 984	5	2 708	14.7	2.2	318	4
Japan	54	46 823	1	1 325	263.1	28.9	1 439	5
Korea (Republic)	20	17 647	6	6 520	141.1	34.8	339	8
Pakistan	2	425	1	300	2.6	2.7	47	10
Taiwan, China	6	4 949	2	2 600	39.9	20.7	170	1
Total Asia	**112**	**82 642**	**35**	**33 373**	**529.4**		**2 450**	**3**
Belgium	7	5 863			45.0	51.7	233	7
Bulgaria	2	1 906	2	1 906	14.2	35.9	147	3
Czech Republic	6	3 678			25.7	33.8	110	10
Finland	4	2 696	1	1 600	22.6	32.9	123	4
France	59	63 260	1	1 600	391.8	75.2	1 700	2
Germany	17	20 470			127.7	26.1	751	5

Table 6.5 Nuclear Energy: capacity, generation and operating experience at 1 January 2010

	Reactors in operation		Reactors under construction		Net generation in 2009	Nuclear share of electricity generation in 2009	Total operating experience to end-2009	
	Units number	Capacity MW_e	Units number	Capacity MW_e	TWh	%	years	months
Hungary	4	1 859			14.3	43.0	98	2
Lithuania					10.0	76.2	43	6
Netherlands	1	482			4.0	3.7	65	0
Romania	2	1 300			10.8	20.6	15	11
Russian Federation	31	21 743	9	6 894	152.8	17.8	994	4
Slovakia	4	1 711	2	810	13.1	53.5	132	7
Slovenia	1	666			5.5	37.8	28	3
Spain	8	7 450			50.6	17.5	269	6
Sweden	10	8 958			50.0	37.4	372	6
Switzerland	5	3 238			26.3	39.5	173	10
Ukraine	15	13 107	2	1 900	77.9	48.6	368	6
United Kingdom	19	10 097			62.9	17.9	1 457	8
Total Europe	**195**	**168 484**	**17**	**14 710**	**1 105.2**		**7 086**	**4**
Iran (Islamic Rep.)			1	915				
Total Middle East			**1**	**915**				
TOTAL WORLD	**437**	**370 187**	**55**	**50 855**	**2 558.1**	**14**	**13 911**	**3**

Notes:

1. The capacity and output of the Krsko nuclear power plant, shown against Slovenia in the table, is shared 50/50 between Slovenia and Croatia
2. Total world operating experience includes reactor years for Italy and Kazakhstan which no longer operate nuclear power plants
3. Source: Power Reactor Information System, International Atomic Energy Agency

Table 6.6 Nuclear fuel cycle capability

	Conversion	Enrichment	Fuel fabrication	Reprocessing
Argentina	X		X	
Belgium			X	
Brazil	X		X	
Canada	X		X	
China	X	X	X	X
France	X	X	X	X
Germany		X	X	
India	X		X	X
Japan		X	X	X
Kazakhstan			X	
Korea (Republic)			X	
Netherlands		X		
Pakistan	X	X	X	
Romania			X	
Russian Federation	X	X	X	X
Spain			X	
Sweden			X	
United Kingdom	X	X	X	X
United States of America	X	X	X	

Notes:

1. Source: NEA, 2008

COUNTRY NOTES

The Country Notes on Nuclear have been compiled by the Editors, largely on the basis of material published in:

- *Nuclear Power Reactors in the World*, Reference Data Series No. 2, 2009 Edition, International Atomic Energy Agency, Vienna;
- *WNN Weekly*, World Nuclear Association, London;
- *WNN Weekly Digest*, World Nuclear Association, London;
- Press reports and industry web sites.

Information provided by WEC Member Committees has been incorporated when available.

Albania

It was reported in April 2009 that Albania and Croatia plan to construct a jointly-owned NPP on the shores of Lake Shkoder, near Albania's frontier with Montenegro.

Argentina

There are two NPPs: Atucha-I, a 335 MW_e PHWR supplied by Germany, and Embalse, a Canadian-designed 600 MW_e PHWR; Atucha-I came on line in 1974, Embalse in 1983. In 2008 the two nuclear stations provided 6.2% of Argentina's electricity output. Nuclear's share increased to 6.9% in 2009.

The construction of a third unit (Atucha-II), a 692 MW_e PHWR, has been interrupted since 1995.

The Argentinian WEC Member Committee reports that the Expansion Plan of the Ministry of Energy envisages continued, and growing, use of nuclear energy for electricity generation. The completion and commissioning of Atucha II is foreseen for 2011, while in 2012 Embalse is expected to see the extension of its operating licence by 25 years and an increase of 35 MW_e in its capacity. The fourth NPP, consisting of two units each of 750 MW_e, is expected to be connected to the network in 2016/2017. The Member Committee foresees that by the end of 2020 four reactors will be in operation in Argentina, with an aggregate capacity of 3 232 MW_e.

In December 2009 the governor of the northwestern province of Formosa was reported as stating that the prototype of the domestically-designed CAREM small modular nuclear reactor would be installed in the province.

Armenia

An NPP came into operation at Medzamor, 64 km from the capital Yerevan, in 1976 but it was closed down in 1989 following an earthquake the previous year. Concern over the station's safety from a seismic point of view was exacerbated by the repercussions of the Chernobyl incident.

One of the two original WWER units (Medzamor-2) has been upgraded and refurbished, coming back into commercial operation in 1996 with a capacity of 376 MW_e. It provided 39.4% of Armenia's electricity output in 2008, and around 45% in 2009.

Armenia has faced international pressure, especially from its neighbour Turkey, to shut down Medzamor-2 on the grounds of safety. In May 2006 the Armenian Minister of Finance and Economy announced plans for the construction of a 1 000 MW_e nuclear plant to replace Medzamor-2.

It was reported in November 2007 that the Armenian Government had approved the closure of Medzamor-2; no date for closure was given. The USA has indicated its support for the construction of a replacement plant.

Australia

In November 2006 a draft report was issued by a government task-force set up to study the nuclear energy industry. The report was quoted as saying that 'nuclear power is the least-cost low-emission technology that can provide base-load power', and as predicting that Australia could have a nuclear power reactor in operation in as little as ten years - although 15 years would be more probable - and could potentially have up to 25 nuclear power reactors in operation by 2050, supplying one-third of the country's electricity.

Bangladesh

The authorities in Bangladesh were reported in August 2009 to be planning the introduction of nuclear power into the country.

Belarus

In October 2007 the President of Belarus stated that construction of the country's first NPP was planned to start in 2008. The Government has indicated that it envisages the installation of two units with a combined capacity of 1 000 MW_e between 2013 and 2015, with two more units planned for operation by 2025. High-level talks on the project have been held both with China and Russia. May 2009 saw the signing of an agreement between the governments of Belarus and Russia for cooperation on the peaceful use of nuclear energy, followed a few months later by one for Russian assistance in a feasibility study into the financing and construction of two reactors at a site in the northeast of the country, near to its borders with Lithuania and Poland.

Belgium

A total of seven reactors were constructed between 1975 and 1985, four units at Doel and three at Tihange; they are all of the PWR type, with a current aggregate net generating capacity of 5 863 MW_e. In 2008, nuclear power provided about 54% of Belgium's electricity generation, but 2009 saw a fall of two percentage points in nuclear's share.

In January 2003, Belgium's Senate voted for a nuclear phase-out law which stipulates that all seven units shall be closed after completing 40 years of operation. The first reactors are thus due to be shut down in 2015, the last in 2025. However, the preliminary report of a study commissioned by the Federal Energy Ministry, released in November 2006, concludes that the substantial change in circumstances since the passing of the phase-out law 'requires a paradigm shift of the current official Belgian standpoint on nuclear power'.

In October 2009 the Belgian Government announced that its plans for phasing out nuclear power would be put back for ten years.

Brazil

At the end of 2008, Brazil had two NPPs in operation: Angra-1, a 491 MW_e net PWR, and Angra-2 (1 275 MW_e net). In an electricity market dominated by hydropower, nuclear's share of generation in 2008 and 2009 was only about 3%.

Work on the construction of a third unit at Angra, of similar size to Angra-2, was started in 1983, but suspended after about three years.

According to a press report in July 2008, the completion of Angra-3 had become more doubtful following the setting of 60 exacting conditions by Brazil's environment minister. However, Angra-3 took a step forward in March 2009 with the granting of an environmental licence, and another in July, when the Ministry of Mines and Energy announced tax incentives for its construction.

In September 2008, the Brazilian nuclear energy company Eletronuclear submitted a plan for six new reactors to the Government, and made a further move in August of the following year, with the opening of an office in the northeastern city of Recife to conduct studies into the siting of a new NPP.

A ministerial spokesman was reported in June 2009 to have confirmed that the Brazilian Government was planning to construct four new NPPs by 2030.

Bulgaria

Six WWER units have been constructed at Kozloduy, in the north-west of the country, close to the border with Romania. Four units (each of 408 MW_e net capacity) were brought into operation between 1974 and 1982, and two others (each of 953 MW_e capacity) were commissioned in 1987 and 1989, respectively.

Kozloduy-1 and -2 were shut down in December 2002, followed by Kozloduy-3 and -4 at the end of 2006, in accordance with the terms of Bulgaria's accession to the European Union. The combined output of the two Kozloduy reactors remaining in service provided nearly 33% of Bulgaria's net electricity generation in 2008, rising to almost 36% in 2009.

In April 2005 the Government approved the construction of a second NPP, comprising two

1 000 MW_e gross (953 MW_e net) PWRs, to be sited at Belene which is, like Kozloduy, on the banks of the Danube, Bulgaria's border with Romania. Work on this site had begun in 1987 but has been on hold since 1991.

A contract for two Russian VVER-1000 reactors (each 953 MW_e net) to be installed at Belene was signed in January 2008. The Government issued a construction permit for the plant in July of the same year.

The Bulgarian WEC Member Committee foresees a total nuclear capacity of 4 000 MW_e (3 812 MW_e net) at end-2020, with four units in operation.

It was reported in December 2009 that Bulgarian ministers were ‘actively considering new build’ at Kozloduy.

Canada

There are currently 20 nuclear power reactors in Canada that are operational or being refurbished for operation in the near future. These reactors are for the most part located in the province of Ontario, which houses 18 reactors: Bruce (8), Pickering (6) and Darlington (4). There is one reactor in Quebec (Gentilly) and another in New Brunswick (Point Lepreau). Of these 20 reactors, 18 are currently in full commercial operation. Two nuclear reactors have been laid-up at the Bruce A station, but are in course of refurbishment, with their return to service scheduled to take place during the second half of 2011.

All Canadian nuclear power plants are of the Pressurised Heavy Water Reactor (PHWR) type, using the CANDU design. Canada's operational nuclear generation capacity is 12 577 MW_e. In 2008, these facilities provided 88.3 TWh, equal to 14.8% of Canada's total electrical generation. According to IAEA data, nuclear’s share was unchanged in 2009.

In addition to the 20 reactors noted above, two reactors, Pickering A2 and A3 (both rated at 515 MW_e) are shut down and considered unlikely to be brought back into service. Pickering A1 and A4 remain in operation.

Ontario Power Generation (OPG), the owner and operator of the Pickering and Darlington NPPs, announced in early 2010 that Darlington would be refurbished but that Pickering B would be operated for another ten years and then shut down.

The Ontario provincial government announced in June 2008 that the Darlington NPP had been chosen as the site for two new reactors. However, in June 2009 the provincial government suspended the bidding process for building new reactors at Darlington. OPG is proceeding with the environmental assessment process and obtaining a site preparation licence.

Bruce Power is currently proposing two alternative sites in Alberta in connection with its Peace Region Nuclear Power Project. The locations are Lac Cardinal, about 30 km west of the town of Peace River, and Whitemud, 30 km north of Peace River. The specific reactor design to be used has not yet been decided, but the indicated total generating capacity is in the range of 3 200 to 4 400 MW_e. Bruce Power plans to submit its environmental assessment report to the Federal and Provincial regulators in 2010. Commissioning of the plant is envisaged for 2018.

China

China's first NPP, Qinshan 1, a 288 MW_e PWR, was connected to the grid in December 1991 and began commercial operation in April 1994. Ten more NPPs (eight PWRs and two PHWRs) have subsequently been installed. At end-2009, China's nuclear generating capacity stood at 8 438 MW_e; with output from the eleven units providing nearly 2% of its electricity generation during the year.

Tianwan 2, a Russian-built 1 000 MW_e (gross) WWER, began commercial operation on 16 August 2007. Excavation of the site for the Sanmen NPP in Zhejiang province got under way in February 2008, with construction commencing officially in April 2009. Shortly afterwards it was reported that an agreement had been signed for the construction of China's first inland NPP at Xianning City, Hubei. In November work commenced on new nuclear units at Ningde and Fuqing, both in Fujian province. Construction of two new reactors at Fangjiashan, near the existing NPP at Qinshan in Zhejiang, began just before the end of 2008. It was reported in June 2009 that six units were under various stages of construction at the Fuqing site. By three months later construction work had commenced on the first two reactors (out of an eventual total of at least six) at the Haiyang NPP in the eastern province of Shandong. Construction of Sanmen 2, China's third AP1000 reactor, began officially in mid-December.

In October 2009 it was reported that a high-level agreement had been signed with Russia for design work on two 800 MW_e fast neutron reactors for construction in China.

Work started officially in January 2010 on the construction of Ningde 3 in the northeast Chinese province of Fujian. This reactor is one of four CPR-1000 units at the site, of which the first is due on line at the end of 2012.

April 2010 witnessed a number of progress reports on China's nuclear building programme. First concrete was poured at the sites of the Taishan (Guangdong) and Changjiang (Hainan) NPPs, while fuel loading began at Unit 1 of the second phase of the Ling Ao NPP, also in Guangdong.

China is interested in developing the pebble bed reactor and is planning to cooperate with South Africa in High Temperature Reactor (HTR) demonstration projects and commercialisation: in this connection, a memorandum of understanding was signed in March 2009. Although both countries use the same pebble bed concept as the source of heat, their planned power conversion systems differ. China's first HTR plants will incorporate indirect-cycle steam turbine systems, while the South African versions will feature direct-cycle gas turbine systems.

It was reported in December 2009 that the Chinese shipping company Cosco was contemplating the development of nuclear-powered container vessels, as a means of reducing greenhouse-gas emissions from shipping.

Czech Republic

There are four reactors at Dukovany, which came into operation between 1985 and 1987. By end-2008, each unit had a net capacity of 427 MW_e. Two units have been constructed at Temelín, each with an end-2008 capacity of 963 MW_e: the first unit came on line in December 2000, the second during 2003. In 2008, nuclear power provided 32.5% of the republic's net electricity generation; 2009 witnessed an increase in nuclear's share to 33.8%.

In July 2008 the Czech utility CEZ asked the Ministry of the Environment to carry out an environmental impact assessment for two additional reactors at the Temelin NPP site. In August of the following year CEZ launched a public tender for their construction.

The capacity of Dukovany 3 was uprated by 38 MW_e in May 2009. The IAEA quotes the Czech Republic's nuclear generating capacity at 1 January 2010 as 3 678 MW_e (net).

Egypt (Arab Republic)

The WEC Member Committee reported in October 2006 that Egypt was studying the viability of constructing nuclear reactors for electricity generation and sea water desalination. The first nuclear power plant was expected to be operational by 2015.

Estonia

The Ministry of Economic Affairs and Communication announced in March 2008 that it was going to compile a shortlist of possible sites for Estonia's first NPP.

Finland

Four nuclear reactors were brought into operation between 1977 and 1980: two 488 MW_e WWERs at Loviisa, east of Helsinki, and two 840 (now 860) MW_e BWRs at Olkiluoto. In 2009 the four units accounted for nearly 33% of Finland's net electricity output.

The construction licence for building Finland's fifth reactor, Olkiluoto 3, was granted by the Government in early 2005, subsequent to a Decision-in-Principle ratified by Parliament in 2002. The new nuclear power unit of 1 600 MW_e (net) subsequently experienced considerable delays in construction and is not expected to begin commercial operation before mid-2012 at the earliest. By October 2009, the start-up date for Olkiluoto 3 was envisioned by the plant owner as ‘beyond mid-2012’.

Meanwhile, the generating capacity of Olkiluoto will be increased by about 25 MW_e during its annual maintenance outage, according to a news report in May 2010.

The Finnish WEC Member Committee reports that environmental impact procedures for additional reactor units have been undertaken by Teollisuuden Voima Oy at the Olkiluoto site, by Fortum Power and Heat Oy at the Loviisa site and by Fennovoima Oy at three candidate sites: Pyhäjoki and Simo in northern Finland and Ruotsinpyhtää on the southern coast.

After the completion of the EIA report, the companies filed to the Government their applications for Decisions in Principle (DiP) for the planned reactor unit(s). The submitted DiP applications will be handled according to the requirements of the Nuclear Energy Act under the leadership of the Ministry of Employment and the Economy. The review process requires a minimum of one year's time. As there are three DiP applications, their essential parts will be handled together, with the aim of having possible DiP or DiPs handled in the Parliament during 2010. Provided that one or more of the DiP application(s) are approved by the Government and confirmed by Parliament, the company(ies) can make the final site selection (if necessary) and apply for a construction licence for the new reactor unit(s). After receiving the licence, the construction of the plant(s) could be started.

France

France has pursued a vigorous policy of nuclear power development since the mid-1970s and now has by far the largest nuclear generating capacity of any country in Europe, and is second only to the USA in the world. At end-2009 there were 59 reactors in operation, with an aggregate net capacity of over 63 000 MW_e. NPPs provide about 75% of France's net electricity output. Apart from a single fast reactor (Phenix), PWRs account for the whole of current nuclear capacity.

Electricité de France (EDF) announced in October 2005 that it was planning to increase the generating capacity of five reactors at three of its nuclear power plants in 2008-2010 by replacing turbine rotors, thus adding some 30 MW_e to each unit's capacity.

In December 2006, the French Government's Atomic Energy Committee announced a plan to construct a sodium-cooled fast reactor by 2020, with the final decision whether to go ahead being made in 2012. A design for a gas-cooled fast reactor will also be developed concurrently. These fourth-generation models are envisaged as entering commercial service after 2035-2040.

Construction of EDF's first European Pressurised Water Reactor (EPR), net capacity 1 600 MW_e) began at Flamanville (Normandie) towards the end of 2007, with completion scheduled for 2012. Work on a second EPR is planned to start at Penly in 2012.

The French WEC Member Committee reports that the PPI (long-term investment plan) for electricity 2009, taking an economic perspective and subject to safety requirements, gives preference to a central scenario involving the extension of the life of the current nuclear plants beyond 40 years. However, the ASN (nuclear safety authority) is the only body authorised to pronounce upon the closure or extension of a reactor. The PPI thus has to build in a safety margin in terms of electricity generating capacity corresponding to the uncertainties resulting from the absolute primacy accorded to nuclear safety. This preoccupation, allied to the necessity to smooth the investment effort involved in renewing the existing nuclear park and to maintain the associated industrial expertise, justifies the introduction (already decided) of two new-generation reactors, the first at Flamanville expected in 2012, the second at Penly in 2017. These considerations could also justify the launching of new EPR capacity following the completion of the Penly EPR.

Germany

A total of 17 reactor units, with an aggregate net generating capacity of 20 470 MW_e, were operational at the end of 2009. Nuclear power provided just over 26% of Germany's net electricity generation in that year.

In June 2000, the Federal Government concluded an agreement with the German utility companies that provided for an eventual phasing-out of nuclear generation. The agreement specified a maximum of 2 623 TWh for the lifetime production of all existing nuclear reactors, which implied an average plant lifetime of 32 years. As the newest German reactor (Neckarwestheim-2) was connected to the grid in January 1989, it could be expected to survive until 2021; however, utilities would be allowed to switch productive capacity between stations, so that the life of the newer, more economic plants could be extended by prematurely shutting down other units. Moreover, the calculated 32-year average lifespan was predicated on a capacity factor of over 90%; using a somewhat lower (and more realistic) level of, say, 85% the average plant lifetime would approach 35 years.

Germany's pioneer PWR, the 340 MW_e (net) unit at Obrigheim, was shut down on 11 May 2005 under the terms of the 2000 nuclear phase-out agreement, after 36 years of successful operation. The next reactors due for closure under the phase-out plan are three PWRs; Biblis A (net capacity 1 167 MW_e, which came into service in 1975), Biblis B (1 240 MW_e, 1977) and Neckarwestheim (785 MW_e, 1976).

The WEC Member Committee for Germany reports that the present coalition has maintained the policy of phasing out nuclear power, despite the fact that one party sees a necessity for nuclear generation. Final closure is scheduled by 2010 for the three NPPs (with a combined capacity of 3 192 MW_e) mentioned in the previous paragraph. Applications for lifetime extensions and electricity production allowances for the Biblis reactors were submitted by RWE Power but dismissed by the Federal Ministry. The Member Committee’s current expectation is that at the end of 2020 Germany will possess only three operational nuclear reactors, with a capacity of 5 300 MW_e.

Hungary

Four WWER reactors, with a current aggregate net capacity of 1 859 MW_e, came into commercial operation at Paks in central Hungary, between 1983 and 1987. Their contribution to Hungary's total net electricity generation rose from about 37% in 2008 to 43% the following year.

It was reported in July 2007 that Paks-1 and -4 had each been uprated to approximately 500 MWe (gross), some 8% higher than their original design capacity. Work on uprating Paks-2 and -3 was planned to start in 2008.

In March 2009 the Hungarian Parliament approved a government proposal to begin detailed preparations for new generating capacity at Paks. Three months later the Hungarian Atomic Energy Authority licensed Paks-2 to operate at a higher power output.

India

At the end of 2009, India had 18 reactor units in operation, with an aggregate net generating capacity of 3 984 MW_e. Sixteen were PHWRs, the other two being of the BWR type: most were relatively small units, with individual capacities up to 202 MW_e; the exception is Tarapur-3 and -4, each with a net capacity of 490 MW_e. Output from India's nuclear plants accounted for 2.2% of its net electricity generation in 2009.

According to the IAEA, five reactor units were under construction at the beginning of 2010, with an aggregate net generating capacity of 2 708 MW_e.

Two 202 MW_e PHWRs were under construction at end-2009: Kaiga-4 and Rajasthan-6, as well as two 917 MW_e WWERs (Kudankulam-1 and -2) and a 470 MW_e fast breeder reactor (PFBR).

Rajasthan-6 was connected to the grid at the end of March 2010.

Up to six of Areva's EPRs could be constructed at Jaitapur, Maharashtra state, following the signing of an MOU in February 2009.

In September 2009 the Indian cabinet endorsed the reservation of two coastal sites (Mithi Virdi in Gujarat and Kovada in Andhra Pradesh) for nuclear power parks, each with up to eight reactors.

Towards the end of 2009, an agreement was announced for further cooperation between Russia and India in respect of four reactors planned for Kudankulam and others at Haripur in West Bengal.

The completion of India's first fast breeder reactor, initially expected by the end of 2010, was reported in February 2010 to be likely to be delayed by up to a year.

Indonesia

The Minister of Research and Technology announced plans in January 2003 for the construction of Indonesia's first NPP. In September 2006, it was reported that before the end of the year the Government would select an agency to be responsible for implementing a project to construct two 1 000 MW_e nuclear power reactors by 2016. These will be built on one of three sites in north central Java. Later in 2006, the Minister of Energy and Mineral Resources stated that construction of the first unit was scheduled to begin in 2010, with a view to its becoming operational in 2017. Indonesia plans for nuclear energy to contribute some 4 000 MW_e to its electricity generating capacity by 2025.

A preliminary deal signed in July 2007 envisaged the use of Korean Republic technology for Indonesia's first two NPPs.

Iran (Islamic Republic)

Construction of two 1 200 MW_e PWRs started at Bushehr in the mid-1970s, but work was suspended following the 1979 revolution. In April 2006, the IAEA reported that Iran had one unit under construction: Bushehr-1 (1 000 MW_e gross, 915 MW_e net).

Iran announced an international tender in April 2007 for the design and construction of two light-water reactors, each of up to 1 600 MW_e, for installation near Bushehr.

The final shipment of nuclear fuel for Bushehr-1 arrived from Russia in January 2008. During February 2009, a 'pre-commission' test was carried out using 'virtual' fuel. Pre-start testing was reported to be in progress in January 2010. Commissioning tests continued during March. On 21 August the process of loading nuclear fuel into the first unit at Bushehr began under the supervision of inspectors from the IAEA.

Italy

The WEC Member Committee for Italy reports that in 2009 the Parliament gave the green light for a return to nuclear power, through which Italy hopes to cover 25% of its electricity needs in the long term. Italy and France have agreed to cooperate in the production of nuclear energy using the advanced third-generation European Pressurised Reactor (EPR) developed by EDF in conjunction with Areva and Siemens. The Italian Government has undertaken to adopt the guidelines and criteria for choosing reactor sites by July 2010.

The main Italian power company, Enel, aims to start up the first nuclear unit (1 600 MW_e) by 2020. By the end of 2025, Enel plans to build and bring into operation three other plants, each with 1 600 MW_e capacity, reaching a total of four units installed – on at least three different sites – with an aggregate capacity of 6 400 MW_e.

Japan

According to IAEA data, there were 55 operable nuclear reactors at the end of 2008, with an aggregate generating capacity of 49 315 MW_e gross, 47 278 MW_e net. Within this total there were 28 BWRs (24 764 MW_e gross, 23 908 MW_e net), 23 PWRs (19 366 MW_e gross, 18 420 MW_e net) and four ABWRs (5 185 MW_e gross, 4 950 MW_e net).

Tomari-3, an 866 MW_e (net) PWR entered commercial service on 22 December 2009.

At the beginning of 2010, total net nuclear generating capacity was 46 823 MW_e in 54 reactors, which provided about 29% of Japan's net generation of electricity during the year. One reactor, Shimane-3 (a 1 325 MW_e ABWR) was under construction.

As at end-2008, the IAEA listed eleven reactors as planned for construction, comprising eight ABWRs, two APWRs and one BWR.

The Japanese WEC Member Committee expects that by the end of 2020 there will be 62 nuclear reactors in operation, with a total gross capacity of 60 197 MW_e (approximately 57 700 MW_e net).

The Monju prototype fast-breeder reactor (246 MW_e net) has finally been put back into operation, more than 14 years after a serious leak of sodium caused it to be shut down. Extensive testing of the remodelled FBR began at the end of August 2007 and was scheduled to last a year, with the restart set for October 2008. However in January 2009, further delays in safety checks were reported to have set back operational status by several months. By August the expected start-up date had slipped to February 2010. When that month arrived, it was announced that Monju had completed a test procedure to ensure that it was safe to restart. It was reported in early May 2010 that the reactor had at last been restarted.

Jordan

In May 2009 an intergovernmental agreement was signed with Russia for cooperation on nuclear energy. Four months later Tractebel Engineering of Belgium was awarded a contract to carry out a siting study for Jordan's first NPP. By May 2010 a shortlist of three preferred bidders had been drawn up. The NPP is planned to be in operation by 2015, probably at a site about 25 km south of Al Aqabah.

Kazakhstan

The only NPP to have operated in Kazakhstan was BN-350, a 70 MW_e fast breeder reactor located at Aktau on the Mangyshlak Peninsula in the Caspian Sea. It came into service in 1973 and was eventually shut down in June 1999. Reflecting its small generating capacity, and its additional use for desalination and the provision of process heat, BN-350's contribution to the republic's electricity supply was minimal: over its lifetime of operation, its average annual output was only about 70 GWh.

A government plan to install two small VBER-300 nuclear reactors by 2015-2016 was announced in November 2007. The first was expected to be sited at Aktau, where the country's sole previous NPP was located.

The WEC Member Committee for Kazakhstan considers that, in local conditions, large-capacity NPPs are not appropriate: a preferred direction for power industry development might be the establishment of a regional power industry based on commercially available, reliable and safe NPPs with a capacity in the range of 100-300 MW_e. The Committee expects that reactors of this size would find a ready market in the region, as they would optimally comply with long-term development and power supply needs, and provide a perfect match with the capacity range of the fossil-fuel power plants that will in due course need to be replaced as a result of resource depletion.

The joint-venture project for the VBER-300 reactor at Aktau benefits from Kazakhstan and Russia's many years' experience in designing, manufacturing and maintaining marine nuclear installations (ships and submarines) and modern NPPs.

Korea (Democratic People's Republic)

A project for the construction of a 1 040 MW_e PWR was initiated in 1994 by the Korean Peninsula Energy Development Organisation (KEDO), funded by the USA, the Republic of Korea, Japan and the EU. It was suspended in 2002 and finally abandoned in June 2006.

Korea (Republic)

At end-2009, there were 20 nuclear reactors (16 PWRs and 4 PHWRs) in operation, with a reported aggregate net capacity of 17 647 MW_e. Nuclear power makes a substantial contribution to Korea's energy supply, providing 34.8% of its electricity in 2009.

Six more reactors are planned for completion during the next five years, with commercial operation scheduled to commence between 2010 and 2014. Construction of the 960 MW_e Shin-Kori-1 and -2 PWRs began in June of 2006 and 2007, respectively; these units are planned to come into service at end-2010 and end-2011.Work on Shin-Wolsong-1 and -2 (also known as Wolsong-5 and -6) got under way in 2007-2008; these two further 960 MW_e OPR-1000 reactors are scheduled to come into operation in 2011 and 2012.

Contracts were awarded in August 2006 for the construction of two APR-1400 reactors (each of 1 340 MW_e net capacity) at the Shin-Kori site (Shin-Kori-3 and -4), with completion planned for 2013 and 2014. Ministerial approval was granted in September 2007 and a construction licence for the two units issued in April 2008. Work on the construction of Shin-Kori-3 began in October of the same year.

The WEC Member Committee for the Korea Republic reports that the National Energy Committee has announced 'The 1st National Energy Basic Plan', which defines the long-term strategy for the Korean energy industry over the coming twenty years and stresses the importance of nuclear power. By 2030, nuclear power will account for 41% of total generating plants and 59% of overall generating capacity. The Government is encouraging strategic partnerships and the development of next-generation reactors, in order to foster the growth of nuclear power as an export industry.

Following the sale of four NPPs to the UAE at the end of 2009, the Republic of Korea's Ministry of Knowledge Economy declared that its aim was to promote the export of 80 NPPs worth $400 billion by 2030, and for the country to become the world's third largest supplier of power reactors.

Libya/GSPLAJ

In July 2007 France and Libya signed a memorandum of understanding for a joint project to construct a nuclear-powered desalination plant in Libya.

Libya's Nuclear Energy Institute announced in January 2010 that practical measures were being taken to advance its plans to use nuclear power for electricity generation and desalination.

Lithuania

Two LWGRs (each of 1 500 MW_e gross capacity) were built at Ignalina, north-east of Vilnius, in the mid-1980s: one was commissioned in December 1983 and the other in August 1987. After the accident at Chernobyl, the capacity of the Ignalina NPP was derated to 2 600 MW_e gross (2 370 MW_e net) for safety reasons. Ignalina-1 was shut down on 31 December 2004, in accordance with the terms of Lithuania's accession to the European Union. In 2009, Ignalina-2 accounted for over three-quarters of the republic's electricity generation.

The Lithuanian WEC Member Committee reports that, in line with the country's obligations under the EU Accession Treaty, Unit 2 of Ignalina NPP was permanently closed down at the end of 2009. However, it points out that the National Energy Strategy approved by the Seimas in 2007 declares that, taking into consideration energy security issues and the possibility of using the existing infrastructure at Ignalina, new NPP capacity will be commissioned in Lithuania. Construction of the new plant would avoid heavy dependence on imports of fossil fuels, reduce atmospheric pollution and possibly mitigate related economic consequences. Currently it is planned to commission the new unit in 2019. It is expected that decisions on the particular type of technology to be employed and the capacity of the NPP and its units, as well as on a timetable for project implementation, will be made in the near future.

The Ministry of Environment gave its approval in May 2009 to plans to build an NPP of up to 3 400 MW_e capacity at Visaginas, close to Lithuania's borders with Latvia and Belarus.

Malaysia

The Malaysian utility Tenaga was reported in July 2008 to have set up, at the request of the Government, a task force to examine the possibility of constructing an NPP in the interior of the country. In May 2010 it was reported that a search for a suitable site had been sanctioned.

Mexico

There is a single nuclear power station with two BWR units of total net capacity 1 300 MW_e, located at Laguna Verde in the eastern state of Veracruz. The first unit was brought into operation in April 1989 and the second in November 1994. Laguna Verde's electricity output accounted for 4.8% of Mexico's total net generation in 2009.

A major retrofit project for Laguna Verde was announced in March 2007; when completed in 2010, the capacity of each unit will have been increased by 20% to about 785 MW_e.

The Mexican WEC Member Committee reports for the present *Survey* that the construction of further nuclear capacity has not been programmed. However, NPPs constitute an option that is under continual review.

Morocco

In February 2010, plans were announced for two 1 000 MW_e NPPs for operation after 2020, as part of Morocco's submission to the Copenhagen Accord.

Netherlands

Two NPPs have been constructed in the Netherlands: a 55 MW_e BWR at Dodewaard (which operated from 1968 to 1997) and a 449 MW_e PWR at Borssele (on line from 1973). Borssele's output accounted for 3.7% of Dutch electricity generation in 2009.

In January 2006 the Dutch Government agreed to a 20-year life extension for the Borssele plant, allowing it to operate until December 2033; six months later Parliament ratified the decision. Also in June 2006, the chairman and CEO of Delta, one of the companies with shareholdings in Borssele's operator EPZ, revealed that Delta was investigating the possibility of constructing a new reactor at Borssele, which could be operating by 2016. A major refit completed at the end of 2006 resulted in Borssele's capacity being raised to 482 MW_e.

September 2006 saw a reversal of the Government's phase-out policy, when new conditions for the construction of NPPs were announced. Any new reactor must be a third-generation model, with barriers to prevent containment breaches. Other rules relate to the disposal of high-level waste and used fuel, plant dismantling and decommissioning funds.

In June 2009 the Dutch utility Delta began a process designed to lead to an application to build an NPP, to be operating by 2018.

Nigeria

The Federal Government has approved the technical framework for fast-tracking the deployment of NPPs in Nigeria. The country's nuclear roadmap envisages the installation of 1 000 MW_e by 2017 and 4 000 MW_e by 2027.

In March 2009 Russia and Nigeria agreed to cooperate on the peaceful use of nuclear energy, including the construction of NPPs.

Pakistan

For the present *Survey* the Pakistan WEC Member Committee has reported that two nuclear power plants (KANUPP at Karachi (K-1) and CHASNUPP unit 1 (C-1) at Chasma) are currently in operation. K-1, a PHWR of 125 MW_e (net), commissioned in 1971, has completed its design life of 30 years. After refurbishment to extend its life by 15 years and the granting of the necessary approval by the Pakistan Nuclear Regulatory Authority, it is now operating at 90 MW_e. Pakistan's second NPP (C-1), a PWR-type plant of 300 MW_e (net), started commercial operation on September 15, 2000. The country's third NPP, C-2, is under construction, with commissioning scheduled for 2011. Nuclear power provided 2.7% of Pakistan's net electricity generation in 2009.

In 2005, an Energy Security Plan was adopted by the Government of Pakistan, which called for a significant increase in nuclear capacity to 8 800 MW_e by 2030, with an increasing proportion of local content.

Philippines

After a government decision in 2007 to re-examine the scope for using nuclear power in the Philippines, the feasibility of rehabilitating the mothballed Bataan NPP was examined by an IAEA team early in the following year. The Korean Republic has reportedly also offered assistance.

Poland

The Polish WEC Member Committee reports that the country's first NPP is planned to be operating by the end of 2020, although its capacity has not been officially specified. The *Frame Schedule for Nuclear Energy Activity* (July 2009), developed on the basis of the *Polish Energy Policy till 2030* project and the *Ministry of Economy Strategic Plan*, envisages that the *Polish Nuclear Energy* programme will be accepted by the Polish Government by the end of 2010. This programme will include a development schedule providing detailed information concerning the numbers, capacities and location of the nuclear reactors planned. For the time being, the Member Committee is assuming that the first reactor in service will be an EPR 1500 from the French company Areva.

Romania

Romania's first nuclear plant - a PHWR supplied by AECL of Canada, with a current net capacity of 655 MW_e - came on line in 1996 at Cernavoda in the east of the republic. Cernavoda-2 entered commercial service in October 2007, having achieved grid connection on 7 August. In 2009, the two reactors supplied over 20% of Romania's electricity generation.

The Cernavoda NPP was designed for five reactors, using Canadian CANDU-type technology. While completion of the third and fourth units is being planned, there appear to be no plans to construct the fifth unit.

The Romanian WEC Member Committee has reported for the present *Survey* that the Romanian Energy Strategy for 2007-2020, which has been approved by the Government, recognises the place of the nuclear sector as a key factor in the energy industry.

In February 2010 it was announced that the Romanian power company EnergoNuclear and AECL had signed a contract for the Canadian company to assess the technical and commercial viability, and planning of Cernovada-3 and -4, in order to define what is required to complete the project.

Russian Federation

There were 31 nuclear units installed at ten different sites at the end of 2009, with an aggregate net generating capacity of 21 743 MW_e. The reactor types represented consisted of eleven 925 MW_e LWGRs, nine 950 MW_e WWERs, four 411 MW_e WWERs, four 11 MW_e LWGRs, two 385 MW_e WWERs and one 560 MW_e FBR. In all, NPPs provided almost 18% of the Russian Federation's electricity output in 2009.

The IAEA reports that nine reactor units, with an aggregate capacity of 6 894 MW_e, were under construction at the end of 2009.

Work was resumed in November 2007 on Kalinin-4, originally begun in 1986 but halted in 1991. In March 2008 an overall plan for siting new NPPs was announced, involving up to 42 new reactors by 2020.

Construction officially started in June 2008 on the first reactor at Novovoronezh Phase II, followed about a year later by that on the second unit. Approval was given in August 2008 for the construction of the 2 400 MW_e Baltic NPP in Kaliningrad; the first unit is planned to start up in 2015. It was reported in October 2008 that construction of the first new reactor at Leningrad Phase II had begun.

Site licences were issued in November 2009 for the Seversk nuclear power and heating plant in the Tomsk Oblast, Siberia. The containment dome at Kalinin 4 was installed in December 2009. It was reported in March 2010 that Volgodonsk 2, near Rostov, had been synchronised with the regional power grid and would enter commercial operation later in the year.

Slovakia

Four 408 MW_e WWERs were brought into service at Bohunice between 1978 and 1985; a slightly smaller (388 MW_e net) WWER came into operation at Mochovce in 1998. Mochovce-2 (also 388 MW_e) was connected to the grid just before the end of 1999 and went commercial in April 2000. The Bohunice-1 reactor (408 MW_e) was shut down on 31 December 2006, in accordance with the terms of Slovakia's accession to the European Union on 1 May 2004. Bohunice-2 was withdrawn from service at the end of 2008. The remaining four reactors are reported to have a current net capacity of 1 711 MW_e and to have provided 53.5% of the republic's electricity output in 2009.

Under a contract awarded in September 2007, Bohunice-3 and -4 will be uprated by a total of 120 MW_e in 2010. In June 2009 it was reported that contracts had been signed with the main suppliers for the completion of Mochovce-3 and -4.

A joint venture was established in May 2009 between the Czech utility CEZ and the state-owned Slovakian nuclear and decommissioning company Javys for the construction of an NPP at the Bohunice site. The Government gave its consent to the project in December 2009.

Slovenia

A bi-national PWR (current capacity 666 MW_e net) has been in operation at Krsko, near the border with Croatia, since 1981. Krsko's output, which is shared 50/50 with Croatia, accounted for 37.8% of Slovenia's net electricity generation in 2009. According to the Slovenian WEC Member Committee, in their input to the 2007 *Survey*, Krsko will operate till 2023, with possible extension.

It was reported in June 2006 that the Slovenian Ministry of Energy was considering the construction of a second unit at Krsko. Further details emerged in October 2006, when the Economics Minister stated that the new reactor would probably be a PWR, with a net installed capacity of 1 000 MW_e; construction could begin in 2013, with commercial operation from 2017. However, the Member Committee currently expects that only the one reactor will be operational at Krsko at the end of 2020. In January 2010 GEN Energija, a Slovenian IPP, was reported to have submitted an application to the Ministry of Economy regarding a second reactor at Krsko.

South Africa

There is a single nuclear power station at Koeberg, about 40 km north of Cape Town. The plant has two 900 MW_e PWR units which were commissioned in 1984-1985. The plant, which is owned and operated by Eskom, the national utility, provided nearly 5% of South Africa's electricity in 2009. In December 2008 Eskom cancelled the construction of a second NPP and froze long-term plans for up to 17 more. Retrofitting the low-pressure turbines at the Koeberg NPP will lead to a 65 MW_e increase in generating capacity.

Nuclear fuel is procured and delivered to the Koeberg NPP in accordance with government-authorised contracts for the supply of enriched uranium and for the supply of fabrication services for the nuclear fuel assemblies. These contracts are sufficient to provide the Koeberg station with 100% of its fuel requirements until the end of 2010.

The South African WEC Member Committee considers that while coal will remain South Africa's major energy resource for the foreseeable future, the republic needs to reduce coal's current 88% share of the energy mix to below 70% by 2030. To achieve this, a much higher proportion of nuclear (currently 4%) is proposed by 2030.

The process to introduce further NPPs is now being led by Government, with the continued participation of Eskom. A number of investigations relating to possible sites for future stations are continuing. These activities include, amongst others, environmental impact assessments of three sites for proposed NPPs, EPAs for transmission line routes associated with these sites, and the geotechnical and other studies required to characterise the sites in support of a future application for a nuclear installation licence from the National Nuclear Regulator.

Development of the pebble bed modular reactor (PBMR) concept, which is based on a number of small reactors operating in tandem, has been undertaken in South Africa for a number of years, but now appears to be in jeopardy.

In March 2007 it was reported by *World Nuclear News* that PBMR Pty, the South African company developing the pebble bed concept, had discussed with Sasol the possibility of employing the PBMR in the production of synthetic fuels. Another possible application that has been considered is the use of a PBMR as a source of energy for oil sands extraction.

In March 2009 South Africa was reported to have signed an MOU with China aimed at advancing pebble-bed technology. It was reported in September that the PBMR Demonstration Power Plant project had been indefinitely postponed. The following February saw the signing of an agreement with Mitsubishi Heavy Industries for collaboration on the development and commercialisation of the PBMR concept.

However, only two weeks later PBMR encountered serious problems, when the South African Government stopped funding the development of the pebble bed reactor, presaging massive staff cuts. In early March, PBMR's CEO resigned.

Spain

Nine nuclear reactors were brought into commission between 1968 and 1988. José Cabrera-1 (Zorita-1), Spain's oldest NPP (142 MW_e), was permanently shut down on 30 April 2006 after 38 years of operation. It had previously been scheduled for closure in 2008, but in 2004 the Government decided to close it two years earlier.

At the end of 2009, the remaining eight reactors had an aggregate net capacity of 7 450 MW_e and in that year provided 17.5% of Spain's electricity generation. Two of the units are

BWRs (total capacity 1 510 MW_e), the rest being PWRs.

The Garoña NPP (a 446 MW_e BWR) was granted a four-year life extension in July 2009.

Sweden

Between 1971 and 1985 a total of 12 nuclear reactors (nine BWRs and three PWRs) commenced operation. The 10 units remaining in service at end-2009 had an aggregate net capacity of 8 958 MW_e. Nuclear power provided 42% of Sweden's net output of electricity in 2008, but its share fell to 37.4% the following year.

Sweden's coalition government annulled the country's anti-nuclear policies early in 2009. In May of the same year approval was given for increasing the thermal output of Ringhals 3 by 5%, and test operation of the uprated unit for one year was sanctioned in the following October.

It was announced in June 2009 that the world's first permanent disposal site for used nuclear fuel would be constructed at Forsmark in eastern Sweden, with site works possibly beginning in 2013.

A capacity expansion of almost 38% for Unit 2 of the Oskarshamn NPP received government approval in April 2010.

For the present *Survey*, the Swedish WEC Member Committee has reported that it foresees some expansion of nuclear capacity, with higher thermal reactor and generator output capacity in the existing plant. The current Government has decided that it will be possible to replace existing plant with new (up to a maximum of ten).

Sweden's nuclear capacity at end-2020 is forecast by the WEC Member Committee to total 10 000 MW_e from 10 units, implying that an overall increase of around 1 062 MW_e (or 11.9%) is obtained as a result of uprating existing reactors during the years 2009-2020, assuming that no new reactors are brought into service in this period.

Switzerland

There are three PWRs and two BWRs in operation, with a total net generating capacity of 3 238 MW_e at the beginning of 2010. All five reactors were commissioned between 1969 and 1984. Their output in 2009 accounted for 39.5% of Switzerland's total power generation.

The Swiss WEC Member Committee reports that decommissioning of the three oldest NPPs, Beznau I and II and Mühleberg, with a combined capacity of 1 085 MW_e (one-third of the country's total nuclear capacity) is expected around 2020. Furthermore, drawing rights for some 2 500 MW_e of French nuclear capacity will gradually expire in the second half of the next decade. Replacement of this capacity will provide a major challenge for Swiss energy policy in the coming years.

Three general licence applications for new NPPs (at the existing sites of Beznau, Gösgen and

Mühleberg) have been filed by the three main Swiss utilities. The Nuclear Energy Law of 2005 requires general licences for NPPs to be voted by Parliament. Under Swiss legislation, parliamentary decisions can be challenged in a popular referendum. Public opinion is currently split into two equal camps of pros and cons. Opponents have announced that they would launch a referendum against any parliamentary approval of general NPP licences. This is expected to occur around 2013/14. Meanwhile, efforts are under way to form a consortium among the utilities so as to reduce the licence applications to two, since three applications slow down licensing procedures and mobilise opposition, given that the country will need only one or possibly two NPPs in the future.

In April 2008 the Government adopted the conceptual part of the 'Deep Geological Repository' sectoral plan, thus initiating a three-step procedure that will result in the designation of suitable sites for deep geological repositories within ten years. As a first step, suitable geological regions were delineated in the autumn of 2008. Consultations continue.

Taiwan, China

There are six reactors in service at three locations (Chinshan, Kuosheng and Maanshan), with an aggregate net generating capacity of 4 949 MW_e at end-2009; the four BWRs and two PWRs were all brought on line between 1977 and 1985. In 2009 nuclear plants provided 20.7% of Taiwan's net electricity generation.

Two more BWRs, with a total net capacity of 2 600 MW_e, are under construction at a fourth location (Lungmen). Owing to the intense political controversy generated by this project, its progress and eventual completion date remain subject to uncertainty. In August 2006, additional government funding was granted to Taipower for the completion of the Lungmen NPP. The first 1 300 MW_e ABWR unit may now commence operations in 2011, some five years behind the original schedule, while Lungmen-2 might be completed about a year later.

Early in 2010, Taipower was reported to be considering the uprating of the six existing reactors and the completion of three additional ones by 2025.

Thailand

The Thai energy minister announced in November 2007 that between 2008 and 2011 Thailand would carry out preparatory work on nuclear projects.

Turkey

A tender was launched in March 2008 for the construction of a nuclear power plant at Akkuyu on the Mediterranean coast. By April, four companies were reported to have already submitted bids in this connection. In May 2010 an agreement was signed by Turkey and the Russian Federation for Rosatom to build four 1 200 MW_e VVER reactors at Akkuyu on a BOO basis.

Ukraine

Four 925 MW_e RBMK reactors were installed at Chernobyl between 1977 and 1983. In April 1986 the last unit to be completed (Chernobyl-4) was destroyed in the world's worst nuclear accident. Chernobyl-2 was closed down in 1991, Chernobyl-1 in 1996 and Chernobyl-3 in December 2000.

The European Bank for Reconstruction and Development granted a loan to Ukraine to finance the completion in 2004 of two 950 MW_e (net) nuclear reactors (Khmelnitski-2 and Rovno-4), to replace the electricity output lost as a result of the shutdown of Chernobyl-3. Khmelnitski-2 commenced commercial operation in December 2005, and Rovno-4 followed some four months later.

At end-2009 there were 15 nuclear reactors (with a total net generating capacity of 13 107 MW_e) in service at four sites: they had come into operation between 1980 and 1995. Nuclear plants accounted for 48.6% of Ukraine's power output in 2009.

In mid-2006, Energoatom invited bids to undertake a feasibility study for completing the Khmelnitski-3 and -4 reactors, which had in 2005 received government approval for completion. These two 950 MW_e WWERs are reported by the IAEA to be under construction, with grid connection foreseen for 2015-2016.

United Arab Emirates

In April 2008 the Government of the UAE published a comprehensive national policy on nuclear energy, which envisaged the eventual installation of a series of NPPs in the Emirates. In May of the following year President Obama approved a nuclear energy cooperation agreement between the USA and the UAE. By October the latter had established a national nuclear regulatory authority, whilst at the end of the year it was reported that the UAE had selected Korean Republic companies to lead the construction of four APR1400 reactors. In April 2010, the preferred site of the first NPP to be constructed in the Emirates was reported to be Braka, 53 km west of Ruwais. Construction is planned to begin in late 2012, with commercial operation of the first two units envisaged for 2017-2018, followed by units 3 and 4 in 2019-2020.

United Kingdom

The UK had 19 nuclear reactor units in service at the end of 2009, with an aggregate net generating capacity of 10 097 MW_e. In 2008, nuclear power accounted for 13% of net electricity generation, but nuclear's share recovered some lost ground the following year, rising to 17.9%. Four Magnox reactors (Sizewell A-1 and -2 and Dungeness A-1 and -2) were shut down at the end of 2006, after operating for about forty years. Only one of the first generation of British nuclear power plants (Oldbury) is still in operation, although it had been scheduled to be shut down in 2008. However, towards the end of 2008 it was announced that Oldbury, the UK's oldest operational NPP, would continue in service for about another two years.

For the present *Survey*, the United Kingdom WEC Member Committee reports that, on the basis of published lifetimes, all but one of the UK's existing nuclear power stations are due to close by 2025. The Government concluded in 2008 that new NPPs should have a role to play in the UK's future energy mix, alongside other low-carbon sources. The Government's policy is to facilitate investment in nuclear power by removing potential barriers. This involves work to streamline the planning and regulatory processes for new NPPs.

The Government is currently preparing a draft National Policy Statement for nuclear power. This will set out the national need for new nuclear power, and include a draft list of sites that the Government has judged to be potentially suitable for the deployment of new NPPs by the end of 2025. Subject to public consultation and Parliamentary scrutiny, the National Policy Statement would be used by the new Infrastructure Planning Commission when it makes decisions on applications for development consent for new NPPs.

The Government expects the first new nuclear power station to be operational from around 2018.

In January 2009 the UK Government gave the nuclear industry two months in which to nominate sites for the first wave of new NPPs. In April the Government published a list of eleven potential sites for new NPPs, nominated through the Strategic Siting Assessment process.

The UK Member Committee estimates that a maximum of two new NPPs will be in operation by the end of 2020, on the basis of assumptions derived from announcements by energy companies regarding their aspirations for new nuclear power in the UK:

- EDF has said that it intends to build four new EPR reactors (each of around 1.6 GW_e) by 2025, with the first one operational by the end of 2017;
- RWE and E.ON have announced a joint venture with an objective of delivering at least 6 GW_e of new NPPs, with the first station coming on line at around the end of the next decade.

United States of America

At the end of 2009, IAEA data show that there were 104 nuclear reactor units connected to the grid, with an aggregate net generating capacity of 100 683 MW_e (equivalent to 27% of total world nuclear capacity). Nuclear plants accounted for 20.2% of US electricity output in 2009.

The United States WEC Member Committee has provided the following notes on the status of nuclear power in the USA:

Licence Renewals As of 31 December 2008, 52 of the 104 operating nuclear reactors in the US, representing 48% of the total nuclear capacity, had their operating licences renewed for an additional twenty years. Licence renewal applications for 18 reactors, representing 19% of the total nuclear capacity, are still under review. No licence expirations are expected prior to 2012.

New Reactor Activity The last construction permit issued by the Nuclear Regulatory Commission (NRC) for a unit that was not subsequently cancelled was for Shearon Harris Unit 1 in North Carolina in 1978. The last newly-built reactor to go on line was Watts Bar 1 in 1996. (Browns Ferry 1, a re-built reactor, went on line in June 2007).

In 2007, UniStar filed a partial application for a combined construction and operating licence (COL) to build and operate an Evolutionary Power Reactor (EPR) at Calvert Cliffs, ending a three-decades-long drought in licence applications. Prior to the implementation of the COL process, applicants were required to file separately for the construction permit and the operating licence.

The first full application for a COL was submitted on 20 September 2007, by South Texas Project Nuclear Operating Company to build and operate two Advanced Boiling Water Reactors. Three other COL applications were filed in 2007: Bellefonte, Alabama (two Advanced Passive 1000, or AP1000); North Anna, Virginia (Economic Simplified Boiling Water Reactor, or simply ESBWR), and W.S. Lee III, South Carolina (two AP1000s).

Twelve more applications were filed in 2008: Bell Bend, Pennsylvania (EPR); Callaway, Missouri (EPR); Comanche Peak, Texas (two EPRs); Enrico Fermi, Michigan (ESBWR); Grand Gulf, Mississippi (ESBWR); Levy County, Florida (two AP1000s); Nine Mile Point, New York (EPR); River Bend, Louisiana (ESBWR); Shearon Harris, North Carolina (two AP1000s); Victoria County, Texas (two ESBWRs); Virgil C. Summer, South Carolina (two AP1000s), and Vogtle, Georgia (two AP1000s).

As of July 2009, fourteen COL applications representing more than 28 GW in new capacity were under NRC review. Five of these applicants have completed contract negotiations with the firm that will build the reactor. The five projects that are 'fully committed' include Calvert Cliffs, Levy County, South Texas, Virgil Summer, and Vogtle. Together, they total 9 reactors. For additional information on potential reactors consult the following online source: http://www.eia.doe.gov/cneaf/nuclear/page/nuc_reactors/reactorcom.html

Financing is a key in the recent surge of COL applications. The cost of labour and materials is already rising. On 30 June 2008, the Department of Energy (DOE) announced two solicitations for applications for Federal loan guarantees for nuclear power projects (up to US$ 18.5 billion), and for 'front-end' nuclear power facility projects (up to US$ 2 billion). The 'front end' of the nuclear fuel cycle involves the activities prior to nuclear fission (such as enrichment).

Interestingly, the next reactor that is likely to be completed in the United States is not among these COL applications. TVA resumed construction of Watts Bar 2 in 2007, and EIA now includes the unit in its projections. It is anticipated that the unit will go on line in 2012.

The Westinghouse-designed reactor has a capacity of 1 100 MW_e. In 1996, Watts Bar 1 became the last new reactor to go on line in the United States in the 20th century. At that time, TVA projected that market demand would be insufficient to support a second reactor and construction ceased on unit 2.

Market Outlook The EIA's *Annual Energy Outlook 2009* (AEO) projections show that through 2020 the nuclear industry experiences some growth, with uprates and some new units providing between 4 000 and 12 000 MW_e of new capacity. In the reference case of the AEO, which uses a base set of assumptions, nuclear capacity increases from 101 266 MW_e in 2007 to 110 300 MW_e in 2020. Past 2020, this case also shows continued moderate growth, such that by 2030 there is 112 600 MW_e of nuclear capacity.

However, from 2020 the AEO shows significantly different results between a low case assessment, which assumes unfavourable conditions for nuclear plant investment, and a high case assessment which assumes favourable conditions for nuclear plant investment. In the low nuclear growth case, retirements of existing plants bring capacity down and new construction essentially ceases, resulting in a net drop of nuclear capacity to 74 300 MW_e by 2030. In the high nuclear growth projection, nuclear capacity increases to about 132 200 MW_e due to a significant amount of new plant construction. Even under the high growth scenario, nuclear power would represent only about 10.8% of the Nation's total electricity capacity in 2030, which is not much different from the nuclear sector's share of total capacity in 2008.

The U.S. nuclear industry will remain an important component of the U.S. energy portfolio. Many states have supportive regulatory environments for continued and, in some cases, expanded nuclear participation. However, the extent of the nuclear sector's participation within the mix of U.S. energy sources will depend on market forces which are uncertain as of this time.

Vietnam

A pre-feasibility study for nuclear power development was completed in early 2005 by an exploratory committee set up by the Government in 2001. The study envisaged the construction of a 2 000 MW_e NPP in either Ninh Phouc or Ninh Hai, both situated in Ninh Thuan province, with anticipated completion during the period 2017-2020. In May 2006 the chairman of the Vietnamese Atomic Energy Commission (VAEC) was reported as saying that a feasibility study for the NPP project would be completed in 2008. He indicated that if the project received approval, VAEC would organise construction to begin around 2011, with a view to completing the project by 2017. He added that the feasibility study had been ordered by the Ministry of Industry in anticipation of Vietnam's readiness to construct two to four reactors of 2 000-4 000 MW_e by 2020. In November 2009 the National Assembly approved a resolution on investment policy in connection with Vietnam's plans to construct two NPPs.

7. Hydropower

COMMENTARY

Level of Deployment

Hydropower is currently being utilised in over 160 countries. At end-2008, global installed hydropower capacity stood at about 874 GW. This figure is based upon data reported by WEC Member Committees, supplemented by information provided by national and international sources, including the International Hydropower Association (IHA). As far as possible the data refer to net installed capacity excluding pumped-storage schemes. According to data made available to the IHA, this capacity is derived from some 11 000 stations, with around 27 000 generating units.

Fig. 7.1 shows the countries with the highest installed capacities, as at end-2008. It should be noted that a comparison with installed capacity is not the same as that of generation, as many countries rely on hydropower less for base-load supply and more for load-following operations; consequently, for example, Canada tends to generate more from hydropower than the U.S. (in 2008, Canada produced 377 TWh, whereas the U.S. produced 255 TWh).

A breakdown of the total installed capacity by region (Fig. 7.2) shows that Asia, led by China, has overtaken Europe, while North America and South America take third and fourth place respectively. Africa remains the region with the poorest ratio of deployment to potential.

Figure 7.1 Distribution of installed hydropower capacity at end-2008
(Source: WEC Member Committees, Aqua-Media International and published statistics)

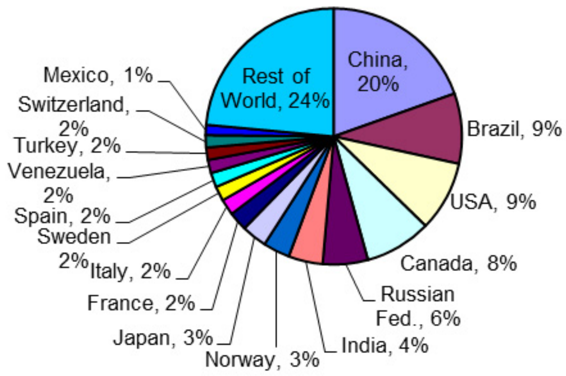


Figure 7.2 Current installed hydropower capacity by region
(Source: WEC Member Committees, Aqua~Media International and published statistics)

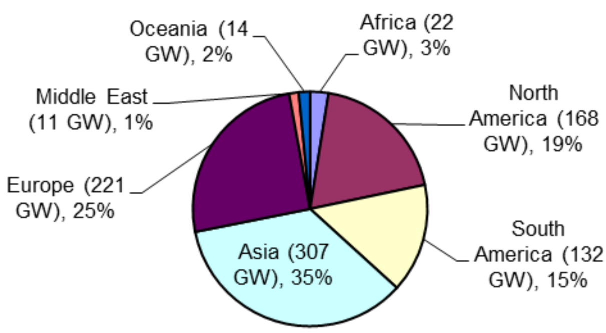


Figure 7.3 Hydropower capacity at beginning-2008: installed and under construction
(Source: International Hydropower Association)

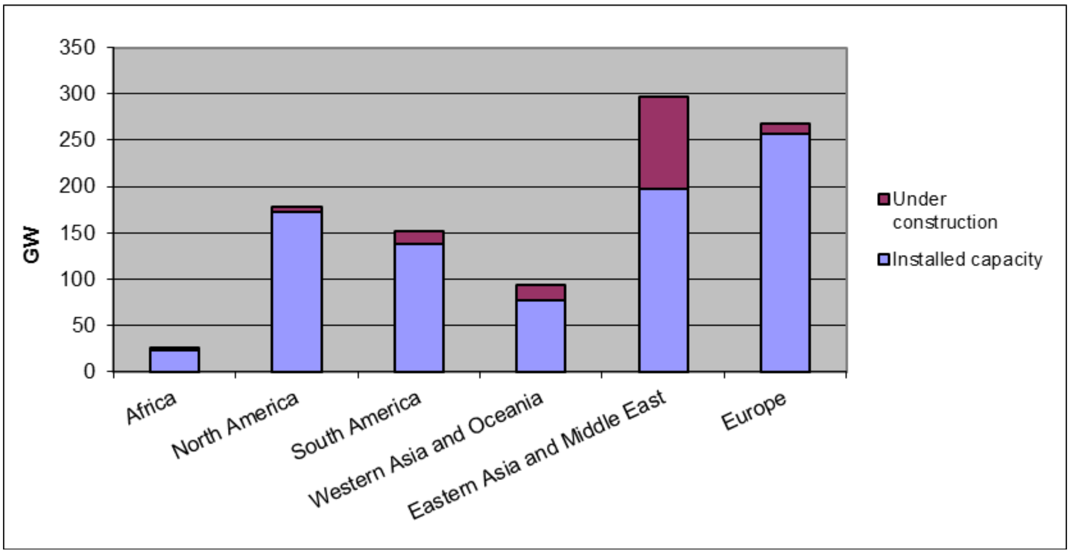


Figure 7.4 Technically and economically feasible hydropower capability
(Source:Aqua~Media [data reallocated to reflect WEC regions])

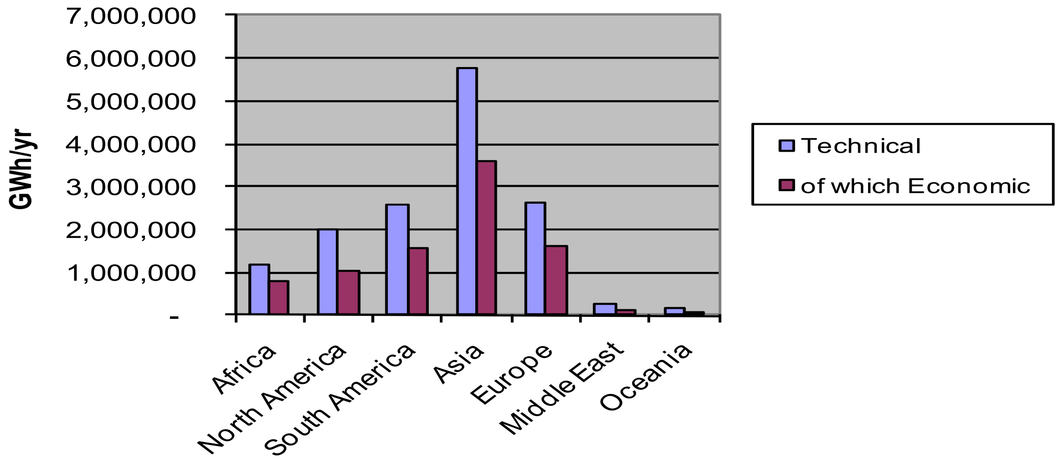


Fig. 7.3 shows hydropower capacity currently under construction. While China is clearly driving the development of the resource, what is of interest is the fact that Europe and North America, despite their existing levels of hydropower deployment, are continuing to develop substantial new hydropower capacity. The North American region, for example, has at least 19 GW of development under planning, of which 14.5 GW is identified in Canada, according to Natural Resources Canada.

Given the large identified hydropower potential within Africa, as well as important sustainability concerns around water and energy on this continent, it is clear that issues of finance and funding are major impediments to hydro development. This is evidenced by the strong growth of hydro in South America, China and other Asia, where there are similar concerns but where finance is more readily accessible.

The Potentials Debate

There is considerable debate regarding the quantification and classification of the world's hydropower resources. Hydropower potentials have been published on a regular basis in the technical literature; however, several researchers have commented that there are significant discrepancies and inconsistencies between the data for each country. Potential has typically been categorised as gross theoretical, technically feasible or economically feasible.

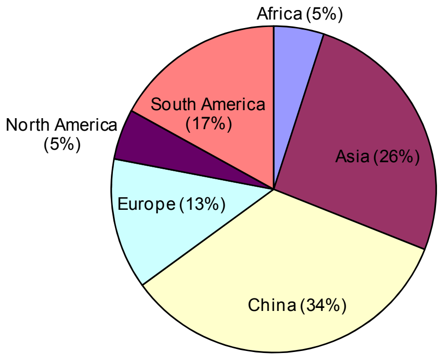
The meaning of the world's theoretical potential (Table 7.1) is of no practical purpose if countries have taken different approaches in their national estimations. There appears to be a wide range of opinion as to how theoretical potential should be measured, for example, from the theoretical energy associated with precipitation falling on the land surface, to a summation of the sites that have been assessed within the national territory.

Worldwide technical potential (Table 7.1) is increasingly challenged as it tends to be based only on specific sites that have been studied at some point in the distant past. It thus tends to exclude other sites that could be developed.

Economically feasible potential (Table 7.1) is also questioned on the basis that much of the evaluation is based on energy prices at different times in the past, again tending to underestimations. Further evidence of the lack of a standardised, consistent approach is the considerable variation between the proportions of economic potential to that described as technically feasible, by region (Fig. 7.4).

Notwithstanding the above, the IHA estimates that, if the global level of deployment were to equate to the level already realised in Europe, only one-third of the realistic hydro potential has been developed to date. This estimate, in itself, is considered to be conservative, given that considerable new development continues in the

Figure 7.5 Regional shares of capacity growth 2011-2020
(Source: International Hydropower Association)



European region. It is clear that the growth potential within the hydropower sector remains significant.

Future Development

Development, especially in the less-developed regions such as Africa and Asia, will rely heavily on the availability of long-term funding mechanisms and partnerships. Further development of hydropower within the UN Framework Convention on Climate Change's Clean Development Mechanism (UNFCCC CDM) and recognition of the role it will play in climate change adaptation-driven funding will be important if these regions are to receive the required support.

Orders for hydropower equipment clearly demonstrate that hydro development continues to show strong growth well into the future. While there is a dip in 2009-2010, it is reasonable to assume that this reflects recent financial uncertainty. From the period after 2010, growth is substantial, with worldwide hydro capacity expected to grow significantly over the period between 2011 and 2020.

Again, an analysis of the regional distribution of this growth confirms earlier comments about financing. As Fig. 7.5 depicts, the growth trends per region remain uneven in the 2011-2020 period, with China, Asia and South America continuing to show strong growth. Africa's share of new capacity remains small at 5%, compared, for example, with Europe at 13-14%.

Issues surrounding financing in those areas where it is going to be most needed must be addressed, if hydropower is to deliver not only on its ability to supply clean energy, but also on its capacity to provide a sustainable low-carbon energy option, and thus assist in climate-change adaptation.

The Changing Role of Hydropower

Hydropower can be classified as 'run of river' (where the power is generated through the flow of a river), 'reservoir' (where power is generated through the release of stored water) or 'pumped storage' (where stored water is recycled, see the comments below).

The drive for renewable energy

The renewable energy sector is benefiting from national policy interventions aimed at incentivising the use of the various renewable technologies. These are having a positive effect on the maturation of such energy forms. However, it is important that policymakers ensure that such support does not lead to market distortions which could damage the system as a whole. Hydro is in the unique position of being able to satisfy both base load and peaking requirements. This dual role highlights possible shortcomings in current policies: these generally provide supply incentives to producers of renewable energy (including hydro) to produce electricity independently of demand. While this has the effect of bringing an increased level of certainty to investors - which has clearly stimulated the renewables sector to unprecedented levels of growth - it has led to inflexibility in the power system.

Given the availability issues associated with other forms of renewable energy (for example, wind and solar are both variable sources of supply, and tidal, while predictable, is intermittent), and the clear indication that renewable energy production will, at least in the short and medium term, require some form of base-load provision from thermal generation, these policies will increase the stress on existing power systems. There is currently an insufficient incentive to address peaking services and intermittency issues. Given the long lead-in times for the development of storage projects, as well as the large up-front capital requirements, policymakers will need to address these issues with a sense of urgency.

As the use of renewable energy expands, the flexibility of hydropower will assume greater importance. By matching the other renewable energies with hydropower, synergies develop from hydro's capacity to supply power on demand, which allows for the balancing out of variability, as well as supplying the peak load. Unless the incentives are in place to capitalise on this flexibility, the substantial benefits it offers will be lost.

Also, current policy tends to favour projects with the minimum land-to-power ratio. Hence, many new hydro projects are designed to have only run-of-river capabilities. The absence of storage introduces a further level of variability, imposing more stress on the assets that have storage to back up this vulnerability. The repercussions relate to quantitative and qualitative issues. Power systems must manage significant changes in supply throughout various short- and long-term cycles. Thus, a considerable capacity must be scheduled to meet changes in demand. In addition, operating storage plants need to be flexible enough to provide voltage and frequency regulation. Such ancillary services are fundamental to secure and reliable systems; however, renewable energy policy is not, as yet, incentivising this.

The increasing need for storage

Most hydropower projects were developed to provide base load to the power system, and this pattern will continue in developing countries. However, the variable nature of the growing portfolio of renewables, as well as the costs associated with shutting down thermal energy options (resulting in their being kept running through periods of low demand) means that there is often excess power in a grid at times of low demand. This has led to an increasingly important role for pumped storage hydro, where, to store energy for use in periods of high demand, water is pumped from a lower to a higher reservoir. Currently, there are more than 127 GW of pumped storage throughout the world[1]. Recent reporting in the technical press

[1] HRW, Dec 2009, www.hydroworld.com, accessed 26/01/2010.

indicates that at least 15 projects are under construction in nine countries, and that these will add a further 8.8 GW of capacity. The power plants range in size from 150 to 1 353 MW.

It is anticipated that the market for pumped storage will increase by 60% over the next four years[2]. This is a clear reflection of the increasingly important role that storage will play in the future, with increased requirements for peak load and intermittent source balancing. However, as pumped storage is a net user of electricity (it requires electricity to pump the water to the higher storage reservoir), it depends on strong differentials in the market price, between low and peak demand, for its viability.

Climate change considerations

The issue of climate change is in the minds of most policy makers. In a hydropower context, the issue can be split into four aspects: greenhouse-gas footprint, hydrological vulnerability, climate-change mitigation, and adaptation. All of these aspects are being studied at the project, river basin, regional and global levels.

Water resources are under increasing competition from multiple uses. This is predominantly driven by population growth and evolving living standards, with further threats from increasing intensity of weather events linked to climate change. The energy sector is a major water user, thus water and energy policies need to be more closely coordinated.

In view of the above, it is expected that hydro will play a major and increasing role in both climate mitigation and adaptation. As well as the energy services it provides, freshwater storage will be required to supply an increasing number of water-related services. This will call for new design approaches for the future, especially regarding provision for extreme floods and droughts, and this will affect both new and existing assets.

The Clean Development Mechanism

The CDM market has played a major role in delivering renewable energy to the developing world, and it is anticipated that the hydropower projects sector will continue to be one of the main contributors to the carbon credits market. The majority of hydropower projects in the pipeline are at the validation stage, with 60% at this early stage of the process.

Figs. 7.6(a) and 7.6(b) highlight the status of all registered projects at the end of 2009. Of the 1 985 projects registered by the CDM Executive Board by the end of 2009, 541 are hydropower projects, representing 27% of the total, and 52% of the renewable energy project Certified Emission Reductions (CERs) issued for this period. When considering the predicted volumes of CERs to be delivered, registered hydro projects are expected to generate around 47 million carbon credits per year, equivalent to 14% of the total.

[2] Alstom, Levallois-Perret, France, 2009

Figure 7.6(a) Number of CDM projects by type at end-December 2009

(Source: derived from www.un.org)

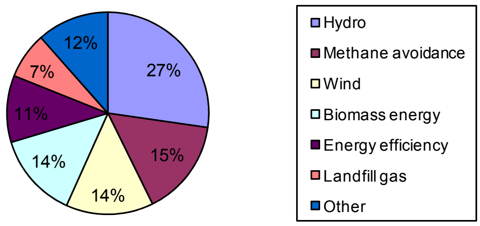
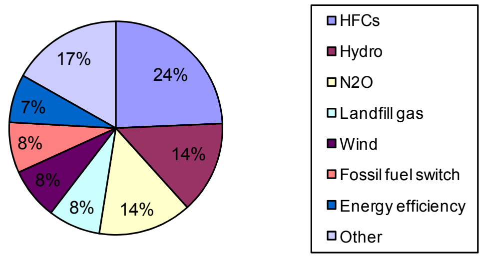


Figure 7.6(b) Expected thousand CERs/year until 2012 per project type

(Source: derived from www.un.org)



A significant portion of the 541 registered hydro projects are based in China (65%), India (11%) and Brazil (6%). In line with expectations, only two small projects (less than 15 MW) have to date been registered in Africa.

The European Emissions Trading Scheme (EU ETS), the world's largest multinational emissions trading scheme, allows operators to use a certain amount of these CDM credits as offsets against their emissions. The European Union's ETS Directive requires member states to ensure that hydro projects (above 20 MW) meet 'relevant international [sustainability] criteria'. Differences in the application of this obligation resulted in an unwillingness on the part of carbon exchanges to accept such credits. To address this issue and ensure that CERs from large hydro were eligible across the EU, the European Commission has issued a harmonised guidance for developers. This has contributed to improving uniformity and market confidence in the sector. It is expected that the Hydropower Sustainability Assessment Protocol (currently under a cross-sectoral review, and building on a previous version produced by the IHA) will provide an even more robust tool. Its development will be an important step in achieving a generally accepted matrix within which to assess hydro projects.

Sustainability Aspects

The hydro sector has been working on a definition of sustainability for more than a decade. It has probably been party to the most in-depth dialogue within the energy and industrial arenas. As mentioned above, a cross-sector forum, comprising governments, financial institutions, environmental/social NGOs and the hydro industry, has been reviewing a hydropower sustainability assessment protocol. This protocol assesses project performance in four stages of development: planning, design optimisation, construction and operation. The three pillars of sustainability are comprehensively addressed by a series of topics. Beyond the quality of environmental and social impact and management plans, two topics that have received particular attention are downstream sustainability flows and physical/economic resettlement.

A major emphasis has been placed on the trade-offs and optimisations that are required between the social, environmental and economic aspects of development. For downstream flows, for example, the needs to meet environmental services and resources for riparian livelihoods need to be balanced against the benefits of diverting water from a stretch of river. With regard to the appropriation of land for development, there is an increasing measure of agreement on international practice in relation to negotiated agreements and benefit sharing, not just for communities requiring resettlement, but also for host communities that may be indirectly affected.

The Hydropower Sustainability Assessment Forum has been reviewing the IHA's sustainability protocol over the past two years. During 2010, it will be presenting a revised draft for consideration by the hydro sector. It is expected that this process will lead to the establishment of a sustainability standard for hydropower in the longer term. The steps taken to date are important in ensuring that the hydropower sector not only continues to deliver significant amounts of clean energy, but is also able to contribute significantly to the wider issues of climate change and sustainability into the future.

Richard Taylor
International Hydropower Association

DEFINITIONS

This chapter is restricted to that form of hydraulic energy that results in the production of electrical energy as a result of the natural accumulation of water in streams or reservoirs being channelled through water turbines. Energy from tides and waves is discussed in Chapters 13 and 14.

Annual generation and capacity attributable to pumped storage is excluded. Where such installations produce significant energy from natural run-off, the amount is included in the total for annual generation.

It must be recognised that for some countries it is not possible to obtain comprehensive data corresponding exactly to the definitions. This particularly applies to small hydro schemes, many of which are owned by small private generators. Also, not all countries use the same criteria for the distinction between small and large hydro. In this Survey, small hydro mainly applies to schemes of less than 10 MW. However, some countries and other sources of data make the distinction between small and large schemes at other levels.

In the tables, the following definitions apply:

Gross theoretical capability is the annual energy potentially available in the country if all natural flows were turbined down to sea level or to the water level of the border of the country (if the watercourse extends into another country) with 100% efficiency from the machinery and driving water-works. Unless otherwise stated in the notes, the figures have been estimated on the basis of atmospheric precipitation and water run-off.

Gross theoretical capability is often difficult to obtain strictly in accordance with the definition, especially where the data are obtained from sources outside the WEC. Considerable caution should therefore be exercised when using these data.

Where the gross theoretical capability has not been reported, it has been estimated on the basis of the technically exploitable capability, assuming a capacity factor of 0.40. Where the technically exploitable capability is not reported, the value for economically exploitable capability has been adopted, preceded by a ">" sign.

Technically exploitable capability is the amount of the gross theoretical capability that can be exploited within the limits of current technology.

Economically exploitable capability is the amount of the gross theoretical capability that can be exploited within the limits of current technology under present and expected local economic conditions. The figures may or may not exclude economic potential that would be unacceptable for social or environmental reasons.

Capacity in operation is the total of the rated capacities of the electric generating units that are installed at all sites which are generating, or are capable of generating, hydro-electricity.

Actual generation is the net output (excluding pumped-storage output) in the specified year.

Probable annual generation is the total probable net output of electricity at the project sites, based on the historical average flows reaching them (modified flows), net heads, and the plant capacities reported, making allowance for plant and system availability.

Capacity planned refers to all sites for which projects have been proposed and plans have been drawn up for eventual development, usually within the next 10 years.

Capacity under construction and planned relates to all units not operational but which were under construction, ordered or about to be ordered at the end of 2008.

TABLES

Table 7.1 Hydropower: capability at end-2008 (TWh/yr)

	Gross theoretical capability	Technically exploitable capability	Economically exploitable capability
Algeria	12	4	
Angola	150	65	
Benin	2	N	
Burkina Faso	1	1	N
Burundi	6	2	1
Cameroon	294	115	105
Central African Republic	7	3	
Chad	N	N	
Congo (Brazzaville)	> 50	10	
Congo (Democratic Rep.)	1 397	774	145
Côte d'Ivoire	46	12	6
Egypt (Arab Rep.)	>125	> 50	50
Ethiopia	650	> 260	162
Gabon	200	80	33
Ghana	28	11	
Guinea	26	19	18
Guinea-Bissau	1	N	N
Kenya	> 24	9	
Lesotho	5	2	
Liberia	28	11	
Madagascar	321	180	49
Malawi	15	> 6	
Mali	12	5	
Mauritius	N	N	
Morocco	12	5	
Mozambique	> 103	> 38	32
Namibia	23	9	6
Niger	3	> 1	
Nigeria	43	32	30
Rwanda	2	1	
Senegal	11	4	2
Sierra Leone	11	7	
Somalia	2	1	

Table 7.1 Hydropower: capability at end-2008 (TWh/yr)

	Gross theoretical capability	Technically exploitable capability	Economically exploitable capability
South Africa	73	14	5
Sudan	> 48	> 19	19
Swaziland	4	1	N
Tanzania	39	20	
Togo	4	2	
Tunisia	1	N	N
Uganda	> 33	> 13	13
Zambia	53	30	20
Zimbabwe	44	18	
Total Africa	**3 909**	**1 834**	
Belize	1	N	N
Canada	> 2 067	827	536
Costa Rica	224	28	25
Cuba	3	1	
Dominica	N	N	N
Dominican Republic	50	9	6
El Salvador	7	5	
Greenland	550	18	
Grenada	N	N	
Guatemala	59	24	
Haiti	4	1	N
Honduras	16	7	
Jamaica	1	N	
Mexico	430	135	33
Nicaragua	33	10	7
Panama	26	> 12	12
United States of America	2 040	1 339	376
Total North America	**5 511**	**2 416**	
Argentina	354	169	78
Bolivia	178	126	50
Brazil	3 040	1 250	818
Chile	227	162	97
Colombia	1 000	200	140
Ecuador	169	134	106

Table 7.1 Hydropower: capability at end-2008 (TWh/yr)

	Gross theoretical capability	Technically exploitable capability	Economically exploitable capability
French Guiana	2	1	N
Guyana	81	37	22
Paraguay	111	85	68
Peru	1 577	395	260
Surinam	39	13	8
Uruguay	32	10	6
Venezuela	731	261	100
Total South America	**7 541**	**2 843**	
Afghanistan	394	88	
Armenia	22	7	4
Azerbaijan	44	16	7
Bangladesh	4	2	1
Bhutan	263	99	56
Cambodia	88	34	5
China	6 083	2 474	1 753
Cyprus	59	24	
Georgia	136	70	41
India	2 638	660	442
Indonesia	2 147	402	40
Japan	718	136	
Kazakhstan	170	62	29
Korea (Republic)	52	26	19
Kyrgyzstan	163	99	55
Laos	233	63	
Malaysia	230	123	
Mongolia	57	9	
Myanmar (Burma)	348	139	
Nepal	733	154	15
Pakistan	> 475	204	
Philippines	47	20	18
Sri Lanka	21	8	7
Taiwan, China	103	20	16
Tajikistan	527	264	264
Thailand	18	16	15
Turkey	433	216	140
Turkmenistan	24	5	2
Uzbekistan	88	27	15
Vietnam	300	123	100
Total Asia	**16 618**	**5 590**	

Table 7.1 Hydropower: capability at end-2008 (TWh/yr)

	Gross theoretical capability	Technically exploitable capability	Economically exploitable capability
Albania	40	15	12
Austria	150	75	56
Belarus	8	3	1
Belgium	1	N	N
Bosnia-Herzegovina	70	24	19
Bulgaria	27	15	
Croatia	20	12	11
Czech Republic	13	4	
Denmark	N	N	N
Estonia	2	N	
Faroe Islands	1	N	N
Finland	31	23	16
France	270	100	70
Germany	120	25	20
Greece	80	20	15
Hungary	10	8	4
Iceland	184	64	40
Ireland	1	1	1
Italy	190	65	48
Latvia	7	4	4
Lithuania	6	2	1
Luxembourg	N	N	N
Macedonia (Republic)	9	6	
Moldova	2	1	1
Montenegro	27	11	
Netherlands	11	N	N
Norway	600	240	206
Poland	25	12	7
Portugal	32	25	20
Romania	70	32	21
Russian Federation	2 295	1 670	852
Serbia	27	19	18
Slovakia	10	7	6
Spain	162	61	37

Table 7.1 Hydropower: capability at end-2008 (TWh/yr)

	Gross theoretical capability	Technically exploitable capability	Economically exploitable capability
Sweden	200	130	90
Switzerland	125	43	41
Ukraine	45	22	17
United Kingdom	35	14	
Total Europe	**4 919**	**2 762**	
Iran (Islamic Rep.)	448	179	50
Iraq	225	90	67
Israel	N	N	
Jordan	4	2	
Lebanon	2	1	
Syria (Arab Rep.)	11	5	4
Total Middle East	**690**	**277**	
Australia	265	100	30
Fiji	3	1	
French Polynesia	1	N	N
New Caledonia	2	1	N
New Zealand	205	77	
Papua New Guinea	175	53	15
Solomon Islands	3	> 1	
Western Samoa	N	N	N
Total Oceania	**654**	**233**	
TOTAL WORLD	**39 842**	**15 955**	

Notes:

1. A quantification of hydropower capability is not available for a number of countries for which capacity and generation are shown in Table 7.2
2. As the data available on economically exploitable capability do not cover all countries, regional and global totals are not shown for this category
3. Sources: WEC Member Committees, 2009/10; *Hydropower & Dams World Atlas 2009*, supplement to *The International Journal on Hydropower & Dams*, Aqua~Media International; estimates by the Editors

Table 7.2 Hydropower: status of development at end-2008 (all schemes)

	In operation		Under construction	Planned
	Capacity	Actual generation in 2008	Capacity	Capacity
	MW	GWh	MW	MW
Algeria	278	560		
Angola	790	3 147	80	1 164 - 5 514
Benin	1	1	48	250
Burkina Faso	32	111		75
Burundi	32	111	1	177
Cameroon	729	3 772		1 819
Central African Republic	19	130		30 -137
Chad				6
Comoros	1	2		
Congo (Brazzaville)	89	394	120	0 - 1 621
Congo (Democratic Rep.)	2 410	7 303	162	3 690 - 43 000
Côte d'Ivoire	606	1 884		277
Egypt (Arab Rep.)	2 842	15 510		48
Equatorial Guinea	1	2		
Ethiopia	663	3 369	3 147	7 510
Gabon	170	893		
Ghana	1 180	5 619	400	425
Guinea	123	519		240
Kenya	719	3 247	41	160
Lesotho	76	200		26
Liberia				100
Madagascar	124	700	29	157 - 708
Malawi	300	1 100		429
Mali	155	500	140	100
Mauritania	30	120		
Mauritius	59	84		
Morocco	1 265	916	40	40
Mozambique	2 179	14 710		2 870 - 5 000

Table 7.2 Hydropower: status of development at end-2008 (all schemes)

	In operation		Under construction	Planned
	Capacity	Actual generation in 2008	Capacity	Capacity
	MW	GWh	MW	MW
Namibia	240	1 308	80	585
Niger				125
Nigeria	1 900	7 645	3 300	950 - 11 500
Réunion	121	632	20	
Rwanda	55	130		120 - 209
São Tomé & Príncipe	6	10	4	26
Senegal	60	293		123
Sierra Leone	4	18	50	85 - 310
Somalia	5	15		
South Africa	661	751	3	120
Sudan	575	1 457	1 200	2 000 - 3 600
Swaziland	61	161		
Tanzania	561	2 098		1 868
Togo	66	200	48	
Tunisia	70	38		20
Uganda	340	1 392	337	1 000
Zambia	1 632	9 729	570	1 141 - 4 400
Zimbabwe	754	5 521	1	400 - 3 400
Total Africa	**21 984**	**96 302**	**9 821**	
Belize	32	160		18
Canada	73 436	377 370	2 357	14 500
Costa Rica	1 510	7 384	200	1 083 - 1 621
Cuba	30	120		
Dominica	7	21		
Dominican Republic	804	1 438	292	140
El Salvador	472	2 033	66	261
Greenland	56	202	15	23

Table 7.2 Hydropower: status of development at end-2008 (all schemes)

	In operation		Under construction	Planned
	Capacity	Actual generation in 2008	Capacity	Capacity
	MW	GWh	MW	MW
Grenada				
Guadeloupe	10	21		
Guatemala	777	3 010	276	1 700
Haiti	63	480		
Honduras	522	2 290	7	612
Jamaica	24	170		0 - 75
Mexico	11 463	39 220	750	1 374
Nicaragua	105	529	52	230 - 1 202
Panama	869	4 322	597	1 100
Puerto Rico	85	338		
St Vincent & the Grenadines	6	25		1
United States of America	77 483	254 831		311
Total North America	**167 754**	**693 964**	**4 612**	
Argentina	9 950	30 600	125	2 800
Bolivia	440	2 310	88	2 338 - 3 064
Brazil	77 507	365 062	8 580	68 000
Chile	5 026	24 261	322	5 800
Colombia	8 996	43 020		429
Ecuador	2 033	9 040	1 971	1 706 - 6 986
French Guiana	116	512		
Guyana	1	1		100
Paraguay	8 130	53 710	395	200 - 1 790
Peru	3 242	19 040	220	98
Surinam	189	1 360		0 - 732
Uruguay	1 358	8 070		70
Venezuela	14 567	86 700	2 704	0 - 7 250
Total South America	**131 555**	**643 686**	**14 405**	

Table 7.2 Hydropower: status of development at end-2008 (all schemes)

	In operation		Under construction	Planned
	Capacity	Actual generation in 2008	Capacity	Capacity
	MW	GWh	MW	MW
Afghanistan	400	1 000	200	500
Armenia	1 080	1 797	146	134
Azerbaijan	1 020	2 300		1 030
Bangladesh	230	1 300		0 - 315
Bhutan	1 488	7 134	1 200	10 376
Cambodia	12	55	193	704 - 1 194
China	171 000	580 000	80 000	49 000 - 65 000
Cyprus	1	2		
Georgia	2 635	7 200		3 512 - 22 000
India	37 825	114 827	15 000	35 000
Indonesia	4 519	11 528	541	859 - 1 403
Japan	27 910	74 144	862	19 047
Kazakhstan	2 260	7 437	300	174
Korea (Democratic People's Rep.)	4 780	13 000		
Korea (Republic)	1 605	3 070		
Kyrgyzstan	2 910	10 604	240	2 732 - 4 764
Laos	673	3 777	2 655	2 706 - 13 406
Malaysia	1 910	6 700	3 344	628
Mongolia	28	5		120
Myanmar (Burma)	1 541	3 866	1 600	12 710 - 32 000
Nepal	590	2 759	135	2 230 - 25 000
Pakistan	6 481	27 701	1 600	17 000
Philippines	3 291	9 843	60	593
Sri Lanka	1 300	4 128	200	262 - 472
Taiwan, China	1 938	4 274	400	140 - 184
Tajikistan	5 030	15 800	168	1 190 - 8 790
Thailand	3 481	7 113		

Table 7.2 Hydropower: status of development at end-2008 (all schemes)

	In operation		Under construction	Planned
	Capacity	Actual generation in 2008	Capacity	Capacity
	MW	GWh	MW	MW
Turkey	13 700	33 270	8 600	22 700
Turkmenistan	1	3		
Uzbekistan	1 710	6 396	341	1 762
Vietnam	5 500	24 000	7 534	14 066
Total Asia	**306 849**	**985 033**	**125 319**	
Albania	1 432	3 850		2 000
Austria	8 429	33 986	1 100	1 600
Belarus	13	50	34	83 - 176
Belgium	107	397		
Bosnia-Herzegovina	2 380	2 834	4	570
Bulgaria	1 535	2 824	80	1 520 - 2 391
Croatia	2 075	5 589	40	283
Czech Republic	1 045	2 024		6
Denmark	9	26		
Estonia	8	48	1	2 - 10
Faroe Islands	31	96		
Finland	3 050	16 889		27
France	20 981	59 301		
Germany	4 740	20 900	113	20
Greece	3 243	2 345	484	160
Hungary	51	213		
Iceland	1 879	12 427	80	362 - 402
Ireland	249	969	1	
Italy	17 623	41 623		2 100
Latvia	1 562	3 107		
Lithuania	101	329	3	5 - 105
Luxembourg	40	106		

Table 7.2 Hydropower: status of development at end-2008 (all schemes)

	In operation		Under construction	Planned
	Capacity	Actual generation in 2008	Capacity	Capacity
	MW	GWh	MW	MW
Macedonia (Republic)	528	738	36	968
Moldova	64	318		
Montenegro	658	1 538		681 - 741
Netherlands	38	95		7
Norway	29 490	139 981	587	3 706
Poland	839	2 797	2	406
Portugal	4 873	7 296		2 000
Romania	6 375	17 006	668	1 414
Russian Federation	49 700	180 000	7 000	12 000
Serbia	2 891	10 056		300
Slovakia	1 776	3 927		140
Slovenia	1 027	3 959	108	617
Spain	16 077	17 787	264	
Sweden	16 195	68 400	156	
Switzerland	13 476	34 874	794	
Ukraine	4 514	10 949		160
United Kingdom	1 630	5 140	10	59
Total Europe	**220 734**	**714 794**	**11 565**	
Iran (Islamic Rep.)	7 423	17 987	5 083	10 426
Iraq	2 273	506	30	800 - 5 000
Israel	6	27		
Jordan	12	62		
Lebanon	280	280	76	
Syria (Arab Rep.)	1 505	2 869		
Total Middle East	**11 499**	**21 731**	**5 189**	
Australia	7 826	14 884	140	
Fiji	85	85		40

Table 7.2 Hydropower: status of development at end-2008 (all schemes)

	In operation		Under construction	Planned
	Capacity	Actual generation in 2008	Capacity	Capacity
	MW	GWh	MW	MW
French Polynesia	47	165		10
New Caledonia	78	460		18
New Zealand	5 375	22 091	18	612
Palau	10	18		
Papua New Guinea	222	513	42	307 - 2 281
Solomon Islands	10	20		20
Vanuatu	1	5		1
Western Samoa	12	51		
Total Oceania	**13 666**	**38 292**	**200**	
TOTAL WORLD	**874 041**	**3 193 802**	**171 111**	

Notes:

1. As the data available on planned capacity do not cover all countries or are quoted in terms of a range, regional and global totals are not shown for this category
2. Sources: WEC Member Committees, 2009/10; *Hydropower & Dams World Atlas 2009*, supplement to *The International Journal on Hydropower & Dams*, Aqua~Media International; national and international published sources; estimates by the Editors

Table 7.3 Hydropower: status of development at end-2008 for small-scale schemes (<10MW)

	Economically	In operation		Under construction and planned	
	Economically exploitable	**Capacity**	**Actual generation in 2008**	**Capacity**	**Probable annual generation**
	GWh/yr	**MW**	**GWh**	**MW**	**GWh**
Africa					
Ethiopia		6	16		
Morocco	1	N			
Swaziland		1	1		
North America					
Canada		980	4 860	1 784	8 845
Mexico		125			
United States of America	198 151	2 858	11 973		
South America					
Argentina		83	297	30	
Asia					
Japan		3 490		118	533
Kazakhstan	7 500	87	295	1 643	9 175
Pakistan	1 901	4	37	178	813
Thailand		63	188		
Europe					
Austria	10 000	1 179	4 600	200	700
Bulgaria		205	527		
Croatia	220	17	66	19	66
Czech Republic		292	967	6	32
Denmark		5	13		
Finland	1 330	341	1 107		
France		1 847	6 985		
Hungary	200	14	8		
Ireland		20	85	1	
Italy	12 500	2 606	9 159		

Table 7.3 Hydropower: status of development at end-2008 for small-scale schemes (<10 MW)

		In operation		Under construction and planned	
	Economically exploitable capability	Capacity	Actual generation in 2008	Capacity	Probable annual generation
	GWh/yr	MW	GWh	MW	GWh
Latvia		26	69		
Lithuania		26	73		
Macedonia (Republic)	1 093	45	103	68	
Portugal		307	486	50	
Romania	768	274	491	111	426
Serbia		35	16		
Slovenia	1 115	135	350	85	340
Sweden		1 142	4 800		
Switzerland	190 - 300			354	1 464
United Kingdom		173	568	59	
Middle East					
Iran (Islamic Rep.)		39	61	304	1 314
Israel		6	27		
Oceania					
New Zealand		95	402	12	52

Notes:

1. The data on small-scale schemes are those reported by WEC Member Committees. They thus constitute a sample, reflecting the information available in particular countries: they should not be considered as complete, or necessarily representative of the situation in each region. For this reason, regional and global aggregates have not been computed
2. Sources: WEC Member Committees, 2009/10

COUNTRY NOTES

The Country Notes on Hydropower have been compiled by the Editors, drawing principally upon the 2009 edition of the *Hydropower & Dams World Atlas*, supplement to *The International Journal on Hydropower & Dams*, published by Aqua~Media International, together with information provided by WEC Member Committees in 2009/10 and various national published sources.

Angola

According to *Hydropower & Dams World Atlas 2009,* Angola's estimated hydropower potential is, at 150 TWh/yr, one of the highest in Africa. So far, only a small fraction of the country's hydro potential has been harnessed. Work is, however, proceeding on the rehabilitation of some existing hydro plants. In particular, the capacity of the 180 MW Cambambe HPP is being increased to 260 MW through a modernisation programme.

In May 2009 an MOU was signed between the Government of Angola and Norsk Hydro to examine the feasibility of constructing 750-1 000 MW of new hydro capacity as part of an integrated aluminium production project. Studies are in progress on major hydro schemes at Lauca and Caculo-Cabaca on the Kwanza river, each with an installed capacity of 2 000 MW, and on a bi-national project at Baynes Mountain on the Cunene (see country note on Namibia).

Argentina

Hydropower & Dams World Atlas 2009 quotes Argentina's gross theoretical hydropower potential as some 354 000 GWh/yr. The Argentinian WEC Member Committee reports the technically feasible potential as 169 000 GWh/yr. Hydro output in 2008 was 30.6 TWh, in the context of an end-year installed capacity of 9 950 MW. A substantial portion of Argentina's hydro capacity is accounted for by its 50% share in two bi-national schemes: Salto Grande (installed capacity 1 890 MW), shared with Uruguay and Yacyretá (3 100 MW), shared with Paraguay.

The only sizeable hydro plant under construction is Los Caracoles (125 MW). The level of the Yacyréta reservoir is being raised, which will increase the capacity of the power plant by about 350 MW. It has been operating at a reduced head, with its capacity restricted to 1 800 MW. (see the Country Note on Paraguay).

Planned hydro developments include two major bi-national projects - Garabí (circa 1 500 MW) on the river Uruguay (a joint project with Brazil) and Corpus Christi (circa 2 880 MW) on the Paraná (jointly with Paraguay). Major projects within Argentina's borders include Condor Cliff and La Barrancosa on the Santa Cruz river in the south of the republic, with an aggregate capacity of about 1 740 MW, and Chihuido 1 (478 MW) and Chihuido 2 (circa 234 MW) on the Neuquén in northern Patagonia.

The Argentinian WEC Member Committee reports that, given the new macro-economic context that has arisen in recent times, the Ministry of Energy has accorded priority to the updating of the *Catalogue of Hydroelectric Projects*. The implementation of this policy involves the organisation of the Project Library, the updating and improvement of cost-estimation procedures, the review of existing projects using consistent criteria, and the evaluation of the resource up to the level of technical and economic pre-feasibility.

As a first step, the Ministry has undertaken an urgent review of 30 medium-scale projects and revised the procedures for cost estimation through the issue of a Manual on the subject. The first hydro projects have been selected on this basis, and an implementation process initiated, consisting in the first instance of a call for expressions of interest from investors, followed by bidding for construction, financing and operation.

The WEC Member Committee also reports that Argentina possesses 75 small, mini and micro hydro plants (of up to 30 MW capacity), with an aggregate capacity of 377 MW and an annual generation equivalent to 1.6% of national electricity demand. (Within this category it reports 83 MW for hydro units of less than 10 MW, generating a total of 297 GWh in 2007.) The project review undertaken by the Ministry of Energy has identified 116 projects (of up to 30 MW) in 14 provinces, with a total capacity of 425 MW and an average annual output of some 1 900 GWh. Adding this capacity to the plants presently in service, this category of hydropower could supply around 2.2% of Argentina's estimated electricity demand by 2016.

Australia

Australia is the driest inhabited continent on earth, with over 80% of its landmass receiving an annual average rainfall of less than 600 mm/yr and 50% less than 300 mm/yr. Rainfall, evaporation rates and temperatures also vary greatly from year to year, resulting in Australia having very limited and variable surface and groundwater resources.

Although Australia's gross theoretical hydropower potential is put at 265 TWh/yr, its economically exploitable capability is estimated by *Hydropower & Dams World Atlas 2009* as only 30 TWh/yr, of which more than 55% has already been harnessed.

The 140 MW Bogong plant in the state of Victoria is under construction, and scheduled to enter operation in 2010. This scheme constitutes an upgrade of the Kiewa HPP, and harnesses the overflow from the McKay Creek power station, conveyed to Kiewa via a specially-constructed 6.5 km tunnel.

Austria

Out of a total gross theoretical hydro potential of 150 TWh/yr, Austria's technically feasible potential is estimated at about 75 TWh/yr, of which 75% is considered to be economically exploitable. At present, the total installed capacity of hydro-electric power stations (excluding pumped-storage plants) is 8 430 MW; net generation in 2008 was approximately 34 TWh. Most of Austria's HPPs are of the run-of-river type.

The construction of a number of (mostly fairly small) pure hydro plants and the refurbishment/extension of some existing stations is under way or planned, but the construction of large hydro installations in Austria is currently confined to a number of pumped-storage schemes. Kops II (450 MW) was completed in 2009, while work is continuing at Limburg II, which will add 480 MW to the capacity of the Kaprun pumped-storage plant in 2012, and at Reisseck II (430 MW), part of the Reisseck-Kreuzeck hydro complex, scheduled to be completed in 2014.

Bhutan

Bhutan possesses a huge hydropower resource, its gross theoretical potential being assessed at over 263 TWh/yr, with a technically feasible capability of more than 99 TWh/yr (corresponding to a potential generating capacity of around 23 500 MW). Current installed hydro capacity is 1 488 MW, having recently been augmented by the commissioning of the 1 020 MW Tala HPP, Bhutan's first bi-national project, developed in conjunction with India.

Two more hydro plants are under construction - Punatsangchhu I (1 095 MW, for completion by 2015) and Dagachhu (114 MW). A further 2 400 MW of capacity is at the planning stage, notably Punatsangchhu II (circa 1 000 MW) and Mangdechhu (circa 720 MW).

The Governments of Bhutan and India are jointly planning to construct a total of ten HPPs, with an anticipated aggregate installed capacity of 11 576 MW, for development by 2020. The programme includes a number of massive projects, the largest being the Sunkosh Reservoir (4 000 MW), Kuri Gongri (1 800 MW) and Wangchhu Reservoir (900 MW) schemes. The principal function of the bi-national plants will be to boost Bhutan's exports of electricity to India.

Bolivia

Bolivia has a considerable hydro potential, its technically feasible potential being assessed at 126 TWh/yr, of which 50 TWh/yr is considered to be economically exploitable. Only a minute proportion of the potential has been harnessed so far – end-2008 hydro capacity, according to OLADE, was 440 MW, with an output of about 2.3 TWh.

Hydropower & Dams World Atlas 2009 reports that 88 MW of additional hydro capacity was under construction in early 2009. A wide range (2 338-3 064 MW) is quoted for planned hydro capacity, some of which relates to projects forming part of the Rio Madeira scheme outlined below.

Bolivia is working with Brazil on a mammoth joint project to exploit the hydro-electric potential of the Rio Madeira complex in the Amazon region. Within this project are the 800 MW Cachuela Esperanza plant sited entirely in Bolivia and the Guajara-Mirim plant (3 000 MW) to be located on the border between the two countries.

Brazil

Hydroelectric power is one of Brazil's principal energy assets: the republic has by far the largest hydropower resources on the continent. The Brazilian WEC Member Committee reports that the gross theoretical capability is estimated to be 3 040 TWh/yr, with an economically exploitable capability of about 818 TWh/yr, of which over 45% has so far been harnessed. Hydro output in

2008 was 365 TWh, which accounted for 80% of Brazil's electricity generation.

According to the Member Committee, Brazil had 8 580 MW of hydro capacity under construction at the end of 2008, with an estimated annual generation of around 41 TWh. Further hydro capacity reported to be planned for future development totalled 68 000 MW, with a projected annual output of some 327 TWh.

Hydropower & Dams World Atlas 2009 reports that major projects under way in early 2009 included two huge schemes on the Madeira river – Santo Antônio do Rio Madeira (3 150 MW) and Jirau (3 300 MW) – as well as Estreito (1 087 MW) on the Tocantins, Foz do Chapecó (855 MW) on the Uruguai, and at least eight more plants, each of over 100 MW.

Within the overall picture reported by the Brazilian Member Committee, small-scale hydro (since 1998, defined in Brazil as plants with a capacity of <30 MW) has an economically exploitable capability of 11 200 GWh/yr. The aggregate installed capacity of small HPPs was 1 001 MW at end-2008, and they produced a total of 5 300 GWh in 2008, equivalent to just over 47% of the assessed economic potential. A total of 513 MW of small-hydro capacity is planned for future installation which, if all the plans are implemented, will add some 2.5 TWh to Brazil's electricity supply.

Current legislation gives incentives to small-scale hydropower (<30 MW), in order to improve competition in the energy market. These incentives are specified as:

a) a 5% discount on energy transport rates due on load generation;

b) small HPPs may sell directly to captive consumers with a load above 500 kW (usually the limit for freeing consumers is 3 MW).

Cameroon

The technically exploitable hydro capability (115 TWh) is the fourth largest in Africa but the current level of utilisation of this potential is, like that in other hydro-rich countries in the continent, very low. Within a total hydro capacity of 729 MW, Cameroon's major stations are Song Loulou (installed capacity 396 MW) and Edéa (264 MW), for both of which contracts have been awarded for refurbishment. Annual hydro-electric output is about 3 850 GWh, implying a capacity factor of around 0.60.

The Cameroon WEC Member Committee reported for the 2007 *Survey* that development plans existed for new hydro stations at Nachtigal (230 MW), Menveele (120 MW), Lompangar (25 MW) and Birni à Warak (80 MW). A contract was signed in August 2007 for the construction of the 230 MW (earlier quoted as 120 MW) Memve'ele (or Menveele) hydro plant, and the following year the scheme was reported to have entered the final stage of planning. The 75 MW (previously 80 MW) Birni à Warak project was the subject of an agreement signed in 2008 between the Ministry of Energy and Water and the U.S. Trade and Development Agency. (Note that capacity levels and the spelling of project names vary from one source to another).

Canada

Canada possesses enormous hydropower potential – the Canadian Hydropower Association assessed Canada's 'total unexploited technical hydro potential' in 2005 as 163 173 MW, of which over half was in Québec, Alberta and British Columbia. At the end of 2007, total installed hydroelectric capacity was 73 436 MW.

Canada is one of the largest hydro producers in the world; in 2008, around 60% of its electricity generation was provided by hydroelectric power plants, which generated more than 377 TWh.

There are a number of significant hydroelectric projects under construction. In total, these projects will increase hydro generation capacity by more than 2 350 MW, with a probable annual generation of 11.15 TWh. According to Natural Resources Canada, hydro capacity reported to be in the course of planning adds up to a massive 14 500 MW, potentially supplying more than 68 TWh/yr.

In Québec, Eastmain 1A (893 MW) is scheduled for completion in 2012. Construction of the 200 MW Wuskwatim HPP in northern Manitoba is on course for completion in the same year. A considerable amount of refurbishment and upgrading of hydro plants is being carried out at various locations.

The total installed capacity of small hydro plants (of <10 MW) totalled 980 MW at end-2007, with an estimated annual generation of 4 860 GWh. Small-scale HPPs are located throughout the country, notably in British Columbia, Ontario, Québec, Nova Scotia, Newfoundland and Labrador. A total of 1 784 MW of additional small hydro capacity is reported as planned, with a projected generation of 8 845 GWh/yr.

Chile

There is a substantial hydropower potential, with a technically exploitable capability estimated at about 162 TWh/yr, of which about 15% has so far been harnessed. Hydro output in 2008 was 24.3 TWh, equivalent to just over 40% of Chile's total net electricity generation.

The *Balance Nacional de Energía* published by the Comisión Nacional de Energía gives Chile's end-2008 installed hydro capacity as 5 026 MW. *Hydropower & Dams World Atlas 2009* reports that at mid-2009 at least 322 MW was under construction, notably La Higuera (155 MW) and La Confluencia (145 MW), both run-of-river plants on the Tinguiririca in central Chile.

More than 5 800 MW of new HPPs is at the planning stage, including major projects at Alto Maipo (531 MW), Angostura (309 MW), Neltume and Choshuenco (580 MW) and Rio Cuervo (440-600 MW), together with five plants (total capacity of approximately 2 750 MW) on the Baker and Pascua rivers in the southern region of Aysen.

China

China's hydroelectric resources are vast, however measured: its gross theoretical potential exceeds 6 000 TWh/yr, its technically feasible potential is put at 2 474 TWh/yr while its economically feasible potential has been assessed at 1 753 TWh/yr - in all instances, far larger than that of any other country in the world. Current hydro-electric generation (including output from pumped-storage schemes) is in excess of 500 TWh/yr, contributing about 16% of the republic's electricity generation in 2008.

China leads the world in hydro-electric development: *Hydropower & Dams World Atlas 2009* reported that in early 2009 some 80 000 MW of hydro capacity was under construction. The largest hydro project is the Three Gorges complex (eventual capacity 22 500 MW), which is gradually being brought into operation, with completion scheduled for 2010. Three Gorges generated nearly 80 TWh in 2009, more than all of Japan's hydro stations produce annually.

Besides the Three Gorges project, there are many other massive plants in hand. Examples of such projects include Xiluodu (12 600 MW), Xiangjiaba (6 000 MW), Longtan (6 300 MW), Jinping II (4 800 MW), Xiaowan (4 200 MW), Laxiwa (4 200 MW), Jinping I (3 600 MW), Pubugou (3 600 MW), Dagangshan (3 600 MW) and Goupitan (3 000 MW).

Planned schemes include two huge hydro plants on the Jinsha Jiang (River Yangtze): Wudongde (9 000 MW) and Baihetan (12 600 MW).

In early 2009 China had 13 875 MW of pumped-storage capacity, with 5 960 MW under construction and 36 680 MW planned.

Colombia

The theoretical potential for hydropower is very large, being quoted by *Hydropower & Dams World Atlas 2009* (HDWA) as 1 000 TWh/yr, of which 20% is classed as technically feasible. Hydro output in 2008 represented around 30% of the economically exploitable capability of 140 TWh/yr and accounted for about three-quarters of Colombia's electricity generation.

The Porce III hydro plant (660 MW) is scheduled for completion in December 2010. Environmental permission has been granted for the planned Pescadero Ituango scheme (2 400 MW) on the river Cauca.

According to HDWA, some 10 000 MW of new capacity is being planned for medium- to long-term implementation, including the first stage of Pescadero Ituango (1 200 MW), as well as Sogamoso (800 MW), Quimbo (400 MW), and Porce IV (400 MW). In addition, there is estimated to be scope for uprating existing HPPs by a total of around 500 MW.

Congo (Democratic Republic)

The assessed potential for hydropower is by far the highest in Africa, and one of the highest in the world. The gross theoretical potential of the Congo River is almost 1 400 TWh/yr and the technically feasible exploitable capacity is put at

100 000 MW. The current level of hydroelectric output is equivalent to only around 3% of the republic's economically exploitable capability. Hydro provides virtually the whole of its electricity.

The national public electricity utility SNEL has 17 hydro plants, of which 11 plants have an installed capacity of over 10 MW. The total rated capacity of SNEL's hydropower plants is 2 410 MW; with the largest stations being Inga 1 (351 MW) and Inga 2 (1 424 MW). The power plants of these stations are either being (or planned to be) refurbished, in order to boost their faltering performance by an additional 660 MW. Moreover, a significant increase in capacity would be provided by the Inga 3 project (4 320 MW), which is currently in the planning phase.

There is also a huge scheme (Grand Inga, 40 000 MW or more), incorporating the supply of electricity to other parts of Africa via new long-distance high-voltage transmission lines. Both the power generating plant and transmission network have been the subject of preliminary investigations and pre-feasibility studies.

These studies identified three major African interconnection HVDC projects:

- Northern Highway (Inga to Egypt);
- Southern Highway (Inga to South Africa);
- Western Highway (Inga to Nigeria).

These electricity Highways would supply the five African power pools: SAPP, WAPP, PEAC, EAPP and COMELEC.

The World Energy Council is facilitating the development of the Congo River hydropower projects. WEC states that 'the Inga Projects offer a unique opportunity to provide affordable and clean electricity to more than 500 million Africans who do not have it today'.

A WEC Workshop on 'Financing the Inga hydropower Projects' was held in London in April 2008. The main objective of the Workshop was to identify the key requirements and potential partners for an accelerated and sustainable development of the overall Inga hydropower projects, namely: the rehabilitation of existing installations including Inga 1 & 2 and the development of Inga 3 (4 320 MW) and Grand Inga (40 000 MW).

The WEC also identified basic principles to move forward the Inga Projects. The Workshop recognised the sense of urgency to progress the projects and to coordinate the planning process in an orderly and timely manner. But these will highly depend on factors such as the improvement of the political situation in the DRC, strong government support for the projects and a high level of cooperation/integration with the key stakeholders.

Costa Rica

For a country with a surface area of only 51 100 km^2, Costa Rica has a surprisingly large hydroelectric potential. Its gross theoretical potential is estimated at 223.5 TWh/yr, within which a hydropower capacity of 5 694 MW has been assessed as economically feasible (after exclusion of areas within national parks).According to the Instituto Costarricense de Electricidad, aggregate installed hydro capacity was 1 510 MW at end-2008, equivalent to about 64% of Costa Rica's total generating capacity, and about 27% of its estimated economic potential.

Several new hydro plants are under construction or planned: nearing completion are Pirris (128 MW) and Toro 3 (50 MW), both due to enter service in 2011, together with three BOT schemes, each with 50 MW capacity and scheduled for operation in 2013: Torito on the Reventazon river, at the end of the tail-race of the Angostura HPP, and Capulin-San Pablo and Chucas on the Tarcoles. Two larger projects reported to be at the feasibility stage in 2009 were Diquís (622 MW), planned for completion in 2016, and Reventazón (298 MW), planned for 2014.

Czech Republic

The overall potential for all sizes of hydropower is quite modest (technically exploitable capability: 3 978 GWh/yr, as reported by the Czech WEC Member Committee). Total hydroelectricity output in 2008 was 2 024 GWh, representing 51% of this potential. Hydropower furnishes less than 3% of the republic's electricity generation.

A relatively high proportion (nearly 40%) of the technically exploitable capability is classified as suitable for small-scale schemes; installed capacity in this category at the end of 2008 was 292 MW, equivalent to about 28% of the Czech Republic's total hydro capacity. Actual generation from small-scale schemes in 2008 accounted for nearly 48% of hydro output, reflecting the higher average capacity factor achieved by small hydro compared with the larger stations.

The *State Energy Concept* provides support for the construction of further small-scale HPPs, in particular through favourable feed-in tariffs, which guarantee a positive return on investment. Investment subsidies serve as another effective stimulus. The number of sites available for the construction of small hydro plants is reported to be small. Licensing procedures are fairly complex and often somewhat protracted.

The only planned extensions to the Czech Republic’s hydro generating capacity comprise two small plants presently under construction; a 5 MW plant at Litomerice on the Elbe (Energo-Pro Co.) and a 0.5 MW plant at Melnik (CEZ, plc). Over half of the existing small HPPs use obsolete technology (dating from 1920-1950). There are plans to modernise the technology, with the aim of improving efficiency by up to 15%.

Ecuador

The gross theoretical hydro potential is substantial, at about 167 TWh/yr, within which there is estimated to be an economically feasible capability of nearly 106 TWh/yr. According to *Hydropower & Dams World Atlas 2009*, Ecuador had a number of small-to-medium sized hydro schemes under construction in 2009, including Toachi-Pilaton (228 MW) and Mazar (160 MW). Preliminary works at the site of the largest of the plants under way, Coca Codo Sinclair (1 500 MW), have been completed; commercial operation is scheduled to commence in 2015.

The total amount under construction in 2009 was 1 971 MW, whilst a further 1 690 MW of hydro capacity was being planned for installation by 2020. In addition to these developments, more than 5 GW of new HPPs was reported to be under study for longer-term implementation, including some 4 GW on the river Zamora and 1.3 GW on the Guayllabamba.

Ethiopia

There are enormous resources for hydro generation, the gross theoretical potential (650 TWh/yr) being second only to that of Congo (Democratic Republic) in Africa. *Hydropower & Dams World Atlas 2009* shows Ethiopia's economically feasible potential as 162 TWh/yr, of which 10% represents the potential for small-scale hydro installations. The Ethiopian WEC Member Committee reports that hydro output in 2008 was about 3 369 GWh, a minute fraction of the assessed potential. Currently, hydropower provides more than 95% of Ethiopia's electricity.

The WEC Member Committee also reports that 3 147 MW of hydropower capacity was under construction at end-2008, with a probable total annual generation approaching 11 TWh. The current construction programme comprises five HPPs: Amerti Neshe (97 MW); Beles (460 MW); Gilgel Gibe II (420 MW); Gilgel Gibe III (1 870 MW); and Tekeze (300 MW).

Further capacity increases, at various stages of planning, total more than 7 500 MW. A contract was signed with China in July 2009 for constructing the Gibe IV and Halele Werabesa schemes, which will add 2 150 MW to Ethiopia's hydro capacity.

Finland

The Finnish WEC Member Committee reports that Finland's gross theoretical hydro capability is 30.9 TWh/yr, with a technically exploitable component of about 22.6 TWh/yr, of which just over 70% is regarded as economically exploitable. At end-2008, total installed hydro capacity was 3 050 MW. Net generation of hydroelectricity during 2008 was 16.9 TWh, substantially higher than the reported 'probable annual generation' of 13.05 TWh.

No further hydro capacity is reported to be under construction or planned. Even judged against the lower ('probable') level, it is clear that Finland has already harnessed a high proportion of its economic hydro potential. Moreover, as pointed out by the Member Committee in their submission for the 2007 *Survey*, a significant proportion of the natural flows suitable for power production are located in preservation areas.

Small-scale (<10 MW) hydropower capacity is reported to amount to 341 MW, producing an average annual output of 1 107 GWh, not far below the assessed economically exploitable capability for small-scale hydro of 1 330 GWh/yr.

France

France is one of Western Europe's major producers of hydroelectricity, but its technically feasible capacity has now been very largely exploited. At the end of 2008, total hydroelectric generating capacity (excluding pumping) stood at 20 981 MW. The year’s net production of 59.3 TWh compares with an estimated technically exploitable capability of 100 TWh/yr, of which 70% is considered to be economically exploitable.

The total output capacity of small-scale (less than 10 MW) plants is approximately 1 850 MW, which generated almost 7 TWh in 2008.

The PPI (long-term plan for investments in electricity generation) for the period 2009-2020 envisages targets for an increase of 3 TWh/yr in electricity output and of 3 000 MW in installed capacity through the installation of new small units and the enlargement of existing facilities.

A buy-back tariff (Arrêté dated 25 June 2006) is in operation for hydro-electric installations with a capacity of less than 12 MW. The tariff was revised in an Arrêté of 1 March 2007.

Ghana

There are 17 potential hydro sites, of which only Akosombo (upgraded in 2005 from 912 to 1 038 MW) and Kpong (160 MW) have so far been developed; their total net capacity, according to the Volta River Authority (VRA) website, is 1 180 MW. Electricity generation in Ghana is a responsibility of the VRA, which was established in 1961. The average annual output of its two existing hydro stations (circa 5 600 GWh) is equivalent to about half of Ghana's technically exploitable hydro capability, as assessed in 1985.

Construction of the 400 MW Bui dam on the Black Volta is under way. Completion of the work, being undertaken by China's Sino Hydro Corporation, is scheduled for 2012. The *Hydropower & Dams World Atlas 2009* states that a total of 425 MW of smaller HPPs (with installed capacities of 100 MW or less) is planned for implementation over the forthcoming ten years.

Guinea

Guinea is well-endowed with water resources, having 1 165 watercourses draining into 23 hydrographic basins, of which 16 are shared with neighbouring countries. The WEC Member Committee reported for the 2007 *Survey* that the gross theoretical hydro capability had been assessed as 26 TWh/yr, the technically exploitable capability as 19.3 TWh/yr and the economically exploitable capability as 19 TWh/yr. *The Hydropower & Dams World Atlas 2009* concurs with the first two measures but quotes the third as presently 18.2 TWh/yr. With a current installed hydro capacity of 123 MW and a 2008 output of not much more than 500 GWh, it is clear that the republic's potential has barely been touched - less than 3% of the economic capability has been harnessed so far.

The capacity potential corresponding to the technically exploitable capability of 19.3 TWh/yr is 6 100 MW, located mainly in the regions of Basse Guinée (46%) and Moyenne Guinée (43%), with minor amounts in Haute Guinée (8%) and Guinée Forestière (3%). Some 40% of the national hydro potential lies in the basin of the River Konkouré.

The Guinea WEC Member Committee reported that there were no hydro plants actually under construction at end-2005 but that three plants - Fomi (90 MW), Souapiti (508 MW) and Kaléta (238 MW), with a total probable annual generation of 3 940 GWh, were under study. Additional hydro output which might feasibly become available in the longer term was put at over 5 100 GWh/yr. Taken together with the planned development of hydro capacity, this would imply an eventual total output of some 9.5 TWh/yr, equivalent to more than half the currently assessed economically exploitable capability.

Iceland

Apart from its geothermal resources, Iceland's hydropower potential represents virtually its only indigenous source of commercial primary energy. Its gross theoretical potential of 184 TWh/yr includes 40 TWh of economically exploitable output. Hydroelectricity production in 2008 was 12 427 GWh, implying that around 30% of this economic potential has been developed. Hydropower provided 20% of Iceland's primary energy consumption and 75% of its electricity generation in 2008.

The 690 MW Fljótsdalur HPP, which is part of the Kárahnjúkar hydro scheme, came into operation in November 2007 and reached its full load in February of the following year. Iceland's total installed hydro capacity is now 1 879 MW. A further 80 MW of hydro capacity is under construction at the Búdarháls site on the Tungnaá river in southern Iceland. A number of other projects have been awarded licences or are at the planning stage.

The technically exploitable capability of small-scale hydro plants has been reported to be 12.3 TWh/yr, equivalent to about 19% of the level for total hydro. Installed capacity of small hydro at end-2008 was 55 MW, equivalent to 2.9% of total hydro capacity.

India

India's hydro resource is one of the largest in the world: according to the 2008 edition of the *Hydropower & Dams World Atlas*, its gross theoretical hydropower potential is estimated to be 2 638 TWh/yr, within which is a technically feasible potential of some 660 TWh/yr and an economically feasible potential of 442 TWh/yr. The public utilities' total installed hydroelectric capacity amounted to 37 825 MW at the end of 2008, with a corresponding generation of 115

TWh, equivalent to 16.0% of India's public sector electricity generation.

Hydropower & Dams World Atlas 2009 reports that in early 2009 about 15 GW of hydro capacity was under construction and a further 35 GW was at various stages of planning. As part of India's 11th Five Year Plan, Teesta V (510 MW) in Sikkim and Omkareshwar (520 MW) in Madhya Pradesh have both recently been commissioned. Large hydro plants currently under construction within the 11th Five Year Plan include Subansiri Lower (2 000 MW) in Assam, and Parbati II (800 MW) and Parbati III (520 MW) in Himachal Pradesh.

Numerous other hydro projects are under way or at the planning stage. In addition, 55 hydro schemes have been designated as suitable for renovation and upgrading, which could in due course result in an increment of some 2 500 MW to India's generating capacity.

Hydropower & Dams World Atlas 2009 reports that there are at least 420 small-scale hydro plants in operation, with an aggregate installed capacity of 2 046 MW; a further 187 small-hydro schemes, with an aggregate capacity of 521 MW, were under construction in 2007, the most recent year reported on in this connection.

Indonesia

At some 2 150 TWh/yr, Indonesia's gross theoretical hydro potential is the third largest in Asia. Its technically feasible potential is just over 400 TWh/yr, of which about 10% is considered to be economically exploitable. Average annual hydro output is about 11.5 TWh, indicating the evident scope for further development within the feasible potential. Hydro presently provides approximately 8% of Indonesia's electricity supply.

Hydropower & Dams World Atlas 2009 reports that 541 MW of hydroelectric generating capacity was under construction in 2009, including major new HPPs at Asahan 1 (180 MW) and Asahan 3 (154 MW), due for completion in 2012 and 2011, respectively. Between 859 and 1 403 MW of additional hydro capacity was at the planning stage.

Iran (Islamic Rep)

Hydropower & Dams World Atlas 2009 quotes the gross theoretical hydropower potential as 179 TWh/yr, of which 50 TWh/yr is regarded as technically feasible.

The Iranian WEC Member Committee reports that installed hydropower capacity was 7 423 MW at end-2007, and that Iran had 5 083 MW of hydro capacity under construction and that a further 10 426 MW was in various phases of planning.

Italy

The WEC Member Committee for Italy reports that the maximum national theoretical hydroelectric capability has been estimated at about 190 000 GWh/year (converting into energy all the water available). However, a plausible value for the technically exploitable capability might be about 65 000 GWh, while the economically exploitable capability has been estimated at about 25% of the gross theoretical capability, or 47 500 GWh.

In late 2008, 2 184 hydro plants were in operation, with an aggregate installed capacity of 17 623 MW and a total annual output of 41 623 GWh. (These figures appear to include pumped-storage plants.) Hydroelectric power represented about 74% of total installed renewable capacity. Hydro output in 2008 (a year in which there was abundant rainfall) showed strong growth (+26.8%), which brought it back to the 2004 level.

As regards planned capacity, the *Italian Position Paper 2007* specifies a number of historical and environmental policies that must be implemented in the future (e.g. the release of a minimal vital water flow). Given these trends, and taking account of the effects of new investment, especially in small hydroelectric plants, production is expected to reach 43.15 TWh by 2020, with the installed capacity rising to 20 200 MW.

The gross theoretical capability of small-scale HPPs in Italy is put at 38 000 GWh/yr (one-fifth of total hydro), within which the economically exploitable component is estimated to be 12 500 GWh/yr, as derived from the aforementioned *Italian Position Paper*.

In 2008, plants with a capacity of less than 10 MW represented approximately 14% of total installed hydro capacity, with facilities in the 1-10 MW class accounting for about 11% and the smaller plants for around 3%. As there are problems in building large HPPs, future increases in hydro output may be provided very largely by small hydropower projects.

Japan

A high proportion of Japan's massive potential for hydro generation has already been harnessed. *Hydropower & Dams World Atlas 2009* (HDWA) quotes its gross theoretical capability as about 718 TWh/yr, of which 136 TWh is regarded as technically exploitable. Hydro generation (excluding pumped storage output) amounted to about 74 TWh, representing nearly 7% of Japan's total electricity output.

Most of the sites suitable for the installation of large-scale conventional hydro-electric plants have now been developed. The great majority of the larger hydro projects presently under construction or planned in Japan are pumped-storage schemes. In 2008 Japan had about 7 GW of all types of hydro capacity under construction, of which nearly 90% was accounted for by four large pumped-storage schemes: Omarugawa (1 200 MW), Kannagawa (2 820 MW), Kyogoku (600 MW) and Kazunogawa (1 600 MW).

The technically exploitable capability for small-scale hydro developments is reported by the Japanese Member Committee to be 47 TWh/yr, a relatively high proportion (34%) of the total hydro level. Developed small-hydro capacity at end-2008 was about 3.5 GW, equivalent to 12.5% of total conventional hydro capacity. Small-scale capacity planned for construction totalled 118 MW, with a probable annual generation of 533 GWh.

Jordan

For the 2007 *Survey of Energy Resources*, the Jordanian WEC Member Committee reported that pre-feasibility studies had indicated a technical hydro potential of 400-800 MW through exploiting the difference in elevation of about 400 metres between the Red Sea and the Dead Sea. Terms of Reference for this project were approved by the three parties concerned (Jordan, Palestine and Israel) during a conference held at the Dead Sea in May 2005. In July 2008, the World Bank awarded a contract for a feasibility study, which was expected to take 24 months to complete.

Conventional hydropower resources in Jordan are limited, owing to the fact that surface water resources are almost negligible at present. There are two small HPPs: the King Talal Dam with a rated capacity of 5 MW and a scheme at Aqaba thermal power station which utilises the available head of returning cooling seawater, also with a capacity of 5 MW. There are no plans for the expansion of conventional hydro capacity.

Kazakhstan

The WEC Member Committee reports that the main hydropower resources are located in the eastern and southeastern regions of the country. Kazakhstan's major HPPs are located as follows:

- on the Irtysh river – Bukhtarma (675 MW), Ust-Kamenogorsk (332 MW) and Shulbinsk (702 MW);
- on the Ili river – Kapchagay (364 MW);
- on the Syrdarya river – Shardara (100 MW).

The Moinak HPP (300 MW) is presently under construction. By 2020 it is planned to commission Kerbulak (50 MW), Bulak (68 MW) and number of smaller HPPs with a total installed capacity of 56 MW.

In Kazakhstan, according to existing legislation, small-scale HPPs include those with a capacity of up to 35 MW.

Laos

Only a very small proportion of Laos's massive hydro endowment has so far been harnessed. Its technically feasible potential is quoted by *Hydropower & Dams World Atlas 2009* (HDWA) as 18 000 MW, whereas its total installed hydropower capacity at end-2008 was less than 700 MW.

According to HDWA, the Ministry of Energy and Mines lists 60 HPPs, with a total installed capacity of 16 061 MW, as being at various stages of construction or planning. Six hydro schemes, with a total capacity of 2 131 MW, were under construction in 2009, with twelve more totalling 3 230 MW reported to be at an advanced stage of negotiation. An additional 42 projects, totalling 10 700 MW, are the subject of feasibility studies.

Much of the new hydro generating capacity is destined to meet demand from neighbouring countries; export arrangements are already in place with Thailand, Vietnam and Cambodia. Among the plants presently under construction, the largest are:-

- Nam Ngum 2 (615 MW), scheduled for completion in 2013;
- Nam Theun 1 (424 MW), due to enter operation in 2014 (exporting to Thailand);
- Xe Kaman 3 (250 MW, completion expected in 2010 (90% of its output to be sold to Vietnam).

In March 2010, the Nam Theun 2 HPP (1 070 MW) began commercial exports of electricity to the Thai state utility EGAT.

Lithuania

The Lithuanian WEC Member Committee states that, based on the provisions of the National Energy Strategy, the possibility of constructing HPPs (with capacities of more than 10 MW) on the River Neris could be considered. However, their construction is uncertain, in view of environmental restrictions.

The Kruonis pumped storage plant was built in 1992-1998 and comprises four units, each with a capacity of 225 MW. The plant serves to supply the peak and semi-peak loads of Lithuanian consumers and neighbouring countries.

Opportunities for the construction of small HPPs with capacity of less than 10 MW are limited. The total probable annual generation of existing and new small hydro plants is expected by the Member Committee to reach about 160 GWh in 2020.

Macedonia (Republic)

Out of a number of hydro plants being planned as BOT schemes in 2009, the largest were Galishte (194 MW) on the river Vardar, and a 333 MW pumped-storage plant at Chebren on the Black river.

Madagascar

Madagascar has a considerable land area (greater than that of France, for example) and heavy annual rainfall (up to 3 600 mm). Consequently, the potential for hydropower is correspondingly large: gross theoretical potential is put at 321 TWh/yr, within which the technically feasible potential is 180 TWh/yr, of which about 27% is deemed to be economic. With current installed capacity standing at 124 MW and annual hydro output about 700 GWh, the island's hydro capability has scarcely begun to be utilised.

There are three HPPs of over 10 MW installed capacity in service: Mandraka (24 MW), Andekaleka (58 MW) and Sahanivotry (15 MW). An additional 29 MW unit is being installed at Andekaleka, while Mandraka II (57 MW) will be developed to utilise the full head available at the site.

Malaysia

There is a substantial potential for hydro development, with a total technically feasible potential of about 123 TWh/yr, most of which is located in Sarawak (87 TWh/yr) and Sabah (20 TWh/yr); a considerable proportion of Peninsular Malaysia's technically feasible potential of 16 TWh/yr has already been developed.

Construction of the 2 400 MW Bakun hydro plant in Sarawak continued during 2009. It is expected to begin partial operation at the end of 2010 and to be fully operational by the end of the following year. Work on the 944 MW Murum hydro project (also in Sarawak) is progressing, with the plant due to commence operations in 2012.

Mexico

With a technically feasible hydropower potential, according to *Hydropower & Dams World Atlas 2009*, of 135 TWh/yr and an economically exploitable capability of 33 TWh/yr, Mexico possesses a considerable hydroelectric potential. The Mexican WEC Member Committee reports that installed hydro capacity at end-2008 was 11 463 MW, with 2008 generation amounting to 39.2 TWh.

For the present *Survey*, the Mexican WEC Member Committee has reported that La Yesca (750 MW) is under construction for CFE, and that 1 374 MW of hydro capacity is planned by CFE for future development. Generating capacity at La Villita Michoacán is being boosted by 400 MW, and at Infiernillo Guerrero by 200 MW, through refurbishment and uprating programmes. The start of construction work on CFE’s La Parota (900 MW) hydro project on the Papagayo river has been put back by three years, with completion now scheduled for 2021.

End-2008 installed capacity of small-scale hydropower is reported by the Mexican WEC Member Committee to have been 125 MW.

Mozambique

Hydropower & Dams World Atlas 2009 quotes Mozambique's gross theoretical hydro potential as 103.4 TWh/yr, with a technically feasible level of about 37.6 TWh/yr, of which some 84% was regarded as economically feasible in 2009. By far the greater part of the country's installed hydro capacity of 2 306 MW (of which, 2 179 MW is in operation) is provided by the Cahora Bassa plant (2 075 MW) on the Zambezi. The South Bank Powerhouse (5 x 415 MW) at Cahora Bassa has been refurbished in recent years. A project for a 1 250 MW North Bank Powerhouse is under study.

By mid-2009, a framework agreement had been signed for the 1 500 MW Mphanda Nkuwa hydro scheme, and environmental studies had been completed. Other potential future hydro projects in Mozambique include Boroma (444 MW) and Lupata (654 MW).

Myanmar (Burma)

The country is well endowed with hydro resources: its technically feasible potential is given by *Hydropower & Dams World Atlas 2009* as 39 720 MW. At an assumed annual capacity factor of 0.40, this level would imply an annual output capability of almost 140 TWh; actual output in 2008 was only 3.9 TWh. There thus appears to be ample scope for substantial development of hydropower in the long term.

The Shweli 1 plant (600 MW) on the Shweli river in northeast Myanmar was completed in 2008. Work on the Yeywa (790 MW) project on the Myitnge river, towards the centre of the country, is nearing completion. Longer-term projects include a major export-orientated scheme, Ta Sang (7 110 MW) on the Thanlwin (or Salween) river, from which it is planned to supply 1 500 MW to Thailand. In March 2010, construction of this project (the first of a planned series of five HPPs on this river) was reported to be getting under way.

More than 5 000 MW of additional hydro capacity is planned, involving 14 projects, including Shweli 2 (640 MW), Shweli 3 (360 MW), Shwezaye (660 MW) and Tanintharyi (600 MW).

Namibia

Namibia's only perennial rivers are the Kunene and Kavango (forming borders with Angola and Zambia in the north) and the Orange River bordering South Africa in the south. Any plans to develop hydro power are thus subject to lengthy bilateral negotiations. Another problem leading to limited exploitation of hydro resources is the scarcity of rain and the extensive droughts.

In mid-2009, the Governments of Namibia and Angola were reported to be planning the construction of a 300-500 MW hydro plant at Baynes Mountain on the Kunene.

Nepal

There is a huge theoretical potential for hydropower, reported by *Hydropower & Dams World Atlas 2009* (HDWA) to be some 733 TWh/yr, with a technically exploitable capability put at 44 000 MW (corresponding to an output of about 154 TWh/yr, assuming a capacity factor of 0.40). The HDWA quotes Nepal's economically exploitable capability as 14 742 GWh/yr. Actual hydro generation in 2008, according to the Nepal Electricity Authority, was 2 759 GWh, a small fraction of the economic potential.

Total hydro capacity at end-2008 was 590 MW, with about 135 MW under construction, including Middle Marsyangdi (70 MW), which entered commercial service in February 2009. HDWA reports that plans exist for an additional 2 230 MW to be installed by 2017, including 400 MW for export to India. There are at least three large projects - West Seti (750 MW), Upper Karnali (300 MW) and Upper Tama Koshi (601 MW) – that are expected to go ahead in the near term. Preparation of the Detailed Project Report on West Seti was suspended in February 2010 on account of 'internal problems' affecting the company concerned.

HDWA reports that there are 42 small and mini hydro schemes in operation, with an aggregate capacity of very nearly 20 MW. Additional small plants under construction or planned for installation in the near term total some 30 MW.

Norway

Norway possesses Western Europe's largest hydro resources, both in terms of current installed capacity and of economically feasible potential. *Hydropower & Dams World Atlas 2009* (HDWA) reports a gross theoretical capability of 600 TWh/yr, of which 205.7 TWh is economically exploitable. The hydro generating capacity installed by the end of 2008 had an output capability equivalent to about 60% of the economic potential. Hydro generation provides virtually all of Norway's electric power.

According to HDWA, more than fifty (mostly quite small) hydro plants were under construction in Norway (as at mid-2009).

The economically exploitable capability applicable to small-scale hydro schemes was reported by HDWA to be 22.1 TWh/yr. Installed capacity of small hydro plants was stated to be 1 521 MW, with an average annual output capability of 6.8 TWh. Some 46 small HPPs were under construction in 2009, with an aggregate installed capacity of about 133 MW, giving an average annual output of some 470 GWh. A further 326 were planned, with an installed capacity totalling 1 029 MW and annual output averaging 3 663 GWh.

Pakistan

At 30 June 2009, total installed hydro capacity was 6 481 MW, almost exactly one-third of total national generating capacity. According to *Hydropower & Dams World Atlas 2009* (HDWA), Pakistan has a gross theoretical hydro potential of approximately 475 TWh/yr, of which some 204 TWh/yr is regarded as technically feasible. The main potential sources of hydropower are on the rivers Indus and Jhelum, plus sites at Swat and Chitral.

Hydro capacity in operation at the end of 2009 included major plants at Tarbela (3 478 MW), Ghazi Barotha (1 450 MW) and Mangla (1 000 MW); gross hydro-electric output during the year was 27.7 TWh, accounting for 30% of Pakistan's electricity generation.

In 2009 the 969 MW Neelum Jhelum hydro scheme and various smaller schemes in the 70-130 MW bracket were reported to be moving ahead. Several huge public sector projects – including Bunji (7 100 MW), Diamer Basha (4 500 MW) and Dasu (4 320 MW), all sited on the Indus – are being developed, as well as private-sector schemes such as Kohala (1 100 MW) on the Jhelum. Total hydro capacity reported to be under construction in early 2009 was some 1 600 MW. About 17 000 MW of additional hydro capacity is planned for construction starts over the next ten years.

HDWA quotes Pakistan's small-scale (1-22 MW) hydro potential as 302 GWh/yr, but states that only 68 MW out of an installed capacity of 107 MW is actually in operation. A total of 350 MW of small hydro capacity is reported to be planned.

Paraguay

In the context of energy supply, Paraguay's outstanding natural asset is its hydroelectric potential, which is mainly derived from the river Paraná and its tributaries. The country's gross theoretical capability for hydroelectricity is about 111 TWh/yr, of which 68 TWh is estimated to be economically exploitable. Two huge hydroelectric schemes currently utilise the flow of the Paraná: Itaipú, which Paraguay shares with Brazil, and Yacyretá, which it shares with Argentina.

Itaipú is one of the world's largest hydroelectric plants, with a total generating capacity of 14 000 MW, of which Paraguay's share is 7 000 MW. This share is far in excess of its present or foreseeable needs and consequently the greater part of the output accruing to Paraguay is sold back to Brazil. Itaipú's 19th 700 MW unit entered commercial operation in September 2006, and the 20th came on line during 2007.

The bi-national plant at Yacyretá, downstream from Itaipú, has an installed capacity of 3 100 MW. There are 20 generating units, each of 155 MW capacity but operating at only 120 MW per unit, owing to the level of the reservoir being held below that originally planned. The level of the Yacyréta reservoir is being raised, which will enable the bi-national plant's turbines to operate nearer to their design capacity of 155 MW each.

Paraguay has a wholly-owned 210 MW hydro plant (Acaray), which will probably be uprated by 45 MW during the next few years. The state electric utility, ANDE, also plans to install two 100 MW units at the existing Yguazu dam. An environmental impact study has been conducted for the projected bi-national Corpus Christi dam (2 880 MW, to be shared with Argentina), sited on the Paraná, downstream of Itaipú and upstream of Yacyretá. The 300 MW Aña-Cuá scheme constitutes another bi-national project with Argentina.

Peru

Peru's topography, with the Andes running the length of the country, and many fast-flowing rivers, endows the republic with an enormous hydroelectric potential. Its hydro capability is assessed by *Hydropower & Dams World Atlas 2009* as one of the largest in the whole of South America, with an economically exploitable capability of some 260 TWh/yr. Current utilisation of this capability is very low - at around 7%. Hydro provided nearly 60% of Peru's electric power in 2008.

In their response to the SER 2010 questionnaire, the Peruvian WEC Member Committee stated that at end-2008 one medium-sized HPP was under construction - El Platanal (220 MW). This plant has subsequently been reported to have commenced operation at the end of 2009. The Member Committee also noted that a 98 MW hydro plant is planned for Machu Picchu, with a scheduled start-up date of 2012.

HDWA reports that there were 204 small-scale hydro plants in operation in 2009, with an aggregate capacity of 237 MW, and that a further 11 plants with capacities between 1 and 10 MW are planned for installation over the next ten years.

In April 2009 an intergovernmental agreement was signed between Peru and Brazil which authorised Brazil to design, finance, construct and operate up to six hydro plants on Peruvian territory, primarily to meet its own energy needs. The proposed sites are Inambari (2 000 MW), Sumabeni (1 074 MW), Paquitzapango (2 000 MW), Urubamba (940 MW), Vizcatan (750 MW) and Chuquipampa (800 MW).

Philippines

The 225 MW Agus III hydro scheme on Mindinao in the southern Philippines is being carried out by a private company, with completion scheduled for 2011.

Romania

Romania stands in the middle ranks of European countries as far as hydroelectric resources are concerned. The WEC Member Committee reports that there is a gross theoretical capability is 70 TWh/yr, within which 32.2 TWh/yr is technically exploitable and 20.9 TWh/yr economically exploitable. At end-2008, total installed hydro capacity was 6 375 MW, whilst net generation of hydroelectricity in 2008 was just over 17 TWh, indicating that the bulk of Romania’s economic hydro resource has already been harnessed.

The Member Committee also reports that 668 MW of hydro capacity is under construction, with a probable annual output of 2 395 GWh. Planned capacity amounts to 1 414 MW, which would produce an estimated 3 344 GWh/yr. There is deemed to be scope for additional hydro capacity capable of producing about 2 552 GWh/yr. If all this capacity were to be developed, the presently estimated economically exploitable capability would be exceeded, but installed capacity would still be well within the assessed technical limit.

Within the national aggregates quoted above, small-scale hydro accounts for 274 MW of installed capacity, which produced an estimated 491 GWh in 2008. Planned capacity increases in the less-than-10 MW category amount to some 111 MW, of which 61 MW relates to units of between 4 and 10 MW and 50 MW to smaller units. Altogether these new units would produce an estimated 426 GWh/yr.

Russian Federation

Russia's hydro resource base is enormous - the gross theoretical potential is some 2 295 TWh/yr, of which 852 TWh is regarded as economically feasible. The bulk of the Federation's potential is in its Asian regions (Siberia and the Far East). Hydro generation in 2008 (approximately 180 TWh) represented 21% of the economic potential and accounted for about 19% of total electricity generation.

According to *Hydropower & Dams World Atlas 2009*, installed hydroelectric generating capacity at end-2008 was about 49 700 MW; some 7 000 MW of additional capacity was under construction and about 12 000 MW of further capacity was planned.

The largest hydro scheme currently under construction in the Federation is the 3 000 MW plant at Bogucchany on the Angara river in southeast Siberia; the initial stage is scheduled to go on-line in 2010, but full capacity will not be reached until some years later.

Hydro schemes expected to be completed during 2010-2011 include Irganai (800 MW) in Dagestan, southern North Caucasus, Zelenchuk (320 MW) in Karachai-Circassia, North Caucasus and Kashkhatau (60 MW) in Kabardino-Balkaria, North Caucasus. Other major HPPs under construction comprise Ust-Srednekansk (570 MW), Telman (450 MW), Svetlin (360 MW), Zaramag (352 MW) and Nizne (321 MW).

Major hydro developments are under consideration for the Volga-Kama cascade (expanding capacity by 2 010 MW), and for up to seven HPPs on the Timpton river in South Yakutia (with a total installed capacity of 9 000 MW). The first plant to be built under the latter scheme would be Kankunskaya (1 600 MW).

South Africa

The current emphasis in South Africa is very much on the development of pumped-storage facilities. Two large plants - Ingula (1 332 MW) and Lima (1 500 MW) are under construction, and further projects are being studied.

Spain

In terms of hydro-electric resources, Spain stands in the middle rank of West European countries, with a gross theoretical capability of 162 TWh/yr. Along with this level, *Hydropower & Dams World Atlas 2009* reports that some 61 TWh/yr is considered to be technically exploitable, of which 37 TWh (61%) is classed as economically exploitable at present. The average level of hydro-electricity generation (excluding pumped-storage plants) in 2006-2008 (approximately 25 TWh) indicates that Spain has already harnessed a considerable proportion of its economic hydro resources.

For the 2007 *Survey*, the Spanish WEC Member Committee reported provisional data for end-2005 showing that small-scale HPPs had a total generating capacity of 1 788 MW, and that their output in 2004 was 4 729 GWh. During the period 2005-2010 some 450 MW of small hydro capacity was scheduled to be added, leading to an eventual total output from small-scale hydro of around 6 000 GWh/yr.

Sudan

The economically feasible potential is some 19 TWh/yr. Until recently, hydro development had been on a very limited scale, with end-2008 installed capacity only about 575 MW. However, following the completion of the 1 250 MW Merowe HPP in early 2010, the country's hydro capacity has risen to over three times its 2008 level.

In 2008, a contract was awarded for the design of five hydro schemes in northern Sudan. Most of Sudan's pre-2008 hydro plant is at least 40 years old, providing a potential for uprating estimated at about 200 MW.

Swaziland

The Swaziland WEC Member Committee reports that a feasibility study of a site for a hydro power station on the lower Maguduza has recently been implemented. It states that the site has a potential of 20 MW, with a projected annual production of 69 GWh.

Sweden

Sweden has one of the highest hydro potentials in Western Europe: *Hydropower & Dams World Atlas 2009* reports a gross theoretical capability of 200 TWh/yr, of which 90 TWh is economically exploitable. According to the Swedish WEC Member Committee, the average annual capability of the 16 195 MW hydro capacity installed at the end of 2008 was 65 TWh, about 72% of the economic potential. Actual hydro output in 2008 was 68.4 TWh, which provided nearly half of Sweden's electricity generation.

The construction of new hydro plants has largely ceased, on account of environmental and political considerations. Future activity is likely to be very largely confined to the modernisation and refurbishment of existing capacity.

The Member Committee reports that there was 1 142 MW of small-scale hydro capacity at the end of 2008, which had generated a total of 4.8 TWh during the year.

Switzerland

Whilst Switzerland has already developed a relatively high proportion (over 85%) of its substantial economically exploitable hydro capability, attention is now being focused on small-scale hydropower (defined in Switzerland as schemes below 300 kW). Under the new feed-in regime introduced in 2008, mini-hydro projects totalling 354 MW, with an estimated output of 1 464 GWh, have qualified for feed-in tariffs and are thought likely by the Swiss WEC Member Committee to be built in the coming years.

Tajikistan

The terrain and climate are highly favourable to the development of hydropower. Apart from the Russian Federation, Tajikistan has the highest potential hydro generation of any of the FSU republics. Its economically feasible potential is estimated to be 263.5 TWh/yr, of which only about 6% has been harnessed so far. Hydropower provides about 95% of Tajikistan's electricity generation.

Installed hydro capacity amounts to about 5 500 MW, of which just over 5 000 MW was reported to be operational in early 2009. The principal site is Nurek (3 000 MW), which produces approximately 11.2 TWh/yr. The fourth and last unit at the Sangtuda 1 plant on the river Vakhsh came into operation in May 2009; together, the four units have added 670 MW to Tajikistan's capacity.

Work on the Rogun project (2 400-3 600 MW), also on the Vakhsh, is still suspended. A number of medium- and large-sized hydro projects are under planning or being considered. In particular, the Governments of Tajikistan and Iran have agreed to proceed with Sagtuda 2 (220 MW), whilst the 850 MW Shurob hydro scheme in northern Tajikistan has been reported to be under consideration.

Hydropower & Dams World Atlas 2009 states that an enormous hydro potential exists on the river Panj (the principal tributary of the Amu-Darya): 14 HPPs with an aggregate capacity of 18 720 MW could eventually be developed. (As the Panj forms Tajikistan's border with Afghanistan, a portion of the capacity/output would presumably accrue to the latter country). In 2009 planning was reported to be in hand on the 4 000 MW Dashtidjumskaya project on the Panj.

Tanzania

The 900 MW Stieglers Gorge hydro project on the river Rufiji appears to be moving ahead, with the Canadian-registered company Energem Resources acquiring a 40% stake in the scheme.

Turkey

Hydropower & Dams World Atlas 2009 reports a gross theoretical hydropower potential of 433 TWh/yr, a technically feasible potential of 216 TWh/yr and an economically feasible potential of 140 TWh/yr. Hydro output of 33.3 TWh in 2008 points to a considerable degree of development potential.

At end-2008, operational hydro capacity amounted to 13.7 MW. A further 8.6 GW of capacity was under construction at 148 sites, with an envisaged total average output of around 20 TWh/yr. Some 22 700 MW of additional capacity is planned for development over the longer term.

According to HDWA, Turkey's small-scale hydropower potential is an estimated 4 811 GWh/yr. The total installed capacity of such HPPs is quoted as 189 MW, providing an average output of 758 GWh/yr.

Uganda

Following a successful financial closure at the end of 2008, contracts have been awarded for the 250 MW Bujagali scheme, and work is now well under way. The project is for five 50 MW units, to be installed at a site on the Victoria Nile, approximately 8 km downstream of the 180 MW Nalubaale (formerly Owen Falls) station, and is scheduled for commissioning in 2011-2012.

United Kingdom

While the overall amount of installed hydro-electric capacity is extremely modest, opportunities for development do exist, especially in the small-hydro sector (defined in this context as plants up to 5 MW). *Hydropower & Dams World Atlas 2009* quotes the technically feasible potential for small hydro so defined as 4 100 GWh/yr, with the economically feasible potential for undeveloped sites as 1 000 GWh/yr.

Construction was completed in 2009 of the 100 MW Glendoe hydro scheme in Scotland, the first sizeable such plant to be built in the UK for fifty years.

The UK WEC Member Committee reports that a study into the potential hydro resource is currently under way. The draft findings of this study show a potential of up to 248 MW of small-scale hydro left to be developed in England and Wales. This study complements one undertaken in Scotland on behalf of the Forum for Renewable Energy Development in Scotland, which showed a potential for up to 657 MW of small-scale hydropower.

The 2008 Energy Act provided the wherewithal for the Government to introduce feed-in tariffs (FIT). From 1 April 2010 renewable energy electricity-generating technologies, up to a maximum of 5 MW, qualify for generation and export tariffs. FITs will work alongside the Renewables Obligations. In the case of new hydro schemes, where both the product and installer are certificated, the generation tariffs are on a decreasing scale from GBP 0.199/kWh for up to 15 kW capacity to GBP 0.045/kWh for installations of 2-5 MW. These rates will remain the same for a period of 20 years (although adjusted for inflation through a link to the Retail Price Index). The tariff payable for electricity exported to the grid is GBP 0.03/kWh, regardless of the size of the installation.

United States of America

The hydro resource base is huge: the United States WEC Member Committee reports that the gross theoretical potential was assessed in 2006 as 2 040 TWh/yr, and that the annual technically exploitable capability is 1 339 TWh, based on publications of the U.S. Department of Energy (Idaho National Environmental and Engineering Laboratory), other U.S. Departments and the Electric Power Research Institute (EPRI). The end-2008 hydro capacity of 77.5 GW had an average annual capability of about 268 TWh, equivalent to 20% of the assessed technical potential. The Member Committee states that there have been no comprehensive assessments of the U.S. potential for all economically exploitable hydropower, and that, moreover, the economics of these projects is unknown and is in constant flux due to policy and commodity pricing.

On the issue of Exploitable Capability, the U.S. Member Committee quotes from the 2006 report by the Idaho National Laboratory:

'It is concluded from the study results that there are a large number of opportunities for increasing U.S. hydroelectric generation throughout the country that are feasible based on an elementary set of feasibility criteria. These opportunities collectively represent a potential for approximately doubling U.S. hydroelectric generation (not including pumped storage), but more realistically offer the means to at least increase hydroelectric generation by more than 50%.

Actual hydroelectric output of 254.8 TWh in 2008 accounted for 6.2% of U.S. net electricity generation. No hydro capacity was reported to be under construction at end-2008, although some 311 MW was at the planning stage.

The reported technically exploitable capability of small-scale hydropower (5 MW and below) is 782 TWh, with about 198 TWh/yr rated as economically exploitable. The installed generating capacity of small hydro plants totalled 2.86 GW at end-2008; probable annual generation is put at 10 154 GWh, but actual generation in 2008 was some 18% higher, at 11 973 GWh, equivalent to 4.8% of total U.S. hydro output.

Various incentives for small-scale hydro exist in the form of Federal and State production tax credits and Federal grants and loan guarantees. Moreover the Federal Energy Regulatory Commission, which is responsible for the licensing of private, municipal and State hydro-electric projects, has an exemption for hydro projects with an installed capacity of 5 MW or less which also meet certain conditions.

Uruguay

According to *Hydropower & Dams World Atlas 2009*, the technically exploitable potential is 10 TWh/yr, within a gross theoretical potential of 32 TWh. Some 6 TWh/yr of hydro capacity is regarded as economically feasible for development at present.

During the 1980s almost all of Uruguay's incremental generating capacity was in the form of hydropower, notably through the commissioning of the bi-national Salto Grande (1 890 MW) plant on the river Uruguay; the republic shares its output with Argentina. No hydro plants are reported to be presently under construction and only about 70 MW is planned: future increases in generating capacity are likely to be largely fuelled by natural gas.

Venezuela

Hydropower & Dams World Atlas 2009 (HDWA) reports a gross theoretical hydropower potential of 731 TWh/yr, of which 261 TWh/yr is considered as technically feasible and approximately 100 TWh/yr economically exploitable. Hydro-electric output in 2008 was 86.7 TWh. About 73% of the republic's electricity requirements are met from hydropower.

In early 2009, hydro capacity in operation amounted to 14 627 MW. The principal HPPs under construction were Tocoma (2 160 MW) on the river Caroní and La Vueltosa (514 MW) in the Andean region.

A large increase in hydro-electric capacity occurred during the 1980s, the major new plant being Guri (Raúl Leoni), on the Caroní in eastern Venezuela - its installed capacity of 8 850 MW makes it one of the world's largest hydro stations. The Tocoma HPP, located 18 km downstream of Guri, is the last in the series of major hydro plants constructed by the state-owned company EDELCA on the lower Caroní. Eventually, the total installed capacity on the lower Caroní (comprising, in order of flow, Guri, Tocoma, Caruachi and Macagua) will exceed 16 000 MW.

HDWA states that no very large hydro plants are firmly planned for the next ten years, but mentions a number of schemes that have been studied, including several on the upper and middle reaches of the Caroní and others on the Colorada in the Andean region.

Vietnam

Vietnam has abundant hydro resources, particularly in its central and northern regions. Its gross theoretical potential is put at 300 000 GWh/yr, with an economically feasible potential of 100 000 GWh/yr. Total installed hydro capacity was about 5 500 MW at end-2008 and an output of about 24 TWh provided about one-third of Vietnam's power supply. The largest HPPs currently in operation are Hoa Binh (1 920 MW), Yali (720 MW), Tri An (420 MW) and Ham Thuan (300 MW).

Hydropower & Dams World Atlas 2009 (HDWA) reports that a massive programme of hydro development is under way, with around 7 500 MW under construction and many other projects (including several large pumped-storage schemes) at various stages of planning. In early-2009, 16 plants totalling 5 715 MW were being constructed for the state corporation EVN, with the largest individual project being the 2 400 MW Son La scheme, which is due to commence operating in 2010. A further 1 819 MW of hydro capacity was being installed by private developers under BOT or IPP arrangements.

Zambia

Zambia's two major hydro plants are being refurbished and upgraded: the 900 MW Kafue Gorge (Upper) station by 90 MW and Kariba North Bank (presently 600 MW) by 120 MW.

Economic and technical feasibility studies are being conducted on the Kafue Gorge Lower IPP project (750 MW) and a 210 MW scheme at Kalungwishi. Further rehabilitation and new-build projects are being developed or studied, including the 120 MW Itezhi Tezhi scheme on the Kafue river and the 1 800 MW Baroka Gorge bi-national project with Zimbabwe.

8. Peat

COMMENTARY

Introduction

Peat is the surface organic layer of a soil, consisting of partially decomposed organic material, derived mostly from plants, that has accumulated under conditions of waterlogging, oxygen deficiency, acidity and nutrient deficiency. In temperate, boreal and sub-arctic regions, where low temperatures (below freezing for long periods during the winter) reduce the rate of decomposition, peat is formed from mosses, herbs, shrubs and small trees (Joosten & Clarke, 2002). In the humid tropics, it is formed from rain forest trees (leaves, branches, trunks and roots) under near-constant high temperatures (Page, et al., 1999).

Peatlands are areas of landscape, with or without vegetation, that have a naturally accumulated peat layer at the surface. (Figs. 8.1 and 8.2). For land to be designated as peatland, the thickness of the peat layer must be at least 20 cm if drained, and 30 cm if undrained. Peatland reserves are most frequently quoted on an area basis because initial inventory normally arises through soil survey or remote sensing. Even where peat deposit thickness and total peat volumes are known, it is still not possible to quantify the reserves in energy terms because the energy content of *in situ* peat depends on its moisture and ash content. The organic component of peat deposits has, however, a fairly constant anhydrous, ash-free calorific value of 20-22 MJ/kg and, if the total

Figure 8.1 Cranberry Moss, a natural peatland in the Midlands of England (Source: Rieley)

Figure 8.2 Undrained peat swamp forest in Central Kalimantan, Indonesia (Source: Rieley)

quantity of organic material is known, together with the average moisture and ash content, then the peat reserve can be expressed in standard energy units.

The Nature of Peatlands and Peat

Globally, peatlands are major stores of carbon. Peatlands are also vital environmental 'regulators'. Peat is accumulating on the ground all the time and the top layers of mires and peatlands form complex ecosystems. Joosten and Clarke (2002) describe peatlands as analogous to living organisms because they grow, mature and may even die. Joosten and Clarke continue: peat is 'sedentarily accumulated material consisting of at least 30% (dry weight) of dead organic material'. Peat is the partly decomposed remains of the biomass that was produced, mostly by plants, on waterlogged substrates; it is mostly water-saturated and therefore not compacted. The peat harvested today in the northern hemisphere was formed mostly during the Holocene epoch (the last 10 000 years), after the retreat of the glaciers that once covered most parts of the hemisphere. Those plant species, which formed the basal peat, are still forming peat today.

Resources

The estimation of peat resources on a global scale is difficult and data for many countries are imprecise or only partially ascertained. Nevertheless it is clear that the world possesses huge reserves of peat overall (Fig. 8.3). The total area of pre-disturbance peatland, based on reports from WEC Member Committees and published sources, notably Immirzi, et al. (1992) and Joosten & Clarke (2002), is about 4 million km^2, equivalent to 3% of the world's land surface (Table 8.1). Most of the world's peatland is in North America and Siberia. There are large areas in northern and central Europe and in Southeast Asia, together with some in tropical Africa, Latin America and the Caribbean (Table 8.2). 85% of the global peatland area is in only four countries, Russia, Canada, the USA and Indonesia. Large areas of European peatland (excluding the Asian part of the Russian Federation), totalling 450 000 km^2 (11% of the total global area) have for centuries been utilised for agriculture and forestry. According to Immirzi, et al. (1992), 40% of the peatland area in Europe (again, excluding Asian Russia) and 5% overall in the rest of the world has been used in this way, although since their assessment was published, large areas of peatland in Indonesia and Malaysia have been deforested, drained and converted to agriculture for arable crops and plantations. A relatively small area (5 000 km^2, or only 0.1% of the total peatland area) has been used to extract peat for energy, horticulture and a range of other industrial and medical uses (Fig. 8.4).

Figure 8.3 Global distribution of mires

(Source: International Peat Society)

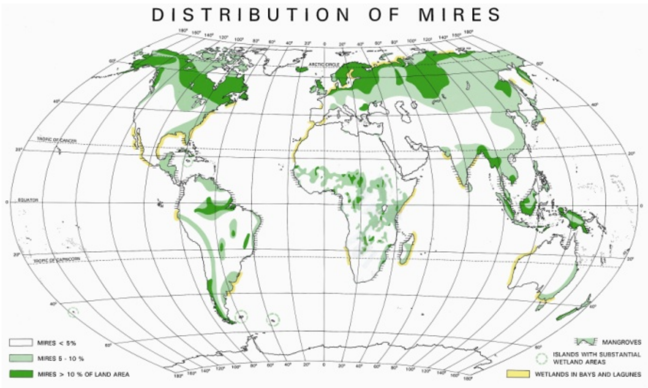
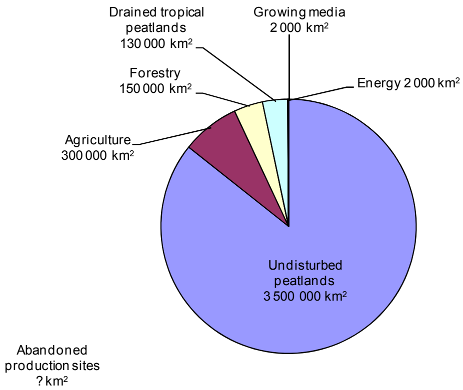


Figure 8.4 Estimated global use of peat*

(Source: International Peat Society)



* Excludes the area of peatland that is affected by indirect peat uses such as flooding for reservoir construction or extraction of minerals beneath peatland

The average thickness of the peat layer is difficult to determine precisely owing to a lack of data for most countries. This makes it virtually impossible to determine accurately the overall volume of peat and therefore the amount of carbon it contains. Immirzi, et al., (1992) used an estimated global mean thickness of 1.5 metres while Gorham (1991) used 2.3 for boreal and sub-arctic peatlands. The thickness of tropical peatland is likely to be greater. An indicative estimate of the total volume of peat *in situ* is in the order of 6 000-13 800 billion m^3, containing 300-695 billion tonnes of carbon. According to Strack (2008) the global peat carbon pool is in the region of 500 billion tonnes. The reserve base in the major countries extracting peat (principally for energy and horticulture), including 'reserves currently under active cultivation or economically recoverable under current market conditions', has been assessed (Couch, 1993) as 5 267 million tonnes (air-dried).

Production Methods

Peat is either extracted as sods (traditionally hand-cut, nowadays predominantly mechanically harvested) or as fine granules (using a mechanical miller to disturb and grind the top layer of the peat bog surface) (Figs. 8.5 and 8.6). Peat *in situ* contains around 90% water, some of which is removed by drainage and most of the remainder by drying in the sun and wind. The resulting 'air-dried' peat has a moisture content of 40-50%. The bulk of peat production is obtained by milling and used in electricity or heat generation. A proportion of the milled peat is converted into briquettes, which provide a convenient household fuel. The main countries producing and using fuel peat are Belarus, Estonia, Finland, Indonesia, Ireland, Russian Federation and Sweden (Table 8.3).

Uses of Peat

Peat has a large number of uses, which may be classified under three headings:

- Energy (as fuel for electricity/heat generation, and directly as a source of heat for industrial, residential and other purposes) (Figs. 8.7 and 8.8);
- Horticultural and agricultural (e.g. as growing medium, soil improver, cowshed/stable litter, compost ingredient);

Figure 8.5 Peat milling machine. A 25-40 mm layer is removed from the surface of the peat production site and dried in the sun
(Source: Turveteollisuusliitto)

- Other (e.g. as a source of organic and chemical products such as activated carbon, resins and waxes, medicinal products such as steroids and antibiotics, and therapeutic applications such as peat baths and preparations).

Fuel Peat Utilisation in the European Union

Fuel peat utilisation in the European Union is summarised in the following (edited) extract from the report, *Fuel Peat Industry in EU* (Paappanen, Leinonen and Hillebrand, 2006) (Table 8.4):

'The total annual peat use during the 2000´s has been 3 370 ktoe. The three largest users are Finland (59% of total use), Ireland (29%) and Sweden (11%), corresponding to 99% of the total use. Peat is used in combined heat and power plants (CHP) (45% of the total use), in condensing power generation (CP) (38%), district heating (DH) (10%) and residential heating (RH) (8%). The total number of power plants is 125. The approximate number of people receiving heating energy from peat is 1.94 million.

The total annual value of fuel peat sales is 390 million Euros. The total employment effect of peat production and use is 13 100 – 16 100 man-years, including direct and indirect employment.

The total primary energy consumption in the six EU countries mentioned in the Report is

Figure 8.6 After milling, peat is turned 3-5 times to speed up the drying process
(Source: Turveteollisuusliitto)

approximately 120 mtoe of which about 3.8 mtoe is produced with peat. Therefore the overall share of peat of primary energy consumption is 3% in these countries.

In Finland and in Ireland about 5-7% of primary energy consumption relies on peat. In Estonia and Sweden peat's share is 1.9% and 0.7% respectively. In Latvia and Lithuania peat makes a smaller contribution to primary energy consumption.

The importance of peat at national level is most significant in Finland, where over 22% of all fuel used by CHP plants is peat. In DH plants this share is 19%, and 8% for CP generation. The use of peat and wood is bound together. Owing to technical and economic reasons, peat cannot fully be replaced with wood or other renewable or recyclable fuels. Peat also decreases the dependence of energy production on imported fuels. The only alternative to peat is coal, which cannot replace all of the peat, because of the technical characteristics of boilers.

In Ireland, which does not have any substantial fossil fuel reserves, peat is an important source of domestic energy, and therefore it is included in the fuel mix. One of the principal energy sectors in Ireland is the electricity sector and of this peat contributes 8.5%. In Estonia about 4% of district heat is produced using peat. In Sweden the importance of peat at a national level is relatively low, 0.7% of primary energy consumption, but of CHP and DH the peat share is 4% and 6%, respectively.

Figure 8.7 Greenhouses in Finland heated with sod peat (Source: Turveteollisuusliitto)

The regional benefits of peat production are mostly directed to rural areas, which suffer from migration of young people and from a workforce with a high average age, as well as from relatively low levels of income. Peat contractors usually also practice agriculture or forestry or some kind of contracting work. Therefore peat brings extra income to people and regions that are less developed economically.

Peat has both a short-term and a long-term role in security of energy supply. For example, in Finland and Estonia the reserve supplies correspond to 7-17 months use, which can easily cover short-term interruptions in energy supply.'

Future Developments in the Use of Peat for Energy

VTT Technical Research Centre of Finland is experimenting with gasification equipment designed for the development of second-generation transport biofuels. In this process, synthesis gas will be refined from biomass for the production of diesel fuels. In addition to synthesis applications, the work involves development of new solutions for gas turbine and fuel cell power plants, as well as for the application of hydrogen for transport purposes. The gasification plant will be able to utilise any carbonaceous raw material, including forest industry residues, bark, biomass from fields

Figure 8.8 Forssan Energia, Finland, uses both peat and wood-based fuels in combined heat and power production (Source: Turveteollisuusliitto)

including peat fields), refuse-derived fuels and peat.

Peat Resources Limited is a Toronto-based clean energy company, which was formed to develop and produce peat fuel. The company has identified large biomass resources of fuel-grade peat in Ontario and Newfoundland. The former contains over 200 million tonnes, sufficient to supply Ontario Power's northern generating stations for more than 20 years. In Newfoundland, permits cover about 130 000 hectares of productive peatlands. Peat Resources Limited aims to be the principal supplier of peat fuel, on a sustainable basis, to the North American energy market.

Peat from a Climate Impact Point of View

The Intergovernmental Panel on Climate Change (IPCC) changed the classification of peat from fossil fuel to a separate category between fossil and renewable fuels (25th session of IPCC, Port Louis, Mauritius, 2006). Peat now has its own category: 'peat'. The emission factor of peat is similar to fossil fuels.

Balance of Peat Usage and Life-Cycle Analysis

The total production area for fuel peat in the EU amounts to 1 750 km^2 (0.34% of the total peatland area). The total annual use of fuel peat

Figure 8.9 Drained and burned peat swamp forest in Central Kalimantan, Indonesia (Source: Rieley)

has amounted to 12 million delivered tonnes of peat (4 million tonnes of carbon) during recent years (Paappanen, Leinonen and Hillebrand, 2006). The world's annual peat harvest is equivalent, according to Joosten and Clarke (2002), to about 15 million tonnes of carbon.

The present sequestration rate of carbon in all mires of the world is estimated to be 100 million tonnes annually (Strack, 2008), thus exceeding the annual use of peat 3 to 6 times, although areas where peat is accumulating are not necessarily the same as those where it is being used. Peat extraction and peat accumulation may be in global balance but this is not necessarily so on a country or regional basis.

Many peatlands that were drained and used for agriculture and forestry in the past are now sources of greenhouse gases, owing to degradation and oxidation of the unsaturated peat layer. If these areas are not significant sources of food or other income for local people, they could be used for peat production and afterwards transformed relatively easily into carbon sinks by rewetting them. They could be restored to peat-forming mires, reclaimed to forests or planted with energy crops. These new carbon sinks will be needed in coming decades. The possibility of reusing energy peat production sites as new carbon sinks constitutes another difference between peatlands and fossil-fuel producing coal mines and oil wells.

Wise Use of Peat

The International Peat Society (IPS) joined with the International Mire Conservation Group (IMCG) to develop a procedure for the reasoned and wise use of peat and peatlands globally (Joosten and Clarke, 2002). This contains sound advice for the peat industry to adopt the 'wise use' approach and will mean that most of the remaining peat bogs in Europe and North America will not be utilised (less than 0.4% of the total peatland area in Europe is currently used in this way) and those that are will have after-use plans, to be implemented at the industry's expense once the extraction work has ended. In most cases, former extraction sites are destined to become CO_2 sinks once again.

In order to put CO_2 emissions into context, it is important to emphasise that most of the carbon released from peatland in the world today occurs in tropical Southeast Asia as a result of peatland deforestation, large-scale land-use change, drainage, degradation and fire. In 1997, between 0.87 and 2.57 billion tonnes of carbon (equivalent to 2.9-8.5 billion tonnes CO_2) were discharged into the environment as a result of forest and peat fires in Indonesia in just four months (Page, et al., 2002). Since then, it is estimated that an average of around 2 billion tonnes of CO_2 have been released every year from peatland in Southeast Asia (Fig. 8.9). This is equivalent to about 30% of global CO_2 emissions from fossil fuels (Hooijer, et al., 2006). Developed countries should assist in the wise use of tropical peatlands in agriculture and forestry, in order to prevent thoughtless release of CO_2 into the atmosphere. From a climate-impact point of view, peat is much more acceptable than fossil fuels and if peat can be used in a wise way, this will be to the benefit of mankind now and in the future.

Strategy for Responsible Peatland Management

During recent years various stakeholders have identified a need for a global peatland management strategy. The IPS has launched a project, in collaboration with a wide range of interested parties, to create a *Strategy for Responsible Peatland Management*. The work started in 2009 and the strategy should be finalised by summer 2010.

The main objective of this peatland strategy is to manage peatlands responsibly for their environmental, social and economic values, according to the following priorities:

- Biodiversity;
- Water protection;
- Climate and climate-change processes;
- Economic requirements;
- After-use, rehabilitation and restoration;
- Human and institutional capacity and information dissemination;
- Engagement of local people;
- Good governance.

The Responsible Peatland Management Strategy encompasses all uses of peatlands and includes nature conservation and protection, various forms of economic use, as well as recreational and traditional uses. It sets out practical objectives for peatland management applicable at a number of levels (global, regional, national and sub-national) and identifies actions that will contribute to the responsible management of peatlands. By presenting commonly accepted principles, it provides a framework for the future development of a more detailed standard for peatland management to be used in voluntary certification.

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DEFINITIONS

Types of Peat Fuel

There are three main forms in which peat is used as a fuel:

- **Sod peat** - slabs of peat, cut by hand or by machine, and dried in the air; mostly used as a household fuel;
- **Milled peat** - granulated peat, produced on a large scale by special machines; used either as a power station fuel or as raw material for briquettes;
- **Peat briquettes** - small blocks of dried, highly compressed peat; used mainly as a household fuel.

TABLES

Table 8.1 Peat: areas of peatland
(square kilometres)

Algeria	10
Angola	264
Benin	100
Botswana	2 625
Burkina Faso	10
Burundi	323
Cameroon	1 077
Central African Republic	100
Chad	10
Congo (Brazzaville)	6 220
Congo (Democratic Rep.)	2 800
Côte d'Ivoire	725
Egypt (Arab Rep.)	46
Ethiopia	200
Gabon	548
Gambia	100
Ghana	59
Guinea	1 952
Kenya	2 440
Lesotho	20
Liberia	120
Madagascar	1 920
Malawi	492
Mali	400
Mauritania	60
Mauritius	1
Morocco	10
Mozambique	575
Namibia	10
Niger	30
Nigeria	1 600

Table 8.1 Peat: areas of peatland
(square kilometres)

Réunion	1
Rwanda	830
Senegal	36
Sierra Leone	1
South Africa	300
St Helena	80
Sudan	9 068
Tanzania	100
Togo	10
Tunisia	1
Uganda	7 300
Zambia	12 201
Zimbabwe	1 400
Total Africa	**56 175**
Bahamas	10
Belize	735
Bermuda	1
Canada	1 113 280
Costa Rica	370
Cuba	5 293
Dominica	1
Dominican Republic	10
El Salvador	90
Greenland	5
Guadeloupe	2
Haiti	120
Honduras	4 530
Jamaica	128
Martinique	1
Mexico	1 000
Nicaragua	3 710

Table 8.1 Peat: areas of peatland (square kilometres)

Panama	7 870
Puerto Rico	100
St Kitts & Nevis	1
Trinidad & Tobago	10
United States of America	625 001
Total North America	**1 762 268**
Argentina	2 400
Bolivia	509
Brazil	23 875
Chile	10 472
Colombia	5 043
Ecuador	5 001
Falkland Islands	11 510
French Guiana	1 620
Guatemala	1
Guyana	8 139
Paraguay	100
Peru	50 000
Surinam	1 130
Uruguay	1 000
Venezuela	10 000
Total South America	**130 800**
Afghanistan	120
Armenia	55
Azerbaijan	10
Bangladesh	375
Brunei	909
Bhutan	1
Cambodia	7 000
China	53 120
Cyprus	1
Georgia	200
India	400

Table 8.1 Peat: areas of peatland (square kilometres)

Indonesia	206 950
Japan	2 000
Kazakhstan	50
Korea (Democratic People's Rep.)	1 360
Korea (Republic)	5
Kyrgyzstan	100
Laos	200
Malaysia	25 889
Maldives	1
Mongolia	50
Myanmar (Burma)	1 228
Nepal	1
Pakistan	100
Philippines	645
Singapore	1
Sri Lanka	158
Thailand	638
Turkey	120
Vietnam	533
Total Asia	**302 220**
Albania	179
Andorra	5
Austria	200
Azores	1
Belarus	23 500
Belgium	160
Bosnia-Herzegovina	150
Bulgaria	25
Croatia	1
Czech Republic	200
Denmark	1 400
Estonia	9 020
Faroe Islands	30

Table 8.1 Peat: areas of peatland (square kilometres)

Finland	89 000
France	1 500
Germany	13 000
Greece	71
Hungary	330
Iceland	8 000
Ireland	11 800
Italy	300
Latvia	6 600
Liechtenstein	1
Lithuania	3 520
Luxembourg	3
Macedonia (Rep.)	30
Moldova	10
Norway	28 010
Poland	12 500
Portugal	20
Romania	1 000
Russian Federation	1 390 000
Serbia and Montenegro	300
Slovakia	26
Slovenia	100
Spain	60
Sweden	66 000
Switzerland	300
Ukraine	8 000
United Kingdom	27 500
Total Europe	**1 702 852**
Iran (Islamic Rep.)	10
Iraq	100
Israel	40
Jordan	1
Lebanon	1
Syria (Arab Rep.)	3
Total Middle East	**155**
Antarctica	3 000
Australia	1 350
Fiji	40
Kiribati	2
Micronesia	33
New Zealand	3 610
Palau	1
Papua New Guinea	10 986
Samoa	1
Solomon Islands	10
Total Oceania	**19 033**
TOTAL WORLD	**3 973 503**

Notes:

1.Sources: Immirzi, et al., 1992; Joosten and Clarke, 2002; www.carbopeat.org

Table 8.2 Peatland area by region (square kilometres)

Africa	56 175
North America	1 762 268
South America	130 800
Asia	302 220
Europe	1 702 852
Middle East	155
Oceania	19 033
of which, tropical peatland	**41 547**
TOTAL WORLD	**3 973 503**

Notes:

1. Sources: Immirzi, et al., 1992; Joosten and Clarke, 2002; www.carbopeat.org

Table 8.3 Peat: production and consumption for fuel in 2008 (thousand tonnes)

	Production	Consumption
Burundi	10	10
Total Africa	**10**	**10**
Falkland Islands	13	13
Total South America	**13**	**13**
Austria	1	1
Belarus	2 364	2 208
Estonia	214	294
Finland	4 971	7 959
Ireland	3 089	4 139
Kazakhstan		1
Latvia	11	9
Lithuania	67	38
Macedonia (Republic)		4
Romania	10	39
Russian Federation	762	884
Sweden	837	1 201
Ukraine	358	340
United Kingdom	20	20
Total Europe	**12 704**	**17 137**
TOTAL WORLD	**12 727**	**17 160**

Notes:

1. Data on production relate to peat produced for energy purposes; data on consumption (including imported peat) similarly relate only to fuel use
2. Tonnages are generally expressed in terms of air-dried peat (35%-55% moisture content)
3. Differences between production and consumption can be due to two factors: i) import and export of peat and ii) peat may be stored, since production can vary significantly between years as a result of differences in weather conditions during the harvesting season
4. Sources: *Energy Statistics of OECD Countries*, 2009 Edition, International Energy Agency; *Energy Statistics of Non-OECD Countries*, 2009 Edition, International Energy Agency; Eurostat; web sites; estimates by the Editors

Table 8.4 Fuel peat industry in the EU

	Finland	Ireland	Sweden	Estonia	Latvia	Lithuania	Total
Fuel peat resources, ktoe	1 100 000	47 500	370 000	10 000	57 000	4 000	**1 589 000**
Annual peat use, ktoe	1 980	984	372	28	0	4	**3 368**
Number of peat producers	250	300	25	30	11	11	**630**
Number of machine & boiler manufacturers	22	1	9	9	0	0	**41**
Number of peat-fired power plants	55	3	20	40	0	7	**125**
Number of people getting heating energy from peat	480 000	1 000 000	390 000	65 000	0	0	**1 940 000**
Value of domestic trade, million €	204	153	27	2	0	3	**390**
Value of international trade, million €	0.5	0.0	16.9	7.1	0.3	0.2	**17.9**
Employment, man-years	7 000	2 300	1 700	2 100	0	0	**13 100**

Notes:
1. Source: Paappanen, *et al*, 2006

COUNTRY NOTES

The Country Notes on Peat have been compiled by the Editors, drawing principally upon the following publications:

- Lappalainen, E., (Editor), 1996. Global Peat Resources, International Peat Society, Finland;
- Couch, G.R., 1993. Fuel peat - world resources and utilisation, IEA Coal Research, London.

Information from national publications and organisations and personal communications has been incorporated, as applicable.

Argentina

Peat bogs exist on the Isla Grande de Tierra del Fuego, in the highland valleys of the Andean Cordillera, and in other areas. However, economic exploitation of peat is almost entirely confined to Tierra del Fuego, where relatively small amounts (circa 3 000 m^3 per annum) are extracted, almost entirely for use as a soil-improvement agent.

Belarus

The peatlands of Belarus are by far the most extensive in Eastern Europe (excluding the Russian Federation), amounting to some 24 000 km^2. The largest areas of peat formation are in the Pripyat Marshes in the south and in the central area around Minsk. Peat has been used as a fuel for many years, with the highest consumption during the 1970s and 1980s. The use of peat as a power station fuel ceased in 1986; fuel output in recent years has been largely confined to the production of peat briquettes, mainly for household use.

The IEA reports that 2008 peat production was just under 2.4 million tonnes. Consumption of peat by CHP and heat plants amounts to around 200 000 tpa, with the balance of peat supply being consumed by a variety of small-scale users. Current annual output of peat briquettes is approximately 1.2 million tonnes, of which half is consumed in the residential sector and around 20% is exported.

Brazil

The area of peatland is estimated to be nearly 24 000 km^2, the second largest in any South American country. There are extensive deposits in the Middle Amazon and in a large marshy plain (Pantanal) near the Bolivian border. Smaller areas of peatland exist in some coastal locations; those in the industrialised southeast of Brazil (in the states of Espírito Santo, Rio de Janeiro and São Paulo), and further north in Bahia state, have attracted interest as potential sites for the production of peat for energy purposes. The Irish peat authority Bord na Móna carried out preliminary surveys in Brazil in the early 1980s but no production of peat for fuel has yet been developed.

The total amount of peat *in situ* has been estimated as 25 billion tonnes. According to the Ministry of Mines and Energy, 'measured/indicated/inventoried resources' of peat amount to just over 129 million tonnes, with an 'inferred/estimated' additional amount of 358 million tonnes.

Burundi

The National Peat Office (ONATOUR) is an industrial and commercial parastatal organisation. Its aims are to exploit and commercialise peat; to promote the use of peat in industry and agriculture; and to undertake research and studies into the subject of peat.

The knowledge and potential of peat in Burundi has been known since the time the country was under Belgian control. Exploitable reserves have been estimated at 57 million tonnes at 30% humidity in an area of around 150 km^2.

ONATOUR is the only enterprise in the Great Lakes region of Africa that mechanically produces peat sods. Since it was established in 1977, 300 000 tonnes, some 0.5% of reserves, have been produced.

As far as fuel peat is concerned, the major users are military camps and prisons, which take 90% of production. The remaining 10% is in the form of dust and is lost during handling or stockpiling. The use of 10 000 tonnes of peat per annum – the average annual level of production - obviates the need to prune 150 ha of forest or cut down 80 ha of plantation wood.

ONATOUR has already sold nearly 225 000 tonnes of peat since its formation, with the army being the principal client, representing more than 90% of sales. Following the acquisition of new machinery, it is likely that production of peat in 2010 will total 15 000 tonnes.

Canada

Canada's peatlands are estimated to exceed 1.1 million km^2 in area and are second only to those of the Russian Federation.

There have been a number of assessments of the potential for using peat as a fuel (including for power generation) but at present there is virtually no use of peat for energy purposes and none is likely in the immediate future. Canada is, however, a major producer (and exporter) of peat for horticultural applications.

China

Peatlands totalling some 53 000 km^2 are quite widely distributed but do not have a high overall significance in China's topography, accounting for only about 0.5% of the country's land area. The principal peat areas are located in the region of the Qingzang Plateau in the southwest, in the northeast mountains and in the lower Yangtze plain in the east.

Peat has been harvested for a variety of purposes, including fuel use, since the 1970s. Some is used in industry (e.g. brick-making), but the major part of consumption is as a household fuel. Peat has been reported to be sometimes mixed with animal dung as input to biogas plants. No information is available on the current level of peat consumption for fuel.

Denmark

Human activities, chiefly cultivation and drainage operations, have reduced Denmark's originally extensive areas of peatland from some 20-25% of its land area to not much more than 3%. Out of a total existing mire area of 1 400 km^2, freshwater peatland accounts for about 1 000 km^2; the remainder consists of salt marsh and coastal meadow. Commercial exploitation of peat resources is at a low level: in 1995 the area utilised was some 1 200 ha, producing about 100 000 tonnes per annum. Almost all the peat produced is used in horticulture.

Estonia

Peatlands are a major feature of the topography of Estonia, occupying about 20% of its territory. They are distributed throughout the country, with the largest mires being located on the plains. Estonia has a long history of peat utilisation: mechanised harvesting dates from 1861, whilst the first peat-fired power plant was operating in 1918 and peat briquetting began in 1939. Total peat resources are estimated to be 1.64 billion tonnes, of which active resources amount to 1.12 billion tonnes. At 1 January 2004, economically and ecologically exploitable deposits of highly-decomposed (HD) peat, suitable for fuel use, were some 241 million tonnes.

Annual use of peat for fuel has averaged about 350 000 tonnes in recent years but, as in other countries, tends to be highly variable. In thousands of tonnes, Estonian internal consumption rose from 371 in 2006 to 455 in 2007 and then fell away to 294 the following year. A considerable proportion of the production of peat is used to produce briquettes, most of which are destined for export. In 2007, briquette production totalled 128 000 tonnes, of which 75% was exported, the balance being very largely consumed in the residential sector. As a consequence of the low peat harvest in 2008, output of briquettes in that year was nearly halved. Exports of peat briquettes, however, fell by only 5 000 tonnes, whilst domestic consumption actually increased. This was possible through a substantial drawdown in stocks of briquettes, which fell by 40 000 tonnes.

Most of the consumption of un-briquetted peat is accounted for by district heating and electricity generation (mainly CHP). Some sod peat (27 000 tonnes in 2008) is exported, but annual amounts are highly variable.

Finland

With their total area of some 89 000 km^2, the Finnish peatlands are some of the most important in Europe and indeed globally - Finland has the highest proportion of wetlands of any nation in the world. Peat deposits are found throughout Finland, with a greater density to the west and north of the country.

The area of peat potentially suitable for commercial extraction is 6 220 km^2, of which about 22% contains high-grade peat suitable for horticulture and soil improvement. The remaining 78% (together with other deposits from which the surface layers have been harvested for horticultural use) is suitable for fuel peat production. In 2009, the total area used for peat production was about 630 km^2. The energy content of peat technically suitable for extraction is about 12 800 TWh, while the amount of fuel peat consumption has recently varied between 10 and 30 TWh/yr.

According to the Association of Finnish Peat Industries, quoted by Statistics Finland, 2008 peat production in Finland – the latest available – rose by nearly 7%. However, 2007 peat production was 66% lower than in the previous year, whereas Finnish consumption of peat fuel grew by about 9% in 2007 over 2006. This apparent discrepancy between supply and demand is an excellent illustration of one of peat's special features. Owing to the vagaries of the weather, in particular the amount of sunshine, wind and rainfall during the peat harvesting, milling and drying season, annual production levels vary greatly. In order to cope with such circumstances, the principal peat-consuming countries maintain large buffer stocks, which enable them to smooth out supplies to power plants and other consumers.

In 2007, CHP plants accounted for almost 52%, and power stations for 30%, of the total national consumption of fuel peat; industrial users consumed 12%, the balance being used in heat plants (5%), and directly in the residential and agricultural sector (1%). The share of peat fuel was about 7% of total energy consumption.

The Keljonlahti hybrid CHP plant (200 MW heat, 210 MW electricity) has been brought into operation in Jyväskylä. The plant uses about 1 million tonnes of wood and peat each year.

Greece

Despite the drainage of large stretches of former fenland, and the loss of much peat through oxidation and self-ignition, peat resources in Greece are still quite considerable. The largest deposits are in the north of the country, at Philippi in eastern Macedonia and Nissi in western Macedonia. The Philippi peatland covers about 55 km^2 and is nearly 190 m deep - the thickest known peat deposit in the world.

Fuel Peat: World Resources and Utilisation quotes total reserves as 4 billion tonnes: the proportion of this amount that might be suitable for fuel use is indeterminate.

Peat resources in Greece have not so far been commercially exploited, either for use as fuel or for agricultural, horticultural or other purposes. Schemes for peat-fired electricity generation at Philippi and Nissi have been proposed in the past, but have subsequently been abandoned.

Iceland

Peatlands cover 8 000 km^2 or about 8% of Iceland's surface area; the ash content of the peat is usually high (10-35%), owing to the frequent deposition of volcanic ash. Although peat has traditionally been used as a fuel in Iceland, present-day consumption is reported as zero. In the past, an important non-energy application of peat consisted of the use of 'peat bricks' in the construction of buildings.

Indonesia

The peatlands are by far the most extensive in the tropical zone (estimated at 207 000 km^2) and rank as the fourth largest in the world: they are located largely in the sub-coastal lowlands of Kalimantan and Sumatra. A feasibility study was carried out between 1985 and 1989 regarding the use of peat for electricity generation in central Kalimantan; no project resulted, but a small peat-fired power plant has operated in southern Sumatra.

Ireland

More than 17% of the republic's land surface is classified as peatland. Peat deposits totalling nearly 12 000 km^2 are widely distributed, being especially prominent along the western seaboard and across the Midland Plain in the centre of the island. Domestic consumption of peat for energy purposes in Ireland dates back to prehistoric times, with documentary evidence of its use existing from as early as the 8th century. After large stretches of the island's forests were cleared in the 17th century, peat (called 'turf' when cut) became the only fuel available to the majority of households.

Mechanical methods of extraction were adopted on a large scale following World War II, both for the production of milled peat (used as a power-plant fuel and in the manufacture of peat briquettes) and to replace manual cutting of sod peat for household use. Production of fuel peat in 2008 (as reported to the IEA) was about 3.1 million tonnes, with consumption of around 4.1 million tonnes.

Out of the total consumption of peat for energy purposes in 2007, nearly 67% was used in power stations and heat plants, 14% was briquetted and 17% consisted of sod peat, used predominantly as a residential fuel. Peat briquettes are also almost all used as household fuel.

Since its foundation in 1946, the Irish Peat Development Authority (Bord na Móna) has promoted the economic development of Ireland's peat resources. A number of power stations and briquetting plants have been built near peat deposits. A programme has been undertaken to replace five old peat-fired power plants with three more efficient and more environmentally-friendly peat-fired power plants. The first of the new stations, built by Edenderry Power Ltd near Clonbulloge, County Offaly, with a net output capacity of 120 MW, was commissioned in November 2000. It consumes approximately 1 million tonnes of milled peat per annum. The other new stations were constructed at Lough Ree (100 MW), replacing the existing Lanesboro station in December 2004, and West Offaly (150 MW), which replaced Shannonbridge in January 2005. The peat consumption rates of Lough Ree and West Offaly are 800 000 tpa and 1 245 000 tpa, respectively.

During the last five fiscal years, Bord na Móna's production of milled peat has ranged from 2.5 to 4.2 million tonnes, with an average annual level of just under 3.4 million tonnes. Sales of milled peat to power stations rose from just under 2 million tonnes in 2004/05 to nearly 3.1 million tonnes in 2008/09, in line with the input capacity (quoted above) of the three new peat-fired plants.

In 2008/09, 882 000 tonnes of milled peat were consigned to Bord na Móna's briquetting plants, which produced 217 000 tonnes of peat briquettes during the same period; these levels were close to the five-year averages of 903 000 and 219 000 tonnes respectively.

Latvia

Peatlands cover an estimated 6 600 km^2, or about 10% of Latvia's territory, with the major deposits being located in the eastern plains and in the vicinity of Riga. Of the estimated total tonnage of peat resources (1 500 million tonnes), 230 million tonnes is suitable for fuel use.

Peat has been used in agriculture and as a fuel for several hundred years: output peaked in 1973, when fuel use amounted to 2 million tonnes. By 1990, the tonnage of peat extracted had fallen by 45% and fuel use was down to only about 300 000 tonnes. There has been a steep decline in consumption since then, with deliveries to the Riga CHP-1 plant coming to an end in 2004. The production of peat briquettes ceased in 2001. Currently, only minor tonnages of peat (less than 10 000 tpa) are consumed by heat plants and industrial users.

Lithuania

Peatlands (totalling about 3 500 km^2) are widespread, with the larger accumulations tending to be in the west and southeast of the country. About 71% of the overall tonnage of peat resources is suitable for use as fuel. Energy use of peat fell from 1.5 million tonnes in 1960 to only about 0.1 million tonnes in 1985, since when consumption has declined further to around 65 000 tonnes per year. The principal peat consumers are heat plants, producers of semi-briquettes, and households; the last-named also account for virtually all of Lithuania's modest consumption of locally-produced peat semi-briquettes, together with briquettes imported from Belarus (8 000 tonnes in 2007).

Norway

Although there are extensive areas of essentially undisturbed peatland, amounting to some 28 000 km^2, peat extraction (almost all for horticultural purposes) has been at a relatively low level in recent years.

Peat had traditionally been used as a fuel in coastal parts of the country; unrestrained cutting led to considerable damage to the peatland, which in 1949 resulted in legislation to control extraction.

Poland

The area of peatland is some 12 500 km^2, with most deposits in the northern and eastern parts of the country.

Much use was made of peat as a fuel in the years immediately after World War II, with some production of peat briquettes and peat coke; by the mid-1960s fuel use had, however, considerably diminished. Current consumption of peat is virtually all for agricultural or horticultural purposes.

Romania

There are estimated to be 1 000 km^2 of peatlands. Peat production for energy purposes has dwindled to a very low level; annual consumption of around 40 000 tonnes is largely met by imports.

Russian Federation

The total area of peatlands has been estimated at some 1 390 000 km^2, of which 85% are located in Siberia.

The bulk of current peat production is used for agricultural/horticultural purposes. Peat deposits have been exploited in Russia as a source of industrial fuel for well over a hundred years. During the 1920s, the use of peat for power generation expanded rapidly, such that by 1928 over 40% of Soviet electric power was derived from peat. Peat's share of power generation has been in long-term decline, and since 1980 has amounted to less than 1%.

According to the IEA, 2008 production of peat for fuel was less than 0.8 million tonnes. The main users are CHP plants and briquetting works; most of the residual consumption of peat, whether as such or in the form of briquettes, takes place in the rural residential sector.

Sweden

In Western Europe, the extent of Sweden's peatlands (66 000 km^2 with a peat layer thicker than 30 cm) is second only to Finland's: the deposits are distributed throughout the country, being particularly extensive in the far north.

The use of peat as a household fuel has never been of much significance in Sweden. Production of peat for industrial energy use began during the 19th century and, after reaching a peak level during World War II, declined to virtually zero by 1970. Use of peat as a fuel for power stations and district heating plants started in the mid-1980s and now constitutes by far the greater part of consumption. In 2007, CHP plants accounted for 73% of total consumption, heat plants for 23% and industrial users for the remainder.

Sweden's reliance on peat as a fuel is considerably lower than that of Finland or Ireland, and moreover it imports about a third of its requirements, chiefly from Belarus, Latvia and Estonia. The Swedish Peat Producers Association forecasts that over the longer term peat imports will tend to decrease, as the Baltic States will need to increase their use of indigenous fuels in the face of rising natural gas prices, particularly following the commissioning of the North Stream pipeline between Russia and Germany. The Association considers that Sweden needs to produce more of its own fuel peat, but reports that there are problems in obtaining licences, on account of a resistance to peat production. It states that its biggest problem is achieving greater public acceptance of peat as a fuel.

Energy peat production in Sweden in 2008 was 837 000 tonnes, 61% higher than the corresponding level in 2007. The Government's energy and climate policy (February 2009) points out that 'under certain conditions and to a limited extent, peat can be used with a positive net climate impact'. It therefore considers that Sweden should take action to ensure that this point is taken into account by the IPCC and in the EU's regulatory framework.

Ukraine

There are estimated to be 8 000 km^2 of peatlands, more than half of which are located in Polesie, in the north of the country. The other main area for peat deposits is the valley of the Dnieper, in particular on the east side of the river. Peat production rose during the period of the communist regime, reaching 7.5 million tonnes in 1970, when 73% was used in agriculture and 27% for fuel. In recent years consumption of peat for fuel purposes has fallen to less than 350 000 tonnes per annum, the bulk of which is consumed by households, either directly or in the form of peat briquettes.

United Kingdom

Peatlands cover an area of some 27 500 km^2, most deposits being in the northern and western regions.

The total UK peatland area is more than twice that of Ireland, but the extraction of peat is on a very much smaller scale. Almost all peat industry output is for the horticultural market; there is, however, still quite extensive (but unquantified) extraction of peat for use as a domestic fuel in the rural parts of Scotland and Northern Ireland. Anecdotal evidence suggests that peat-cutting for fuel in Scotland has declined in recent years, having been replaced to some extent by purchases of peat briquettes imported from Ireland.

United States of America

The area of peatlands in the USA has been estimated at some 625 000 km^2, the majority of which is located in Alaska. In the contiguous United States, the major areas of peat deposits are in the northern states of Minnesota, Michigan and Wisconsin, along the eastern seaboard from Maine to Florida and along the Gulf coastal region as far as Louisiana.

The potential uses of peat as fuel were evaluated during the 1970s; a Department of Energy study published in 1980 covered - in addition to direct combustion uses - the potential for producing liquid fuels from peat.

Interest in developing the use of peat for energy purposes has diminished since 1980. A small (23 MW) power plant was constructed in 1990 in Maine, to be fuelled by local peat. Initial problems associated with the use of inappropriate harvesting equipment were overcome but it was then difficult to obtain further permits to exploit the larger bog area required; the boilers were subsequently fuelled mainly by wood chips.

9. Bioenergy

COMMENTARY

Introduction

The supply of sustainable energy is one of the main challenges that mankind will face over the coming decades, particularly because of the need to address climate change. Biomass can make a substantial contribution to supplying future energy demand in a sustainable way. It is presently the largest global contributor of renewable energy, and has significant potential to expand in the production of heat, electricity, and fuels for transport. Further deployment of bioenergy, if carefully managed, could provide:

- an even larger contribution to global primary energy supply;
- significant reductions in greenhouse gas emissions and potentially other environmental benefits;
- improvements in energy security and trade balances, by substituting imported fossil fuels with domestic biomass;
- opportunities for economic and social development in rural communities;
- scope for using wastes and residues, reducing waste disposal problems and making better use of resources.

This commentary provides an overview of the potential for bioenergy and the challenges associated with its increased deployment. It

Figure 9.1 Share of bioenergy in the world primary energy mix

(Source: based on IEA, 2006; IPCC, 2007)

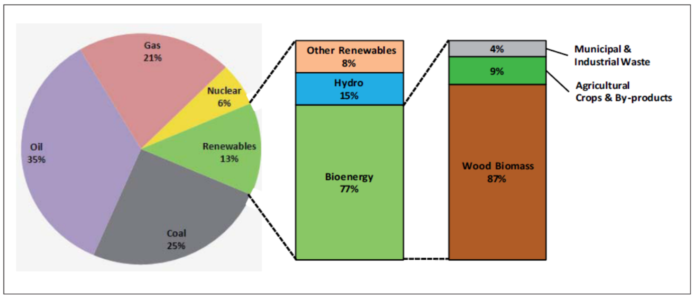
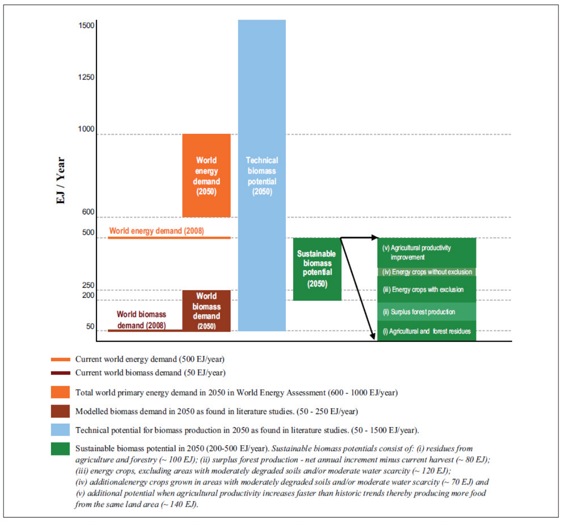


Figure 9.2 Technical and sustainable biomass supply potentials and expected demand

(Source: adapted from Dornburg, et al. [2008], based on several review studies)



discusses opportunities and risks in relation to resources, technologies, practices, markets and policy. The aim is to provide insights into the opportunities and required actions for the development of a sustainable bioenergy industry.

Biomass Resources

At present, forestry, agricultural and municipal residues, and wastes are the main feedstocks for the generation of electricity and heat from biomass. In addition, very small shares of sugar, grain, and vegetable oil crops are used as feedstocks for the production of liquid biofuels. Today, biomass supplies some 50 EJ globally, which represents 10% of global annual primary energy consumption. This is mostly traditional biomass used for cooking and heating (Fig. 9.1).

There is significant potential to expand biomass use by tapping the large volumes of unused residues and wastes. The use of conventional crops for energy use can also be expanded, with careful consideration of land availability and food demand. In the medium term, lignocellulosic crops (both herbaceous and woody) could be produced on marginal, degraded and surplus agricultural lands and provide the bulk of the biomass resource. In the longer term, aquatic biomass (algae) could also make a significant contribution. Based on this diverse range of feedstocks, the technical potential for biomass is estimated in the literature to be possibly as high as 1 500 EJ/yr by 2050, although most biomass supply scenarios that take into account sustainability constraints indicate an annual potential of between 200 and 500 EJ/yr (excluding aquatic biomass). Forestry and agricultural residues and other organic wastes (including municipal solid waste) would provide between 50 and 150 EJ/yr, while the remainder would come from energy crops, surplus forest growth, and increased agricultural productivity.

Projected world primary energy demand by 2050 is expected to be in the range of 600 to 1 000 EJ (compared to about 500 EJ in 2008). Scenarios looking at the penetration of different low-carbon energy sources indicate that future demand for bioenergy could be up to 250 EJ/yr. This projected demand falls well within the sustainable supply potential estimate, so it is reasonable to assume that biomass could sustainably contribute between a quarter and a third of the future global energy mix (Fig. 9.2).

Whatever is actually realised will depend on the cost competitiveness of bioenergy and on future policy frameworks, such as greenhouse gas emission reduction targets. Growth in the use of biomass resources in the mid-term period to 2030 will depend on many demand and supply side factors. Strong renewable energy targets being set at regional and national level (e.g. the European Renewable Energy Directive) are likely to lead to a significant increase in demand. This demand is likely to be met through increased use of residues and wastes, sugar, starch and oil crops, and increasingly, lignocellulosic crops. The contribution of energy crops depends on the choice of crop and planting rates, which are influenced by productivity increases in agriculture, environmental constraints, water availability and logistical constraints. Under favourable conditions substantial growth is possible over the next 20 years. However, estimates of the potential increase in production do vary widely. For example, the biomass potential from residues and energy crops in the EU to 2030 is estimated to range between 4.4 and 24 EJ. The long-term potential for energy crops depends largely on:

- land availability, which depends on food sector development (growth in food demand, population diet, and increased crop productivity) and factors limiting access to land, such as water and nature protection;

- the choice of energy crops, which defines the biomass yield levels that can be obtained on the available land.

Other factors that may affect biomass potential include the impact of biotechnology, such as genetically modified organisms, water availability, and the effects of climate change on productivity.

The uptake of biomass depends on several factors:

- biomass production costs – US$ 4/GJ is often regarded as an upper limit if bioenergy is to be widely deployed today in all sectors;

- logistics – as with all agricultural commodities, energy crops and residues all require appropriate supply chain infrastructure;

- resource and environmental issues – biomass feedstock production can have both positive and negative effects on the environment (water availability and quality, soil quality and biodiversity).

These will result in regulations restricting or incentivising particular practices (e.g. environmental regulations, sustainability standards, etc.).

Drivers for increased bioenergy use (e.g. policy targets for renewables) can lead to increased demand for biomass, leading to competition for land currently used for food production, and possibly (indirectly) causing sensitive areas to be taken into production. This will require intervention by policy makers, in the form of regulation of bioenergy chains and/or regulation of land use, to ensure sustainable demand and production. Development of appropriate policy requires an understanding of the complex issues involved and international cooperation on measures to promote global sustainable biomass production systems and practices. To achieve the bioenergy potential targets in the longer term, government policies and industrial efforts need to be directed at increasing biomass yield levels and modernising agriculture in regions such as Africa, the Far East and Latin America, directly increasing global food production and thus the resources available for biomass. This can be achieved by technology development and by the diffusion of best sustainable agricultural practices. The sustainable use of residues and wastes for bioenergy, which present limited or zero environmental risks, needs to be encouraged and promoted globally.

Figure 9.3 Schematic view of the wide variety of bioenergy routes (Source: E4tech, 2009)

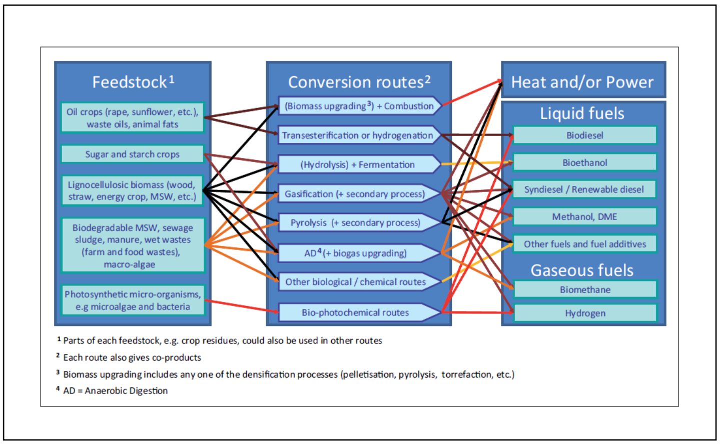
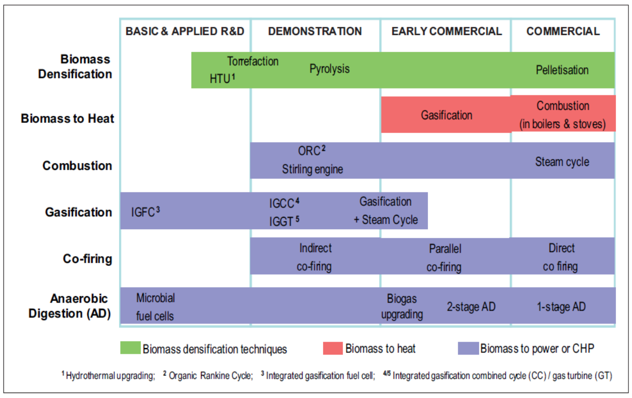


Figure 9.4 Development status of the main technologies to upgrade biomass and/or convert it into heat and/or power (Source: E4tech, 2009)



Biomass Conversion Technologies

There are many bioenergy routes which can be used to convert raw biomass feedstock into a final energy product (Fig. 9.3). Several conversion technologies have been developed that are adapted to the different physical nature and chemical composition of the feedstock, and to the energy service required (heat, power, transport fuel). Upgrading technologies for biomass feedstocks (e.g. pelletisation, torrefaction and pyrolysis) are being developed to convert bulky raw biomass into denser and more practical energy carriers for more efficient transport, storage and convenient use in subsequent conversion processes.

The production of heat by the direct combustion of biomass is the leading bioenergy application throughout the world, and is often cost-competitive with fossil fuel alternatives. Technologies range from rudimentary stoves to sophisticated modern appliances. For a more energy efficient use of the biomass resource, modern, large-scale heat applications are often combined with electricity production in combined heat and power (CHP) systems.

Different technologies exist or are being developed to produce electricity from biomass. Co-combustion (also called co-firing) in coal-based power plants is the most cost-effective use of biomass for power generation. Dedicated biomass combustion plants, including MSW combustion plants, are also in successful commercial operation and many are industrial or district heating CHP facilities. For sludges, liquids and wet organic materials, anaerobic digestion is currently the best-suited option for producing electricity and/or heat from biomass, although its economic case relies heavily on the availability of low-cost feedstock. All these technologies are well established and commercially available.

There are few examples of commercial gasification plants, and the deployment of this technology is affected by its complexity and cost. In the longer term, if reliable and cost-effective operation can be more widely demonstrated, gasification promises greater efficiency, better economics at both small- and large-scale and lower emissions compared with other biomass-based power generation options. Other technologies (such as Organic Rankine Cycle and Stirling engines) are currently in the demonstration stage and could prove economically viable in a range of small-scale applications, especially for CHP (Fig. 9.4).

In the transport sector, first-generation biofuels are widely deployed in several countries, mainly bioethanol from starch and sugar crops and biodiesel from oil crops and residual oils and fats. Production costs of current biofuels vary significantly depending on the feedstock used (and their volatile prices) and on the scale of the plant. The potential for further deploying these first-generation technologies is high, subject to sustainable land-use criteria being met.

Figure 9.5 Development status of the main technologies to produce biofuels for transport (Source: E4tech, 2009)

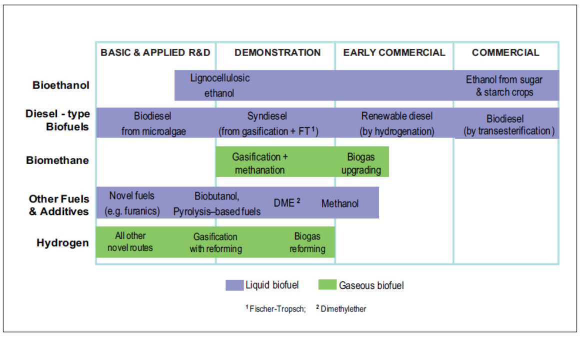
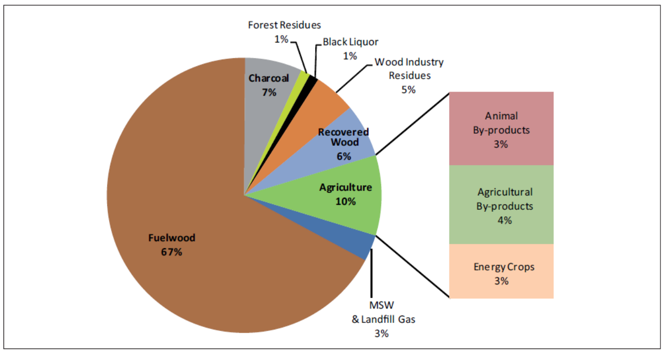


Figure 9.6 Share of biomass sources in the primary bioenergy mix
(Source: based on data from IPCC, 2007)



First-generation biofuels face both social and environmental challenges, largely because they use food crops which could lead to food price increases and possibly indirect land-use change. While such risks can be mitigated by regulation and sustainability assurance and certification, technology development is also advancing for next-generation processes that rely on non-food biomass (e.g. lignocellulosic feedstocks such as organic wastes, forestry residues, high-yielding woody or grass energy crops and algae). The use of these feedstocks for second-generation biofuel production would significantly decrease the potential pressure on land use, improve greenhouse gas emission reductions when compared to some first-generation biofuels, and result in lower environmental and social risk. Second-generation technologies, mainly using lignocellulosic feedstocks for the production of ethanol, synthetic diesel and aviation fuels, are still immature and need further development and investment to demonstrate reliable operation at commercial scale and to achieve cost reductions through scale-up and replication. The current level of activity in the area indicates that these routes are likely to become commercial over the next decade. Future generations of biofuels, such as oils produced from algae, are at the applied R&D stage, and require considerable development before they can become competitive contributors to the energy markets (Fig. 9.5).

Further development of bioenergy technologies is needed, mainly to improve the efficiency, reliability and sustainability of bioenergy chains. In the heat sector, improvement would lead to cleaner, more reliable systems linked to higher-quality fuel supplies. In the electricity sector, the development of smaller and more cost-effective electricity or CHP systems could better match local resource availability. In the transport sector, improvements could lead to higher quality and more sustainable biofuels.

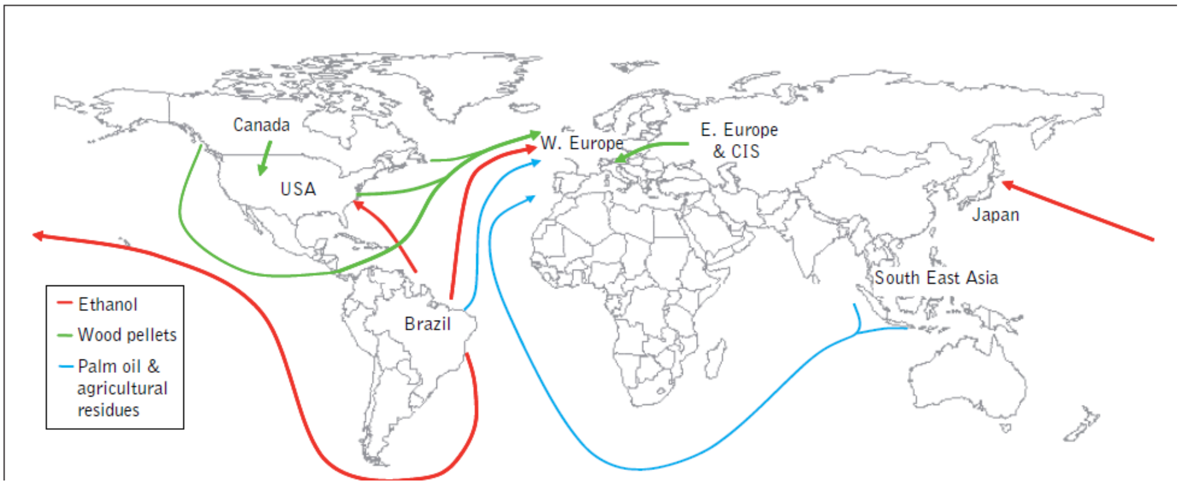
Ultimately, bioenergy production may increasingly occur in bio-refineries where transport biofuels, power, heat, chemicals and other marketable products could all be co-produced from a mix of biomass feedstocks. The link between producing energy and other materials deserves further attention technically and commercially.

Bioenergy Markets

The predominant use of biomass today consists of fuel wood used in non-commercial applications, in simple inefficient stoves for domestic heating and cooking in developing countries, where biomass contributes some 22% to the total primary energy mix. This traditional use of biomass is expected to grow with increasing world population. However, there is significant scope to improve its efficiency and environmental performance and thereby help reduce biomass consumption and related impacts (Fig. 9.6).

In industrialised countries, the total contribution of modern biomass is on average only about 3% of total primary energy, and consists mostly of heat-only and heat and power applications. Many

Figure 9.7 Main international biomass for energy trade routes* (Source: Junginger and Faaij, 2008)



*Intra-European trade is not displayed, for the sake of clarity

countries have targets to significantly increase biomass use, as it is seen as a key contributor to meeting energy and environmental policy objectives. Current markets, growing as a result of attractive economics, mostly involve domestic heat supply (e.g. pellet boilers), large-scale industrial and community CHP generation (particularly where low-cost feedstocks from forest residues, bagasse, MSW etc. are available), and co-firing in large coal-based power plants. The deployment of dedicated electricity plants has been mainly confined to low-cost feedstocks in relatively small-scale applications, such as the use of biogas and landfill gas from waste treatment. Globally, the use of biomass in heat and industrial energy applications is expected to double by 2050 under business-as-usual scenarios, while electricity production from biomass is projected to increase, from its current share of 1.3% in total power production to 2.4 – 3.3% by 2030 (corresponding to a 5 - 6% average annual growth rate).

Transport biofuels are currently the fastest growing bioenergy sector, receiving a great deal of public attention. However, today they represent only 1.5% of total road transport fuel consumption and only 2% of total bioenergy. They are, however, expected to play an increasing role in meeting the demand for road transport fuel, with second-generation biofuels increasing in importance over the next two decades. Even under business-as-usual scenarios, biofuel production is expected to increase by a factor of 10 to 20 relative to current levels by 2030 (corresponding to a 6 - 8% average annual growth rate).

Global trade in biomass feedstocks (e.g. wood chips, vegetable oils and agricultural residues) and processed bioenergy carriers (e.g. ethanol, biodiesel, wood pellets) is growing rapidly. Present estimates indicate that bioenergy trade is modest – around 1 EJ (about 2% of current bioenergy use). In the longer term, much larger quantities of these products might be traded internationally, with Latin America and Sub-Saharan Africa as potential net exporters and North America, Europe and Asia foreseen as net importers. Trade will be an important component of the sustained growth of the bioenergy sector (Fig. 9.7).

The quest for a sustainable energy system will require more bioenergy than the growth projected under the business-as-usual scenarios. A number of biomass supply chain issues and market risks and barriers will need to be addressed and mitigated to enable stronger sustained growth of the bioenergy sector. These include:

- ***Security of the feedstock supply*** - this is susceptible to the inherent volatility of biological production (due to weather and seasonal variations), which can lead to significant variations in feedstock supply quantity, quality and price. Risk mitigation strategies already common in food and energy markets include having a larger, more fluid, global biomass sector and the creation of buffer stocks.

- ***Economies of scale and logistics*** - many commercially available technologies suffer from poor economics at a small scale, but conversely larger scales require improved and more complex feedstock supply logistics. Efforts are required to develop technologies at appropriate scales and with appropriate supply chains to meet different application requirements.
- ***Competition*** - bioenergy technologies compete with other renewable and non-renewable energy sources and may compete for feedstock with other sectors such as food, chemicals and materials. Also, the development of second-generation biofuel technologies could lead to competition for biomass resources between bioenergy applications, and potentially with other industry sectors. Support needs to be directed at developing cost-effective bioenergy routes and at deploying larger quantities of biomass feedstocks from sustainable sources.
- ***Public and NGO acceptance*** - this is a major risk factor facing alternative energy sources and bioenergy in particular. The public needs to be informed and confident that bioenergy is environmentally and socially beneficial and does not result in significant negative environmental and social trade-offs. However, the industry is confident such challenges can be met as similar challenges have been addressed in other sectors and appropriate technologies and practices are being developed and deployed.

Interactions with Other Markets

Developments in the bioenergy sector can influence markets for agricultural products (e.g. food and feed products, straw) and forest products (e.g. paper, board). However, this impact is not straightforward, owing to:

- other factors, such as biomass yield variations and fossil fuel price volatilities influencing markets just as much or more than biomass;
- other policy domains, including forestry, agriculture, environment, transport, health and trade, also having influence on bioenergy policies;
- a lack of transparency in many product and commodity markets, especially in forest products, making it difficult to assess the impact of bioenergy development.

While all forms of bioenergy interrelate with agriculture and/or forest markets through their feedstock demand, the impact of first-generation liquid biofuels on food prices has been a topic of strong debate in recent years. Although different studies reveal a wide variety of opinions on the magnitude of these impacts, most model-based demand scenarios indicate a relatively limited risk of biofuels significantly affecting the price of food crops. In general, markets can work to dampen these effects.

Markets will need access to monetary and physical resources, and will need to function efficiently and transparently in order to counteract the pressure of increasing demand. There is therefore an important role for policy in providing support to an increasingly efficient industry, for example in terms of yields, use of residues and wastes, and land use, while providing regulation to avoid negative impacts associated with the exploitation of physical resources. This requires active coordination between energy, agriculture and forestry, trade and environmental policies.

Bioenergy and Policy Objectives

Bioenergy can significantly increase its existing contribution to policy objectives, such as CO_2 emission reductions and energy security, as well as to social and economic development objectives.

Appreciating where bioenergy can have the greatest impact on GHG emissions reduction relies on both an understanding of the emissions resulting from different bioenergy routes and the importance of bioenergy in reducing emissions in a particular sector. Bioenergy chains can perform very differently with regard to GHG emissions. Substituting biomass for fossil fuels in heat and electricity generation is generally less costly and provides larger emission reductions per unit of biomass than substituting biomass for gasoline or diesel used for transport. However, the stationary bioenergy sector can rely on a range of different low-carbon options while biofuels are the primary option for decarbonising road transport until all-electric and/or hydrogen fuel cell powered vehicles become widely deployed, which is unlikely to be the case for some decades. In the long term, biofuels might remain the only option for decarbonising aviation transport, a sector for which it will be difficult to find an alternative to liquid fuels.

Land suitable for producing biomass for energy can also be used for the creation of biospheric carbon sinks. Several factors determine the relative attractiveness of these two options, in particular land productivity, including co-products, and fossil fuel replacement efficiency. Also, possible direct and indirect emissions from converting land to another use can substantially reduce the climate benefit of both bioenergy and carbon sink projects, and need to be taken into careful consideration. A further influencing factor is the time scale that is used for the evaluation of the carbon reduction potential: a short time scale tends to favour the sink option, while a longer time scale offers larger savings as biomass production is not limited by saturation but can repeatedly (from harvest to harvest) deliver greenhouse gas emission reductions by substituting for fossil fuels. Mature forests that have ceased to serve as carbon sinks can in principle be managed in a conventional manner to produce timber and other forest products, offering a relatively low GHG reduction per hectare. Alternatively, they could be converted to higher yielding energy plantations (or to food production) but this would involve the release of at least part of the carbon store created.

The use of domestic biomass resources can make a contribution to energy security, depending on which energy source it is replacing. Biomass imports from widely distributed international sources generally also contribute to the diversification of the energy mix. However, supply security can be affected by natural variations in biomass outputs and by supply-demand imbalances in the food and forest product sectors, potentially leading to shortages.

The production of bioenergy can also result in other (positive and negative) environmental and socio-economic effects. Most of the environmental effects are linked to biomass feedstock production, many of which can be mitigated through best practices and appropriate regulation. Technical solutions are available for mitigating most environmental impacts from bioenergy conversion facilities and their vehicle fleets such as city buses have historically been diesel powered but are very suitable for the introduction of new fuels, e.g. biogas or ethanol. The performance and sustainability of liquid biofuels is a current RD&D focus. Their use is largely a question of appropriate environmental regulations and their enforcement. The use of organic waste and agricultural/forestry residues, and of lignocellulosic crops that could be grown on a wider spectrum of land types, may mitigate land and water demand and reduce competition with food.

Feedstock production systems can also provide several benefits. For instance, forest residue harvesting improves forest site conditions for planting, thinning generally improves the growth and productivity of the remaining stand, and removal of biomass from over-dense stands can reduce the risk of wildfire. In agriculture, biomass can be cultivated in so-called multifunctional plantations that – through well chosen locations, design, management, and system integration – offer extra environmental services that, in turn, create added value for the systems.

Policy around bioenergy needs to be designed so that it is consistent with meeting environmental and social objectives. Bioenergy needs to be regulated so that environmental and social issues are taken into consideration, environmental services provided by bioenergy systems are recognised and valued, and so that it contributes to rural development objectives.

Lessons for the Future

As the deployment of many bioenergy options depends on government support, at least in the short and medium term, the design and implementation of appropriate policies and support mechanisms is vital, and defensible, particularly given the associated environmental benefits and existing government support for fossil fuels. These policies should also ensure that bioenergy contributes to economic, environmental and social goals. Experience over the last couple of decades has taught us the following:

- A policy initiative for bioenergy is most effective when it is part of a long-term vision that builds on specific national or regional characteristics and strengths, e.g. in terms of existing or potential biomass feedstocks available, specific features of the industrial and energy sector, and the infrastructure and trade context.
- Policies should take into account the development stage of a specific bioenergy technology, and provide incentives consistent with the barriers that an option is facing. Factors such as technology maturity, characteristics of incumbent technologies and price volatilities all need to be taken into consideration. In each development stage, there may be a specific trade-off between

incentives being technology-neutral and closely relating to the policy drivers and on the other hand creating a sufficiently protected environment for technologies to evolve and mature.

- There are two classes of currently preferred policy instruments for bio-electricity and renewable electricity in general. These are technology-specific feed-in tariffs and more generic incentives such as renewable energy quotas and tax differentiation between bioenergy and fossil-based energy. Each approach has its pros and cons, with neither being clearly more effective.
- Access to markets is a critical factor for almost all bioenergy technologies, so that policies need to pay attention to grid access, and standardisation of feedstocks and biofuels.
- As all bioenergy options depend on feedstock availability, a policy strategy for bioenergy should pay attention to the sectors that will provide the biomass. For the agricultural and forestry sectors, this includes consideration of aspects such as productivity improvement, availability of agricultural and forest land and access to and extractability of primary residues. For other feedstocks, such as residues from wood processing and municipal solid waste, important aspects are mobilisation and responsible use.
- A long-term successful bioenergy strategy needs to take into account sustainability issues. Policies and standards safeguarding biomass sustainability are currently in rapid development. Due to the complexity of the sustainability issue, future policy making and the development of standards will need to focus on integrated approaches, in which the complex interactions with aspects such as land use, agriculture and forestry, and social development are taken into account.
- Long-term continuity and predictability of policy support is also important. This does not mean that all policies need to be long-term, but policies conducive to the growth of a sector should have a duration that is clearly stated and in line with meeting certain objectives, such as cost reduction to competitive levels with conventional technologies.
- The successful development of bioenergy does not only depend on specific policies which provide incentives for its uptake, but on the broader energy and environment legal and planning framework. This requires coordination amongst policies and other government actions, as well as working with industry and other stakeholders to establish a framework conducive to investment in bioenergy.

A Sensible Way Forward

Climate change and energy security are problems for which solutions need to be developed and implemented urgently. The scale of the challenge is such that it will require contributions from disparate sources of energy. Bioenergy already contributes significantly to addressing these problems and can contribute much further through existing and new conversion technologies and feedstocks.

Furthermore, bioenergy can contribute to other environmental and social objectives, such as waste treatment and rural development. However, policy makers and the public at large will need to be comfortable that this expansion is sustainable. Bioenergy can result in many external benefits but also entails risks. A development and deployment strategy needs to be based on careful consideration of the strengths and weaknesses, as well as the opportunities and threats that characterise it.

- Current bioenergy routes that generate heat and electricity from the sustainable use of residues and wastes should be strongly stimulated. These rely on commercial technologies, lead to a better use of raw materials, and result in clear GHG savings and possibly other emission reductions compared to fossil fuels. The development of infrastructure and logistics, quality standards and trading platforms will be crucial to growth and may require policy support.
- Further increasing the deployment of bioenergy, and in particular of biofuels for transport in the short term, should be pursued by:
  - paying specific attention to sustainability issues directly related to the biomass-to-energy production chain, and avoiding or mitigating negative impacts through the development and implementation of sustainability assurance schemes;
  - incentivising biofuels based on their potential greenhouse gas benefits;
  - considering potential impacts of biomass demand for energy applications on commodity markets and on indirect land-use change;
  - defining growth rates that result in feedstock demands that the sector can cope with on a sustainable basis.
- Development of new and improved biomass conversion technologies will be essential for widespread deployment and long-term success. Public and private funding needs to be devoted to research, development and deployment as follows:
  - for liquid biofuels - advanced technologies that allow for a broader feedstock base using non-food crops with fewer (direct and indirect) environmental and social risks, and higher greenhouse gas benefits;
  - for power and heat production - more efficient advanced technologies, such as gasification and advanced steam cycles, and technologies with improved economics at a smaller scale to allow for more distributed use of biomass;
  - for novel biomass - upgrading technologies and multiproduct bio-refineries, which could contribute to the deployment and overall cost-competitiveness of bioenergy.
- As the availability of residues and wastes will limit bioenergy deployment in the long term, policies stimulating increased productivity in agriculture and forestry, and public and private efforts aimed at development of novel

energy crops, such as perennial lignocellulosic crops and other forms of biomass, such as algae, are essential for a sustained growth of the bioenergy industry. These efforts need to be integrated with sustainable land-use policies which also consider making efficient and environmentally sound use of marginal and degraded lands.

Acknowledgement

This paper is based on the Executive Summary of a report prepared for the IEA Bioenergy Agreement by a consortium led by the Energy Research Centre of the Netherlands (ECN), and including E4tech, Chalmers University of Technology and the Copernicus Institute of the University of Utrecht.

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IEA Bioenergy Agreement

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TABLES

Table 9.1 Bagasse: estimated potential availability - 2008 (thousand tonnes)

	Bagasse potential availability	
	at 50% humidity	dry matter
Benin	33	16
Burkina Faso	130	65
Burundi	78	39
Cameroon	326	163
Chad	118	59
Congo (Brazzaville)	220	110
Congo (Democratic Rep.)	228	114
Côte d'Ivoire	489	245
Egypt (Arab Rep.)	3 804	1 902
Ethiopia	1 108	554
Gabon	68	34
Guinea	65	33
Kenya	1 834	917
Madagascar	52	26
Malawi	1 011	505
Mali	114	57
Mauritius	1 564	782
Morocco	276	138
Mozambique	816	408
Niger	33	16
Nigeria	68	34
Rwanda	33	16
Senegal	326	163
Sierra Leone	20	10
Somalia	65	33
South Africa	7 872	3 936
Sudan	2 125	1 063
Swaziland	2 163	1 082
Tanzania	933	466
Uganda	845	422
Zambia	673	337
Zimbabwe	948	474
Total Africa	**28 438**	**14 219**

Table 9.1 Bagasse: estimated potential availability - 2008 (thousand tonnes)

	Bagasse potential availability	
	at 50% humidity	**dry matter**
Barbados	103	52
Belize	281	140
Costa Rica	1 146	573
Cuba	4 712	2 356
Dominican Republic	1 604	802
El Salvador	1 947	974
Guatemala	6 991	3 496
Honduras	1 239	619
Jamaica	458	229
Mexico	19 364	9 682
Nicaragua	1 565	782
Panama	571	285
United States of America	10 026	5 013
Total North America	**50 006**	**25 003**
Argentina	7 980	3 990
Bolivia	1 108	554
Brazil	105 266	52 633
Colombia	6 638	3 319
Ecuador	1 663	831
Guyana	730	365
Paraguay	391	196
Peru	3 276	1 638
Suriname	23	11
Uruguay	23	11
Venezuela	2 249	1 125
Total South America	**129 347**	**64 674**
Bangladesh	359	179
China	47 026	23 513
India	84 551	42 276
Indonesia	9 438	4 719
Japan	595	298
Laos	33	16

Table 9.1 Bagasse: estimated potential availability - 2008 (thousand tonnes)

	Bagasse potential availability	
	at 50% humidity	**dry matter**
Malaysia	114	57
Myanmar (Burma)	587	293
Nepal	456	228
Pakistan	16 270	8 135
Philippines	7 872	3 936
Sri Lanka	245	122
Taiwan, China	212	106
Thailand	25 343	12 672
Vietnam	3 472	1 736
Total Asia	**196 572**	**98 286**
Unspecified	838	419
Total Europe	**838**	**419**
Iran (Islamic Rep.)	1 320	660
Total Middle East	**1 320**	**660**
Australia	15 057	7 529
Fiji	921	461
Papua New Guinea	114	57
Western Samoa	8	4
Total Oceania	**16 101**	**8 050**
TOTAL WORLD	**422 622**	**211 311**

Notes:

1. Sources: Bagasse potential availability based on production of cane sugar published in the *I.S.O. Sugar Yearbook 2009*, International Sugar Organization;
2. Bagasse potential availability conversion factor *from United Nations Energy Statistics Yearbook* (assumes a yield of 3.26 tonnes of fuel bagasse at 50% humidity per tonne of cane sugar produced)

COUNTRY NOTES

The Country Notes on Bioenergy reflect the data and comments provided by WEC Member Committees in 2009/10, supplemented where necessary by information provided for previous editions of the WEC *Survey of Energy Resources.*

Unless otherwise specified, the data relate to the year 2008.

Albania

Biomass type:

Municipal solid waste		
quantity of raw material available	405	ttoe
Forestry/wood processing		
quantity of raw material available	237	ttoe

Data refer to 2002

Algeria

Biomass type:

Municipal solid waste		
quantity of raw material available	5	million tonnes
Forestry/wood processing		
quantity of raw material available	3.7	million tonnes
Urban agricultural wastes		
quantity of raw material available	1.33	million tonnes

Data refer to 2005

Argentina

Biomass type:

Soya		
biodiesel production capacity	1 361 020	tonnes/yr
biodiesel production	712 066	tonnes
yield of biodiesel	38.02	GJ/tonne
total energy production	27 023	TJ
potential energy production (based on 2008 installed capacity	51 746	TJ/yr
Sugar cane		
ethanol production	186 300	tonnes
yield of ethanol	26.81	GJ/ tonne
total energy production	4 995	TJ

During 2008 680 353 tonnes of biodiesel were exported, the majority to the Netherlands and the USA.

Australia

Biomass type:

Municipal solid waste *		
quantity of raw material available	~6.9	million tonnes
yield of solid fuel	~9	GJ/tonne
electricity generating capacity	103 700	kW
Sugar cane bagasse **		
quantity of raw material available	11.4	million tonnes

yield of solid fuel	~9.3	GJ/tonne
electricity generating capacity	368 600	kW
Forestry/Wood processing * **		
quantity of raw material available	~ 25	million tonnes
yield of solid fuel (operational)	11	GJ/tonne
electricity generating capacity	76 500	kW
direct use from combustion	~ 66 000	TJ

Unless otherwise stated, data refer to 2002.
* 98 700 kW from landfill gas and 5 000 kW from MSW gasification (SWERF plant, Wollongong).
** Data refer to 1997. Sugar industry generation includes the Rocky Point sugar mill cogeneration plant, which uses some wood waste in the non-crushing season.
*** Includes Tumut pulp and paper mill power plants, plus Maryvale pulp and paper and Visy's plant in Brisbane. Direct combustion assumes 6 million tonnes of firewood used mainly for domestic heating.

Approximately 80 megalitres/yr ethanol produced.
Biodiesel production relatively low. Estimated to be below 20 million litres in 2002.
The Bureau of Rural Sciences has developed a bioenergy atlas for Australia.

Austria

Biomass type:

Municipal solid waste		
quantity of raw material available *	2.4	million tonnes
direct use from combustion	16 421	TJ
total energy production	30 270	TJ

Wood		
quantity of raw material available *	4.3	million tonnes
direct use from combustion	64 429	TJ
total energy production	64 464	TJ
Other biomass		
quantity of raw material available	11.9	million tonnes
ethanol capacity	5 000	TJ/yr
biodiesel capacity	17 000	TJ/yr
biodiesel production	8 900	TJ
biogas production	6 000	TJ
electricity capacity **	555 000	kW
electricity generation **	9 000	TJ
direct use from combustion	63 775	TJ
total energy production	118 302	TJ

Unless otherwise stated, data refer to 2007.
* Data refer to 2008
** including MSW and wood

Belgium

Biomass type:

Municipal solid waste		
quantity of raw material available	1.1	million tonnes
electricity generating capacity	76 600	kW
electricity generation	1 765	TJ

Black liquor/bark		
quantity of raw material available	0.2	million tonnes
electricity generating capacity	31 000	kW
electricity generation	585	TJ

Data refer to 1996

Bolivia

Biomass type:

Animal dung		
direct use from combustion	3 270	TJ
Sugar cane bagasse		
direct use from combustion	10 458	TJ
Crop residues		
direct use from combustion	307	TJ

Data refer to 1996

Botswana

Biomass type:

Municipal solid waste		
direct use from combustion	1 420	TJ

Estimated

Brazil

Biomass type:

Municipal solid waste		
quantity of raw material available	40	million tonnes
electricity generating capacity	41 870	kW
electricity generation	924	TJ
total energy production	2 311	TJ
Sugar cane bagasse		
quantity of raw material available	140.89	million tonnes
electricity generating capacity	3 608	MW
electricity generation	44 210	TJ
direct use from combustion	1 155 943	TJ
total energy production	1 256 429	TJ
Wood		
quantity of raw material available	92.61	million tonnes
solid fuel production capacity	295 000	TJ/yr
yield of solid fuel	6.81	GJ/tonne
solid fuel production	264 574	TJ
electricity generating capacity	148 481	kW
electricity generation	3 015	TJ
direct use from combustion	692 742	TJ
total energy production	1 201 966	TJ

Forestry/wood processing		
quantity of raw material available	3.56	million tonnes
electricity generating capacity	89 109	kW
electricity generation	1 967	TJ
direct use from combustion	33 496	TJ
total energy production	40 196	TJ
Rice hulls		
quantity of raw material available	0.16	million tonnes
electricity generating capacity	25 210	kW
electricity generation	477	TJ
direct use from combustion	635	TJ
total energy production	1 828	TJ
Soy oil		
quantity of raw material available	4.87	million tonnes
biodiesel production capacity	126 517	TJ/yr
yield of ethanol	6.56	GJ/tonne
biodiesel production	31 819	TJ
Other biodiesel		
quantity of raw material available	0.60	million tonnes
biodiesel production	8 490	TJ
Black liquor		
quantity of raw material available	18.46	million tonnes
electricity generating capacity	848 640	kW
electricity generation	21 633	TJ
direct use from combustion	171 935	TJ
total energy production	221 043	TJ
Cane juice		
quantity of raw material available	170.05	million tonnes
ethanol production capacity	494 500	TJ/yr
yield of ethanol	2.64	GJ/tonne
ethanol production	435 447	TJ
total energy production	437 855	TJ
Molasses		
quantity of raw material available	19.49	million tonnes
ethanol production capacity	152 905	TJ/yr
yield of ethanol	7.13	GJ/tonne
ethanol production	146 794	TJ
total energy production	147 531	TJ

Bulgaria

Biomass type:

Wood		
direct use from combustion	28 280	TJ

Forestry/wood processing		
direct use from combustion	2 829	TJ
Rape/sunflower seed oil		
biodiesel production	97	TJ

In 2007 1 046 TJ of biomass were exported

Cameroon

Biomass type:

Wood		
consumption for fuel	9 580 621	tonnes
Charcoal		
consumption for fuel	138 952	tonnes
Sawdust and shavings		
consumption for fuel	175 383	tonnes

Data refer to 2005

Canada

Biomass type:

Municipal solid waste		
quantity of raw material available	11.856	million tonnes
biogas production capacity	0.003	TJ/yr
yield of biogas	51.5	GJ/tonne
electricity generating capacity	211 187	kW
direct use from combustion	1.688	TJ
Wood		
solid fuel production	101 808	TJ
Forestry/wood processing		
quantity of raw material available	36	million tonnes
solid fuel production capacity	37 000	TJ/yr
yield of solid fuel	18.5	GJ/tonne
solid fuel production	37 000	TJ
electricity generating capacity *	1 075 140	kW
electricity generation	23 069	TJ
Corn		
ethanol production capacity	24 341	TJ/yr
yield of ethanol	9.49	GJ/tonne
ethanol production	21 524	TJ
Wheat		
ethanol production capacity	8 703	TJ/yr
yield of ethanol	8.9	GJ/tonne
ethanol production	7 563	TJ
Wheat straw		
ethanol production capacity	47	TJ/yr
Canola		
biodiesel production capacity	2 932	TJ/yr
yield of biodiesel	37.8	GJ/tonne
Fish oil		
biodiesel production capacity	5 209	TJ/yr
yield of biodiesel	37.8	GJ/tonne
biogas production	1.348	TJ

* Data refer to 2007

Over 30.4 million tonnes of waste was generated in Canada during 2002. This translates into 971 kg per person. Households accounted for 39% of this total, with the remainder generated in the industrial, commercial and institutional sector, construction, renovation and demolition. As a country, Canada still disposes of more than 78% of waste.

There are approximately 50 large municipal waste water facilities in Canada with a potential to produce 84 million m^3/yr methane with a wet calorific value of 37 300 kJ/m^3.

Canadian wood pellet production during 2008 was 2 million tonnes; domestic sales were 250 000 tonnes with 450 000 tonnes sold to the USA and 1 300 000 tonnes overseas. A typical Canadian wood pellet specification has a net calorific value of 18.5 GJ/tonne.

Many food and beverage companies currently produce and use biogas in their operations, but details are proprietary information.

During 2008 Canada imported 570 million litres of ethanol, 85% of which originated in the USA.

Colombia

Biomass type:

Sugar cane bagasse		
quantity of raw material available	10.6	million tonnes
Wood		
quantity of raw material available	5.9	million tonnes
Sugar cane		
quantity of raw material available	4.252	million tonnes
ethanol production capacity	8 490	TJ/yr
ethanol production	5 414	TJ
Palm oil		
quantity of raw material available	76.444	million tonnes
biodiesel production capacity	3 421	tonnes/yr
biodiesel production	4 426	tonnes

Côte d'Ivoire

As reported for SER 2004:

Data concerning the use of biomass energy (apart from wood and charcoal) are unavailable. To resolve this problem, a strategy is being devised to collect data on production and consumption of all forms of biomass.

There is a programme for restructuring the institutional framework of renewable energies and a project concerning the inventory and the evaluation of agricultural and industrial waste.

Natural biomass, agricultural waste and industrial waste constitute the potential renewable energies for direct use.

78% of the population consumes biomass energy in different forms (firewood, charcoal by city dwellers, agricultural and industrial waste).

The agricultural and industrial energy resources are estimated at more than 4 mtoe/yr. They constitute an important source of energy and essentially come from palm oil, manufactured wood, coffee, rice and sugar cane.

The principal technologies used for the conversion of biomass into energy are carbonisation, gasification and fermentation.

Firewood and charcoal constitute 60% of the national energy consumption. As well as household consumption, wood fuels are also used in restaurants, ironwork, bakeries, potteries, curing and drying feed.

Croatia

Biomass type:

Municipal solid waste		
quantity of raw material available	1.5	million tonnes
electricity generating capacity	2 000	kW
electricity generation	0.0144	TJ
Wood		
quantity of raw material available	1.65	million tonnes
yield of solid fuel	15	GJ/tonne
solid fuel production	15 884.1	TJ
direct use from combustion *	13 380	TJ
Forestry/wood processing		
quantity of raw material available **	1.62	million tonnes
solid fuel production capacity ***	3 187	TJ/yr
yield of solid fuel	18	GJ/tonne
solid fuel production ***	1 232.6	TJ
Agricultural crops and residues - vineyard		
quantity of raw material available	0.035	million tonnes
– olives		
quantity of raw material available	0.06	million tonnes
– orchards		
quantity of raw material available	0.143	million tonnes
– wheat		
quantity of raw material available	0.306	million tonnes
– maize		
quantity of raw material available	0.625	million tonnes
- barley		
quantity of raw material available	0.034	million tonnes
– rape		
quantity of raw material available	0.008	million tonnes
biodiesel production capacity	738	TJ/yr
yield of biodiesel	36.9	GJ/tonne
biodiesel production	148.1	TJ
– sunflower		
quantity of raw material available	0.012	million tonnes
– soya		
quantity of raw material available	0.01	million tonnes
- beans		
quantity of raw material available	0.007	million tonnes
Sewage sludge		
electricity generating capacity	3 000	kW
electricity generation	0.0253	TJ
Waste oil		
quantity of raw material available	0.05	million tonnes
biodiesel production capacity	332.1	TJ/yr
yield of biodiesel	36.9	GJ/tonne
biodiesel production	11.808	TJ

* Includes all woody biomass

** Includes forest and wood processing residues and bark

*** Includes briquettes and pellets

Czech Republic

Biomass type:

Municipal solid waste		
quantity of raw material available	0.24	million tonnes
electricity generating capacity	3 000	kW
electricity generation	42	TJ
direct use from combustion	1 966	TJ
total energy production	2 008	TJ
Wood *		
quantity of raw material available	6.9	million tonnes
electricity generation	4 214	TJ
direct use from combustion	63 299	TJ
total energy production	67 513	TJ
Agricultural crops and residues - colza		
quantity of raw material available **	1.05	million tonnes
biodiesel production capacity	12 354	TJ/yr
yield of biodiesel	37.1	GJ/tonne
biodiesel production (estimated)	2 789	TJ
Agricultural crops and residues - corn		
ethanol production capacity	4 320	TJ/yr
yield of ethanol	27.0	GJ/tonne
ethanol production (estimated)	1 626	TJ

* Includes wood wastes, crops, wood chips, bark and other.

In 2008 Czech Republic exported 719 503 tonnes and imported 70 496 tonnes of wood.

** Input to production of FAME.

In 2008 Czech Republic imported 43 657 tonnes of FAME and exported 34 352 tonnes:

	Imports of FAME	Exports of FAME
Austria	3 474	2 892
Germany	15 681	936
Netherlands	1 434	
Poland	529	22 056
Slovakia	19 557	6 924
Switzerland	2 857	
Singapore	25	
Slovenia	100	
Hungary		1 544

Denmark

Biomass type:

Municipal solid waste		
quantity of raw material available *	40 051	TJ
electricity generation **	6 718	TJ
Wood		
quantity of raw material available	25 022	TJ
electricity generation	4 346	TJ

Forestry/wood processing		
quantity of raw material available	16 175	TJ
Agricultural residues - straw		
quantity of raw material available	1.06	million tonnes
electricity generation	2 145	TJ
Biodiesel		
production	3 723	TJ
Biogas		
production	3 928	TJ
electricity generation	896	TJ
Fish oil		
quantity of raw material available	0.04	million tonnes

* Comprising 23 550 TJ renewable waste and 16 501 TJ non-renewable waste.
** Comprising 3 950 TJ renewable waste and 2 768 TJ non-renewable waste.

In 2008 imports of wood and products from the forestry and wood-processing industry totalled 2 176 TJ and 19 299 TJ respectively; imports of ethanol totalled 210 TJ; 3 401 TJ of biodiesel was exported.

Egypt (Arab Republic)

Biomass type:

Municipal solid waste		
quantity of raw material available	2.4	million tonnes
Sugar cane bagasse		
quantity of raw material available	1.4	million tonnes
ethanol production capacity	456.25	TJ/yr
biodiesel production capacity	22.83	TJ/yr
total energy production	479.08	TJ
Forestry/wood-processing		
quantity of raw material available	1.2	million tonnes
Cotton stalks		
quantity of raw material available	1.2	million tonnes
Rice straw		
quantity of raw material available	3.4	million tonnes
Animal dung		
quantity of raw material available	6	million tonnes
biogas production capacity	40	TJ/yr
yield of biogas	4.1	GJ/tonne
biogas production	15	TJ
direct use from combustion	15	TJ
Sewage sludge		
quantity of raw material available	2.4	million tonnes
electricity generating capacity	18 000	kW
Industrial waste		
quantity of raw material available	3	million tonnes
Food processing waste		
quantity of raw material available	2	million tonnes

Data refer to 2002

Estonia

Biomass type:

Municipal solid waste		
quantity of raw material available	0.569	million tonnes
biogas production (landfill gas)	107	TJ
Forestry/wood-processing		
quantity of raw material available	0.567	million tonnes
solid fuel production	8 692	TJ

Data refer to 1999

Ethiopia

Biomass type:

Sugar cane bagasse		
quantity of raw material available	0.830	million tonnes
ethanol production	126.4	TJ
biogas production	0.06	TJ
electricity generation	55 286.7	TJ
Wood		
quantity of raw material available	47.62	million tonnes
Agricultural residues – crop residue		
quantity of raw material available	5.23	million tonnes
Agricultural residues – animal dung		
quantity of raw material available	8.83	million tonnes

Approximately 1 000 biogas digesters are installed with an average capacity of 3 m^3 . Biomass fuel is not traded

Finland

Biomass type:

Municipal solid waste		
quantity of raw material available (1)	2.2	million tonnes
electricity generation ***	2 160	TJ
direct use from combustion ***	2 380	TJ
total energy production *	4 610	TJ
Wood		
direct use from combustion *	48 600	TJ
Forestry/wood processing (2)		
quantity of raw material available	16	million tonnes
yield of solid fuel	17 000	GJ/tonne
solid fuel production	6 340	TJ
electricity generation	36 850	TJ
direct use from combustion (estimated)	252 810	TJ
total energy production (estimated) (3)	296 000	TJ

Agricultural crops and residues – reed canary grass (4)

quantity of raw material available ******	0.05	million tonnes
direct use from combustion ***	750	TJ

Raw biomass for biodiesel production (5)

biodiesel production	2 580	TJ

Biogas from farm and co-digestion plants

quantity of raw material available ****	0.004	million tonnes
electricity generation	24	TJ
direct use from combustion	44	TJ
total energy production	68	TJ

Biogas from landfills (6)

quantity of raw material available ****	0.2	million tonnes
electricity generation	62	TJ
direct use from combustion	1 094	TJ
total energy production	1 156	TJ

Biogas from wastewater treatment plants

quantity of raw material available ****	0.03	million tonnes
electricity generation	118	TJ
direct use from combustion	294	TJ
total energy production	412	TJ

Raw biomass for bioethanol fuel production

ethanol production (7)	770	TJ

* data refer to 2007
*** data refer to 2005
**** data refer to 2004
****** data refer to 2002

1.) The amount of municipal solid waste totalled 2.77 million tonnes in 2008. The quantity of raw biomass material available for energy production was 2.2 million tonnes and has been calculated here by summing the amounts of classified biomass waste types (biowaste, paper and board waste, wood waste) and the estimated amount (80%) of biomass in unclassified waste. The actual use of municipal solid waste for energy production equalled 0.37 million tonnes in 2008.

2.) The present use of bio-energy is dominated by residues and by-products from the forest industry. In 2007 the share of black liquor (and other similar liquors) was 42% of the total use of renewable energy (excluding peat). Wood fuels in industry and energy production also have a significant share (about 26%). The main part of forestry/wood processing residues is exploited by co-generation plants producing electricity and heat.

A substantial share, 61% (227 000 tonnes, 3 860 TJ), of Finnish wood pellets production was exported in 2008. In the same year, imports were 10 000 tonnes.

3.) Total energy production from forestry and wood-processing residues includes firewood and wood residues that have been directly imported and indirectly imported (a proportion of the raw timber consumed by the forestry industry used for energy): 63 000 TJ in 2007.

4.) The acreage of reed canary grass (grown as an energy crop) is increasing rapidly in Finland: in 2005 there were 10 400 ha under cultivation, rising to 16 000 ha in 2008. The crop can be harvested two years after seeding.

5.) The majority of raw biomass for biodiesel produciton in the two Finnish hydrogenated vegetable oil (HVO) plants in operation, launched in 2007 and 2008, is imported palm oil; rapeseed oil and food industry waste streams are additionally used. There exists one demonstration F-T biodiesel plant using wood residuals as raw material.

6.) In Finland a total of 15 biogas reactor plants have been in operation at different municipal wastewater treatment plants by end-2008. Industrial wastewaters were treated anaerobically at three different plants, one at a fluting mill and two in the food-processing industry. Farm-scale biogas plants were operating in eight locations. Municipal solid wastes were treated at three biogas plants.

In 2008, the amount of biogas produced by the reactor installations was 29.9 million m^3 and the combustion of surplus biogas, 3.7 million m^3. Production of thermal, electrical and mechanical energy was 141 GWh.

There were a total of 33 landfill gas recovery plants operating at the end of 2008. The amount of recovered biogas was 112.2 million m^3. The amount of recovered biogas used for the production of electrical and thermal energy was 75.8 million m^3, producing 321.2 GWh.

7.) The figure 770 TJ for the year 2007 consists of bio-based share EtOH eq of ETBE production from imported Brazilian sugar cane EtOH (ethanol). During 2007-2009, five small-scale bioethanol (85% EtOH) production plants, whose combined yearly capacity is less than 200 TJ, were launched. Various domestic raw materials are used for bioethanol production in these plants: bakery waste, potato chip factory waste, brewery waste. The 85% EtOH produced in the plants is processed in an Ethanol Dehydration plant launched in 2008. Its capacity equals 930 TJ/yr and it primarily uses imported ethanol.

France

Biomass type:

Municipal solid waste *		
quantity of raw material available	2 394	thousand toe
electricity generating capacity	772 800	kW
electricity generation	13 586	TJ
direct use from combustion	27 209	TJ
total energy production	40 795	TJ
Wood		
quantity of raw material available	6 379	thousand toe
direct use from combustion	267 025	TJ
Forestry/wood processing		
quantity of raw material available	2 318	thousand toe
electricity generation	4 878	TJ
direct use from combustion	68 902	TJ
total energy production	73 780	TJ
Agricultural residues – straw etc.		
quantity of raw material available	145	thousand toe
direct use from combustion	6 070	TJ

Biogas from landfills		
quantity of raw material available	196	thousand toe
electricity generation	2 218	TJ
direct use from combustion	322	TJ
total energy production	2 540	TJ
Biogas – other		
quantity of raw material available	83	thousand toe
electricity generation	271	TJ
direct use from combustion	2 060	TJ
total energy production	2 331	TJ
Biofuels		
quantity of raw material available	2 076	thousand toe
ethanol production	15 675	TJ
biodiesel production	71 230	TJ
total energy production	86 905	TJ

The above data relate only to metropolitan France and exclude overseas departments (DOM).

* 50% of Municipal Solid Waste is from renewable sources; 50% is non-renewable

Sugar cane bagasse: in the DOM, the quantity of bagasse available in 2008 was 122 thousand toe; 1 278 TJ electricity was generated, 6 949 TJ was used directly from combustion and total energy production totalled 8 227 TJ.

In 2008 imports of ethanol and biodiesel amounted to 2 683 and 14 156 TJ respectively; exports of ethanol and biodiesel amounted to 1 469 and 803 TJ respectively.

Gabon

Biomass type:

Sugar cane bagasse		
quantity of raw material available	113 490	tonnes
direct use from combustion	209 956.5	million kcal

Data refer to 2005

Société Sucrière du Gabon, owner of the plantations, utilises the bagasse as a source of fuel for generating electricity and heat used in the transformation of the sugar cane.

Germany

Biomass type:

Municipal solid waste *		
biodiesel production capacity	940 000	tonnes/yr
biogas production capacity	160	MW
biogas production	9 600	TJ
electricity generating capacity	852 000	kW
electricity generation	11 200	TJ
Forestry/wood-processing **		
direct use from combustion	182 442	TJ

Wood waste etc. **		
electricity generation	639	GWh
Landfill gas **		
electricity generating capacity	142	MW
electricity generation	88	GWh
Sewage sludge gas **		
electricity generating capacity	75	MW
electricity generation	732	GWh
Liquid biofuels **		
plant capacity	500 000	tonnes/yr
Other biogas **		
electricity generating capacity	200	MW
electricity generation	74	GWh

*Data refer to 2002

** Data refer to 2001

Ghana

Biomass type:

Agricultural residues		
quantity of raw material available		
• coconut shell and husk	0.135	million tonnes
• groundnut shells	0.0475	million tonnes
• rice straw and husk	0.120	million tonnes

Data refer to 1990

Greenland

Biomass type:

Municipal solid waste		
solid fuel production capacity	214	TJ/yr
yield of solid fuel	10.5	GJ/tonne
solid fuel production	281	TJ
direct use from combustion	83	TJ
Waste from fishing industry		
yield of biodiesel	38.62	GJ/tonne
biodiesel production	12.33	TJ

Data refer to 2002

Hong Kong, China

Biomass type:

Municipal solid waste		
quantity of raw material available	7.7	million tonnes
Sewage gas		
direct use from combustion	116.2	TJ
Landfill gas		
quantity of raw material available	240	million m^3
biogas production capacity	350	TJ/yr
yield of biogas	0.005	GJ/tonne

biogas production	72	TJ
electricity generation	14	TJ
direct use from combustion	2 000	TJ
total energy production	2 086	TJ

Data refer to 2005

In May 2005, the Hong Kong Government established a renewable energy strategy in its First Sustainable Development Strategy for Hong Kong. The strategy aims for 1-2% of total power generation to come from renewables by the year 2012. This would be met through a combination of wind power, solar energy and waste-to-energy. Municipal solid waste could make a significant contribution to this goal.

Hong Kong's comprehensive Policy Framework for the Management of Municipal Solid Waste (2005-2014) outlines a plan for reducing waste, increasing recycling and recovery, and treating about half of the remaining waste by incineration and/or other methods. These could include waste-to-energy.

A demonstration waste-to-energy facility was operated by Green Island Cement in 2005. This facility combined waste and fuel oil to produce electricity for on-site use.

Of approximately 240 million cubic metres of landfill gas available in Hong Kong in 2005, about 130 million cubic metres were utilised as energy. The unused gas was flared.

In 2005, the major uses of landfill gas in Hong Kong were heating up leachate in the ammonia removal process for the treatment of landfill waste water on-site, and generating electricity for the landfill site infrastructures, such as offices, maintenance workshop and pumping stations.

However, landfill gas was also used in a variety of other ways: as fuel in the production of town gas, and for power generation supplied to the grid; gas from a closed landfill (containing 14.3 million tonnes of waste, including construction and demolition waste) was treated and piped to the gas company where it was used as fuel to provide 72 TJ of energy in the town gas production process. Landfill gas was also used to generate 14 TJ (4 Gigawatt hours) of electricity for the Hong Kong power grid.

Hungary

Biomass type:

Municipal solid waste		
quantity of raw material available	0.2	million tonnes
yield of solid fuel	12.5	GJ/tonne
solid fuel production	25 919	TJ
ethanol production capacity	1 330	TJ/yr
yield of ethanol	26.6	GJ/tonne
ethanol production	1 652	TJ/yr
biodiesel production capacity	5 625	TJ/yr
yield of biodiesel	37.5	GJ/tonne
biodiesel production	5 137	TJ/yr
yield of biogas	23	GJ/tonne
biogas production	688	TJ
electricity generation	1 504	TJ

direct use from combustion	28 093	TJ
total energy production	62 993	TJ
Sugar cane bagasse		
biogas production	170	TJ
Wood		
quantity of raw material available	2.0	million tonnes
Forestry/wood-processing		
Quantity of raw material available	1.8	million tonnes

Iceland

Biomass type:

Municipal solid waste		
electricity generating capacity	831	kW
electricity generation	15	TJ
direct use from combustion	56	TJ
total energy production	71	TJ

Data refer to 2005

The total quantity of municipal waste is in the region of 0.5 million tonnes.

Electricity generation from landfill gas began in 2004.

Indonesia

Biomass type:

Agricultural crops and residues -		
ethanol production capacity	5 023	TJ/yr
biodiesel production capacity	65 930	TJ/yr

Iran (Islamic Republic)

Biomass type:

Wood		
direct use from combustion	24 354	TJ
Agricultural residues – shrubs and scrubs		
direct use from combustion	8 383	TJ

Data refer to 2007

Ireland

Biomass type:

Municipal solid waste		
total energy production	1 085	TJ
Wood		
direct use from combustion	982	TJ
Forestry/wood processing		
total energy production	4 401	TJ
Animal by-products (tallow, meat and bone meal)		
total energy production	2 080	TJ

In 2008 18 000 tonnes of biodiesel and 26 000 tonnes of biogasoline were imported

Israel

Biomass type:

Municipal solid waste		
quantity of raw material available	5	million tonnes
electricity generating capacity	4 500	kW
electricity generation	11	TJ

Italy

Biomass type:

Municipal solid waste*		
electricity generating capacity	619 475	kW
electricity generation	5 602	TJ
Agricultural crops and residues – raw alcohol and cereals		
ethanol production capacity	302	million litres
ethanol production	60	million litres
Agricultural crops and residues – oil seeds, fatty acid		
biodiesel production capacity **	1 910 000	tonnes/yr
biodiesel production	595 000	tonnes/yr
Other – solid biomass		
electricity generating capacity	449 010	kW
electricity generation	9 886.0	TJ
Biogas ***		
electricity generating capacity	365 648	kW
electricity generation	5 614.2	TJ
Bioliquids ****		
electricity generating capacity	121 209	kW
electricity generation	38.8	TJ

* In accordance with the statistical convention used by Eurostat, production from the biodegradable portion of municipal solid waste has been estimated at 50% of total MSW production.

** Estimated as at 1 July 2008 and on the basis of 330 working days/year. Capacity of hydrodiesel is included.

*** Output of biogas-generated electricity increased by 10.5% in 2008

**** Bioliquids include biodegradable liquid waste, biodiesel (1 plant of 0.3 MW) and other bioliquids.

In late 2008 there were 352 plants in operation fuelled by biomass and waste, with a total installed power capacity of 1 555 MW and an output of 5 966 GWh.

In 2008 biomass- and waste-generated electricity represented 10.3% of total renewable generation (compared to the EU15 average of 17.2%) and 1.9% of total electricity generation (an increase from 1.7% in 2007).

Approximately 70% of total installed bioenergy generating capacity was fuelled by biomass and biodegradable solid waste. Plants supplied with biogas, although more numerous, are characterised by a smaller average size (approximately 1.5 MW).

Bio-ethanol utilisation of available capacity was very low during 2008 compared with 2006. During 2010, a 200 000 tonne second-generation bio-ethanol plant using lignocellulosic biomass will be built in Tortona (Piemonte). It will be supplied with agricultural and forestry residues.

The Italian Position Paper foresees a total potential power capacity of 2 415 MW by 2020, an increase of some 55% above the current level.

Japan

Biomass type:

Municipal solid waste		
quantity of raw material available *	0.601	million tonnes
electricity generating capacity **	2 230 000	kW
direct use of energy**	54 983 820	TJ
Sugar cane bagasse		
quantity of raw material available *	0.08	million tonnes
Wood		
quantity of raw material available *	0.438	million tonnes
Agricultural residues – rice husk		
quantity of raw material available *	0.006	million tonnes
Black liquor		
quantity of raw material available *	4.032	million tonnes

* Data relate to FY 1999

** Data refer to 2005

Jordan

Biomass type:

Municipal solid waste		
quantity of raw material available	2	million tonnes
biogas production	3.6	million m^3
electricity generating capacity	1 000	kW
electricity generation	5 142	MWh
direct use from combustion	5 142	MWh

Data refer to 2005

Jordan has executed a pilot project for the utilisation of municipal solid waste for electricity generation through landfill and biogas technology systems. The project is funded by GEF and is considered to be the first of its kind in the region, with a capacity of 1 MW. A biogas company was established to run this plant. During 2006 the capacity of the plant was increased to 3.5 MW and is expected to generate 28 GWh/yr.

Kazakhstan

Biomass type:

Forestry/wood processing		
quantity of raw material available	0.00189	million tonnes
Agricultural residues – wheat		
quantity of raw material available	1.5	million tonnes
ethanol production capacity	N	TJ/yr
yield of ethanol	N	GJ/tonne
ethanol production	N	TJ

The Biokhim factory in North Kazakhstan Oblast produces and exports 4.4 million litres of bio-ethanol annually.

Korea (Republic)

Biomass type:

Municipal solid waste		
direct use from combustion	21 153	TJ
Sugar cane bagasse		
biodiesel production	561	TJ
Wood		
solid fuel production	250	TJ
direct use from combustion	11 970	TJ
total energy production	12 220	TJ
Landfill gas		
electricity generating capacity	30 293	kW
electricity generation	1 356	TJ
direct use from combustion	428	TJ
total energy production	1 784	TJ
Sludge gas		
direct use from combustion	1 161	TJ
Other gas		
direct use from combustion	672	TJ

Data refer to 2005

Latvia

Biomass type:

Municipal solid waste		
electricity generating capacity	9 400	kW
electricity generation	106	TJ
Forestry/wood processing		
electricity generating capacity	3 600	kW
electricity generation	20	TJ

Lebanon

Biomass type:

Municipal solid waste		
quantity of raw material available	1.44	million tonnes

Data refer to 2001.

In 2004, it was reported that biogas projects were installed on a small, trial scale. None were designed to generate electricity but rather provide heating fuel. Plant residues are generally burnt in rural homes for space heating.

Lithuania

Biomass type:

Wood		
quantity of raw material available	0.47	million toe
direct use from combustion	13 770	TJ
Forestry/wood processing		
quantity of raw material available	0.265	million toe
electricity generating capacity	21 000	kW
electricity generation	225	TJ
heat generating capacity	610 000	kW
heat generation	6 685	TJ
direct use from combustion	1 600	TJ
total energy production	8 510	TJ
Agricultural crops and residues – grain		
ethanol production capacity	1 080	TJ/yr
yield of ethanol	27	GJ/tonne
ethanol production	774	TJ
Agricultural crops and residues – rape-seed oil		
biodiesel production capacity	4 070	TJ/yr
yield of biodiesel	37	GJ/tonne
biodiesel production	2 390	TJ
Agricultural crops and residues – organic waste		
yield of biogas	20	GJ/thous. m^3
biogas production	125	TJ
Agricultural residues – straw		
quantity of raw material available	0.012	million tonnes
heat generation	66	TJ
direct use from combustion	33	TJ

In 2008, approximately 24 ktoe (or 3.3%) of biomass was exported to Western European countries.

Since 2000, biomass resources – mostly forestry/wood processing residues have been used for district heat generation at cogeneration plants and heat-only boiler plants.

In 2008, approximately 4 ktoe (or 6.8%) of biofuels were exported. Capacities of production facilities are increasing and in future biofuel exports will rise.

Straw and agricultural waste are utilised for heat generation in the district heating sector. A rise in their use for this purpose is expected.

Luxembourg

Biomass type:

Wood		
solid fuel production	700	TJ
Agricultural residues		
biogas production	226	TJ
Municipal waste residue		
solid fuel production	1 730	TJ

Data refer to 2004

Mexico

Biomass type:

Municipal solid waste		
quantity of raw material available	37.59	million tonnes
electricity generation	820	TJ
Sugar cane bagasse		
quantity of raw material available	6.38	million tonnes
electricity generation	822	GWh
Wood		
quantity of raw material available	246.307	PJ
solid fuel production	246.307	PJ
Forestry/wood processing		
quantity of raw material available	76	million tonnes
Agricultural crops and residues		
quantity of raw material available	83.7	million tonnes
Livestock products		
quantity of raw material available	7.378	million m^3 of biogas

Monaco

Biomass type:

Municipal solid waste		
quantity of raw material available	0.07	million tonnes
electricity generating capacity	2 600	kW
electricity generation	26	TJ
direct use from combustion	72	TJ
total energy production	98	TJ

Data refer to 1996

Morocco

Biomass type:

Animal dung		
biogas production capacity	4.00	TJ/yr
yield of biogas	0.56	GJ/tonne
biogas production	4.00	TJ

Data refer to 1996

Namibia

Namibia does not presently generate electricity from biomass but approximately 50% of the population uses wood and wood products for cooking and heating. Potential is high: about 26 million hectares of grazing land has been encroached by unwanted bushes which could be harvested to make bush blocks, charcoal or used for pyrolysis.

The Cheetah Conservation Fund is currently harvesting bushes from its farm for processing into bush blocks for burning. They are priced at N$ 15/10 kg and sold both locally and to Europe.

Nepal

Biomass type:

Wood		
direct use from combustion	293.17	TJ
Agricultural residues		
direct use from combustion	14.3	TJ
Animal dung		
direct use from combustion	21.63	TJ

Data refer to 2005

Netherlands

Biomass type:

Municipal solid waste		
electricity generation	10 296	TJ
direct use from combustion	1 085	TJ
total energy production	11 381	TJ
Forestry/wood-processing		
direct use from combustion		
• households	5 400	TJ
• industry	1 750	TJ
Landfill gas		
biogas production	2 763	TJ
Sludge		
biogas production	2 041	TJ
Fermentation		
biogas production	5 632	TJ

Data refer to 1999

New Zealand

Biomass type:

Municipal solid waste		
biogas production	2 870	TJ
electricity generating capacity	37 800	kW
electricity generation	726	TJ
direct use from combustion	280	TJ
Forestry/wood processing		
biogas production	40 420	TJ
electricity generating capacity	68 400	kW
electricity generation	4 420	TJ
direct use from combustion	36 000	TJ
total energy production	40 420	TJ

Pakistan

Biomass type:

Sugar cane bagasse		
electricity generating capacity	35 000	kW
electricity generation	0.542	TJ

Paraguay

Biomass type:

Sugar cane bagasse		
quantity of raw material available	0.536	million tonnes
ethanol production capacity *	861.6	TJ/yr
yield of ethanol *	1.303	GJ/tonne
ethanol production **	704.231	TJ
Wood		
quantity of raw material available	4.417	million tonnes
yield of solid fuel	10.501	GJ/tonne
solid fuel production	6 746.3	TJ
direct use from combustion	56 854.52	TJ
total energy production	63 600.82	TJ
Forestry/wood processing		
quantity of raw material available	1.319	million tonnes
direct use from combustion	24 066.79	TJ
Agricultural residues – cotton		
quantity of raw material available	0.263	million tonnes
direct use from combustion	3 844.1	TJ
Agricultural residues - other		
quantity of raw material available	0.062	million tonnes
direct use from combustion	940.9	TJ

Data refer to 2005

* data refer to total (i.e. including non-energy use)

** data refer to energy use

Peru

Biomass type:

Sugar cane bagasse		
quantity of raw material available	1.055	million tonnes
electricity generating capacity	40 200	kW
electricity generation	6 622	TJ

Philippines

Biomass type:

Municipal solid waste		
electricity generation	6	TJ
Sugar cane bagasse		
electricity generation	6 518	TJ
Forestry/wood-processing		
electricity generation	22 981	TJ
Crop residues - coconut		
electricity generation	7 046	GWh
Crop residues – rice		
electricity generation	2 934	GWh
Animal		
electricity generation	146	GWh

Data refer to 2002

Poland

Biomass type:

Municipal solid waste		
direct use from combustion	675	TJ
Wood / Forestry/wood processing		
quantity of raw material available	13 839	thousand m^3
direct use from combustion	127 914	TJ
total energy production	131 474	TJ
Agricultural residues		
direct use from combustion	21 337	TJ
total energy production	31 741	TJ
Industrial waste		
direct use from combustion	16 529	TJ
total energy production	22 282	TJ

The Polish Statistical Office does not currently publish data on itemised bioenergy by type. The following total bioenergy production data are available for 2005:

Solid fuels (biomass and industrial wastes)	49.3	PJ
Liquid biofuels	0.6	PJ
Biogas	2.0	PJ
Electricity	1 506	MWh

Data refer to 2005

Up to the present time renewable energy has not been intensively utilised. However, this situation is likely to change considerably in the short term, owing to European law and Poland's renewable energy obligations. By 2010, it is expected that electricity generation from renewables (geothermal, biomass, wind and hydro) will contribute 9% of the total. Moreover, the share of biofuels in the transport sector will rise to 5.75%.

Portugal

Biomass type:

Municipal solid waste		
quantity of raw material available	1.0	million tonnes
electricity generating capacity	90 000	kW
electricity generation	7 652	TJ
Forestry/wood processing		
quantity of raw material available	8.2	million tonnes
biogas production	962	TJ
electricity generating capacity	417 000	kW
electricity generation	9 737	TJ
direct use from combustion	107 000	TJ
total energy production	117 699	TJ
Agricultural residues		
quantity of raw material available	4 799	thousand toe
Biogas		
quantity of raw material available	588	thousand toe

Date refer to 2005

Romania

Biomass type:

Municipal solid waste		
quantity of raw material available	545	thousand toe
Wood		
quantity of raw material available	487	thousand toe
Forestry/wood processing		
quantity of raw material available	1 175	thousand toe

Russian Federation

Biomass type:

Forestry/wood processing		
quantity of raw material available	73.7	million GJ
electricity generating capacity	560.4	MW
electricity generation	2.2	TWh
direct use from combustion	40.7	million GJ

Data refer to 2001

Senegal

Biomass type:

Municipal solid waste		
electricity generating capacity	20 000	kW
Agricultural residues – peanut shells		
electricity generating capacity	22 000	kW
Biomass potential (per annum)		
Peanut shells	197 500	tonnes (221 MW)

Palmetto shells	1 740	tonnes
Sugar cane bagasse	250 000	tonnes (20 MW)
Rice husks	217 212	tonnes
Sawdust	3 000	cubic metres
Millet/Sorghum/Maize stalks	4 052 900	tonnes
Typha reed	1 000 000	tonnes
Cotton stalks	23 991	tonnes
Peanut haulm	790 617	tonnes

Data refer to 1999

Serbia

Biomass type:

Municipal solid waste		
quantity of raw material available	2.8	million tonnes
Wood		
quantity of raw material available	1.0	million tonnes
direct use from combustion	6 000	TJ
Forestry/wood processing		
quantity of raw material available	0.36	million tonnes
direct use from combustion	1 800	TJ
Agricultural crops and residues		
quantity of raw material available	56 200	TJ
biodiesel production capacity	4	TJ/yr
yield of biodiesel	40	GJ/tonne
biodiesel production	2 400	TJ
Orchard		
quantity of raw material available	14 100	TJ
Vineyard		
quantity of raw material available	6 100	TJ

Singapore

Biomass type:

Municipal solid waste		
electricity generating capacity	135 000	kW
electricity generation	3 994.68	TJ

Data refer to 2002

Slovakia

Biomass type:

Wood		
quantity of raw material available	0.4	million tonnes

Forestry/wood processing	
quantity of raw material available	1.4 million tonnes
Agricultural residues - straw	
quantity of raw material available	0.73 million tonnes
Agricultural residues – corn	
quantity of raw material available	0.67 million tonnes
Agricultural residues – other	
quantity of raw material available	0.63 million tonnes
Dung	
quantity of raw material available	13.7 million tonnes

Data refer to 2005

Slovenia

Biomass type:

Wood	
quantity of raw material available	1.458 million tonnes
electricity generating capacity	59 MW
electricity generation	838 TJ

South Africa

Biomass type:

Sugar cane bagasse	
quantity of raw material available *	3.6 million tonnes
Wood	
quantity of raw material available *	11.2 million tonnes
Forestry/wood processing	
quantity of raw material available *	8.1 million tonnes

Data generally refer to 2003

* Calculated from a TJ value, using conversion factors of 14 MJ/kg for bagasse and 17 MJ/kg for fuel wood and forestry wastes.

A data collection system for biofuels has not yet been formalised in South Africa.

Spain

Biomass type:

Agricultural residues	
quantity of raw material available	5 768 563 * toe
ethanol production capacity	415 000 tonnes/yr
ethanol production	257 000 tonnes
biodiesel production capacity	322 000 tonnes/yr
biodiesel production	150 000 tonnes

* Potential = 12 802 208 toe

The breakdown of bioenergy electricity generation capacity is not available. Total installed electricity generating capacity stood at 3 440 kW at end-2004 and provisionally at 3 660 kW at end-2005.

In 2004 the total direct and indirect energy produced from all bioenergy sources was 4 167 035 toe.

The estimated potential of forestry/wood processing residues is of 11 819 000 toe, but at end-2004 only 7 576 040 toe were being exploited.

Data refer to 2005

Sri Lanka

As preliminary steps towards eventual large-scale use of wood for electricity generation, two facilities have been installed in Sri Lanka:

- in the village of Endagalayaya, a 3.5 kW_e electrical generator coupled with a gasifier system processing chips of Gliricidia Sepium; this provides lighting for 31 houses, with each having 2 light bulbs indoors and one externally to deter elephants and other wild animals;
- at Walapane, a 1 MW_e dendro-thermal power plant fuelled by Gliricidia wood, and capable of generating 6 447 MWh/yr.

Gliricidia Sepium is a fast-growing tropical tree cultivated by local farmers.

A biomass gasifier at Madampe, in the Coconut Triangle, also uses wood as feedstock. The gas is used to dry coconut fibre prior to its conversion into briquettes, which are then exported for use as a growing medium.

Swaziland

Biomass type:

Sugar cane bagasse *		
quantity of raw material available	0.490	million tonnes
electicity generating capacity	16 500	kW
electricity generation	386	TJ
Forestry/wood-processing **		
quantity of raw material available	0.574	million tonnes
electicity generating capacity	15 600	kW
electricity generation	198	TJ
Agricultural residues – molasses		
quanity of raw material available	0.123	million tonnes
ethanol production capacity	856	TJ/yr
yield of ethanol	4.6	GJ/tonne
ethanol production	565	TJ

* Data taken from 2003 Energy Balance

** Data taken from 2007 Energy Balance

In 2008 15 000 tonnes of molasses imported from Tsb Sugar, South Africa

Sweden

Biomass type:

Municipal solid waste		
electricity generating capacity	282	kW
electricity generation	4 990	TJ
Wood		
electricity generating capacity	2 652	kW
electricity generation	33 720	TJ

Switzerland

Biomass type:

Municipal solid waste		
solid fuel production capacity	25 525	TJ/yr
energy produced – heat	8 652	TJ
energy produced - electricity	3 316	TJ
biogas production capacity	2 357	TJ/yr
energy produced – heat	1 071	TJ
energy produced – electricity	523	TJ
energy produced - gas	66	TJ
electricity generation	3 839	TJ
total energy production	13 562	TJ
Wood		
solid fuel production capacity	30 694	TJ/yr
energy produced – heat	20 126	TJ
energy produced - electricity	333	TJ
biogas production capacity	295	TJ/yr
energy produced – heat	31	TJ
energy produced – electricity	95	TJ
electricity generation	428	TJ
total energy production	20 585	TJ
Agricultural crops and residues		
biodiesel production	467	TJ
biogas production	66	TJ

Under the new feed-in tariff regime introduced in 2008, biomass-fired electricity generation projects totalling 241 MW (1 339 GWh) qualified for feed-in tariffs and are scheduled to be built in the coming years.

Syria (Arab Rep.)

Biomass type:

Municipal solid waste		
quantity of raw material available	4	million tonnes
Wood		
quantity of raw material available	0.5	million tonnes

Forestry/wood processing		
quantity of raw material available	0.2	million tonnes

Data refer to 2005

Taiwan, China

Biomass type:

Municipal solid waste		
electricity generating capacity	583.8	kW
electricity generation	27 128.9	TJ
Waste cooking oil		
quantity of raw material available	0.15 – 0.2	million tonnes
biodiesel production capacity	275.97	TJ/yr
yield of biodiesel	34.5	GJ/tonne
biodiesel production	5.2 – 6.9	GJ

Data refer to 2005

Tanzania

Biomass type:

Sugar cane bagasse		
quantity of raw material available	229 617	tonnes
Wood		
quantity of raw material available	140	million m^3

Data refer to 2005

The country has a considerable biomass resource in the form of agricultural and forest residues and animal wastes which together account for about 90% of the nation's energy requirements. There is no immediate renewable energy substitute for wood fuel used for cooking apart from biogas, the technology of which has not yet reached a high enough level of dissemination.

According to data for 2003, there was a growing stock of 4.39 billion m^3 woody biomass with a mean annual increment of 140 million m^3. Annual wood fuel consumption is approximately 34 million m^3, contributing to deforestation at an estimated rate of 91 276 ha/yr.

Generally, biomass is not internationally traded.

The Government has formed a National Taskforce to work on liquid fuels promotions. The Taskforce/Special Committee is working in close collaboration with various stakeholders to formulate practical recommendations. The production of ethanol and biodiesel is being developed by small-scale private companies.

Thailand

Biomass type:

Municipal solid waste		
electricity generating capacity	5 000	kW
electricity generation	94.63	TJ
Sugar cane bagasse - husk		
quantity of raw material available	6.69	million tonnes
ethanol production	2 344.217	TJ

Forestry/wood processing – fresh fruit bunch	
quantity of raw material available	3.08 million tonnes

In 2008:

- biodiesel production from sugar cane bagasse, wood and forestry and wood processing residues totalled 12 697.386 TJ;
- 65 802 477 litres of ethanol production derived from molasses were exported to Europe, South Korea, Australia, Japan, Taiwan, Philippines, Singapore and Indonesia;

The quantities of paddy husk, sawdust and fresh fruit used for the production of ethanol total 1 680, 18 930 and 584 167 tonnes per year respectively.

An average of 82 500 tonnes per year of paddy husk are used for the production of solid fuel.

The plant factor for energy production from municipal solid waste is calculated at 60%.

Turkey

Biomass type:

Municipal solid waste	
electricity generating capacity	59.65 kW
electricity generation	220 GWh/yr

Ukraine

Biomass type:

Municipal solid waste	
delivered	2.57 million tonnes
used	0.15 million tonnes
available at end-year	19.57 million tonnes
Sugar cane bagasse	
delivered	6.84 million tonnes
used	1.285 million tonnes
available at end-year	3.5 million tonnes
Wood	
delivered	0.74millionm³
used	1.19 million m³
available at end-year	0.09 million m³
Forestry/wood processing	
delivered	0.24 million m³
used	0.59 million m³
available at end-year	0.03 million m³
Agricultural crops and residues – sugar beet	
quantity of raw material available	3.62 million tonnes
Agricultural crops and residues – bagasse	
quantity of raw material available	3.50 million tonnes
Agricultural crops and residues – rape	
quantity of raw material available	0.28 million tonnes
Agricultural crops and residues – green maize	
quantity of raw material available	0.34 million tonnes

United Kingdom

Biomass type:

Municipal solid waste *		
quantity of raw material available	3.8	million tonnes
electricity generating capacity	375 900	kW
electricity generation	7 061	TJ
direct use from combustion	2 108	TJ
total energy production	9 169	TJ
Wood & forestry/wood processing		
quantity of raw material available	1.4	million tonnes
direct use from combustion	19 151	TJ
Agricultural residues **		
quantity of raw material available	1.1	million tonnes
electricity generating capacity	114 403	kW
electricity generation	2 113	TJ
direct use from combustion	1 776	TJ
total energy production	3 890	TJ
Agricultural residues ***		
quantity of raw material available	1.0	million tonnes
electricity generating capacity	193 257	kW
electricity generation	2 045	TJ
direct use from combustion	5 338	TJ
total energy production	7 383	TJ
Liquid biofuels *****		
ethanol production	1 645	TJ
biodiesel production	10 656	TJ
total energy production	12 301	TJ
Biomass co-fired with fossil fuels *******		
quantity of raw material available	1.4	million tonnes
electricity generating capacity	~340 000	kW
electricity generation	5 806	TJ

* Including non-biodegradable wastes, which account for about 37.5% of the total.

** Includes poultry litter, meat and bone and farm waste.

*** Includes straw, short rotation coppice crops and other plant-based biomass.

**** In 2008 approximately two-thirds of biodiesel and bioethanol was from imported sources.

***** In 2008, of the 1.4 million tonnes of biomass used for co-firing, 1.05 million was imported and 0.35 was home produced.

United States of America

Biomass type:

Municipal solid waste		
quantity of raw material available	254	million tonnes
electricity generating capacity	2 669 000	kW
electricity generation	54 255	TJ
direct use from combustion	20 833	TJ
total energy production	75 088	TJ
Wood		
direct use from combustion	473 502	TJ
Forestry/wood processing		
electricity generating capacity	7 469 700	kW
electricity generation	139 634	TJ
direct use from combustion	788 493	TJ
total energy production	928 127	TJ
Agricultural crops and residues – corn		
ethanol production capacity	939 620	TJ/yr
ethanol production	827 557	TJ
Agricultural crops and residues – soybean		
biodiesel production capacity	351 358	TJ/yr
biodiesel production	91 871	TJ
Agricultural crops and residues – other		
electricity generating capacity	395 600	kW
electricity generation	2 480	TJ
direct use from combustion	29 731	TJ
total energy production	32 211	TJ
Landfill gas		
electricity generating capacity	1 487 400	kW
electricity generation	23 724	TJ
direct use from combustion	88 762	TJ
total energy production	112 487	TJ
Other		
electricity generating capacity	372 800	kW
electricity generation	4 851	TJ
direct use from combustion	10 961	TJ
total energy production	15 812	TJ

In 2008, 28 825 TJ of ethanol was imported from Brazil, Canada, The Netherlands, Trinidad & Tobago and the US Virgin Isles; no exports are reported.

Uruguay

Biomass type:

Municipal solid waste

biogas production capacity	31.5	TJ/yr
electricity generating capacity	1 000	kW

Sugar cane bagasse

quantity of raw material available	0.05	million tonnes
electricity generating capacity	3 000	kW
electricity generation	20.9	TJ
direct use from combustion	502.1	TJ

Wood

quantity of raw material available	1.5	million tonnes
electricity generating capacity	2 800	kW
electricity generation	33.5	TJ
direct use from combustion	16 769.5	TJ

Agricultural residues – sunflower husks

quantity of raw material available	0.03	million tonnes
direct use from combustion	37.7	TJ

Agricultural residues – rice husks

quantity of raw material available	0.24	million tonnes
electricity generation	4.2	TJ
direct use from combustion	748.9	TJ

Black liquor

quantity of raw material available	0.04	million tonnes
electricity generation	58.6	TJ
direct use from combustion	447.7	TJ

Data refer to 2005

In March 2006 the Government passed a decree which is the first stage in encouraging the installation of up to 20 MW of electricity generation based on biomass (<10 MW) provided by IPPs.

10. Solar Energy

COMMENTARY

Introduction

Solar energy is the most abundant permanent energy resource on earth and it is available for use in its direct (solar radiation) and indirect (wind, biomass, hydro, ocean etc.) forms. This commentary is limited to the direct use of solar radiation, the earth's prime energy resource.

The sun emits energy at a rate of 3.8×10^{23} kW. Of this total, only a tiny fraction, approximately 1.8×10^{14} kW is intercepted by the earth, which is located about 150 million km from the sun. About 60% of this amount or 1.08×10^{14} reaches the surface of the earth. The rest is reflected back into space and absorbed by the atmosphere. Even if only 0.1% of this energy could be converted at an efficiency of only 10% it would be four times the world's total generating capacity of about 3 000 GW. Looking at it another way, the total annual solar radiation falling on the earth is more than 7 500 times the world's total annual primary energy consumption of 450 EJ.

The annual solar radiation reaching the earth's surface, approximately 3 400 000 EJ, is an order of magnitude greater than all the estimated (discovered and undiscovered) non-renewable energy resources, including fossil fuels and nuclear. However, 80% of the present worldwide energy use is based on fossil fuels. Several risks are associated with their use. Energy infrastructures - power plants, transmission lines and substations, and gas and oil pipelines - are all potentially vulnerable to adverse weather

Figure 10.1 Transforming the global energy mix: the exemplary path to 2050/2100 (Source: WBGU, 2003)

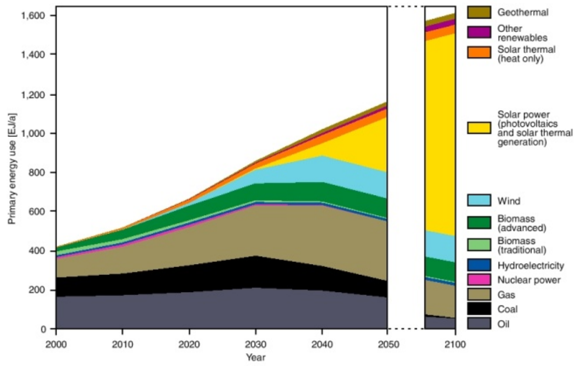
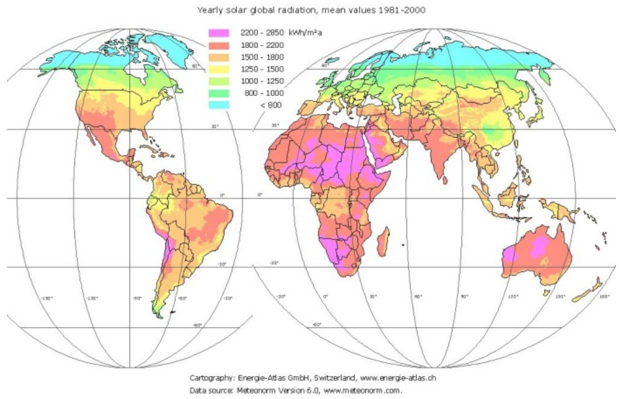


Figure 10.2 Average yearly solar radiation, mean values 1981-2000 (Source: Energie-Atlas GmbH)



conditions or human acts. During the summer of 2003, one of the hottest and driest European summers in recent years, the operations of several power plants, oil and nuclear, were put at risk owing to a lack of water to cool the condensers. In other parts of the world, hurricanes and typhoons put the central fossil and nuclear power plants at risk. World demand for fossil fuels (starting with oil) is expected to exceed annual production, probably within the next two decades. Shortages of oil or gas can initiate international economic and political crises and conflicts. Moreover, burning fossil fuels releases emissions such as carbon dioxide, nitrogen oxides, aerosols, etc. which affect the local, regional and global environment.

Concerns regarding present energy systems are therefore growing because of the inherent risks connected with security of supply and potential international conflicts, and on account of the potential damage they can do to the natural environment in many and diverse ways. World public opinion, international and national institutions, and other organisations are increasingly aware of these risks, and they are pointing to an urgent need to fundamentally transform present energy systems onto a more sustainable basis.

A major contribution to this transformation can be expected to come from solar radiation, the prime energy resource. In several regions of the world the seeds of this possible transformation can be seen, not only at the technological level, but also at policy levels. For example, the European Union has policies and plans to obtain 20% of its energy needs through renewable energy by 2020. The German Advisory Council on Global Change (WBGU) has conducted an analysis of energy needs and resources in the future to the years 2050 and 2100 (Fig. 10.1) which points to a major contribution by solar energy to global energy needs in the long term. This scenario is based on the recognition that it is essential to move energy systems towards sustainability worldwide, both in order to protect the natural life-support systems on which humanity depends and to eradicate energy poverty in developing countries. Of course, this new solar era can be envisioned mainly because of the tremendous scientific and technological advances made during the last century and the ongoing research and development.

By 2100 oil, gas, coal and nuclear, as shown in Fig. 10.1, will provide less than 15% of world energy consumption while solar thermal and photovoltaic will supply about 70%. Key elements of this long-term scenario are the energy efficiency and energy intensity policies that will make the contribution of renewable and solar energy a substantial factor. Those policies will deeply transform the building and construction, industry and transport sectors, increasing their reliance on renewable energy resources.

The transition towards this possible future has already started. In the following paragraphs an attempt will be made to show this by reviewing the state of the art regarding solar radiation resource assessment and the status and rate of growth of the major solar energy technologies, their technical and market maturity as well as institutional and governmental policies and approaches to promote their integration into the world's energy systems.

Figure 10.3 Average daily solar radiation for December (Source: NASA/SSE)

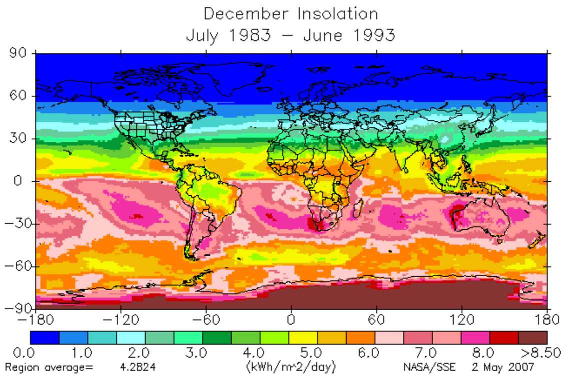
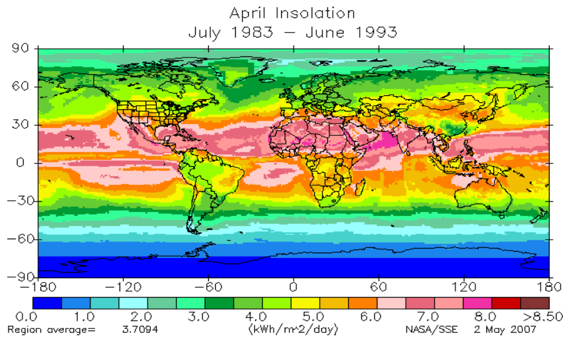


Figure 10.4 Average daily solar radiation for April (Source: NASA/SSE)



Solar Radiation Resources

The amount of solar radiant energy incident on a surface per unit area and per unit time is called irradiance or insolation. The average extraterrestrial irradiance or flux density at a mean earth-sun distance and normal to the solar beam is known as *the solar constant*, which is 1 367 W/m^2 according to the most recent estimate. The energy delivered by the sun is both intermittent and changes during the day and with the seasons. When this power density is averaged over the surface of the earth's sphere, it is reduced by a factor of 4. A further reduction by a factor of 2 is due to losses in passing through the earth's atmosphere. Thus, the annual average horizontal surface irradiance is approximately 170 W/m^2. When 170 W/m^2 is integrated over 1 year, the resulting 5.4 GJ that is incident on 1 m^2 at ground level is approximately the energy that can be extracted from one barrel of oil, 200 kg of coal, or 140 m^3 of natural gas.

However, the flux changes from place to place. Some parts of the earth receive much higher than this annual average. The highest annual mean irradiance of 300 W/m^2 can be found in the Red Sea area, and typical values are about 200 W/m^2 in Australia, 185 W/m^2 in the United States and 105 W/m^2 in the United Kingdom. These data show that the annual solar resource is almost uniform (within a factor of about 2), throughout almost all regions of the world. It has already been shown that economically attractive applications of solar energy are not limited to just the sunniest regions. Northern European countries offer good examples of this.

Figs. 10.3 to 10.5 show the daily solar energy falling on the Earth in the months of December, April and June.

In a period of rapidly growing deployment of solar energy systems, it is imperative that solar resource parameters and their space/time specificity be well known to solar energy professionals, planners, decision makers, engineers and designers. Because these parameters depend on the applications (flat solar thermal collectors, solar thermal power plants, photovoltaic, window glass, etc.), they may differ widely, and might be unavailable for many locations, given that irradiance measurement networks or meteorological stations do not provide sufficient geographically time/site-specific irradiance coverage. This coverage is especially useful because it allows assessment of the output of a solar system in relation to the technical characteristics of the system, local geography and energy demand. It therefore allows a better assessment of the feasibility of a solar energy application and of its value.

Measured solar radiation data are available at a number of locations throughout the world. Data for many other locations have been estimated, based on measurements at similar climatic locations. The data can be accessed through internet web sites of national government agencies for most countries in the world. Worldwide solar radiation data are also available from the World Radiation Data Center (WRDC) in St. Petersburg, Russia. WRDC, operating under the auspices of the World Meteorological Organization (WMO) has been archiving data from over 500 stations and operates

Figure 10.5 Average daily solar radiation for June (Source: NASA/SSE)

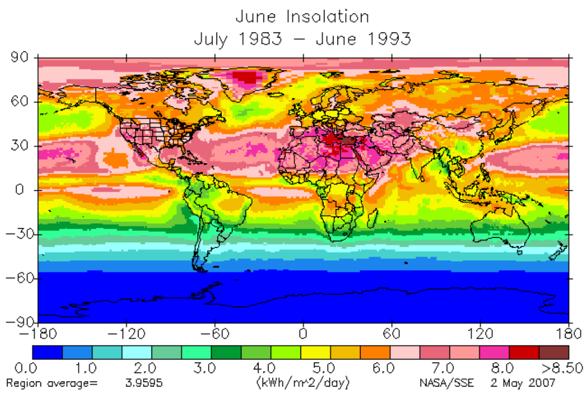
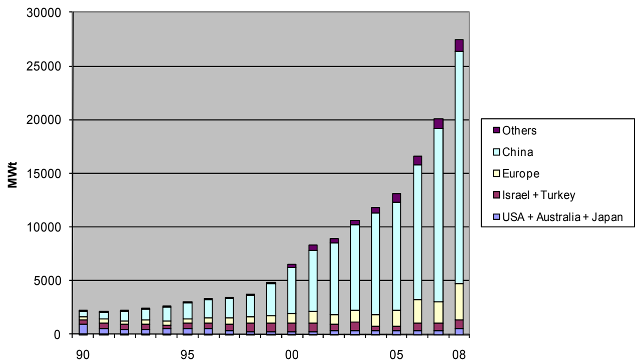


Figure 10.6 Worldwide market for glazed solar water heaters (Sources: IEA SHC, ESTIF)



a web site in collaboration with the National Renewable Energy Laboratory (NREL) (http://wrdc-mgo.nrel.gov). Other sources of data are given in the references at the end of this commentary. Most recently, methods are being developed to convert measurements made by satellites to solar radiation values on the ground. Once these methods are developed and validated, they will be able to provide solar radiation data for any location in the world.

Solar Collectors

Solar thermal collectors are used to heat air, water or other fluids, depending on the applications, while solar photovoltaic (PV) collectors are used to convert sunlight to electricity directly. High-temperature solar thermal collectors are also used to produce electricity indirectly via thermodynamic cycles. Non-concentrating (or flat-plate) types of solar collectors can produce temperatures of about 100°C or less, which is applicable for many uses such as building heating and cooling, domestic hot water and industrial process heat. Medium-temperature concentrating collectors such as parabolic troughs or parabolic dishes may be used to provide temperatures from about 100°C to about 500°C. Such collectors may be used for various applications from refrigeration to industrial process heat and electricity generation. Central-receiver types of solar concentrating collectors are able to produce temperatures as much as 1 000°C or even higher. Therefore, they are used to produce electrical power and as high-temperature furnaces in industrial processes.

PV panels are solid-state and are therefore very rugged, with a long life. At present, panels based on crystalline and polycrystalline silicon solar cells are the most common. However, thin-film solar panels, especially cadmium telluride (CdTe) and copper indium gallium diselenide (CIGS) are gaining market share because of their lower costs. Their efficiencies have gradually increased, while costs have decreased. For example, the efficiencies of multijunction cells and concentrating PV have been reported to be as high as 40%, and most panels available in the market have efficiencies of the order of 15%. The retail price of PV panels came down from about US$ 30/W about 30 years ago to about US$ 2/W in 2010. Thin-film solar cells based on CdTe which use much less material, have production costs less than US$ 1/W. Because of lower cost and therefore lower retail prices, they have steadily increased their global market share.

To evaluate the efficiency of solar energy systems, a standard flux of about 1 000 W/m^2 is used, which is approximately the solar radiation incident on a surface directly facing the sun on a clear day around noon. Consequently, solar systems are rated in terms of *peak watts* (output under a 1 kW/m^2 illumination).

Solar Energy Applications

The energy in solar radiation can be used directly or indirectly for all of our energy needs in daily life, including heating, cooling, lighting, electrical power, transportation and even environmental cleanup.

Many such applications are already cost-competitive with conventional energy sources, for example, PV in remote applications is replacing diesel generator sets. Some applications, such as photovoltaics and solar heating are better known and popular, while others such as solar detoxification of contaminated waters or solar distillation are less known.

Solar water heating is the most developed solar technology and is very cost-effective when life-cycle costs are considered. However, the initial costs (capital investment) of solar water heaters are many times higher than those for electric water heaters. Therefore, most people opt for electric water heaters. In many countries, governments have adopted policies and financing mechanisms that make it easier for consumers to buy solar water heaters. For this reason the adoption of solar water heating worldwide is growing at a rate of more than 25 % per year, as shown in Fig. 10.6.

Adoption of solar water heating can have a great impact on the reduction of peak electrical load and thus greenhouse gas emissions. For example, if all the electric water heaters in the USA (approximately 100 million) were replaced by solar water heaters, it would reduce the peak load by about 100 GW.

Solar Industrial Process Heat (SIPH) is an ideal application of solar energy. As a matter of fact, 30-50% of the thermal energy needed in industrial processes is below 250°C, which can be easily provided by low- and medium-temperature solar collectors. Consequently, this application of solar energy is expected to grow as the cost of fossil fuels goes up.

In industrialised countries, 35-40% of total primary energy consumption is used in buildings. However, if the energy used to manufacture materials and the infrastructure to serve the buildings is taken into account then buildings' share of total primary energy consumption can be around 50%. In Europe, 30% of energy use is for space and water heating alone, representing 75% of total energy use in buildings.

Solar technologies can make a substantial contribution to the energy budget of modern buildings, and consequently to the world's energy use. Buildings can be the largest collectors of solar energy and therefore the electrical appliances (light bulbs, refrigerators, washing machines, etc.) with innovative energy-efficient models, can reduce electricity demand and increase the significance of, e.g. photovoltaic electricity, to the whole energy budget. Passive solar building designs can reduce the conventional energy consumption by as much as 75% and PV can provide the rest. Such designs use knowledge of the position of the sun either to allow sunlight to enter the building for heating or to shade the building for cooling, and employ natural ventilation and daylighting. There is thus a growing trend towards passive solar and Building Integrated Photovoltaics (BIPV) designs. In BIPV designs, PV panels replace some other component of the building such as roof shingles, wall panels or window shades etc. PV manufacturers are developing very attractive patterns, colours and designs of panels, and architects are integrating them into buildings, making them look even more

Figure 10.7 An example of Building Integrated Photovoltaics (Source: Goswami)

attractive. These PV panels consequently become much more cost-effective than they otherwise would. Fig. 10.7 shows an example of a PV integrated building.

Globally, about 8-10 million new buildings are constructed every year, most of them in developing countries. Large areas of these countries do not have access to grid electricity, thus making solar energy an attractive alternative. Even if only a tiny fraction of these buildings were served by solar, the implications for the solar and energy industry could be enormous, not only from a technological point of view but also from a cultural point of view. It would be a contributory factor to changing the way people think about conventional sources of energy and solar energy.

Even though solar building applications can be cost-effective, they may not happen without appropriate policy intervention. New regulations and building codes, regarding energy-saving measures and the integration of energy-efficient and solar technologies in buildings, will be necessary to accelerate the deployment of solar energy. Such policy intervention has been the secret behind several success stories in the use of solar thermal collectors: for example, the 1980 regulation in Israel requiring every new building with a height of less than 27 m to have a solar thermal system on its roof. Similar regulations adopted over the last few years by a number of large and small towns elsewhere have stimulated a significant growth in solar thermal installations.

Because buildings do not exist in isolation, the 'whole building' approach can be extended to

Figure 10.8 The Japanese Cosmotown Kiyomino SAIZ housing development (Source: Goswami)

blocks of buildings or to towns, as in the photovoltaic application shown in Fig. 10.8. This depicts Cosmotown Kiyomino SAIZ, a complex of 79 homes built by the Hakushin Company, with the Kubota Corporation supplying a roof-integrated 3 kW photovoltaic power generation system for each house. This illustration also underlines an argument, often raised against solar energy utilisation: namely land usage. Solar energy is often seen as a 'dispersed' source of energy compared with concentrated fossil fuels and nuclear energy. This argument is misleading because the solar energy systems installed on walls and roofs in Kiyomino do not use land additional to that used for the construction of the buildings themselves. Moreover, land usage for fossil-fuel infrastructures for transportation, distribution and waste storage can be considerable.

The extension of solar energy use from a block of solar buildings to an entire city is possible. There are several cities around the world that are working in this direction, aiming at greater use of solar energy within the context of a long-term plan for sustainable urban development. Such projects focus on cities as complete systems, in which passive solar heating and cooling, daylighting, solar photovoltaic, and solar thermal technologies are integrated.

In the following paragraphs the most widely used solar systems for the production of electricity, heat and fuels are reviewed.

Figure 10.9 Worldwide market for photovoltaic panels (Source: EPIA and P. Maycock)

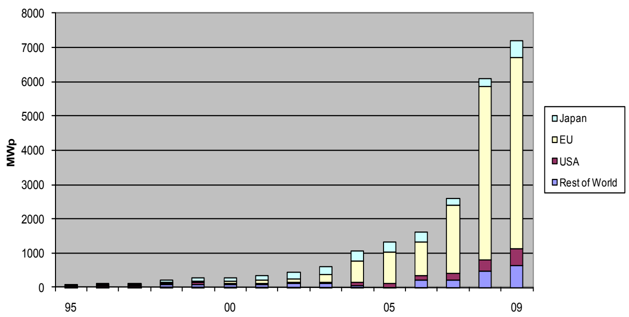
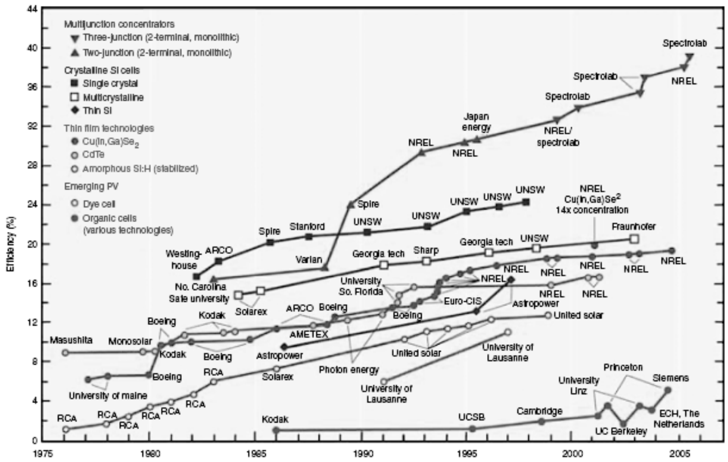


Figure 10.10 World record efficiencies of various PV technologies (Source: Goswami)



Solar Photovoltaic Systems (PV)

Photovoltaic conversion is the direct conversion of sunlight into electricity with no intervening heat engine. As indicated above, photovoltaic devices are rugged and simple in design and require very little maintenance. Perhaps the biggest advantage of solar photovoltaic devices is that they can be constructed as stand-alone systems to give outputs from microwatts to megawatts. That is why they have been used as the power sources for calculators, watches, water pumping, remote buildings, communications, satellites and space vehicles, and even megawatt-scale power plants. With such a vast array of applications, the demand for photovoltaics is increasing every year. In 2009, over 7 200 MW_p of photovoltaic panels were sold for terrestrial uses and the worldwide market is growing at a phenomenal rate: an average of 47% per annum over the past five years.

In the early days of solar cells in the 1960s and 1970s, more energy was required to produce a cell than it could ever deliver during its lifetime. Since then, dramatic improvements have taken place in their efficiency and manufacturing methods. The energy payback period has been reduced to about 2-4 years, depending on the location of use, while panel lifetime has increased to over 25 years. The energy payback period of multijunction thin-film Concentrating PV is projected to be less than one year. As mentioned above, the cost of photovoltaic panels has come down. The current retail cost of solar panels results in system costs of US$ 4-5/W which is cost effective for many Building Integrated applications. For MW-scale PV systems, however, the system costs have come down to US$ 3/W which moves the technology closer to cost effectiveness for on-grid applications considering their long lifetimes (over 25 years), no fuel costs and low maintenance costs. Perhaps however, these dollar costs do not adequately portray the true environmental value of solar PV systems. Even at an energy payback period of 3 years and a lifetime of 25 years, the return on energy investment is more than 8:1 and return on CO_2 avoidance is more than 6:1.

The limits imposed on the efficiency of solar cells due to band gap can be partially overcome by using multiple layers of solar cells stacked on top of each other, each layer with a band gap higher than the layer below it. The efficiency would increase with the number of layers. However, for this concept to work the thickness of each layer must be extremely small; this has been achieved by the development of Thin-Film PV technologies. Some of the materials being developed for thin-film solar cells include cadmium telluride (CdTe), copper indium diselenide (CIS), copper indium gallium diselenide (CIGS), gallium arsenide (GaAs) and indium phosphide (InP). Of these, CdTe and CIS are receiving the most commercial attention at this time. Multijunction thin-film solar cells give even higher efficiencies when exposed to concentrated sunlight. Therefore, a great deal of commercial attention is being focused on Concentrating Photovoltaics or CPV.

The current state of solar cell development is illustrated in Fig. 10.10. While crystalline and polycrystalline silicon solar cells dominate today's

Figure 10.11 Flexible monolithic CIGS prototype mini-module on a polymer foil (Source: Goswami)

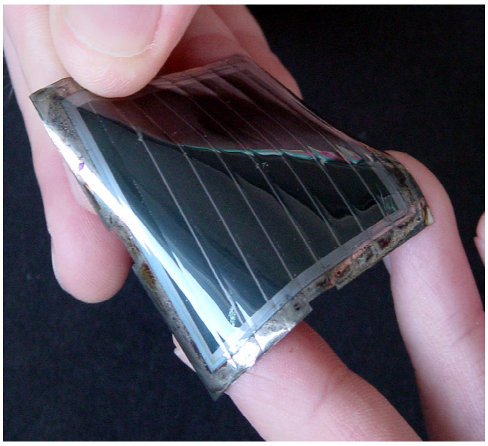
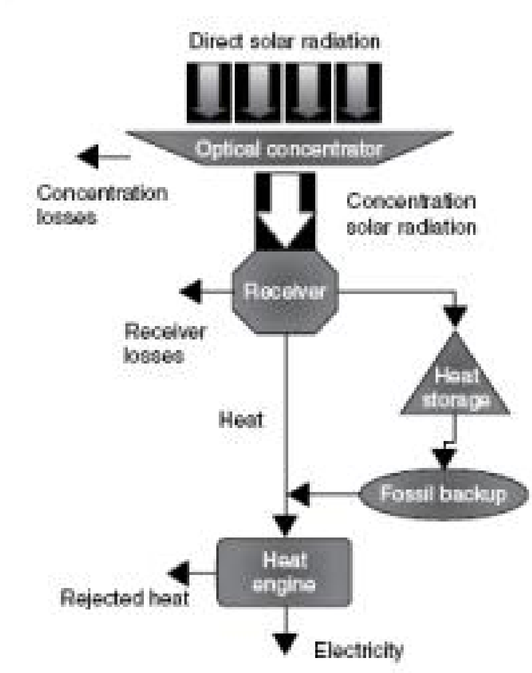


Figure 10.12 Flow diagram for a typical solar thermal power plant (Source: Goswami)



solar industry, the rapid rise in efficiency vs time (experience curve) of the multijunction thin-film cells makes this a particularly attractive technology path.

Under concentrated sunlight, multijunction (GaInP/GaAs/Ge [germanium]) solar cells have demonstrated efficiencies twice (39.3%) that of most silicon cells. This means that, in sunny areas, a multijunction concentrator system can generate almost twice as much electricity as a silicon panel with the same cell area. The concentrating optics focus the light onto a small area of cells, reducing the area of the solar cells by a factor of, typically, 500-1 000 times. The reduced cell area overcomes the increased cell cost. The cell cost is diminished in importance and is replaced by the cost of optics. If the cost of the optics is comparable to the cost of the glass and support structure needed for silicon flat-plate modules, then the cost per unit area can remain fixed while the electricity production is essentially doubled. Thus, in high direct insolation locations, multijunction concentrator technology has the potential to reduce the cost of solar electricity by about a factor of two. The efficiency is a moving target; today's triple-junction cell efficiency is nearly 40%. Thus it may be reasonably extrapolated that multijunction cells may reach 50% efficiency in the future.

The biggest advantage of solar PV systems is that they can provide from a few watts to hundreds of megawatts. Development of flexible thin-film PV panels (Fig. 10.11) makes them ideal for integration in building design. In this way, they can utilise the solar exposure provided by the buildings and therefore not use any extra land.

Solar Thermal Power Plants

Concentrating solar collectors can achieve temperatures in the range of 200°C to 1 000°C or even higher, which is ideal for generating electricity via thermodynamic power cycles. All of the present power plants based on fossil fuels and nuclear power work on the same principles. Therefore this technology takes advantage of the knowledge base relating to conventional power plants. Another advantage of Solar Thermal Power is that it can easily use fossil fuels such as natural gas as a back-up fuel or store high-temperature heat to overcome the disadvantage of the intermittency of sunlight. Fig. 10.12 explains the concept of a solar thermal power plant operating with storage and/or a backup fuel. Fig. 10.13 shows schematic diagrams of the types of concentrating solar collector used for solar thermal power plants.

Solar thermal power plants use direct sunlight, so they must be sited in regions with high direct solar radiation, as those shown in Fig. 10.14.

Among the most promising areas are the south-western United States, Central and South America, Africa, the Middle East, the Mediterranean countries of Europe, south Asia, certain countries of the Former Soviet Union, China and Australia.

Figure 10.13 Schematic diagrams of the four types of Concentrating Solar Power (CSP) systems (Source: Goswami)

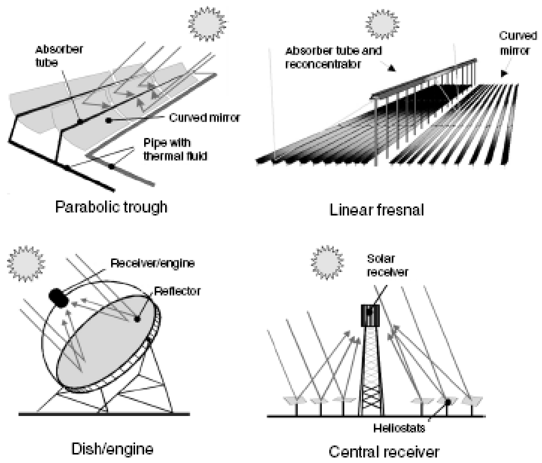
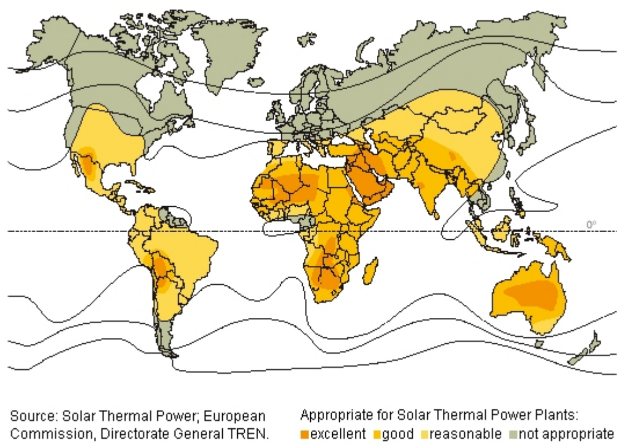


Figure 10.14 Regions of the world appropriate for Concentrating Solar Power (CSP) (Source: European Commission)



CSP capacity of 364 MW was installed in California in 1990 (Figs. 10.15 and 10.16), most of which (354 MW) is still operating. Each year the performance of the plant has improved, due to the learning experience and better operations and maintenance procedures. This power plant is based on parabolic-trough technology, with natural gas as a backup fuel. Although investments in new solar power plants ceased for a while because of a lack of R&D and favourable policies, recently there has been a resurgence of interest in this technology. Nevada Solar One, a 64 MW CSP plant, is the most recent such plant built in the USA. A number of plants are under construction or in the planning stage around the world, which when completed will increase worldwide capacity to about 3 000 MW. Of this, more than 2 000 MW will be in Spain, because of the excellent solar resource and favourable government policies.

The reported capital costs of Solar Thermal Power plants have been in the range of US$ 3 000 3 500/kW, although lower costs are being quoted now. These costs result in a cost of electricity of US$ 0.15-0.20/kWh. Based on ongoing research and development, the capital costs are expected to decrease to below US$ 2 000/kW, which will bring solar thermal power closer to conventional power, even without considering the environmental costs/benefits.

A new generation of solar power systems is under development in various parts of the world. Trough technology with direct steam generation is under experimentation at the Plataforma Solar de Almería, part of the Centro de Investigaciones Energéticas Medioambientales y Tecnológicas (CIEMAT) on Spain's Mediterranean coast. Much the greater part of the research and commercial activity on solar thermal power is happening in Spain, however, research and development in now picking up in the USA and other countries.

Solar Energy Storage Systems

As a result of solar energy's intermittent nature, the growth in worldwide usage will be constrained until reliable and low-cost technology for storing solar energy becomes available. The sun's energy is stored on a daily basis by nature through the process of photosynthesis in foodstuffs, wood and other biomass. The storage of energy from intermittent and random solar radiation can be achieved artificially, by using energy storage technologies (thermal storage, chemically-charged batteries, hydro storage, flywheels, hydrogen, and compressed air), some well-known and widely-applied, whilst others are still under development.

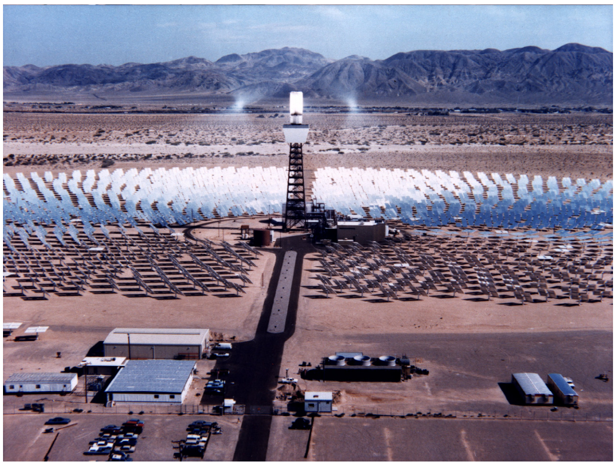
Figure 10.15 Parabolic-trough based solar thermal power plant in California (parabolic trough collectors [top]; power plant [bottom]) (Source: Goswami)

Thermal storage for solar heat and chemically-charged batteries for off-grid PV systems are the most widely used solar energy storage systems today. However, there are many who think that hydrogen produced using solar energy will provide the long-term solution for solar energy storage and much research is being undertaken around the world. Only the future will tell whether hydrogen will become cost-effective as compared with other storage options.

Other Solar Energy Applications

Availability of drinking water is expected to be the biggest problem to face mankind over the next few decades. Even though there is an abundant water resource in the oceans, it must be desalinated before use. Solar energy can play a very important role in this application. Although simple solar desalination and distillation technology has been known for a long time, there has not been much research to improve the technology for large-scale use.

Figure 10.16 Central receiver power plant in California (Source: Goswami)



Other lesser known applications of solar energy include its environmental applications such as solar photocatalytic detoxification and disinfection. This application has been shown to clean contaminated ground water and industrial waste water. It can also be used to disinfect water for potable use.

Conclusion and Outlook

Great advances have been made in the development of solar energy technologies. Efficiencies have been improved and costs have been brought down by orders of magnitude. The technologies have become cost-effective for some applications. However, they are still too expensive for other applications such as grid electricity, unless environmental costs are accounted for or incentives are given for these technologies.

At present, the markets for solar PV technologies are increasing at a rate of more than 35% per year and solar thermal power growth is expected to be even higher. However, these applications are starting from a very small or negligible base. Therefore, an even higher growth rate would be needed to reach the levels envisioned for the future. Strong public policies and political leadership are needed to move forward the application of solar and other renewable energy technologies, while maintaining robust research efforts to advance present technologies and develop new ones.

Countries whose governments have established firm goals for the penetration of renewable energy into primary energy and electricity generation, or have adopted specific policy mechanisms, are achieving great success. Examples are the successful feed-in laws adopted in several European countries, for instance, Germany and Spain; the Renewables Portfolio Standard (RPS) adopted by the majority of the American states, which ensures that a minimum amount of renewable energy is included in the portfolio of electricity production; and city ordinances requiring solar systems to be used for water heating in residential and commercial buildings. Appropriate policy measures have shown that solar applications can be boosted with many positive side effects, from the creation of new industries, new jobs and new economic opportunities, to the protection of the environment.

Energy conservation - through improvements in energy efficiency and decreases in energy intensity - is essential to increase the fractional contribution of renewable energy while meeting the energy needs of society.

Based on a review of the ongoing research in solar energy technologies, it is clear that they will continue to improve, promising higher efficiencies and lower costs. Examples of such promising new technologies beyond the horizon include continued development of new thin-film technologies, nano-scale antennas for conversion of sunlight to electricity, biological nano-scale PV, new concepts in solar desalination, visible light photocatalytic technologies for PV or environmental applications, new thermodynamic combined cycles, and efficient low-cost thermal energy storage for solar thermal power. These developments are expected to help achieve the projected solar energy penetration levels by 2050 and beyond. However, in the meantime, it is essential to adopt policies that will ensure accelerated deployment of the present solar energy technologies.

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TABLES

TABLE NOTES

At this point in time, the quantification of solar energy in terms of installed capacity and annual output of electricity and heat presents extraordinary difficulties, which are probably greater than those encountered with any other source of energy. The combination of comparatively newly-developed technologies, rapid market growth and widespread, virtually worldwide, diffusion (often at the level of individual households, many in remote rural areas) makes comprehensive enumeration extremely difficult, if not impossible. This means that any aggregate data on a national level can be no more than indicative of the situation.

Table 10.1 provides data on photovoltaic generating capacity in 2008, as available from the following sources:

- WEC Member Committees, 2009/10;
- *Trends in Photovoltaic Applications: Survey report of selected IEA countries between 1992 and 2008*, International Energy Agency – Photovoltaic Power Systems Programme, September 2009;
- *The State of Renewable Energies in Europe*, 2009 Edition, 9th EurObserv'ER Report.

The data covered in Table 10.1 constitute a sample, reflecting the information available in particular countries: they should not be considered as complete, or necessarily representative of the situation in each region. For this reason, regional and global aggregates have not been computed.

Table 10.1 Solar Energy: installed photovoltaic capacity at end-2008 (MW_p)

	Installed capacity
Africa	
Algeria	>2.8
Egypt (Arab Rep.)	>4.5
Ethiopia	>2.9
Gabon	>N
Guinea	>0.1
Morocco	10.0
Namibia	0.3
South Africa	12.0
Tanzania	>1.2
North America	
Canada	32.7
Mexico	19.4
United States of America	1 168.5
South America	
Argentina	9.0
Brazil	5.2
Peru	>3.7
Uruguay	>N
Asia	
Bangladesh	>3.5
China	130.0
Hong Kong, China	>0.8
India	160.0
Japan	2 144.2
Korea (Republic)	357.5
Malaysia	8.8
Nepal	>3.3
Sri Lanka	>1.1
Taiwan, China	>1.0
Thailand	34.0
Turkey	4.0
Europe	
Austria	32.4
Belgium	71.2
Bulgaria	0.1
Croatia	0.1
Cyprus	2.2
Czech Republic	54.0
Denmark	3.3
Estonia	N
Finland	5.6
France	179.7
Germany	5 877.0
Greece	18.5
Hungary	0.5
Ireland	0.1
Italy	431.6
Latvia	N
Lithuania	0.1
Luxembourg	24.4
Malta	0.2
Netherlands	57.2
Norway	8.3
Poland	1.0
Portugal	59.0
Romania	0.5
Russian Federation	>N
Slovakia	0.1
Slovenia	0.7
Spain	3 354.0
Sweden	7.9
Switzerland	44.8
Ukraine	0.1
United Kingdom	22.5
Middle East	
Iran (Islamic Rep.)	0.1
Israel	3.0
Jordan	>0.5
Oceania	
Australia	104.5

Notes:

1. The data shown for France include French Overseas Departments (DOM)
2. Countries for which end-2008 capacities are not available are shown with data for end-2005, with the amount prefaced by a '>' sign

COUNTRY NOTES

The Country Notes on Solar Energy have been compiled by the Editors. In addition to national, international, governmental publications/web sites and direct personal communications, the following publications have been consulted:

- *Photovoltaic Power Systems Programme, Annual Report 2008*, International Energy Agency;
- *Trends in Photovoltaic Applications: Survey report of selected IEA countries between 1992 and 2008*, International Energy Agency – Photovoltaic Power Systems Programme, September 2009;
- *Solar Thermal Markets in Europe (Trends and Market Statistics 2008)*, European Solar Thermal Industry Federation, May 2009;
- *Solar Heat Worldwide*, 2009 Edition, IEA Solar Heating and Cooling Programme.

Information provided by WEC Member Committees has been incorporated as available.

Albania

Most of the country receives a level of insolation of more than 1 500 kWh/m^2/yr, within a range of 1 185 to 1 690 kWh/m^2/yr. The western, and especially the southwestern, region of Albania has a particularly significant solar resource. As a whole the country receives an average daily solar radiation of 4.3 kWh/m^2.

In September 2006 various schemes to encourage the development of the solar thermal market were either being planned or at least considered: incentives in the form of tax credits or soft loans; the encouragement of a solar water heater (SWH) manufacturing industry, Government co-financing incentives, legislation for the installation of solar thermal systems in new buildings, etc.

To date the solar resource has been under-utilised. However, in 2009 and 2010 various solar thermal projects are being implemented: a Solar Test Facility for researching and certifying solar water heaters and pilot schemes for solar thermal systems. It is hoped that greater familiarisation will lead to an increased use of renewable energy and improvements in the energy supply situation.

Algeria

At 164 440 TWh/yr solar power, Algeria receives some 5 000 times its annual power consumption. The average hours of sunshine exceed 2 000 h/yr, with the high plateaux and the Sahara receiving 3 900 h/yr. The solar energy received ranges from 1 700 kWh/m^2/yr in the coastal areas to 1 900 kWh/m^2/yr in the highlands and to 2 650 kWh/m^2/yr in the Sahara.

Whilst the share that solar power contributes to the overall supply of energy is small, it has proved invaluable for the electrification of isolated settlements, especially in the south of the country. Rural PV electrification programmes accord priority to regions that are sparsely populated and situated far from the grid. The PV systems provide power for water pumping, public and domestic lighting, telecommunications, refrigeration, and other uses.

A project to develop the market for solar hot water systems began in 2007. Financed by the UNDP, the aim is install SWHs in 5 500 homes and solar panels with an area of 16 000 m^2 in the service sector.

Also during 2007, construction of Algeria's first Integrated Solar Combined-Cycle plant began. Located in the region of Hassi R'mel, the 150 MW plant will be composed of an existing 125 MW gas c-c plant and a 25 MW solar plant using parabolic trough technology over an area of 180 000 m^2. It is expected that the plant will enter commercial production during 2010.

Argentina

The Argentinian WEC Member Committee reports that the country's solar resource potential has been determined by a number of studies, in particular the 'Atlas solar de la República Argentina' by H. Grossi Gallegos and R. Righini, which includes maps of the monthly spacial distribution of average solar irradiation and of the average number of hours' sunshine.

Up to the present, the use of PV in Argentina has been largely confined to supplying unsatisfied demand in remote areas. However, two projects that will be incorporated into the interconnected system were reported in October 2009 to be at the bidding stage: one was for a 1.2 MW_p pilot PV plant in the province of San Juan, while the state-owned energy corporation ENARSA was inviting bids for 10 MW_p of PV capacity and 25 MW of solar thermal.

The Proyecto de Energías Renovables en Mercados Rurales (PERMER), financed by the National Government and carried forward by the Secretaría de Energía, has as its principal objective the supply of electricity to a significant number of people who live in rural areas, and to approximately 6 000 public service establishments of all kinds (schools, emergency medical posts, police detachments, etc,) which are located out of range of energy distribution centres.

The project envisages the installation of mini-hydro stations, wind turbines, diesel plants or hybrid stations using diesel/wind, diesel/solar or solar/wind in small communities as well as the installation of PV systems and/or individual wind turbines which will afford the rural population, in addition to electricity supply, the possibility of developing small productive enterprises.

The implementation of PERMER has enabled the electrification of a large proportion of this population through solar energy (540 schools, 3 260 dwellings and 76 public services, to which can be added a further 1 049, 3 100 and 200, respectively, which are in course of execution).

Australia

With such a large land mass, the levels of solar insolation vary widely by area and over the year. Using annual average levels, Tasmania, the extreme southeast and the southwest coastal area receives between 12 and 18 MJ/m^2 (approximately

1 200-1 800 kWh/m^2/yr); the south and the eastern coastal areas, between 18 and 21 MJ/m^2 (1 800 2 100 kWh/m^2/yr) but the vast majority of the continent, between 21 and 24 MJ/m^2 (2 100-2 400 kWh/m^2/yr).

Australia saw an increase of nearly 27% in installed PV capacity between 2007 and 2008. Although the country has an excellent solar resource and low electricity prices the cost of developing photovoltaic power has been relatively high. However, the Government ratified the Kyoto Protocol in late-2007 and this has resulted in a planned increase to the Renewable Energy Target by 2020.

By end-2008, installed PV power was 105 MW$_p$, of which 33 MW$_p$ was off-grid domestic, 41 MW$_p$ off-grid non-domestic (industry and agriculture), 30 MW$_p$ grid-connected distributed and 1 MW$_p$ grid-connected centralised. Grid-connected capacity represented nearly 30% of the total.

The Renewable Remote Power Generation Program (RRPGP), the Solar Homes and Communities Plan (formerly the Photovoltaic Rebate Program), the Low Emissions Technology and Abatement (LETA) program, and, to some extent, the Mandatory Renewable Energy Target have all played their part in the developmental role of PV in recent years but, together with climate change in general, the subject has now attained a much higher status in the national consciousness.

Photovoltaic components are now widely available in the established retail sector, finding a ready market after the residential grant was doubled in 2007 to 8 000 AUD for the first kW installed. The second half of the year saw many new businesses created and a rise in the accreditation of PV installers. PV systems on community buildings have also benefited by being able to apply for up to 50% of costs up to 2 kW$_p$. The majority of small systems have created Renewable Energy Certificates (RECs). The support schemes have been so successful that the Government introduced means testing in early 2008 in order to curtail demand. In mid-2009 RECs were replaced by the Solar Credits scheme which provides wider support for solar technology in domestic, business and community situations and is irrespective of income.

The Solar Cities program has helped enormously to raise the profile of PV in the cities of Adelaide, Townsville, Blacktown, Alice Springs and Central Victoria. During 2008 the 94 million AUD program added Moreland and Perth as the 6th and 7th Solar Cities. In addition to residential installations, commercial and public buildings are having PV systems incorporated as part of a plan to reduce greenhouse gas emissions. The Program continues until 2013.

The Solar Schools Program, launched in mid-2008, for a period of seven years, has also been enormously popular to the point that it was temporarily suspended in October 2009. Primary and secondary schools can apply for a grant up to 50 000 AUD for the purpose of installing a range of solar technologies, renewable energy systems or energy efficiency measures. More than half of Australian schools applied and it is expected that about 2 500 will be successful during FY

2009/2010. The Program will be re-launched in July 2010, at the beginning of the financial year.

In addition to the PV schemes, the Renewable Energy Bonus Scheme (replacing the Solar Hot Water Rebate Program and the Home Insulation Program) in effect from mid-February 2010 offers households a rebate for replacing electric storage hot water systems: 1 000 AUD for a solar system or 600 AUD for a heat pump system.

Following the installation of the Australian National University's 400 m^2 solar dish concentrator in 1994, construction of a second 500 m^2 ANU dish began during first quarter 2008, with the first sun tests taking place during June 2009. ANU's work on paraboloidal dish concentrators is part of a project to bring to commercial fruition the technology of solar thermal energy storage combined with generation of electricity.

The Australian Solar Institute was launched in January 2009. Its role is to support solar thermal and solar PV R&D.

Austria

The framework of support measures for the Austrian solar photovoltaic market has been, and continues to be fairly complicated, with many overlapping Federal and provincial schemes.

With the attainment of the 15 MW cap on installed PV capacity imposed by the 2003 Federal Green Electricity Act (Ökostromgesetz), Federal support for solar photovoltaic ceased and only regional subsidies continued. However, a revised Act, passed by Parliament in late 2006, has provided further support for new PV installations, albeit on an annual basis, and incorporating a request to the Austrian provinces to double the federal subsidy. According to the 2008 Feed-in Decree the tariffs are defined according to the size and lifetime of installations. A rebate scheme administered by the national Fund for Climate and Energy was launched during 2008. It provides rebates for newly installed private PV systems up to 5 kW_p.

Following several years of very small increments, 2008 saw a 4.7 MW_p addition to PV capacity, more than double that installed during 2007. By end-2008 total installed capacity stood at 32.4 MW_p, of which 90% was grid-connected. A further 5-8 MW_p was expected to be installed during 2009.

Building Integrated PV (BIPV) has, for some time, been implemented in Austria and continues in new and refurbished buildings. During 2008 two national programmes (New Energy 2020 and Buildings of Tomorrow Plus) supporting BIPV were launched.

The Austrian WEC Member Committee reports that total output from active solar heating devices was 4 788 TJ in 2008, with an additional 4 356 TJ from passive sources (e.g. use of appropriate building orientation and design).

With regard to solar collecting panels in operation, the most recent ESTIF (European Solar Thermal Industry Federation) tabulation shows Austria in third place in terms of area installed in 2008, with approximately double that installed in France, Italy or Spain.

Botswana

Botswana receives a high rate of solar insolation - 280-330 days of sun per year with daily average sunshine ranging from 9.9 hours during the summer to 8.2 hours in winter. The average total solar radiation is 21 $MJ/m^2/day$ (approximately 2 100 $kWh/m^2/yr$). However, the country's available resource is currently under-utilised. It is mainly used for domestic solar water heating but PV technology is also used for small-scale generation systems.

The slow uptake of the rich solar resource is due to many barriers: from a lack of basic awareness of the technology and of affordable financing schemes to poor quality and lack of after-sales service, etc.

The Government plans to remove the barriers and increase the use of renewable energy. In 2006 it launched the RE-Botswana Renewable Energy-based Rural Electrification project, a collaboration between the Government and the UNDP Global Environment Facility. The 5-year project is being implemented by the Botswana Power Corporation and aims to help rural communities by, for example, equipping some 65 000 households with PV lighting by 2011.

Brazil

The *Atlas Solarimétrico do Brasil* (FAE/UFPE) demonstrates that the daily solar radiation in Brazil varies between 8 and 22 MJ/m^2 (approximately 800-2 200 $kWh/m^2/yr$), depending on time of year. The high radiation index proves that not only does the solar resource possess a potential that can be utilised, but that because of wide availability, its use need not be centralised.

An analysis of solar PV utilisation for electric power generation points to this particular technology as having a cost advantage. It has been estimated that after taking installed capacity into account, the cost of generation from PV is approximately US$ 7 000/kW_p. The country has a predominantly clean and renewable power mix and in the coming decades other sources of energy will be exploited: less expensive, as in the case of hydroelectric power, and advanced technology, as in the case of sugarcane biomass.

Thus although conditions for solar PV are favourable, dissemination is restricted owing to the high cost and a lack of indigenous production. In Brazil, the average capacity factor of PV is 20%, equivalent to 5 $kWh/m^2/day$. However, there are regions where the use of PV technology is the best technical and economic solution, owing to low local consumption, scattered consumers, problems of access and environmental restrictions. An example of this policy is the adoption of PV technology by the distribution companies under the Programa Luz para Todos (Light for All Programme).

Within the unconnected system, the Programa de Desenvolvimento Energético dos Estados e Municípios - *PRODEEM* (Programme of Energy Development of States and Municipalities) has been instrumental in the installation of an equivalent to 5 MW_p of PV systems, serving approximately 7 000 communities scattered throughout the country.

Within the interconnected system, the share of PV is small. Currently, it is restricted to 29 systems with a capacity of 157 kW_p, mostly installed in centres of research and colleges.

The Ministry of Mines and Energy's Secretariat of Planning and Energy Development has created a work group for Distributed Generation and Photovoltaic Generation (GT-GDSF). The objectives of GT-GDSF are to undertake studies, propose conditions and suggest criteria for grid-connected PV generation - especially for urban buildings, in the short, medium and long term. These studies are currently under way.

According to estimates supplied by Associação Brasileira de Refrigeração, Ar Condicionado, Ventilação e Aquecimento, the installation of solar technology for water heating obviated the need to construct a 582 MW plant.

Although Brazil does not yet have a consolidated programme for providing an incentive for solar heating of water, several actions are under way. Their aim is to allow the creation of an environment that facilitates the use of solar energy as a viable energy for all consumers.

The use of solar energy applications is in line with the objectives of the Plano Nacional sobre Mudança do Clima (National Plan on Climate Change). The Plan encompasses a number of actions and measures already under way or in course of being drawn up for the purpose of combating global warming. The intention is that the renewable energies should continue to have a large share of the electricity matrix.

Bulgaria

The Bulgarian WEC Member Committee reports that average annual solar hours are about 2 150 and average annual solar radiation resources 1 517 kWh/m^2. The total theoretical potential of solar energy is 13 103 ttoe, and the available annual potential is about 390 ttoe.

For the 2004 edition of the present *Survey*, the Member Committee observed that Bulgaria could be divided into three zones according to the solar insolation received, namely:

Zone A - encompasses regions in the southeast, part of the southern Black Sea coastal region and the valleys of the rivers Struma, Mesta and Maritza. The amount of sunshine is over 2 200 h/yr and the total solar radiation received on a horizontal surface is greater than 1 600 kWh/m^2.

Zone B - encompasses regions in the Danube plain, the Dobrudja region, the Trace lowland, west Bulgaria, the Balkan hollow fields and Stara Planina mountain regions. The amount of sunshine ranges from 2 000 to 2 200 h/yr and total solar radiation from 1 500 to 1 600 kWh/m^2.

Zone C - encompasses the remaining parts of Bulgaria, mainly the mountainous regions, where sunshine is less than 2 000 h/yr and total solar radiation less than 1 500 kWh/m^2.

The present installed PV capacity is very small. However, under the National Long Term Programme to Promote the Use of Renewable Energy Sources 2005-2015, it is planned that the solar resource will have a far greater utilisation - particularly in the solar thermal field, where some 60 000 m^2 of collectors are currently in use.

Canada

At 5-5.8 kWh/m^2, the highest mean daily global insolation (south-facing) in Canada is found south of Regina, parallel to the border with the U.S. States of Montana and North Dakota. The slightly lower mean daily level of 4.2-5 kWh/m^2 is received by the majority of the southern half of the country, whilst the majority of the northern half (excluding the far north) receives 3.3-4.2 kWh/m^2. Thus the country's solar resource is considerable and in recent years has been substantially utilised.

The Canadian solar photovoltaic (PV) market has experienced an annual growth rate of about 23% over the five years up to 2008. Installed capacity of solar PV stood at 32.7 MW at end-2008, an increase of 27% over 2007. Of this total, approximately 84% represented domestic and non-domestic off-grid installations.

Off-grid applications are largely stand-alone applications but can form part of a hybrid system, combined with a small wind turbine or diesel generator. They are used for water pumping, transport route signalling, navigational aids, isolated residential buildings, telecommunications, and remote sensing and monitoring, generally in remote areas of the country.

The grid-connected capacity, which represented 16% of the cumulative installed in 2008, is a growing sector. In recent years it has received encouragement as a result of the Government of Ontario's 2006 Renewable Energy Standard Offer Program (RESOP), in which small renewable energy projects have been able to participate in electricity markets. In 2008 RESOP exceeded all expectations, achieving in excess of 1 000 MW of contracted projects, surpassing the 10-year target for renewable energy, in the first year. As a result of this success, the Ontario Power Authority has undertaken a comprehensive review of the RESOP. Various efficiency measures have been implemented in order to ensure its continued success.

The solar thermal market has also demonstrated strong growth in recent years. It has been estimated that by end-2008 some 720 000 m^2 of solar collectors were in operation, an increase of 32% over 2007, which was a 30% increase over 2005. All five types of solar thermal collector (unglazed liquid, unglazed air, glazed liquid, evacuated tube liquid and glazed air) have been installed in all regions of Canada, bar the North, where only two types were reported. Ontario holds first place in terms of sales of solar collectors, followed by the Prairies, British Columbia and the Atlantic Provinces.

The Renewable Energy Deployment Initiative (REDI) was launched in 1998 by Natural Resources Canada (NRCan) to stimulate the demand for cost-effective renewable energy heating and cooling systems, and to help create a sustainable market for those systems. In 2006, the REDI program was superseded by the ecoENERGY for Renewable Heat program. Active solar thermal systems, including air and water heating, represent two of the types of renewable energy technologies presently supported by NRCan's ecoENERGY program.

The Federal Government has several programmes to encourage market development of solar technologies: Sustainable Development Technology Canada, a not-for-profit corporation, was established in 2001 in order to support the development and demonstration of innovative technological solutions including solar PV; Canada Mortgage and Housing Corporation's EQuilibrium™ Sustainable Housing Demonstration Initiative brings together the private and public sectors with the goal of developing homes that are designed and constructed on the basis of a variety of principles, including energy efficiency and resource conservation. The Technology Early Action Measures Program, introduced in 1998, was an investment programme that supported late-stage development and first demonstrations of GHG-reducing technologies. However, its mandate ended in 2008 and the program is being wound down.

China

It is estimated that two-thirds of the country receives solar radiation energy in excess of 4.6 kWh/m^2/day, with the western provinces particularly well endowed. China's annual solar power potential has been estimated to be 1 680 billion toe or 19 536 000 TWh. Capturing 1% of this resource, and utilising it with 15% efficiency, could supply as much electricity as the whole world presently consumes in eighteen months.

China's 11th 5-Year Plan (2006-2010) stresses the need for energy conservation and diversification. In the first phase of the Village Programme, some 250 MW$_p$ of PV systems were planned for installation, bringing power to 2 million households that have been out of reach of mains electricity. Additionally, the 11th Plan is supporting around 50 MW$_p$ of roof-top and BIPV systems, as well as a 20 MW$_p$ demonstration plant in the Gobi desert.

In September 2007 the Chinese National Development and Reform Commission stated that by 2010, total installed PV capacity would amount to 300 MW$_p$, of which 150 MW$_p$ would be installed in remote agricultural and husbandry households. By 2020 it was estimated that total installed PV will have risen to 1.8 GW$_p$ with remote systems amounting to 300 MW$_p$. The Government also planned for the promotion of BIPV in cities, with 50 MW$_p$ installed by 2010 and 1 GW$_p$ by 2020. Furthermore, the targets for grid-connected solar PV/solar thermal power stations were set at 20 MW and 50 MW respectively by 2010 and 200 MW each by 2020. Commercial applications for off-grid solar PV systems were set at 30 MW$_p$ by 2010 and 100 MW$_p$ by 2020.

The deployment of solar thermal systems, particularly in domestic situations, was also covered by the Development Plan. The aim was for 150 million m^2 to be installed by 2010, doubling by 2020.

At the beginning of 2009, preparation of the 12th Five-Year Plan for Energy (2010-2015) was under way. It has been suggested that in the years to come, utilisation of the Chinese solar resource will possibly take a lower priority than other renewable energies available to the country. However, later in the year there were reports that former targets were underestimated and that installed solar capacity could be substantially higher.

One significant area of success has been the growth in the PV manufacturing sector, putting China into a leading position in the world market, albeit with a certain decline in business following the global recession. With the fall in the price of polycrystalline silicon and in order to stimulate the sector, the Government announced in mid-2009 that it would give financial support in the form of subsidies and other incentives.

Croatia

Annual global horizontal irradiation is between 1.20 MW/m^2 for the northernmost parts and mountain areas (Žumberak, Zagorje, parts of Velebit and Gorski kotar) of the country and 1.60 MW/m^2 for the southernmost outer islands (Vis, Lastovo, Palagruža). Croatia has very high spatial variability of solar irradiation, especially in the near-coast areas bounded by the high mountains. This variability results in annual electricity production from photovoltaic being in the range of 950-1 450 kWh for systems with installed peak power of 1 kW_p, inclined at an optimal angle and oriented to the south, without shading.

Current applications of solar PV include mainly autonomous systems, on lighthouses and telecommunication stations. A large number of small devices (measurement stations, emergency phones, etc.) are also equipped with PV modules. Photovoltaics are also used for grid-connected systems and this use is increasing every year.

Solar thermal collectors can generate around 600 kWh/m^2 for the continental part of Croatia and around 1 000 kWh/m^2 for the coastal area. Use of solar thermal collectors is mostly focused on hot water production and heating support, chiefly in private households. The increase in use is largely stimulated by supporting programmes from the counties. There are also some high-visibility projects regarding the use of solar thermal collectors in the hotel sector.

Czech Republic

Although the level of solar insolation in the Czech Republic is not high, the support for solar technology is generous and is thus helping the market to develop. The total theoretical limit for installed PV capacity has been evaluated at 24.3 GW.

The Czech Republic's 2004 National Energy Policy to 2030 advocated a rapid development of renewable energy utilisation. It stipulated that the solar PV sector would be developed and that the stimuli would be extremely high feed-in tariffs for PV-generated electricity, and subsidies from the State Fund for the Environment and EU Operational Programmes.

The Act for the Promotion of Use of Renewable Sources, adopted in March 2005, included a support scheme for renewable energies. The high feed-in tariffs have guaranteed rapid repayment of investment and accelerated new, large PV installations on agricultural land as well as on land for other uses. A further Act included another measure of support – a green bonus – which is paid in addition to the market price. Generators of PV power have the option to choose the feed-in tariff or the green bonus.

In 2008 solar PV-generated electricity amounted to 12.9 GWh, just 0.34% of generation from renewable energy. However, it is estimated that there will be a very steep increase in PV generation from 2009 onwards.

Denmark

Historically there has been no unified national PV programme, although a large number of projects have received support from the Renewable Energy Development Programme of the Danish Energy Authority (DEA), and through the Public Service Obligation (PSO) of the Danish transmission system operator. Since 2004, the DEA has collaborated with the electricity sector and other interested parties in pursuing a national PV strategy that encompasses RD&D, but excludes deployment.

In early 2008 a new energy plan, entitled A Visionary Energy Policy, extending out to 2025, was adopted. Although the plan contains targets for renewable energy in total and financially supports demonstration of emerging renewables (for example, PV and wave power) for an initial four-year period, specific targets for individual energy technologies have been omitted.

In early 2009 a demonstration project was awarded € 3 million for a 1 MW_p BIPV project on the buildings of the municipality of Skive.

At the end of 2008 installed PV power was 3 265 kW_p, of which 2 825 kW_p was grid-connected distributed. As Denmark has an almost universal transmission system, off-grid capacity represents just 13% of capacity.

The European Solar Thermal Industry Federation reports that an estimated solar thermal collector area of 418 280 m^2 was in operation during 2008, an increase of 33 000 m^2 over 2007. Expressed in terms of solar thermal capacity, the cumulative total represents nearly 300 000 kW_t.

Egypt (Arab Republic)

Egypt is located in the world's solar belt and has an excellent solar availability. The Egyptian WEC Member Committee has reported that average solar radiation ranges from about 1 950 kWh/m^2/yr on the Mediterranean coast to more than 2 600 kWh/m^2/yr in Upper Egypt, while about 90% of the Egyptian territory has an average global radiation greater than 2 200 kWh/m^2/yr.

Photovoltaic (PV) solar systems are presently considered economically advantageous only in remote applications of low power demand, where a grid extension appears non-economic, while conventional stand-alone power sources (e.g. diesel generator sets) show excessive operating costs, in addition to polluting the environment.

A number of PV systems have been installed in Egypt, primarily by the New and Renewable Energy Authority (NREA), but also by other national and international entities, including some private companies. The main applications are water pumping, desalination, rural clinics, telecommunications, rural village electrification, ice-making, billboards and cathodic protection.

Egypt's first concentrating solar power (CSP) plant is approaching completion at Koraymat, 90 km south of Cairo. The parabolic trough installation is part of a larger integrated facility that includes two gas turbines of approximately 40 MW each, and a 70 MW steam turbine. The overall output capacity is around 140 MW.

Ethiopia

Although there are many instances of solar technologies being employed throughout the country, at the present time there are no nationally aggregated data. PV is used for telecommunication applications, for rural lighting and for rural social services (water pumping, health and education).

A number of schemes have already been activated or are planned:

- the Ethiopian Alternative Energy Development & Promotion Center (EAEDPC), through the Rural Electrification Fund (REF), has a programme to install 300 institutional PV systems;
- in 2009 the Solar Energy Foundation electrified the village of Rima and surrounding area with the installation of 2 000 solar home systems. The cost to a household is GBP 0.75/month. The project was the recipient of an Ashden Award for Sustainable Energy;
- a further 2 366 solar home systems were installed in various villages – 441 units by REF and 1 925 by The Solar Energy Foundation;
- a plan exists to electrify villages near the town of Lalibella;
- the REF is currently in the process of importing PV equipment for 200 rural health centres and 100 rural schools;
- with the assistance of various stakeholders, 150 000 households, rural schools and health centres will be electrified with PV systems by 2014-2015.

The EAEDPC has commenced a solar/wind assessment within the Global Environment Facility-sponsored Solar and Wind Energy Resource Assessment (SWERA) project.

France

The French WEC Member Committee reports the following developments in the field of solar energy:

- with effect from 1 January 2010, revised purchase tariffs for electricity generated by installations with a capacity of less than 12 MW, varying with the type of installation;

- the development plan for renewable energy (November 2008) incorporates a 2020 target of 5 400 MW for installed PV capacity, corresponding to an output of 450 ttoe;

- a new PPI (long-term investment plan) for electricity is being prepared;

- an invitation to tender for the construction of solar PV power plants in all French regions, up to an aggregate capacity of 300 MW;

- significant support for certain ambitious initiatives, in order to further the establishment of a PV industry network in France.

On the solar thermal side, developments reported comprise:

- the development plan for renewable energy (November 2008) incorporates 2020 output targets of 817 ttoe for individual solar heating installations (covering a total of some 4.3 million households) and 110 ttoe for collective installations;

- the tax credit (at a fixed rate of 50%) which supports the acquisition of solar water heaters by individuals has been extended until 2012;

- the establishment in 2009 of a heating fund, endowed with € 1 billion over three years, to assist in the financing of projects in collective housing, the service sector and industry.

According to IEA-PVPS, by the end of 2008 France (including its overseas Departments) had a total installed PV capacity of 179.7 MW_p, of which 16.2 MW_p was off-grid domestic, 6.7 MW_p off-grid non-domestic, 140.8 MW_p grid-connected distributed, and 16.0 MW_p grid-connected centralised. The quoted total includes some 80-90 MW_p of capacity in place but awaiting grid-connection.

Solar thermal output in 2008 is reported to have been 2 918 TJ, of which 1 839 was in metropolitan France. According to ESTIF, the total glazed area of solar thermal collectors in operation in 2008 was 1 624 000 m^2, giving an output capacity of about 1 137 MW_t. With the assistance of tax credits and support programmes, a total of 388 000 m^2 of solar thermal collectors (including 75 000 m^2 in overseas Departments) was installed during 2008. Although this level implies a slight acceleration in the already brisk rate of growth achieved during 2007, France (including overseas Departments) sank to fourth place in the 2008 European market for solar thermal collectors.

Germany

In 2000 Germany had just 76 MW_p installed PV capacity. By 2003 this figure had grown to 439 MW_p but two years later capacity totalled 1 980 MW_p and the country had overtaken Japan to become the world leader. Between 2005 and end-2008 German growth averaged nearly 44% per annum bringing the total to 5 877 MW_p. The Federal Environment Ministry estimates that by end-2009 capacity had grown a further 51% to 8 877 MW_p. Virtually all capacity is grid-connected. Power output has shown a corresponding growth over the years, amounting to 4.42 TWh in 2008 and an estimated 6.2 TWh in 2009. By end-2008, some 500 000 solar rooftop systems had been installed.

The spectacular success of the utilisation of Germany's solar resource – certainly not the highest in the world – has been the driving force of the Renewable Energy Act (EEG) with its feed-in tariffs, first introduced in 2000 and amended in 2004 and 2008.

In the beginning the principle of the EEG was to stimulate lower prices in the market by reducing the feed-in tariff (guaranteed over a period of 20 years) which, after 2004, dropped by 5% per annum for roof-top modules (6.5% for ground modules). The modification made to the EEG during 2008 resulted in the degression rate being reduced more rapidly from 2009 onwards. For rooftop systems, the new feed-in tariff was set at 8% for up to 100 kW_p and 10% for over 100 kW_p in 2009/2010. In the period 2011/2012 the rate will become 9%. For ground-mounted systems, the rate was set at 10% in 2009/2010 and 9% in 2011. The Government also set a 'Growth Corridor' for new installations: 1 000-1 500 MW_p in 2009; 1 100-1 700 MW_p in 2010 and 1 200-1 900 MW_p in 2011. If the growth in any one year deviates from the planned growth, the rate of degression is adjusted accordingly.

With effect from 1 July 2010 the feed-in tariffs for PV installations on buildings and in open spaces will be reduced and the targeted market volume will be doubled to 3 500 MW_p per annum.

As with solar PV, the solar thermal collector (glazed and vacuum tube) area in Germany has followed an upward trend - nearly 19% - since 1991. Following an earlier Government programme for domestic hot water and heating, the responsible driving force for solar thermal in recent years has been the Market Incentive Programme (MAP), introduced in 1999. Grants for both small and large systems have been available, albeit with not entirely a smooth progression. However, in mid-2008 the Renewable Energy Heating Act was passed and ensured sufficient funds for the MAP during 2009-2012. The Act which came into force at the beginning of January 2009 legislated for new buildings to have a minimum of their heat demand supplied by renewable energy.

According to ESTIF, the market in 2007 for solar thermal technology declined by 37% from 2006. However, it more than doubled between 2007 and 2008, with a newly-installed total of 2.1 million m^2. By end-2008 the collector area was in the region of 11 million m^2, representing a capacity of approximately 7.8 GW_t - by far the biggest in Europe by a factor of nearly 3. The Ministry states that output in 2008 amounted to 4.1 TWh and estimates that comparable figures for 2009 collector area and output were about 13 million m^2 and 4.8 TWh.

Germany possesses some of the largest solar power plants in the world. The 40 MW_p Waldpolenz Solar Park began generating electricity in June 2008 and is expected to generate some 40 million kWh annually. The 53 MW_p Lieberose solar farm in Brandenburg was connected to the grid in the autumn of 2009. Also in 2009, the country's first commercial solar thermal 'power tower' came on line (1.5 MW_e).

Greece

Despite the existence of a very high potential for solar energy applications and the beginning of their deployment in the mid-1970s, major applications have historically been restricted to SWH collectors. There has been a negligible market for large-scale hot water systems in the commercial sector (hotels, hospitals and swimming pools) and an even smaller penetration in industry.

In past years the Hellenic State provided a very favourable taxation environment for solar applications but individual consumers' purchases were mainly limited to SWH collectors, because of the high cost of photovoltaic applications. The European Solar Thermal Industry Federation states that the total glazed area of solar thermal collectors in operation in 2008 was 3 868 200 m^2, giving an output capacity of about 2 708 MW_t. Installations grew only slowly in 2008, but Greece still has the second largest collector area in Europe.

Moreover, the solar PV market is now developing. During 2008, installed capacity approximately doubled, with the addition of more than 9 MW_p. At the beginning of 2009 the Greek Government passed legislation which provides incentives in the form of feed-in tariffs for domestic PV installations. Under the Government's feed-in tariff scheme, the aim is to increase capacity to 700 MW_p , compared with an installed total of about 24 MW_p at the beginning of 2009. In mid-2009, further legislation provided an incentive programme for rooftop PV systems up to 10 kW_p.

India

India has a good level of solar radiation, receiving the solar energy equivalent of more than 5 000 trillion kWh/yr. Depending on the location, the daily incidence ranges from 4 to 7 kWh/m^2, with the hours of sunshine ranging from 2 300 to 3 200 per year. The country has ambitious plans to utilise India's estimated solar power potential of 20 MW/km^2, and 35 MW/km^2 solar thermal and has already developed a substantial manufacturing capability, becoming a lead producer in the developing world.

As a result of the National Action Plan on Climate Change (June 2008), which identified the development of solar energy technologies as a National Mission, the Jawaharlal Nehru National Solar Mission was launched in January 2010. The aim of the Mission is to develop and deploy solar technologies to the extent that by 2022 parity with the grid power tariff will have been achieved. In doing so India hopes to become a world leader in the solar field.

The Mission is expected to facilitate, by providing a favourable policy framework, the installation of 20 000 MW of solar power by 2022. There are three phases planned, each with specific targets:

- Phase I, to 2013, plans 1 000 MW grid-connected (> 33 kV) solar power plants; 100 MW rooftop and small solar plants (LT/11 kV) and 200 MW-equivalent off-grid applications.

- Phase II, 2013-2017, plans a further 3 000 MW grid-connected power generation through the mandatory use of utilities' renewable purchase obligations (with preferential tariffs). Depending on the availability of financial support and subsequent technology transfer, this figure could exceed 10 000 MW by 2017.

- Phase III, 2017-2022, is planned to be the period during which India will have gained the manufacturing expertise, especially in solar thermal technology, to be able to deliver 2 000 MW off-grid applications as well as install 20 million solar lighting systems and an area of 20 million m^2 of solar thermal collectors.

The work of Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY), originally launched by the Government in early 2005 to provide access to electricity for all households within five years, has continued, and gained approval for financing under the Eleventh Five Year Plan (2007-2012).

For those villages too remote ever to be considered for an electricity supply, the Ministry of New and Renewable Energy (MNRE) has continued with its Electrification of Villages Programme, ensuring the distribution of decentralised renewable energy sources. By end-March 2010, over 88 000 solar street lighting systems, nearly 584 000 home lighting systems, in excess of 792 000 solar lanterns and 7 334 solar PV pumps had been installed. The off-grid/distributed category included solar PV power plants totalling 2.46 MW_p. There was a total of 10.28 MW grid-interactive solar power. Under the Solar Thermal programme 3.53 million m^2 of solar water heating systems and around 650 000 solar cookers had been installed.

In February 2009 the MNRE launched a programme to develop solar cities throughout India. In the 11th Plan period, 60 cities will attain the status of Solar City with each State having at least one, with a maximum of 5. 'In principle' approval has been granted to 34 cities (with populations of between 500 000 and 5 million), of which 14 have been issued with sanctions. The sanctions have resulted in each city being awarded 50% of the funding (up to a maximum of Rs 9.5 million) for the preparation of a Master Plan. The Ministry has chosen Nagpur and Chandigarh to act as Modal Solar Cities and thus be examples for others.

At the beginning of 2009 the Government of Gujurat published its Solar Power Policy - 2009. The State has a vast solar potential and by harnessing it not only will there be environmental benefits but also the possibilities for establishing R&D facilities and consequent employment and manufacturing capability. The Policy runs until end-March 2014, during which time installed solar power generators – PV and thermal - will become eligible for financial incentives for a period of 25 years, and the power sold to the distribution system. Individual capacities of both technologies will be subject to a minimum of 5 MW and the maximum total installed will be limited to 500 MW.

In December 2009 it was reported that India’s first megawatt-size grid-connected solar power plant had been inaugurated at Jamuria, West Bengal. Two further 2 MW plants have been established in the Kolar and Belgaum districts of Karnataka – both plants are expected to be expanded by 1 MW each in the near future. An additional 1 MW plant in the Raichur district is planned. In total the MNRE has agreed proposals for a further 28 megawatt-capacity plants in the country.

A common feature of unelectrified areas or locations with poor supply is the use of small (1-10 kW) wind-solar hybrid systems – over 1 000 kW had been installed by end-March 2010.

Iran (Islamic Republic)

In recent years the Iranian Ministry of Energy has instituted several major solar projects and has more in hand:

- at the end of 2008 it was announced that a 250 kW pilot linear parabolic solar heat power plant in Shiraz had been opened;
- a solar park, intended for purchasing equipment for solar thermal research, was established during 2007;
- a 4.3 kW PV system, established during 2006 and operated during 2007, provides lighting for the New Energy Source organisation building in Tehran;
- beginning in 2006, a village electrification project was undertaken in Qazvin province. In the period to August 2008, further villages in the provinces of Zanjan, Gilan, Bushehr, Yazd and Kurdistan received PV systems. A total of 58 systems has helped eleven villages previously without electricity.

Israel

With an average annual insolation of approximately 2 000 kWh/m^2 and few natural energy resources, Israel has pioneered solar energy technology. However, whilst the 1980 law requiring the installation of solar water heaters has had a dramatic effect, PV activity has historically been largely in the realm of academic research.

The 1980 Solar Law is an amalgam of different legislative measures, all designed to lay down national standards and regulations. The Planning and Building Law requires the installation of solar water heaters for all new buildings (including residential buildings, hotels and institutions, but not industrial buildings, workshops, hospitals or high-rise buildings in excess of 27 m), dictating the size of the installation required for a particular type of building; the Land Law governs solar installations in existing multi-apartment buildings and the Supervision of Commodities and Services Law provides governmental supervision of the quality of installations and their guarantees.

The Law has been hugely successful and almost all Israel's residential buildings have solar thermal systems, the vast majority of which are utilised for water heating.

The extensive national grid has precluded the same degree of penetration by PV as has been enjoyed by solar water systems. There has been no PV module manufacturing capability within the country and most activity has been concentrated on maintaining the technical excellence that has been achieved through academic research. However, during the first five years of the 21st century PV-operated cameras for vehicle number-plate recognition were installed for use on Israel's first toll road and PV began to be used for lighting, irrigation, pumping, refrigeration and in parking-ticket machines. A demonstration PV project was initiated in 2005 in the Bedouin village of Drijat, in the Negev desert. In its first phase, the project provided stand-alone PV systems to 20 households, 6 street lamps, a school and a mosque.

At end-2004 installed PV capacity totalled just 0.9 MW_p but by end-2008 capacity had grown to 3.029 MW_p, of which 2.144 MW_p was off-grid domestic, 0.26 MW_p off-grid non-domestic, 0.611 MW_p grid-connected distributed and 0.014 MW_p grid-connected centralised.

During 2008 a new policy allowed for private grid-connected PV systems, together with subsidies aimed at encouraging projects up to 50 kW_p. Various fiscal measures are also assisting deployment. Following a period which saw mostly stand-alone systems installed, almost half the units installed during 2008 were grid-connected.

The Ministry of National Infrastructures has set a target of 10% electricity to come from renewable energy by 2020, with an interim level of 5% by 2014.

At the beginning of 2010, The National Planning and Building Council approved a solar energy planning strategy. The Council's objective is to implement a national outline plan by mid-2010 which will establish the conditions for solar PV installations – from rooftop installations to solar fields.

It has been reported that, with its desire to use renewable energy to a greater extent, the Government has selected four sites in the Negev and the Arava as part of its planned programme for a series of large solar plants. The sites have been approved on environmental grounds but construction is not yet under way. Tenders were issued in 2008 for the construction of a 15 MW_p PV power plant and two solar thermal power plants, each of between 80 and 120 MW_e.

Italy

Since the early 1980s, the main thrust of solar energy in Italy has been photovoltaic, the development of which has ranged from research on materials and devices and experimentation for grid and non-grid applications to the dissemination of such technology through various incentive programmes. However, financial incentives for investment in the solar thermal market have meant that this also has grown strongly in recent years.

There was a boom in Italian solar PV power production during 2008, increasing from 39 GWh in 2007 to 193 GWh (generated by 32 018 installations), a leap of 395%. Of the total installed capacity, small units (less than 20 kW) constituted the vast majority while only eight PV plants exceeded 1 MW. The three regions with the greatest power installed were Puglia, Lombardia and Emilia Romagna. Only a small percentage of installed PV capacity is off-grid; the vast majority is grid-connected distributed.

By end-November 2009 there were about 56 300 PV installations in operation, benefiting from the incentives granted through the Conto Energia mechanism (feed-in programme). Additional capacity amounted to 268 MW_p, bringing the total to more than 700 MW_p. The Italian Position Paper foresees a potential capacity of 9 000 MW_p by 2020, more than ten times the current level.

A new 5 MW_e 'Archimede' solar thermo-electric power plant is in progress at Priolo Gargallo, Sicily, and due to become operational in early 2011. The plant, a collaborative effort between ENEA (the National Agency for New Technologies, Energy and Sustainable Economic Development) and Enel (the Italian electricity and gas utility), is composed of 54 parabolic collectors that concentrate sunlight on a pipe with a new fluid heat carrier (a mixture of sodium and potassium) that can accumulate heat at high temperature. It is the first thermodynamic solar plant using this type of technology.

ESTIF (the European Solar Thermal Industry Federation) reports that following an increase of 77% in 2007, there was a further growth of 28% in the solar thermal market in 2008. Some 295 MW_t new capacity was installed, bringing the end-2008 total to 1 124 MW_t, representing 1 606 230 m^2 of solar thermal collectors.

With 6% of the installed capacity at end-2008, Italy ranks amongst the leaders of Europe's solar thermal sector, after Germany, Greece, Austria and France. However Italy's per-capita solar thermal capacity was only half the European average (19 kW_t vs 38 kW_t per 1 000 inhabitants).

Japan

Between 1997 and 2004 Japan had the largest installed PV capacity in the group of 19 participating members of the IEA-PVPS. However, it first slipped behind Germany in 2005 and then behind Spain during 2008. Nevertheless, the Japanese market increased by nearly 12% over 2007 and represented 16% of the group of 19. By end-year a cumulative total of 2 144 MW_p had been installed, some 84% higher than that of the next largest country, the USA. Grid-connected capacity at 2 053 MW_p represented 96% of the total.

Many policies and financial measures, in the form of subsidies, tax incentives, the renewable portfolio standard and a buyback programme for PV-generated electricity have either been put in place in recent years or are planned. They have been designed to provide the wherewithal for the country to extend the dissemination of solar PV technologies and other renewable energies.

During 2008, a concerted effort was made to develop the support necessary for a wide expansion of PV from 2009 onwards. In July the Japanese Cabinet approved the Government's Action Plan for Achieving a Low-Carbon Society. The Action Plan includes a target for increasing solar power generation capacity to 14 GW_p by 2020 and 53 GW_p by 2030. A second target of the Plan is to roughly halve the current price of the solar power generation system within three to five years. In addition to some 12 policies formulated by the Ministry of Economy, Trade and Industry (METI), the Ministry of Land, Infrastructure and Transport (MLIT) and the Ministry of the Environment (MoE), local governments and municipalities have their own projects and programmes for the furtherance of PV power. A buyback programme for surplus electricity was launched in November 2009.

The electric utilities intend to cooperate in the building of 140 MW_p PV power across 30 locations by 2020.

Japan has a well-developed solar heating sector, with a reported 7 million m^2 of collectors in operation at the end of 2007, of which 98% were of the glazed type.

Jordan

Jordan lies in the so-called earth-sun belt area and has a high solar potential, with a daily average solar irradiance ranging between 4 kWh/m^2 and 7 kWh/m^2, broadly corresponding to annual insolation of 1 400-2 300 kWh/m^2.

Currently the main use of solar energy is for domestic water heating, with approximately 25% of houses having such installations.

In addition, photovoltaic systems are used in remote areas throughout the country. PV installations cover a variety of applications, such as water pumping, telecommunications, schools, desalination and lighting.

The National Energy Research Center reports that by 2020 10 MW of solar PV capacity is projected to be installed.

Jordan, now actively promoting renewable energy, intends to strengthen the role of the National Energy Research Center in order to develop the exploitation of new and renewable energy resources, promote energy conservation and establish suitable regulatory frameworks to manage these resources. The new Energy Law has established the wherewithal to introduce a fund to provide the necessary investment for the development of renewable energy, while the Jordan Renewable Energy and Energy Efficiency Fund (JREEF) has been established as a legally independent entity with the authority to achieve such objectives.

Kenya

Kenya receives a plentiful supply of solar radiation, averaging between 4 and 6 $kWh/m^2/day$ (approximately 1 500-2 200 $kWh/m^2/yr$), but only a small proportion of this resource has so far been harnessed.

The Ministry of Energy estimates that some 220 000 PV units are in current use for lighting, water pumping, refrigeration and telecommunications. The Government is presently carrying out a programme of installing PV systems in schools and other institutional buildings in a number of remote areas, as part of its drive to increase the proportion of renewable sources within Kenya's overall energy supply.

Solar thermal devices are used for drying and water heating, with around 7 000 units in operation at present.

To encourage the utilisation of the renewable energy resources at its disposal, the Kenyan Government introduced in 2008 a feed-in tariff policy for wind, small hydro and biomass. The policy was revised in January 2010 and now includes new tariffs for geothermal, biogas and solar resources. The Government's intention is that solar power will partly displace thermally-generated electricity in isolated and off-grid locations.

Korea (Republic)

After more than doubling to just over 81 MW_p in 2007, installed PV capacity expanded hugely in 2008, reaching 357.5 MW_p by year-end. Of the total, grid-connected capacity accounts for 98% - all the PV capacity installed in the Republic in 2008 was grid-connected. Out of the total grid-connected capacity at end-2008, 84% was classed as centralised.

Of the various support measures contributing to 2008's spectacular growth in PV installations, a favourable feed-in tariff and the 100 000 rooftop programme were the main drivers.

In September 2008 the Ministry of Knowledge Economy presented its long-term strategy, Korea Goes for 'Green Growth': sustainable development in a low carbon society, in which it predicts that by 2030 the Government will achieve a 44-fold increase in the use of photovoltaic energy, compared with 2007.

Asia's largest PV power plant, situated in SinAn, became fully operational in June 2008. An extension completed in September 2008 enlarged the 19.6 MW_p plant to 24 MW_p, sufficient to generate 35 000 MWh per annum, supplying some 7 200 households.

Latvia

Although the amount of sunshine the country receives is only about 1 200 h/yr, solar power is being utilised to good effect, albeit in a small way. The use of solar energy for electricity generation has been limited to small demonstration projects, for example PV systems in lighthouses and lightships. Total installed capacity at end-2008 amounted to 4.8 kW_p.

However, the Regulations on Electricity Production using Renewable Energy Resources and Electricity Price Calculation were approved by the Cabinet of Ministers in February 2009. In accordance with the Regulations the tariff for electricity was approved and the favourable price for solar-generated electricity generation will aid the future development of the technology.

At the end of 2008 a Solar Energy Use Testing Polygon was installed on the roof of the Institute of Physical Energetics. The main goal of the project is to test solar batteries and collectors in real conditions.

Solar collectors have been installed at a number of schools and other locations. The Danish-financed solar thermal project at Aizkraukle Secondary School Nr. 2, completed in 2002 with 155 m^2 of collectors, was at the time the largest such project in the Baltic States. The utilisation of the solar resource for water heating has become more advantageous in recent years owing to the high price of fuels.

It is planned to continue research into the scope for using solar energy in Latvia and into new materials for PV.

Lithuania

The total annual potential of solar energy in Lithuania is assessed at 1 000 kWh/m^2 and the technical potential at about 1.5 TWh per annum. Solar technology has not made a large impact, with solar energy being mainly used for heating, hot water production and the drying of agricultural products. At the present time the Lithuanian Department of Statistics does not collect solar energy data and they are not included in the national energy balance. Total installed PV capacity was approximately 55 kW$_p$ at the end of 2008, with electrical output of some 40 MWh during the year.

Based on data compiled by the Lithuanian Energy Institute, the WEC Member Committee reports that the total area of solar collectors installed is currently about 1 900 m^2, with total heat production in 2008 amounting to 3.5 TJ.

Mexico

The Mexican WEC Member Committee states that more than 70% of the republic's surface receives an insolation in excess of 17 MJ/m^2/day (say, 1 700 kWh/m^2/yr). The scope for solar electricity generation is unlimited from a technological point of view, but constrained by its high cost compared with that of other energy sources.

With respect to electricity generation, the GEF has for some years endeavoured to finance a CSP station, combined with a gas-fired combined cycle station, with the object of demonstrating the advantages of using solar to save on fuels. The Member Committee reports that this project has not yet passed the bidding stage.

It was reported in September 2009 that the Federal Government, with the support of the World Bank, was implementing the Servicios Integrales de Energía project, which is designed to act as a pilot for a national policy of rural electrification via renewable energy, with solar taking the leading role. The project involves endowing approximately 2 500 rural communities with electricity, endeavouring to use the renewable technologies best suited to the local geographical conditions.

At the end of 2008, Mexico's installed PV capacity was about 19.4 MW$_p$. The rate of annual additions has averaged about 0.9 MW$_p$ in recent years. Electricity produced by PV in 2008 is reported as 9.277 GWh. The principal uses of electricity from PV are in rural electrification, communications, water pumping, refrigeration and connections to the grid.

As regards thermal applications of solar energy, the main policy instrument is the Programa para la Promoción de Calentadores Solares de Agua en México 2007-2012, which aims to promote the use of solar energy and boost energy saving in water heating in the residential, commercial, industrial and agricultural sectors, replacing traditional methods.

The Balance Nacional de Energía 2008 published by the Subsecretaría de Planeación Energética y Desarrollo Tecnológico states that at end-2008 there were 1 159 586 m^2 of flat-plate solar collectors installed, mainly used for heating water for swimming pools and general hygiene. Solar heat production in 2008 was 5 584 TJ.

Morocco

The average solar energy potential of Morocco has been estimated at 5 kWh/m^2/day (approximately 1 800 kWh/m^2/yr).

Between the beginning of the Programme d'Electrification Rurale Global (PERG) in January 1996 and the end of 2008, 3 653 villages – 51 509 households - were supplied with photovoltaic kits.

The PROMASOL development project aims to promote the use of renewable energies – especially solar water heating systems – by implementing appropriate financial mechanisms. During 2008 approximately 40 000 m^2 of solar hot water collectors were installed under the project, bringing the total to 240 000 m^2. The objective by 2012 is for 440 000 m^2 to be installed.

A major combined solar and thermal power project was launched in November 2009. It will be comprised of combined-cycle plants located on five sites: Laayoune, Boujdour, Tarfaya, Ain Béni Mathar and Ouarzazate. Covering 10 000 ha, the solar thermal power stations will eventually have a total capacity of up to 2 000 MW$_e$. The first plant, the 472 MW$_e$ Ain Béni Mathar Integrated Solar Thermal Combined Cycle Power Station will use 20 MW$_e$ of solar parabolic trough technology over an area of 180 000 m^2.

Namibia

Namibia has a substantial solar energy potential, owing to its high level of solar radiation – estimated at a daily rate of 5-6 kWh/m^2 (equivalent to around 1 800-2 200 kWh/m^2/yr) and up to 10 hours a day for more than 300 days a year. The Government has been supporting the use of renewable energy since 1993 when it launched the Namibian Renewable Energy Programme (NAMREP). In the following years, and to assist with the problem of financing new technology projects, the Solar Revolving Fund was launched. The Fund, originally designed to aid the adoption of solar home systems, has developed to include solar water heating systems and PV water pumping.

Incentives to further the solar energy technologies have been the establishment of the Renewable Energy and Energy Efficiency Institute in 2006 and in 2007, of NAMREP Phase II (running until 2011), the Off-grid Energisation Master Plan, and a Cabinet Directive which mandated that all public buildings were to have solar water heaters installed. Furthermore, various training programmes covering all aspects of solar energy have been initiated.

These incentives have been successful in encouraging the deployment of solar devices. Between 2004 and 2007 there was an 8-fold increase in stand-alone PV capacity, rising from 16.8 kW$_p$ to 138.7 kW$_p$. Similarly, solar water pumping capacity for isolated systems has risen nearly 5 times. Stand-alone solar thermal capacity has seen the largest growth – a 12-fold increase to 4 313 kW_p.

Data for 2008 are unavailable at the present time owing to the Government's project to undertake a *survey* of all installed renewable energy capacity.

Netherlands

The Clean and Efficient: New Energy for Climate Policy was designed to help meet the Dutch Government's target of renewable energy supplying 20% of total primary energy consumption by 2020. As part of the Policy, SDE (Subsidy for Sustainable Energy) was launched in April 2008 and, although other renewable technologies have a higher priority, the introduction of a feed-in tariff for small-scale PV installations has assisted in the development of the solar sector.

At end-2008 a total of 57.2 MW_p PV had been installed, an increase of 4.4 MW_p over 2007. Of the total, 5.2 MW_p was off-grid, 48.5 MW_p grid-connected distributed and 3.5 MW_p grid-connected centralised. In the period to 2011, an additional 78 MW_p is thought likely to be installed.

The Energy Innovation Agenda, drawn up by the Cabinet and presented to Parliament in mid-2008, has been formulated in order to implement an innovative approach to meeting the energy targets. Some € 9 million were allocated to PV demonstration schemes to be developed during 2009, concentrating on PV in the built environment.

The Stad van de Zon (City of the Sun) Project is a new residential area located between three cities (Heerhugowaard, Alkmaar and Langedijk). It is part of an urban development - HAL-Lokaties – designed to be a net zero CO_2 emissions area and the largest PV housing project in the world. The original plan for a total of 5 MW_p grid-connected PV has been reduced to 2.45 MW_p, owing to financial constraints. The scheme, which began in 2002, saw the start of operations during 2008.

Development of the Dutch solar thermal market began in the mid-1970s and, owing to support from the Government in the form of a Long-Term Agreement for the Implementation of Solar Hot Water Systems (SHWS) and also subsidy schemes, it achieved considerable success, especially in the house-building sector. By 2001 nearly 15% of all new residential dwellings were supplied with a Domestic Hot Water (DHW) system. Installation of solar thermal systems in existing buildings almost stopped after 2003 when the financial incentives ended, but the new-build market was revitalised following the introduction of tighter energy efficiency regulations. The Dutch solar thermal market continues to expand: between 2005 and 2008 it grew at 6.2% per annum, bringing the total installed collector area to 363 341 m^2, giving an output capacity of about 254 MW_t.

Norway

The majority - some 93% - of Norway's commercial solar market consists of domestic off-grid PV systems. Most systems are installed in recreational cabins and leisure craft. Additionally, in public services, PV modules have been installed in the telecommunications sector and the Norwegian Coastal Administration has utilised the technology for lighthouses and coastal lanterns along Norway's coastline.

There are no public schemes to promote PV applications, which is reflected in the fact that at end-2008 there was just 132 kW_p of grid-connected PV capacity and no new large schemes were installed during the year. The grid-connected installations on the Oslo Innovation Centre (17.5 kW_p) and the new Oslo Opera House (35 kW_p) are notable exceptions to the general rule.

Total installed PV capacity was 8.3 MW_p at end-2008, of which the off-grid domestic market accounted for 7.8 MW_p.

Pakistan

According to the Alternative Energy Development Board, Pakistan, the republic is estimated to possess a 2.9 TW solar energy potential, which is being increasingly harnessed, through both PV and thermal technologies.

The many isolated villages in the sparsely-populated areas of Sindh, Balochistan and the Thar Desert are unlikely to be grid-connected in the near future, and thus the utilisation of the solar resource to provide basic services is an effective solution. To date, PV units have been installed in mosques and schools and used for solar lanterns, solar home light systems, street and garden lighting and telecommunications.

Research and development of solar thermal devices is being undertaken by The Pakistan Council of Renewable Energy Technologies (PCRET). Such systems include parabolic/concentrator and box-type solar cookers, solar stills for the provision of clean drinking water, and flat-collector and evacuated-tube solar water heaters. One particular area of success has been the introduction of solar dryers to the agricultural areas. PCRET has designed and developed a solar hybrid dryer for processing - on a commercial basis - apricots, dates and other fruits.

Portugal

Portugal plans for renewable energy to account for 31% of the country’s gross final energy consumption by 2020. Although both hydroelectric and wind power are central to this policy, ever-increasing attention is being paid to the indigenous solar resource.

Dissemination of solar PV was first facilitated by the independent power producer (IPP) law which included a feed-in tariff guaranteed for 15 years. However, revised legislation passed in 2007 has led to a greater flourishing of the PV market. The Renewables-on-Demand programme came into operation in April 2008 and has replaced the IPP Law. It contains two regimes: a general regime relating to any type of micro-generation up to a maximum of 5.75 kW and a special regime which relates to renewable energy schemes up to a maximum of 3.68 kW. Feed-in tariffs support both schemes - the one relating to PV being set at € 0.65/kWh and revised to 95% of its previous value for each additional 10 MW_p of micro-generation capacity installed.

Following many years of slow utilisation of Portugal's solar energy resource, installed capacity grew from just 3.4 MW_p in 2006 to 14.5 MW_p in 2007 and then to 59 MW_p in 2008. It is estimated that by end-2009 installed capacity increased by a further 65% to 96 MW_p. The great majority of PV systems are grid-connected.

In December 2008, the 46 MW_p 250-hectare plant located in Amareleja (Moura municipality), near the border with Spain, came into operation. Amongst the largest PV power stations in the world, the 2 520 solar trackers support 262 080 PV modules, capable of producing 93 GWh/yr.

The market for solar thermal collectors has also grown rapidly in recent years. During 2008 approximately 86 000 m^2 of glazed solar thermal collectors were brought in into operation, bringing the total to 318 950 m^2, with an output capacity of about 223 MW_t. It has been estimated that during 2009, a further 125 000 m^2 were installed.

Russian Federation

With its vast size, Russia necessarily receives a very substantial amount of solar radiation, but the geographical diversity of the country means that the resource is not uniformly available. The average solar radiation in the southern regions is about 1 400 kWh/m^2/yr whilst the remote northern areas receive about 810 kWh/m^2/yr.

The regions with the best potential comprise the North Caucasus, regions bordering the Black Sea and the Caspian, and the southern parts of Siberia and the Far East. Areas below or near latitude 50^{o}N have particularly favourable solar radiation. The resource is extremely seasonal: at 55^{o}N it ranges from 1.69 kWh/m^2/day in January to 11.41 kWh/m^2/day in July.

Although it has been estimated that the gross potential, the technical potential and the economic potential for solar energy are 2.3 trillion tce, 2 300 million tce and 12.5 million tce, respectively, Russia's enormous indigenous fossil fuel reserves have meant that historically little attention has been paid to the renewable energies. However, with about 10 million people having no access to an electricity grid and most rural settlements having no centralised heat supply, the possibilities for off-grid solar energy or hybrid applications are huge.

In January 2009 the Russian Prime Minister signed an Executive Directive for a greater use of renewable energy in order for the efficiency of the electric power sector to be improved. The targets for the share of renewable energy in electricity generation are 1.5% in 2010, 2.5% in 2015 and

4.5% in 2020. Use of the country's solar resource is included in these targets. At the beginning of 2010 it was reported that a Ministerial MOU had been signed between Finland and Russia. The stated objective is that cooperation and shared knowledge will lead to greater energy efficiencies and improved utilisation of renewable energies.

South Africa

As the majority of South Africa receives in excess of 2 500 hours of sunshine per year, has average solar radiation levels ranging from 4.5 to 6.5 kWh/m^2/day and has an annual 24-hour global solar radiation average of about 220 W/m^2, the country is considered to have a high solar energy potential.

The 2003 White Paper on Renewable Energy emphasised the need for renewable energy and set a target of renewable energy generating 10 000 GWh of final energy consumption by 2013. It has been estimated that solar energy could contribute up to 23% of this target.

Historically, the growth in solar energy systems has been quite slow but solar power is increasingly being utilised, not only for the pumping of water through the rural water-provision and sanitation programme, but also for water heating. The Department of Minerals and Energy estimates that over 700 000 m^2 capacity is installed for solar water heating. Of the total, the domestic sector and swimming pools account for 47% and 46% respectively. Commerce and industry account for 6% and agriculture 1%.

The South African public utility Eskom's Solar Water Heating Programme, introduced at the beginning of 2008, is driven by the Government's 10 000 GWh target. The company has estimated that the initiative could lead to a reduction in demand of about 530 MW on the national grid and constitutes a favourable contribution to reducing carbon emissions. At the core of this strategy is a subsidy offered to home owners, aimed at stimulating the uptake of solar water heaters, as it is believed that the high capital costs are limiting the rate of market acceptance of such systems.

Spain

Spain increased its installed PV power five-fold between 2006 and 2007 and a further five times in 2008, bringing cumulative capacity to 3 354 MW$_p$, of which 99% was grid-connected and an equally high percentage is ground-mounted. Capacity installed during 2008 amounted to 2 660 MW$_p$ (1 GW$_p$ greater than in Germany), putting Spain in 2nd place for cumulative installed PV capacity among the IEA-PVPS member countries, behind Germany but well ahead of Japan.

The main thrust in the growth of the Spanish PV market has been in large installations rather than in the residential sector. This is largely because the feed-in tariff has favoured large-scale plants.

The 2010 target of 400 MW installed PV capacity set by the Plan de Energías Renovables en España (PER) 2005-2010 was exceeded during the course of 2007. As a result, the feed-in provisions of the 2005-2010 PER were terminated on 28 September 2008 and replaced by new regulations, as set out in Royal Decree 1578/2008. The Decree contains a number of measures which are designed to support the hitherto neglected residential sector: a revised feed-in tariff (basically, for roof systems up to 2 MW_p and for ground-mounted systems up to 10 MW_p); lower absolute levels for the tariffs, with degression provisions; and an annual quota for installed PV capacity (500 MW_p for 2009, with 267 MW_p for roof-top systems and 233 MW_p for ground-mounted).

It was anticipated that as a result of the new standards the solar PV capacity installed during 2009 would fall dramatically. Provisional figures for 2009 published by Red Eléctrica de España, the operator of the Spanish power system and manager of its transmission grid, suggest that at less than 500 MW_p, this was in fact the case.

The great majority of the world's largest PV power plants are located in mainland Spain. In July 2008, Nobesol announced the completion of Olmedilla de Alarcón, the world's largest PV power plant. At 60 MW_p, the plant is capable of producing 85 GWh annually.

A revised technical building code (CTE), in force since 2006, lays down obligatory requirements to be met by the building industry, including the compulsory incorporation of PV in new large buildings such as offices, government premises and hospitals.

ESTIF, the European Solar Thermal Industry Federation, reports that Spain installed an area of 434 000 m^2 of glazed solar thermal collectors during 2008, bringing the cumulative total to 1 411 166 m^2. This area represents a solar thermal capacity of 988 MW_t, an increase of 44% over 2007. The incremental capacity demonstrated that the country had the second largest glazed collector market in Europe after Germany.

Sweden

With its electricity generation currently dependent on nuclear and hydro, Sweden's market for solar energy is very small. As in Norway and Finland, most applications of PV are in the domestic off-grid sector, where installations are sited in remote cabins, campers, caravans and boats.

In recent years there has been strong growth in the solar PV market, albeit from a very low base. According to the IEA-PVPS, a 29% increase in 2007 over 2006 was followed by a 27% increase in 2008. However, end-2008 installed PV capacity amounted to only 7.9 MW_p. Of the total, 4.1 MW_p was off-grid domestic, 0.7 MW_p off-grid non-domestic and 3.1 MW_p grid-connected distributed.

The stimulus for growth was the 70% investment subsidy available for the installation of PV systems on public buildings. The subsidy ran from May 2005 until the end of 2008 but the programme’s expenditure cap of 150 SEK was reached by end-2007 and growth during the following year was not as great as it could otherwise have been. Much interest, and subsequent implementation of systems, was evident in the major population centres of Stockholm, Gothenburg and Malmö.

Following six months without financial support being available, Sweden introduced a new subsidy beginning 1 July 2009. It now applies to all domestic buildings (with a building permit) and the refund has been lowered to 60% (or 55% for larger companies). Additionally, a privately-generated feed-in tariff scheme has been initiated in the Sala-Heby region. Sala-Heby Energi AB, a power utility, is purchasing electricity from two PV power plants for grid-distribution for at least 10 years.

The market for solar thermal systems continues to grow, with some 18 or 19 000 m^2 being added in each year 2006 - 2008. The total glazed area of solar thermal collectors in operation in 2008 was approximately 290 000 m^2, giving an output capacity of about 202 MW_t.

Switzerland

The SwissEnergy programme is the driving force behind the promotion of renewable energy and the more efficient use of energy. It encompasses a specific 4-year Research and Technological Development (RTD) programme for solar PV, currently 2008-2011. All aspects of R&D are undertaken, including product advancement, demonstration projects through to schemes for market development.

In 2007 the Swiss Parliament passed legislation for a feed-in tariff for the renewable energies, commencing at the beginning of 2009. In the case of PV systems, the law applies to those installed since the beginning of 2006. Solar PV will be assigned 5% of the CHF 320 million, raised by a CHF 0.006/kWh levy on end consumer electricity costs. Some uncertainty exists over future federal funding and assistance might be forthcoming from cantonal sources.

The Federal Office of Energy (OFEN) reports that installed PV capacity has demonstrated an annual growth of 14.5% between 2000 and 2008. By end-2008, capacity – virtually all grid-connected - stood at 44.8 MW_p, some 31% higher than end-2007. Output has seen a correspondingly significant growth, amounting to 34.4 GWh in 2008, 28% higher than 2007.

The solar thermal sector has also demonstrated significant growth in recent years. OFEN reports that there were an additional 51 000 m^2 of glazed collectors (flat-plate and vacuum) installed during 2007, followed by 79 000 m^2 in 2008, bringing the total at year-end to 538 000 m^2, representing 377 MW_t. Output during 2008 amounted to 226 GWh. A further 59 GWh were generated from collectors used for the drying of hay and 64 GWh from non-glazed collectors (used in swimming pools).

Beginning in March 2010 there is to be a drive to promote the solar thermal market throughout Switzerland, as part of the ten-year Programme Bâtiments. Financing of this scheme will come partly from the carbon tax.

Thailand

Thailand has appreciable solar energy resources in almost all regions, especially in the north and northeast. The average daily solar intensity is 18.2 MJ/m^2 (approximately 1 850 $kWh/m^2/yr$). End-2008 installed photovoltaic capacity was 34 MW_p.

The Master Plan for the Development of Renewable Energy envisages the following targets for solar energy capacity in the period 2011-2022:

PV capacity		
Off-grid	55	MW_p
Grid-connected	500	MW_p
Solar hot water		
Production capacity	40 000	m^2/yr
Collector area	300 000	m^2

Current applications of solar energy in Thailand include: solar home systems; battery charging stations; telecommunications; PV for health clinics; ocean navigator systems; greenhouse solar drying; hot water systems; PV for schools and water pumping.

Turkey

Based on meteorological measurements made during 1966-1982, Turkey's average annual number of hours of sunshine is put at 2 640 and its average annual insolation at 1 311 kWh/m^2. More recent research has, however, indicated that these levels could be considerably understated.

The republic's utilisation of its significant solar radiation resource is largely in the form of solar thermal collectors. The market was initiated during the 1970s in response to the growth of the tourism industry and the need for plentiful hot water. The country's energy supply difficulties and the political and economic uncertainties of the 1980s provided further impetus to market development. Although deployment has been extensive - it is estimated that over 10 million m^2 of flat plate collectors have been installed (one of the highest levels for any country in the world) - the sector has not demonstrated a high degree of advanced technology. Turkish customers have historically preferred simple, inexpensive installations, albeit that this approach has sometimes led to problems of utilisation and maintenance.

It is expected that the solar thermal market will continue to grow, largely through the installation of more roof-top collectors, but also possibly through larger-scale projects, such as winter-season greenhouse heating in the agricultural areas of southern Turkey.

Use of solar PV devices in Turkey has been very largely confined to official installations in remote areas: e.g. telecommunications, forest-fire observation towers and roadside emergency facilities. According to the IEA-PVPS, Turkey's total installed PV capacity at end-2008 was only 4 MW_p, almost all off-grid. However, the Turkish Government plans to increase the share of wind and solar power in electricity generating capacity to over 10% by 2020, and public interest in renewable energy, and in particular PV, is reported to be growing.

United Arab Emirates

The Masdar Initiative is a 6 km^2 development located to the east of central Abu Dhabi. Established in 2006, Masdar (Abu Dhabi Future Energy Company) has planned Masdar City to be a ‘zero carbon, zero waste, 100% renewable energy-powered community'. Built on the principals of traditional Arabic architecture, it will nevertheless encompass solar, geothermal and waste-to-energy technologies. In the case of solar, photovoltaic systems, solar thermal evacuated-tube collectors and concentrated solar power plants will all be utilised.

In May 2009, a 10 MW solar PV power plant was inaugurated and connected to the grid. With an output of some 17.5 GWh/yr, the plant has been providing power for the construction of Masdar City. It will also supply the power needs of the Masdar Institute of Technology, a postgraduate university dedicated to the study of renewable energy, which admitted its first students in September 2009.

The launch was announced in January 2010 of an R&D project on advanced concentrated solar power technology, involving an exploration of the commercial viability of incorporating a 'beam-down' process in CSP generation. The Masdar company has announced that it plans to construct a 100 MW CSP plant in Madinat Zayed, western Abu Dhabi, on a BOO basis, but as at April 2010 no contract had been awarded.

United Kingdom

In part for the obvious climatic reasons, the United Kingdom has not installed solar energy devices to anything like the same extent as its more southerly (and therefore generally sunnier) European colleagues. By the end of 2008, the UK's total PV capacity was 22.5 MW_p, equivalent to 0.3 watts per capita, compared with Spain's outstanding 77.1 watts per capita, but even more striking is the contrast with a nearer neighbour: Germany. There the climatic difference is clearly not so marked, but the disparity in PV deployment, at 64.7 watts per capita, is just as wide.

In the UK there has been a Major Photovoltaic Demonstration Programme (MPDP) offering grants for small, medium and large-scale installations, which has encouraged a significant number of new projects. Installed PV capacity is steadily growing, albeit from a very low base. At end-2008, 93% of the UK total of 22.5 MW_p was grid-connected distributed capacity. Phase 1 of the Department of Energy and Climate Change's (DECC) 1996 Low Carbon Buildings Programme has been extended to April 2011. Its objective is to make available grants for the installation of domestic PV systems. Funds in Phase 2, a similar scheme but for public buildings, have been committed and are therefore no longer available.

The utilisation of solar technologies is embodied in The UK Low Carbon Transition Plan and The Renewable Energy Strategy, both presented to Parliament in July 2009. Solar PV and solar thermal will increasingly play their part in helping the UK to meet its aim of greatly decreasing carbon emissions (18% less on 2008 levels by 2020) and greatly increasing the use of the renewable energies (30% of electricity supply by 2020).

The 2008 Energy Act provided the wherewithal for the Government to introduce feed-in tariffs (FIT). From 1 April 2010 renewable energy electricity-generating technologies, up to a maximum of 5 MW, qualify for generation and export tariffs. FITs will work alongside the Renewables Obligations. In the case of new PV schemes, where both the product and installer are certificated, the generation tariffs are on a decreasing scale from GBP 0.361/kWh for up to 4 kW capacity to GBP 0.293/kWh for installations of 100 kW - 5 MW. These rates will remain the same for a period of 25 years (although adjusted for inflation through a link to the Retail Price Index). The rates are subject to variation for new installations after 31 March 2012. The tariff payable for electricity exported to the grid is GBP 0.03/kWh, regardless of the size of the installation.

Solar collectors for heating water are used in the UK to a limited extent. In 2008, according to figures estimated for DECC, they contributed 379 GWh for heating swimming pools, and 104 GWh towards domestic hot water supply. The total glazed area of solar thermal collectors in operation in 2008 was 386 000 m^2, giving an output capacity of about 270 MW_t.

The Renewable Heat Incentive, applicable to renewable systems generating heat (solar thermal included) will come into force on 1 April 2011 to work alongside the feed-in tariffs for electricity.

United States of America

Raw solar resources are far in excess of all projected energy demand in the mid-term. Solar insolation levels in the U.S. vary from less than 400 W/m^2 to over 700 W/m^2, depending on latitude, climate (primarily average cloud cover), terrain, and application (using a fixed-angle collector compared to a collector that tracks the sun). The USA has approximately 9 million km^2 of land area.

The Department of Energy's Solar Energy Technologies Program (Solar Program) ‘works to develop cost-competitive solar energy systems for America’. It focuses its research and development on photovoltaic technologies and concentrating solar power (CSP) systems for electricity generation. The Program includes a market transformation activity to reduce market barriers. It forms partnerships with other programmes so as to integrate basic research results from other government programmes into the Solar Program R&D activities, thereby accelerating commercialisation.

Of the 19 participating members of the IEA-PVPS, the USA, by end-2008, ranked fourth in terms of cumulative installed PV power, having been overtaken by Spain during the year. Some 338 MW_p capacity was installed during the year, bringing the total to 1 169 MW_p, of which 68% was grid-connected.

The California Solar Initiative (CSI) has led to some spectacular growth in the State’s installed capacity. In 2008, in excess of 150 MW was added. By end-2009 approximately 57 500 solar projects had been installed. PV systems in California ensure that the State is included amongst the highest countries in the world ranking list of installed solar capacity. The goal of the CSI is for 1 940 MW of new solar power to be installed by 2017.

Federal tax credits, effective during 2006, helped but it has been the Emergency Economic

Stabilization Act of 2008 and the American Recovery and Reinvestment Act (the Recovery Act) of 2009 that have both been instrumental in the development of the U.S. solar market.

The US$ 787 billion Recovery Act passed into law in early 2009 and provides the wherewithal to promote an economic recovery following the recession. The Act has allotted US$ 16.8 billion for the Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE). The Recovery Act specifically includes provisions for stimulating the solar power sector. Between July 2009 and January 2010 the DoE announced investment totalling US$ 110.8 million, of which US$ 65 million was covered by the Recovery Act. This financial support is designed to assist in the development of solar energy technologies through to full commercial scale and deployment.

In June 2007, 13 U.S. cities were selected by the DoE to be inaugural members of Solar America Cities. The objective of the scheme is to 'Partner with cities committed to achieving a sustainable solar infrastructure through a comprehensive, city-wide approach to solar technology that facilitates mainstream adoption and provides a model for others'. Both electricity-generating and solar thermal (water and space heating and cooling) technologies are promoted. In March 2008, an additional 12 cities joined the programme. The 25 cities now involved are located in 16 States and six are among the 10 largest cities in the USA.

A Renewable Portfolio Standard (RPS) has been adopted by a majority of States and the District of Columbia. Five States have RPS with nonbinding goals. Feed-in tariffs, offered during 2008, are gradually being adopted on a State and cities basis.

The United States Energy Association (the WEC Member Committee for the USA) reports that, according to the EIA, solar thermo-electric capacity at end-2008 was 465 MW_t, producing 785 697 MWh during the year, at a capacity factor of 0.19. Direct solar heating panels produced a total of 47 711 TJ in 2008.

11. Geothermal Energy

COMMENTARY

Geothermal Resources Potential

Geothermal energy comes from the natural heat of the earth primarily due to the decay of the naturally radioactive isotopes of uranium, thorium and potassium. Because of the internal heat, the Earth's surface heat flow averages 82 mW/m^2 which amounts to a total heat loss of about 42 million megawatts. The total heat content of the Earth is of the order of 12.6 x 10^{24} MJ, and that of the crust, the order of 5.4 x 10^{21} MJ (Dickson and Fanelli, 2004). This huge number can be compared to the world electricity generation in 2007 of 7.1 x 10^{13} MJ (IEA, 2009). The thermal energy of the Earth is therefore immense, but only a fraction can be utilised. So far utilisation of this energy has been limited to areas in which geological conditions permit a carrier (water in the liquid or vapour phases) to 'transfer' the heat from deep hot zones to or near the surface, thus giving rise to geothermal resources.

On average, the temperature of the Earth with depth increases about 25-30˚C/km above the surface ambient temperature (called the geothermal gradient). Thus, assuming a conductive gradient, the temperature of the earth at 10 km would be over 300˚C. However, most geothermal exploration and use occurs where the gradient is higher, and thus where drilling is shallower and less costly. These shallow depth geothermal resources occur due to: 1) intrusion of molten rock (magma) from depth, bringing up great quantities of heat; 2) high surface heat flow, due to a thin crust and high temperature gradient; 3) ascent of groundwater that has circulated to depths of several kilometres and been heated due to the normal temperature gradient; 4) thermal blanketing or insulation of deep rocks by thick formation of such rocks as shale whose thermal conductivity is low; and 5) anomalous heating of shallow rock by decay of radioactive elements, perhaps augmented by thermal blanketing (Wright, 1998).

At the base of the continental crust, temperatures are believed to range from 200 to 1 000°C, and at the centre of the earth the temperatures may be in the range of 3 500 to 4 500°C. The heat is transferred from the interior towards the surface mostly by conduction. Geothermal production wells are commonly more than 2 km deep, but rarely much more than 3 km at present. With the average geothermal thermal gradient, a 1 km well in dry rock formations would have a bottom temperature near 40-45°C in many parts of the world (assuming a mean annual air temperature of 15°C) and a 3 km well one of 90-100°C.

Figure 11.1 Geothermal resource type

(Source: White and Williams, 1975)

Resource type	Temperature range (°C)
Convective hydrothermal resources	
Vapour dominated	≈240°
Hot-water dominated	20°-350°+
Other hydrothermal resources	
Sedimentary basin	20°-150°
Geopressured	90°-200°
Radiogenic	30°-150°
Hot rock resources	
Solidified (hot dry rock)	90°-650°
Part still molten (magma)	>600°

Bertani (2003) found that, based on a compilation of estimates produced by a number of experts, the expected geothermal electricity potential ranges from a minimum of 35-70 GW_e to a maximum of 140 GW_e. The potential may be orders of magnitude higher, based on enhanced geothermal systems (EGS) technology. Stefansson (2005) concluded that the most likely value for the technical potential of geothermal resources suitable for electricity generation is 210 GW_e. Theoretical considerations reveal that the magnitude of hidden resources is expected to be 5-10 times larger than the estimate of identified resources.

The magnitude of low-temperature geothermal resources in the world is about 140 EJ/yr of heat. For comparison, the world energy consumption is now about 420 EJ/yr.

It is considered possible to produce up to 8.3% of the total world electricity with geothermal resources, serving 17% of the world population. Thirty nine countries (located mostly in Africa, Central/South America, and the Pacific) can potentially obtain 100% of their electricity from geothermal resources (Dauncey, 2001).

Types of Geothermal Resource

Geothermal resources are usually classified as shown in Fig. 11.1, modelled after White and Williams (1975). These geothermal resources range from the mean annual ambient temperature of around 20˚C to over 300˚C. In general, resources above 150˚C are used for electric power generation, although power has recently been generated at Chena Hot Springs Resort in Alaska using a 74˚C geothermal resource (Lund, 2006). Resources below 150˚C are usually used in direct-use projects for heating and cooling. Ambient temperatures in the 5-30˚C range can be used with geothermal (ground-source) heat pumps which provide both heating and cooling.

Convective hydrothermal resources occur where the Earth's heat is carried upward by convective circulation of naturally-occurring hot water or steam. Underlying some high-temperature convective hydrothermal resources are temperatures of 500 -1 000˚C from molten intrusions of recently solidified rocks. The lower temperature resources result from deep circulation of water along fractures.

Vapour dominated systems ('dry steam') produce steam from boiling of deep, saline waters in low permeability rocks. These reservoirs (few in number) - The Geysers in northern California, Larderello in Italy and Matsukawa in Japan - are being exploited to produce electric energy.

Water-dominated systems ('wet steam') are produced by ground water circulating to depth and

Figure 11.2 World map showing the lithospheric plate boundaries, dots = active volcanoes
(Source: U.S. Geological Survey)

ascending from buoyancy in permeable reservoirs that have a uniform temperature over large volumes. There is typically an upflow zone at the centre of each convection cell, an outflow zone or plume of heated water moving laterally away from the centre of the system, and a downflow zone where recharge is taking place. Surface manifestations include hot springs, fumaroles, geysers, travertine deposits, chemically altered rocks, or sometimes, no surface manifestations (a blind resource).

Hot dry rock resources are defined as heat stored in rocks within about 10 km of the surface from which energy cannot be economically extracted by natural hot water or steam. These hot rocks have few pore space or fractures, and therefore, contain little water and little or no interconnected permeability. In order to extract the heat, experimental projects have artificially fractured the rock by hydraulic pressure, followed by circulating cold water down one well to extract the heat from the rocks and then producing from a second well in a closed system.

Exploitable geothermal systems occur in a number of geological environments. They can also be divided broadly into two groups depending on whether they are related to young volcanoes and magmatic activity or not. High-temperature fields used for conventional power production are mostly confined to the former group, but geothermal fields utilised for direct application of the thermal energy can be found in both groups. The temperature of the geothermal reservoirs varies from place to place depending on the geological conditions.

High-temperature fields (>180°C) - volcanic activity takes place mainly along so-called plate boundaries (Fig. 11.2). According to the plate tectonics theory, the Earth's crust is divided into a few large and rigid plates which float on the mantle and move relative to each other at average rates counted in centimetres per year (the actual movements are highly erratic). The plate boundaries are characterised by intense faulting and seismic activity and in many cases volcanic activity. Geothermal fields are very common on plate boundaries, as the crust is highly fractured and thus permeable to water, and sources of heat are readily available. In such areas magmatic intrusions, sometimes with partly molten rock at temperatures above 1 000°C, situated at a few kilometres below the surface, heat the groundwater. The hot water has lower density than the surrounding cold groundwater and therefore flows up towards the surface along fractures and other permeable structures.

Most of the plate boundaries are below sea level, but in cases where the volcanic activity has been intensive enough to build islands or where active plate boundaries transect continents, high-temperature geothermal fields are commonly scattered along the boundaries. A spectacular example of this is the 'ring of fire' that circumscribes the Pacific Ocean (the Pacific Plate) with intense volcanism and geothermal activity. Other examples are Iceland, which is on the Mid-Atlantic Ridge plate boundary, the East African Rift Valley and 'hot spots' such as Hawaii and Yellowstone.

Low-temperature fields (< 180°C) - geothermal resources unrelated to volcanoes can be divided into four types:

a) resources related to deep circulation of meteoric water along faults and fractures;

b) resources in deep high-permeability rocks at hydrostatic pressure;

c) resources in high-porosity rocks at pressures greatly in excess of hydrostatic (i.e. 'geopressured');

d) resources in hot but dry (low-porosity) rock formations.

These four types are in fact end-members, with most natural systems displaying some intermediate characteristics. All these, with the exception of type c), can also be associated with volcanic activity. Types c) and d) are not commercially exploited as yet.

Type a) is probably the most common type for warm springs in the world. These can occur in most rock types of all ages, but are most obvious in mountainous regions where warm springs appear along faults in valleys. Warm springs of this type are of course more numerous in areas with a high regional conductive heat flow (with or without volcanic activity), but are also found in areas of normal and low heat flow. The important factor here is a path for the meteoric water to circulate deep into the ground and up again. Areas of young tectonic activity are commonly rich in this type.

Type b) is probably the most important type of geothermal resources not associated with young volcanic activity. Many regions throughout the world are characterised by deep basins filled with sedimentary rocks of high porosity and permeability. If these are properly isolated from surface ground water by impermeable strata, the water in the sediments is heated by the regional heat flow. The age of the sediments makes no difference, so long as they are permeable. The geothermal reservoirs in the sedimentary basins can be very extensive, as the basins themselves are commonly hundreds of kilometres in diameter. The temperature of the thermal water depends on the depth of the individual aquifers and the geothermal gradient in the area concerned, but is commonly in the range of 50-100°C (in wells less than 3 km deep) in areas that have been exploited. Geothermal resources of this type are rarely seen on the surface, but are commonly detected during deep exploration drilling for oil and gas.

Enhanced Geothermal Systems (EGS) - the principle of EGS is simple: in the deep subsurface where temperatures are high enough for power generation (150-200°C) an extended fracture network is created and/or enlarged to act as new pathways. Water from the deep wells and/or cold water from the surface is transported through this deep reservoir using injection and production wells, and recovered as steam/hot water. Injection and production wells as well as further surface installations complete the circulation system. The extracted heat can be used for district heating and/or for power generation.

A number of basic problems need to be solved for the realisation of EGS systems, mainly that techniques need to be developed for creating, characterising, and operating the deep fracture system (by some means of remote sensing and control) that can be tailored to site-specific subsurface conditions. Some environmental issues, such as the chance of triggering seismicity and the availability of surface water, also need detailed investigation. There are several places where targeted EGS demonstration is under way.

New developments: drilling for higher temperatures - production wells in high-temperature fields are commonly 1.5-2.5 km deep and the production temperature 250-340°C. The energy output from individual wells is highly variable, depending on the flow rate and the enthalpy (heat content) of the fluid, but is commonly in the range 5-10 MW_e and rarely over 15 MW_e per well. It is well known from research on eroded high-temperature fields that much higher temperatures are found in the roots of the high-temperature systems. The international Iceland Deep Drilling Project (IDDP) is a long-term programme to improve the efficiency and economics of geothermal energy by harnessing deep unconventional geothermal resources (Fridleifsson et al., 2007). Its aim is to produce electricity from natural supercritical hydrous fluids from drillable depths. Producing supercritical fluids will require drilling wells and sampling fluids and rocks to depths of 3.5-5 km, and at temperatures of 450-600°C.

Geothermal Utilisation and Characteristics

Electric Power Generation

Geothermal power is generated by using steam or a hydrocarbon vapour to turn a turbine-generator

Figure 11.3 Examples of common geothermal heat pump installations
(Source: Lund, et al., 2004)

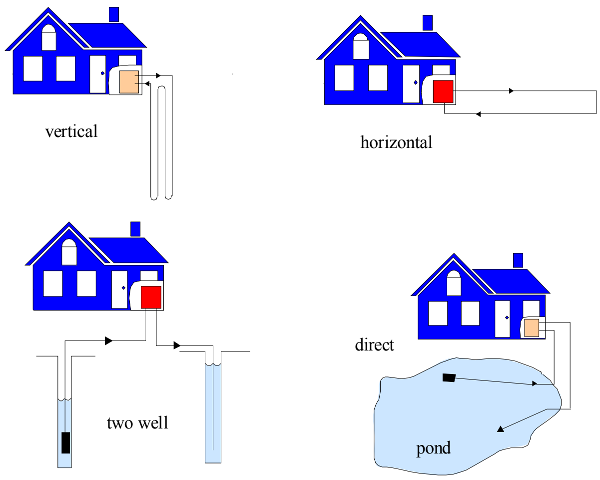
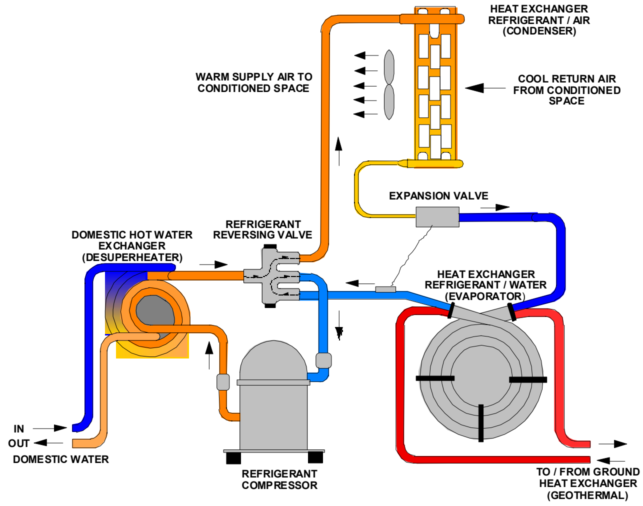


Figure 11.4 CHP in the cooling cycle
(Source: Oklahoma State University)



set to produce electricity. A vapour-dominated (dry steam) resource can be used directly, whereas a hot-water resource needs to be flashed by reducing the pressure to produce steam, normally in the 15-20% range. Some plants use double and triple flash to improve the efficiency, however in the case of triple flash it may be more efficient to use a bottoming cycle (a small binary plant using the waste water from the main plant). Low-temperature resources generally require the use of a secondary low boiling-point fluid (hydrocarbon) to generate the vapour, in a binary or Organic Rankine Cycle (ORC) plant.

Usually a wet or dry cooling tower is used to condense the vapour after it leaves the turbine to maximise the temperature and pressure drop between the incoming and outgoing vapour and thus increase the efficiency of the operation. However, dry cooling is often used in arid areas.

Binary plant technology is playing a very important role in the modern geothermal electricity market. The economics of electricity production are influenced by the drilling costs and resource development (a typical capital expenditure or Capex quota is 30% for reservoir and 70% plant). The productivity of electricity per well is a function of reservoir fluid thermodynamic characteristics (phase and temperature).The higher the energy content of the reservoir fluid, the lesser the number of required wells and as a consequence the reservoir Capex quota is reduced. Single geothermal wells can produce from 1-5 MW_e, however, some producing as high as 30 MW_e have been reported. Binary plants on the reinjection stream could be a very effective way of producing cheap energy, because there would not be any additional pumping costs.

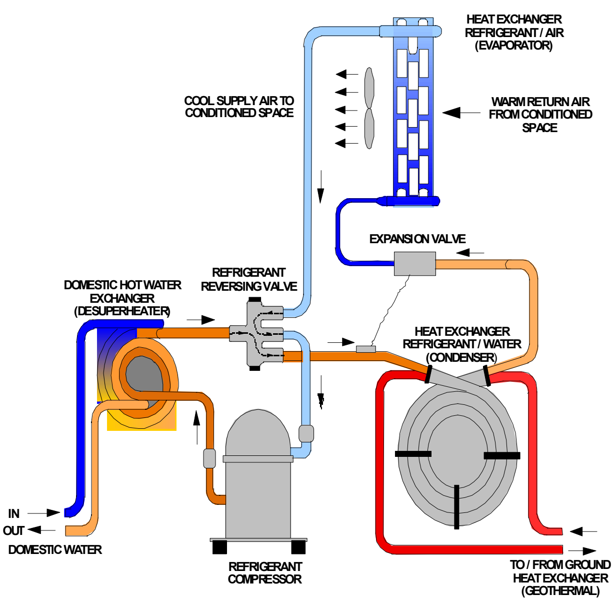
Direct Utilisation

The main advantage of using geothermal energy for direct use projects in the low- to intermediate-temperature range is that such resources are more widespread and exist in at least 80 countries at economic drilling depths. In addition, there are no conversion efficiency losses and projects can use conventional water-well drilling and off-the-shelf heating and cooling equipment (allowing for the temperature and chemistry of the fluid). Most projects can be on line in less than a year. Projects can be on a small scale, such as for an individual home, greenhouse or aquaculture pond, but can also be a large-scale commercial operation such as for district heating/cooling, or food and lumber drying.

It is often necessary to isolate the geothermal fluid from the user side to prevent corrosion and scaling. Care must be taken to prevent oxygen from entering the system (geothermal water is normally oxygen-free), and dissolved gases and minerals such as boron and arsenic must be removed or isolated, as they are harmful to plants and animals. Hydrogen sulphide, even in low concentrations, will cause problems with copper and solder and is harmful to humans. On the other hand carbon dioxide, which often occurs in geothermal water, can be extracted and used for carbonated beverages or to enhance growth in greenhouses. The typical equipment for a direct-use system includes downhole and circulation pumps, heat exchangers (normally the plate type), transmission and distribution lines (normally insulated pipes), heat extraction equipment, peaking or back-up plants (usually fossil-fuel fired) to reduce the number of geothermal wells required, and fluid disposal systems (injection wells). Geothermal energy can usually meet 80-90% of the annual heating or cooling demand, yet only be sized for 50% of the peak load.

Figure 11.5 CHP in the heating cycle

(Source: Oklahoma State University)



Geothermal Heat Pumps

Ground-source heat pumps (GHPs) use the relatively constant temperature of the earth to provide heating, cooling and domestic hot water for homes, schools, governmental and commercial buildings. A small amount of electricity input is required to run a compressor, however the energy output is in the order of four times this input. The technology is not new: Lord Kelvin developed the concept in 1852, which was then modified as a GHP by Robert Webber in Indianapolis in 1945. GHPs gained commercial recognition in the 1960s and 1970s. Europe began using this technology around 1970 and it is now popular in the USA, Canada, Germany, Sweden, Switzerland, France and other western European countries.

GHPs come in two basic configurations: ground-coupled (closed loop) which are installed either horizontally or vertically, and groundwater (open loop) systems, which are installed in wells and lakes. The type chosen depends upon the soil and rock type at the installation, the land available and/or if a water well can be drilled economically or is already on site (Fig. 11.3)

In the ground-coupled system, a closed loop of high-density polyethylene pipe is placed either horizontally (1-2 m deep) or vertically (50-70 m deep) in the ground, and a water-antifreeze solution circulated through the pipe to either collect heat from the ground in the winter or reject heat to the ground in the summer (Rafferty, 2008). The open-loop system uses ground water or lake water directly in the heat exchanger and then discharges it into another well, into a stream or lake, or on the ground (say for irrigation), depending upon local regulations.

Figs. 11.4 and 11.5 show the operation of a typical geothermal heat pump in either heating or cooling mode. A desuperheater can be provided to use reject heat in the summer and some input heat in the winter for domestic hot water heating.

Technical Potential

The main advantage of geothermal heating and power generation systems is that they are available 24 hours per day, 365 days a year and are only shut down for maintenance. Power generation systems typically have capacity factors of 95% (i.e. operate at nearly full capacity year round), whereas direct-use systems have a capacity factor around 25 to 30%, owing to heating not being required year round. Heat pump systems have operating capacities of around 10-20% in the heating mode and double this if the cooling mode is also included.

Within the direct utilisation sector of geothermal energy, geothermal heat pumps have world-wide application, as the shallow ground temperature is within their range anywhere in the world. Traditional direct use heating is limited to where the resource is available in economic depths and where climate justifies the demand.

Figure 11.6 Example of cascaded geothermal resource for multiple uses
(Source: Geo-Heat Centre)

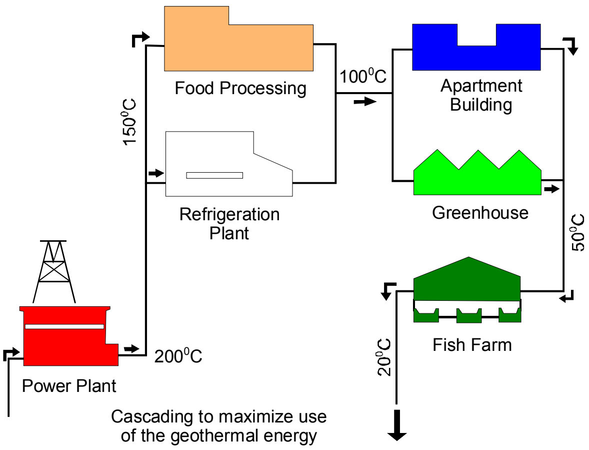
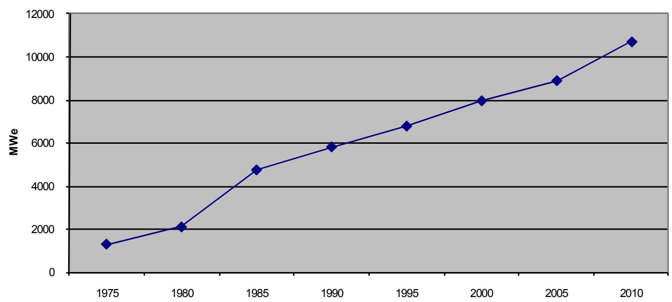


Figure 11.7 Worldwide growth of installed geothermal generating capacity
(Source: International Geothermal Association)



Power generation in the past has been limited by resources above 180°C. However, with recent advances in binary (Organic Rankine) cycle technology, lower-temperature fluids at around 100°C are being utilised, thus increasing the number of potential locations. Drilling depth, fluid quantity and quality, and temperature of the resource determine the economic viability of the project.

More recently, the use of combined heat and power plants has made low-temperature resources and deep drilling more economic. District heating using the spent water from a binary power plant can make a marginal project economic as has been done in Germany, Austria and Iceland. This is a form of cascading (Fig. 11.6), where the geothermal fluid is utilised at progressively lower temperature, thus maximising the energy extracted.

Summary of Current Geothermal Use

Table 11.1 is based on data for 2008 reported by WEC Member Committees for the present *Survey*, supplemented by information submitted to the World Geothermal Congress 2010.

Of the countries utilising their geothermal resource, almost all use it directly but only 24 use it for electricity generation.

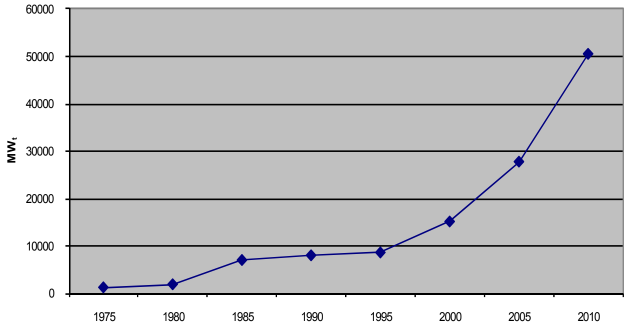
At end-2008, approximately 10 700 MW_e of geothermal electricity generating capacity was installed, producing over 63 000 GWh/yr. Installed capacity for direct heat utilisation amounted to about 50 000 MW_t, with an annual output of around 430 000 TJ (equivalent to about 120 000 GWh). The annual growth in energy output over the past five years has been 3.8% for electricity production and around 10% for direct use (including geothermal heat pumps). Energy produced by ground-source heat pumps alone has increased by 20% per annum over the same period. The low growth rate for electric power generation is primarily due to the low price for natural gas, the main competitor.

The data show that with electric power generation, each major continent has approximately the same percentage share of the installed capacity and energy produced, with the Americas and Asia having over 75% of the total. Whereas, with the direct-use figures, the percentages drop significantly from installed capacity to energy use for the Americas (26.8 to 13.9%) due to the high percentage of geothermal heat pumps with low capacity factor for these units in the U.S. On the other hand, the percentages increased for the remainder of the world due to a lesser reliance on geothermal heat pumps and the greater number of operating hours per year for these units.

Geothermal Electric Power

Electric power has been produced from geothermal energy in 27 countries; however, Greece, Taiwan and Argentina have shut down their plants due to environmental and economic reasons. The

Figure 11.8 Worldwide growth of installed geothermal direct use capacity (Source: International Geothermal Association)



worldwide installed capacity has the following distribution: 27% dry steam, 41% single flash, 20% double flash, 11% binary/combined cycle/hybrid, and 1% backpressure (Bertani, 2010).

Direct Utilisation (including geothermal heat pumps)

The world direct utilisation of geothermal energy is difficult to determine, as there are many diverse uses of the energy and these are sometimes small and located in remote areas. Finding someone or even a group of people in a country who are knowledgeable on all the direct uses is difficult. In addition, even if the use can be determined, the flow rates and temperatures are usually not known or reported, thus the capacity and energy use can only be estimated. This is especially true of geothermal waters used for swimming pools, bathing and balneology.

The total installed capacity, reported at the end of 2009, for the world's geothermal direct utilisation is 50 583 MW_t, almost a two-fold increase over the 2005 data, growing at a compound rate of 12.3% annually. The total annual energy use is 438 071TJ (121 696 GWh), a 60% increase over 2005, growing at a compound rate of 11.0% annually. Compared to ten years ago the capacity increased 12.8%/yr and the use 8.7%/yr. Thus, it appears that the growth rate has increased slightly in recent years, despite the low cost of fossil fuels, economic downturns and other factors. It should, however, be noted that part of the growth from 2000 to the present is due, in part, to better reporting, and includes some geothermal countries that were missed in previous reports. The capacity factor is an indication of the amount of use during the year (i.e. a factor of 1.00 would indicate the system is used at a maximum the entire year, and 0.5 would indicate using the system for 4 380 equivalent full-load hours per year). The worldwide average for the capacity factor is 0.27, down from 0.31 five years ago and 0.40 ten years ago. This decrease is due to the increased use of geothermal heat pumps that have a worldwide capacity factor of 0.19 in the heating mode.

The growing awareness and popularity of geothermal (ground-source) heat pumps had the most significant impact on the data. The annual energy use for these grew at a compound rate of 19.7% per year compared to five years ago, and 24.9% compared to ten years ago. The installed capacity grew 18.0% and 20.9% respectively. This is due, in part, to the ability of geothermal heat pumps to utilise groundwater or ground-coupled temperatures anywhere in the world.

The countries with the largest installed capacity were the USA, China, Sweden, Norway and Germany, accounting for about 63% of the installed capacity and the five countries with the largest annual energy use were: China, USA, Sweden, Turkey and Japan, accounting for 55% of the world use. Sweden, a new member of the 'top-five' obtained its position due to the country's increased use of geothermal heat pumps. However, if considered in terms of the country's land area or population, then the smaller countries dominate. The 'top-five' then become Netherlands, Switzerland, Iceland, Norway and Sweden (TJ/area), and Iceland, Norway, Sweden, Denmark and Switzerland (TJ/population). The largest increases in geothermal energy use (TJ/yr) over the past five years are in the United Kingdom, Netherlands, Korea (Republic), Norway and Iceland; and the largest increases in installed capacity (MW_t) are in the United Kingdom, Korea (Republic), Ireland, Spain and Netherlands, due

Figure 11.9 Worldwide geothermal energy direct use
(Source: International Geothermal Association)

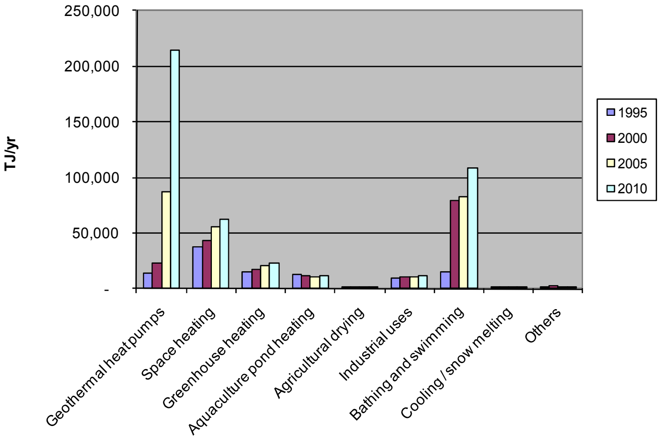
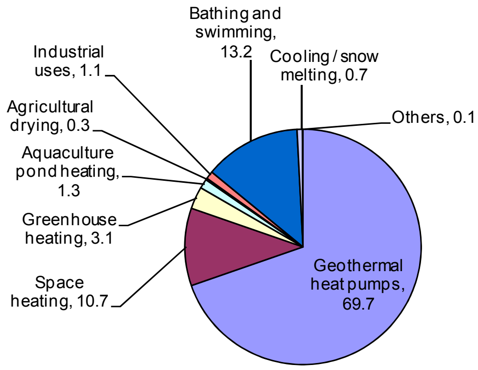
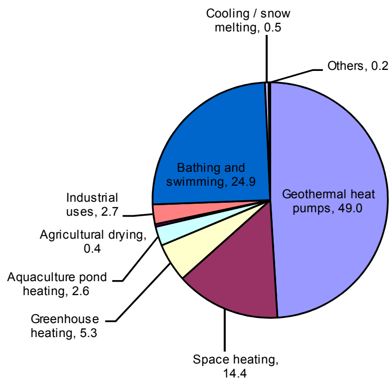


Figure 11.10 Categories of geothermal energy direct use in 2010: (%) capacity (top), utilisation (bottom)
(Source: International Geothermal Association)





mostly to the increased use of geothermal heat pumps.

In 1985, there were only 11 countries reporting an installed capacity of over 100 MW_t. By 1990, this number had increased to 14, by 1995 to 15, by 2000 to 23 and by 2005 to 33. At present there are 36 countries reporting 100 MW_t or more. In addition, six new countries, compared to 2005, now report some geothermal direct utilisation.

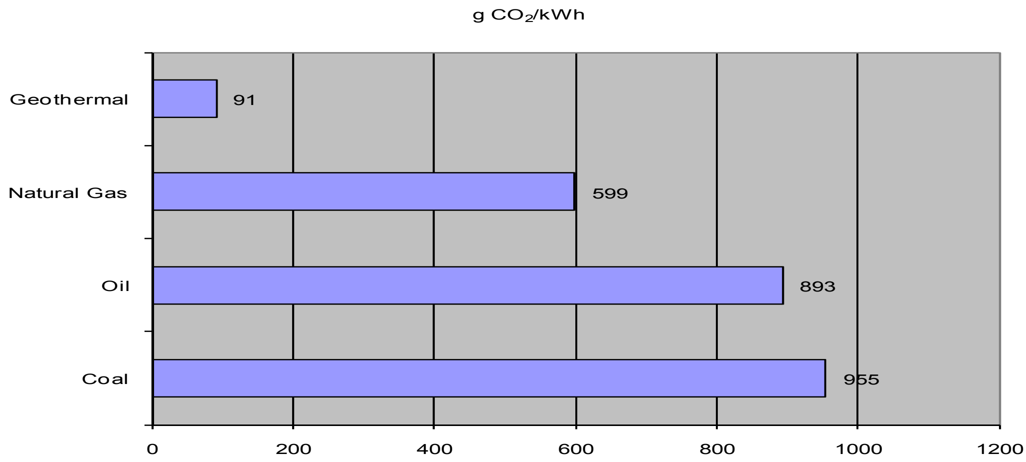
In Fig. 11.10 district heating is estimated at 78% of total space heating energy use and 82% of the installed capacity. Snow melting represents the majority of the cooling/snow melting figure.

Market Development

The factors that must be considered when assessing the viability of a geothermal project will vary from project to project (i.e. it is site-specific), especially between electrical generation and direct use. The economic factors that are common to all projects include supplying the fuel (energy) from the geothermal resource; the design and construction of the conversion facility and related surface equipment such as transformers and transmission lines for electrical generation plants, and pipelines and heat exchangers for district heating projects; and the operation and maintenance (O&M) of the equipment. Finally the market penetration and revenues generated from the sale of electricity or products produced from greenhouses, aquaculture facilities or industrial operations, minus the O&M costs, must be sufficient to meet or exceed the requirements of the financing package.

Financing is a critical factor in the economics of any project, and thus the potential for market penetration and development. For many new projects, the largest annual operating cost is the amortisation of the cost of capital, which can be as high as 75% of the annual operating expense for new geothermal district energy projects, with O&M at 15%, and ancillary energy provisions at 10% making up the balance (Bloomquist and Knapp, 2003). Unfortunately, geothermal projects, especially in the resource development stage, have a high risk of failure. Thus obtaining financing at reasonable rates (or even at all) can be difficult in

Figure 11.11 Comparison of CO² emissions from electricity generation in the USA
(Source: Bloomfield, et al., 2003)



the early stages of a project. Once the resource is proven, then financing is more certain and investors may be more easily found.

Market development is highly dependent upon competition from other sources of electricity or from direct-use product supply (fish, vegetables, flowers, minerals, etc.). Remote areas, often off-grid, are excellent candidates for electrical energy. The availability of transmission lines can be critical and these are often lacking and expensive to construct over large distances. Direct-use projects must have a market and a transportation system to get the products to consumers economically. Unfortunately, geothermal resources that can be utilised are often remote, which may limit their development for commercial operations. However, on the positive side, with increasing fossil fuel prices and limitations on the production of greenhouse gases, development of geothermal energy has become more competitive as a renewable and 'green' energy resource.

Sustainability Issues

Geothermal energy is generally classified as a renewable resource, where 'renewable' describes a characteristic of the resource: the energy removed from the resource is continuously replaced by more energy on time scales similar to those required for energy removal (Stefansson, 2000). Consequently, geothermal production is not a 'mining' process. Geothermal energy can be used in a 'sustainable' manner, which means that the production system applied is able to sustain the production level over long periods. The longevity of production can be secured and sustainable production achieved by using moderate production rates, which take into account the local resource characteristics (field size, natural recharge rate, etc.).

The production of geothermal fluid/heat continuously creates a hydraulic/heat sink in the reservoir. This leads to pressure and temperature gradients, which in turn – after termination of production – generate fluid/heat inflow to re-establish the pre-production state. The regeneration of geothermal resources is a process which occurs over various time scales, depending on the type and size of the production system, the rate of extraction, and on the attributes of the resource.

Environmental Issues

Geothermal fluids contain a variable quantity of gases, largely nitrogen and carbon dioxide, with some hydrogen sulphide and smaller proportions of ammonia, mercury, radon and boron. The amounts depend on the geological conditions of different fields. Most of the chemicals are concentrated in the disposal water which is routinely re-injected into drill holes and thus not released into the environment. The concentration of the gases is usually not harmful and they can be vented to the atmosphere. Removal of hydrogen sulphide released from geothermal power plants is mandatory in the USA and Italy.

The range in CO_2 emissions from high-temperature geothermal fields used for electricity production is variable, but much lower than that for fossil fuel plants.

The gas emissions from low-temperature geothermal resources are normally only a fraction of the emissions from the high-temperature fields used for electricity production. The gas content of low-temperature water is in many cases minute, as in Reykjavik, where the CO_2 content is lower than that of the cold groundwater. In sedimentary basins, such as the Paris Basin, the gas content may cause scaling if it is released. In such cases the geothermal fluid is kept under pressure within a closed circuit (the geothermal doublet) and reinjected into the reservoir without any de-gassing taking place. Conventional geothermal schemes in sedimentary basins commonly produce brines which are generally re-injected into the reservoir and thus never released into the environment (zero CO_2 emission). GHP are environmentally benign and represent a large potential for reduction of CO_2 emission.

Economic and Financial Aspects

The cost of geothermal projects and the production of the energy vary considerably from site to site and from region to region, depending mainly upon the depth, quality, quantity and location of the resource. For any geothermal project, the costs can be divided into the following: land acquisition or leasing; resource exploration and characterisation; drilling and reservoir development; gathering and transmission pipelines; plant design and construction; energy or product transmission to consumers; operation and maintenance; cost of financing, debt and royalty payments; and permitting, legal and institutional issues. The initial stages of a project - finding and developing the resource - are high risk and the cost of capital is usually high. Once the resource is proven, the risk is lower and investors are easier to attract. However, permitting and legal and institutional issues can be a major stumbling block by delaying, adding legal expenses to a project, or even stopping a project altogether.

Implementation Issues

The challenges to geothermal development are varied and include the following issues:

- resource identification and characterisation;
- economics, financial risks;
- development risks (i.e. proving the resource, drilling);
- competition by other forms of energy;
- environmental misconceptions;
- siting and permitting delays;
- transactional costs (i.e. high capital costs);
- transmission capacity (power) or market penetration (direct use);
- local population concerns;
- public perceptions and support;
- lack of knowledge of the benefits of development and utilisation.

Technical and Market Barriers

The major barrier to the exploitation of geothermal energy is the high financial risk in comparison not only with the use of natural gas but also with most other forms of renewable energy.

Development risks are high and prediction of the quality of a resource requires capital investment in drilling and well tests. A resource must also be close to an area of high demand. Those countries, e.g. France and Iceland, who have underwritten the risks at both the reservoir assessment and drilling stage, have been able to develop the resource more readily. Other countries, where geothermal energy plays a significant role in the total energy supply, such as Kenya, Philippines and several central American countries, have governmental support for development. There is a lack of published technical, financial and legislative information for developers, particularly in comparing the experiences gained by others through various individual schemes.

Environmentally, geothermal schemes are relatively benign, but they generally produce a highly corrosive brine which may need special treatment and discharge consents. There is also a possibility of noxious gases, e.g. hydrogen sulphide, being emitted and developers must meet local environmental and planning requirements.

A combination of approaches can be used to overcome these barriers, including:

- educational, including training and outreach;

- technical improvements;
- economic incentives;
- government support.

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TABLES

TABLE NOTES

The data shown in Table 11.1 reflect as far as possible those reported by WEC Member Committees in 2009/10, and relate to the year 2008.

When not available from WEC Member Committees, data were largely drawn from submissions to the World Geothermal Congress, Bali, Indonesia, April 2010 (the full Proceedings of the Congress were not available at the time of going to press). In addition, a small amount of data has been obtained from the Annual Report 2008 of the IEA Geothermal Implementing Agreement and from national statistical sources. The WGC data mostly relate to 2009, but will generally be representative of the capacity and output in 2008. Data for generating capacity reflect as far as possible net installed levels; current operating capacity may be lower in some instances.

The direct use of geothermal energy is not only inherently difficult to quantify but in some instances can be subject to constraints on reporting for reasons of confidentiality, etc. The statistics shown for both capacity and output should therefore be treated as, at best, indicative of the situation in a particular country. As far as possible, direct use includes the capacity and output of geothermal (ground-source) heat pumps.

Annual capacity factors have been calculated on the basis of end-year capacity levels, as average-year data were not available. In general, therefore, the factors shown will tend to be understated.

Table 11.1 Geothermal energy: electricity generation and direct use at end-2008

	Electricity generation			Direct use		
	Installed capacity	Annual output	Annual capacity factor	Installed capacity	Annual output	Annual capacity factor
	MW_e	GWh		MW_t	TJ	
Algeria				56	1 723	0.98
Egypt (Arab Rep.)				1	15	0.48
Ethiopia	9	9	0.11	2	42	0.60
Kenya	163	1 100	0.77	16	127	0.25
Morocco				5	79	0.50
South Africa				6	115	0.61
Tunisia				44	364	0.26
Total Africa	**172**	**1 109**	**0.74**	**130**	**2 465**	**0.60**
Canada				1 126	8 873	0.25
Costa Rica	162	1 130	0.80	1	21	0.67
El Salvador	204	1 421	0.80	2	40	0.63
Guadeloupe	15	89	0.68			
Guatemala	44	294	0.76	2	57	0.78
Honduras				2	45	0.74
Mexico	958	7 047	0.84	156	4 023	0.82
Nicaragua	77	290	0.43			
United States of America	3 277	14 859	0.52	12 037	46 831	0.12
Total North America	**4 737**	**25 130**	**0.61**	**13 326**	**59 890**	**0.14**
Argentina				308	3 907	0.40
Brazil				360	6 622	0.58
Chile				9	132	0.46
Colombia				14	287	0.63
Ecuador				5	102	0.63
Peru				2	49	0.65
Venezuela				1	14	0.63
Total South America				**699**	**11 113**	**0.50**
Armenia				1	15	0.48
China	24	125	0.59	8 898	75 348	0.27
Georgia				25	659	0.85

Table 11.1 Geothermal energy: electricity generation and direct use at end-2008

	Electricity generation			Direct use		
	Installed capacity	Annual output	Annual capacity factor	Installed capacity	Annual output	Annual capacity factor
	MW_e	GWh		MW_t	TJ	
India				265	2 545	0.30
Indonesia	1 054	8 213	0.89	2	43	0.59
Japan	535	3 044	0.65	2 100	25 698	0.39
Korea (Republic)				149	1 365	0.29
Mongolia				7	213	0.99
Nepal				3	74	0.86
Philippines	1 958	10 723	0.63	3	40	0.38
Tajikistan				3	55	0.60
Thailand	N	1	0.49	3	79	0.99
Turkey	34	162	0.54	2 084	36 886	0.56
Vietnam				31	92	0.09
Total Asia	**3 605**	**22 268**	**0.71**	**13 574**	**143 112**	**0.33**
Albania				12	41	0.11
Austria	1	2	0.20	1 080	6 746	0.20
Belarus				3	34	0.31
Belgium				118	547	0.15
Bosnia-Herzegovina				22	255	0.37
Bulgaria				100	1 368	0.43
Croatia				114	557	0.15
Czech Republic				152	922	0.19
Denmark				200	2 500	0.40
Estonia				63	356	0.18
Finland				858	8 370	0.31
France				1 607	15 910	0.31
Germany	7	18	0.31	1 640	9 050	0.17
Greece				135	938	0.22
Hungary				655	9 767	0.47
Iceland	573	4 038	0.80	1 826	24 361	0.42
Ireland				164	843	0.16
Italy	810	5 520	0.78	650	8 000	0.39
Latvia				56	404	0.23

Table 11.1 Geothermal energy: electricity generation and direct use at end-2008

	Electricity generation			Direct use		
	Installed capacity	Annual output	Annual capacity factor	Installed capacity	Annual output	Annual capacity factor
	MW_e	GWh		MW_t	TJ	
Lithuania				65	149	0.07
Macedonia (Republic)				47	601	0.40
Netherlands				1 410	10 699	0.24
Norway				3 300	25 200	0.24
Poland				119	898	0.24
Portugal	28	192	0.78	28	430	0.49
Romania				174	1 520	0.28
Russian Federation	82	441	0.61	308	6 144	0.63
Serbia				119	3 244	0.86
Slovakia				132	3 067	0.74
Slovenia				104	1 136	0.35
Spain				141	684	0.15
Sweden				4 460	45 301	0.32
Switzerland				1 054	5 729	0.17
Ukraine				11	119	0.35
United Kingdom				187	850	0.14
Total Europe	**1 501**	**10 211**	**0.78**	**21 114**	**196 740**	**0.30**
Iran (Islamic Rep.)				42	1 064	0.81
Israel				82	2 193	0.84
Jordan				153	1 540	0.32
Yemen				1	15	0.48
Total Middle East				**278**	**4 812**	**0.55**
Australia	N	1	0.75	130	3 672	0.90
New Zealand	585	3 962	0.77	385	9 552	0.79
Papua New Guinea	56	450	0.92	N	1	0.32
Total Oceania	**641**	**4 413**	**0.78**	**515**	**13 225**	**0.81**
TOTAL WORLD	**10 656**	**63 131**	**0.68**	**49 636**	**431 357**	**0.28**

COUNTRY NOTES

The Country Notes on Geothermal Energy have been compiled by the Editors. A wide range of sources have been consulted, including national, international and governmental publications/web sites, as well as submissions to the World Geothermal Congress, Bali, Indonesia, April 2010 (the full Proceedings of the Congress were not available at the time of going to press). Use has also been made of direct personal communications.

Albania

Albania possesses a large low-enthalpy geothermal resource located in three zones. The largest, Kruja, extends from the Adriatic Sea in the north southwards into northwestern Greece. Of the other two zones, Peshkopia lies in the northeast of the country and Ardenica in the coastal area.

The direct use of the available resource has been recognised and utilised for many centuries. Hot springs, often for recreational purposes, have also been incorporated into spa clinics, many as balneological centres. However, possibilities exist for the resource to be used for space heating and heat pumps.

Algeria

With abundant fossil fuel resources, there has historically been little development of the geothermal resource in Algeria. However the New and Renewable Energy Policy of the Ministry of Mines and Energy will help to utilise the resource, which research has shown to exist in the zone to the north of the Tellian Atlas mountains and to the south in the Saharan platform.

Although the area around Biskra has been found to have high-temperature springs, the more than two hundred springs that have been recorded in the northern part of the country are low-temperature. They are used mainly for balneological purposes, although a small amount of greenhouse heating also exists.

Argentina

Argentina is in the forefront of South American utilisation of geothermal resources and in recent years there has been much progress in the knowledge of, and direct use of, the resource. High-temperature geothermal heat exists in the western region, along the Andes range and moderate to low-temperature thermal fields have been identified in other parts of the country.

Direct use of geothermal heat is widespread in Argentina. At the end of 2004 some 150 MW_t capacity - installed at 70 different locations - was mainly used for bathing and swimming but also with some applications in fish farming, greenhouse and soil heating, individual space heating and snow melting.

The 670 kW binary-cycle pilot power plant at Copahue went off-line in 1996. Investment is being sought to construct a new 30 MW_e station, Copahue II.

Argentina's geothermal resource is being expanded throughout the country with exploitation dependent on the geological characteristics of each occurrence. The thermal potential is undergoing systematic evaluation through various state-supported research programmes.

Australia

As a result of the Federal Government's ongoing promotion of renewable energy and the introduction in 2001 of the Mandatory Renewable Electricity Target (MRET), the development of the Australian geothermal resource continues. In mid-2004 the Government reconfirmed its commitment to MRET. In August 2009 the Federal Government passed the Renewable Energy Target Scheme (RET) legislation, expanding the MRET. The RET states that by 2020 20% of electricity will be supplied by renewable energy, increasing the MRET target by more than four times to 45 TWh.

The Australian geothermal resource can be classified into three categories: Hot Sedimentary Aquifers (HSA); Hot Rock (HR), including Hot Dry Rocks (HDR), and Hot Fractured Rocks and Direct Use (HFR). The first two categories have the potential for electricity generation. However, the sole use of geothermal power for electricity generation in Australia is the 120 kW (gross) Birdsville plant in Queensland. For the past decade it has supplied the town's night time electricity requirements and generally during the winter. When the geothermal plant is able to satisfy demand, an automatic switching system shuts down the fossil-fuel generated electricity system. During 2008 power output amounted to 769 MWh.

Although still operating, the Birdsville plant is nearing the end of its design life and requires replacing. In mid-2009, as part of the Queensland Renewable Energy Plan, the State Government committed AUD 4.3 million to fund such a project, which is currently in the company's works programme for the 2011-2012 financial year.

To date the geothermal resource has largely been used directly, particularly in southeastern Australia. Total national installed capacity for direct use applications is estimated to be 130 MW_t. of which space heating accounts for 75%, bathing and swimming, 6% and ground-source heat pumps for 18%.

It has been estimated that Australia's very significant HDR resource is sufficient to generate the country's electricity requirement for centuries to come. This sector is undergoing rapid expansion: by end-2008 there were 385 Geothermal Exploration Licence (GEL) areas (an increase of 39% over 2007), covering nearly 360 000 km^2. Applications for Geothermal Exploration Permits (GEP), Exploration Licences and Special Exploration Licences had been applied for and, in some cases, granted. The majority of GEL applications had been from South Australia, the remainder were spread across the rest of the country apart from the Northern Territory.

Following the closure of Round 1 of its Geothermal Drilling Program (GDP), in early 2009, the Federal Government presented Round 2 in mid-2009. The AUD 50 million GDP provides a dollar-for-dollar subsidy, capped at AUD 7 million per proof-of-concept project. Further State funding has also been made available. Private investment will be encouraged once the technology has been demonstrated. By end-2008 48 companies were involved in the development of HSA and engineered (or enhanced) geothermal systems (EGS - geothermal reservoirs either with fracture and/or chemical stimulation). Numerous drilling projects are already under way with more planned.

Austria

The balneological importance attached to the country's spas together with the restrictions imposed by the Austrian Water Law, have somewhat impeded the progress of development of the geothermal resource. Generally, there has been a lack of public interest and support; the management of spas have expressed concern for the quality of water supplied which could possibly be affected by further and diversified use of the resource and the difficulty of combining different uses at new sites have all contributed to this lack of progress. In the case of the Water Law, it is stated that the groundwater below the land belongs to the landowner and this can be highly problematical when deviated drilling is necessary.

Austria's aggregate installed capacity of 62 MW_t (excluding geothermal heat pumps) is utilised for direct applications such as district heating, bathing and swimming, industrial process heat, the heating of greenhouses and electricity (Organic Rankine Cycle).

Two small binary power plants, Altheim and Blumau, were brought into operation in 2000 and 2001 respectively.

In the late 1990s the European Union's THERMIE programme provided support for the Simbach-Braunau scheme, a cross-border joint venture between South Germany and Upper Austria - one of the largest district heating schemes in Europe. An installed capacity of over 30 MW serves five hundred people with some 9.3 MW of power.

In addition, it has been estimated by the European Heat Pump Association that there were more than 50 000 ground source heat pumps in use in 2007.

Brazil

The utilisation of Brazil's huge low-temperature geothermal resource has until now been extremely small. Much research has been undertaken by the Geothermal Laboratory of the National Observatory since the 1970s and it is thought that high-temperature geothermal heat exists only in the offshore Atlantic islands.

In 2005 it was reported that the installed capacity (some 360 MW_t) was used directly, largely for bathing and swimming, with just 4 MW_t used for agricultural drying/industrial process heat. The 12 or so systems in place (mostly located in the western-central area and the south) could be classified as BRT (bathing, recreation and tourism), PIS (potential for industrial use and space heating) and TDB (therapeutic, drinking and bathing). The BRT systems totaled 16 MW_t, the PIS, 343 MW_t and the TDB, 3 MW_t, although the PIS element was not being used industrially, but for recreational purposes.

Bulgaria

The number of hydrothermal sources in Bulgaria has been estimated at around 150 with about 50 of them having a total of 469 MW_t of proven potential for extraction of geothermal energy. The majority of the waters have been found to be low-temperature at intervals of 20-90^{o}C. Only about 4% of the total capacity has been found to have water hotter than 90^{o}C. The theoretical potential of Bulgaria's geothermal energy amounts to 13 856 TJ/yr with the technical potential put at 10 964 TJ/yr.

There are in the region of 100 MW_t geothermal systems installed in the country, representing some 23% of the currently discovered thermal potential. The annual average production is around 428 GWh.

Geothermal heat is used entirely for direct purposes: a situation that has persisted since the Romans installed under-floor heating in their hypocausts. Individual space heating has the majority share, with air conditioning, greenhouse heating, bathing and swimming and other uses - aquaculture, and the extraction of chemical derivatives - as the remaining shares. A small plant, located on the northern Black Sea coast, is used for the production of iodine paste and the extraction of methane.

Since 1999 there has been significant development of ground-source heat pumps (GSHP) utilising the low-grade geothermal heat.

Canada

The geography of Canada does not easily lend itself to electricity generated from geothermal resources. However, since the late 1970s exploratory work has been ongoing at a volcanic complex, Mt. Meager in British Columbia. The site may have potential development capacity of 100 MW or greater, but this has not yet been verified.

Ground source heat pumps can be installed almost anywhere in Canada and in total could theoretically meet the entire heating and cooling need of the country’s building stock.

Since 2005 Canada has experienced a major transformation of the ground source heat pump industry. Led by the Canadian GeoExchange Coalition (CGC) and supported by Natural Resources Canada, more than 3 000 industry professionals have been trained to Canadian standards and more than 800 have received their installer or residential designer accreditation. The CGC has also certified thousands of residential installations. For the years 2005 to 2008 the annual rates of growth in installed units were 43%, 22%, 215% and 65% respectively. By end-2008 total installed capacity had reached 746 MW_t. with an output of 4 069 TJ during the year.

Chile

There has been interest in geothermal exploration in Chile since the beginning of the 20th century and although in recent years the question of security of energy supply has given the development greater impetus, a higher emphasis on the use of renewable energy generally needs to be instituted prior to further progress.

It has been established that the Chilean Andes has more than 300 hot spring areas, giving the country an estimated high-temperature (over 150^{o}C) potential of some 16 000 MW_t.

In the opening years of the 21st century the Geology Department of the University of Chile together with the National Oil Company (ENAP) and various countries with geothermal expertise undertook a research project in the central-southern areas of the country. Additionally, ENAP has worked with CODELCO (the National Copper Corporation) in the northern and southern regions. The intention of the studies was to establish areas that would be suitable for the generation of electricity.

Enel, Italy's largest power company, reported in July 2008 that it was engaged on a study to examine the geothermal potential available for electricity generation in the Quebrada del Zoquete valley in the north of Chile.

China

With its move to a fast-growing market economy and increasing environmental concerns, the utilisation of geothermal energy in China continues to increase, but not with the same rapidity as other renewable energies.

Studies have identified more than 3 000 hot springs and more than 300 geothermal fields have been investigated and explored. High-temperature resources are mainly concentrated in southern Tibet and western parts of Yunnan and Sichuan Provinces, whereas low-medium temperature resources are widespread over the vast coastal area of the southeast, the North China Basin, Songliao Basin, Jianghan Basin, Weihe Basin, etc.

Historically, the primary development has been in geothermal energy used directly. Approximately half of installed capacity is used for bathing and swimming, with the next largest sector being district heating. Other uses include agricultural drying, fish farming, greenhouse heating and industrial process heat.

The utilisation of geothermal heat pumps (GHP) has grown dramatically in recent years. GHP applications were used extensively in the 2008 Beijing Olympic Games venues. By end-2009 installed capacity of GHP was some 5.2 GW_t, considerably higher than the installed capacity for other direct uses.

The development of geothermal power generation has been, by comparison, relatively slow, owing to the large hydro-electric resources in those provinces with high-temperature geothermal resources (Tibet and Yunnan). At present the only operational power plant is at Yangbajain (Tibet). Capacity is 24.18 MW_e, generating about 125 GWh annually.

During 2009 the Ministry of Land and Resources announced that during the next five years the utilisation of the country's shallow – less than 200 m deep - geothermal resource would be developed, in particular for the benefit of the construction industry. In mid-2009 it was estimated this resource was already supplying heating and refrigeration for approximately 80 million m^2 at more than 2 200 construction sites.

Since 2002 Icelandic expertise has been assisting China to exploit its geothermal potential. In 2009 it was announced that Shaanxi Green Energy Geothermal Development, a joint venture between Sinopec Star Petroleum, 51% and Enex China, (Geysir Green Energy, 75%; Reykjavik Energy Invest, 25%) 49% had signed an agreement to develop a 250 000 m^2 district heating scheme in Xiong County, Hebei Province. This is to be followed by a 3 million m^2 scheme in 2012.

Colombia

Although knowledge and understanding of the Colombian geothermal resource is still at an early stage, a number of studies dating from at least as far back as 1968 have been undertaken by many organizations, including OLADE, the Colombian Institute of Geology and Mines (INGEOMINAS) etc.

Colombia is located on the Pacific Ring of Fire, which provides positive anomalies in respect of the geothermal resource, exemplified by numerous volcanoes and high-temperature hydrothermal systems, associated with magmatic heat sources.

Although exploratory work is being conducted, there has been no actual utilisation yet of the high temperature resource.

Unassociated with magmatic heat, there are low- to medium- temperature hydrothermal sources, evidenced by warm springs throughout the country. Currently, the small use of geothermal heat is confined to bathing and swimming (including balneology).

Costa Rica

The Central American volcanic belt passes through Costa Rica, evidenced by numerous volcanoes and geothermal areas. The fields of Miravalles, Tenorio and Rincón de la Vieja are located in the northwestern part of the country and have been studied in detail.

To date, Costa Rica's geothermal resources have been utilised almost entirely for electric power generation. A 55 MW_e single flash condensing unit was commissioned in 1994 at Miravalles, followed soon afterwards by an additional 5 MW_e back-pressure unit. A second 55 MW_e condensing unit came on stream in 1998, and subsequently (in 2000) another 29.5 MW_e. With the commissioning of a further 18 MW_e unit in December 2003, the total installed capacity now stands at 162.5 MW_e.

The Instituto Costarricense de Electricidad (ICE) owns and operates Miravalles, with the exception of the 29.5 MW_e plant, which operates under a 15-year BOT contract.

Exploration work on the slopes of the Rincón de la Vieja volcano at the Las Pailas and Borinquen geothermal fields has resulted in the discovery of high-temperature fields.

Construction of a 41 MW_e unit at Las Pailas is currently under way and the plant is expected to be on line during the second half of 2010.

Future development of the country's geothermal resource, for instance the construction of Las Pailas II or Borinquen I will depend on feasibility studies, scheduled for 2011.

In the last 20 years, with the help of the Italian Government and the United Nations Development Fund (UNDP), Costa Rica's low- and medium-temperature resource has been studied. However, at the present time direct use is confined to hotel swimming pools in areas of ecotourism.

Croatia

The considerable Croatian geothermal resource is located in two large geological formations: the Panonian Basin to the north and east, and the Dinarides Belt in the south of the country. These two geologically different regions have significant differences in potential. At the present time usage of the resource is increasing, but it is still at a very low level.

Although there is a theoretical potential to generate electricity, the reservoirs are currently exploited only for direct-use purposes (balneology, recreation and space heating). A total of 18 locations have an aggregate installed capacity of 114 MW_t, which produced 557 TJ of heat output in 2008.

Czech Republic

Geothermal energy has been little used, and then only directly (in spas and swimming pools), for over a century. At the present time only one geothermal source is being utilised as a source of power for installed heat pumps. However, in order to meet the EU target of 13% reliance on renewable energy by 2020, utilisation of the resource will likely play a part, albeit small.

Within the Czech Republic about 60 sites have been identified with a theoretical electricity potential of 250 MW_e and a heat supply capacity of about 2 000 MW_t. The resulting electricity generation has been estimated to be some 2 TWh and usable heat, 4 TWh. It is considered that, if successful, further exploration could lead to higher production.

At the beginning of 2009 ČEZ, the country's largest power company, issued a tender for a survey to determine the feasibility of constructing a geothermal power plant in Liberec, north Bohemia.

Denmark

With the Government's positive attitude towards the utilisation of the country's low-enthalpy resource, there has been an increased usage during the first years of the 21st century, which is expected to continue. It is estimated that there is a sufficient resource to supply heat to several towns for hundreds of years.

There are presently two district heating plants in operation. The first, at Thisted (northern Jutland) began operating in 1984. In 1988 it was enlarged to 4 MW_t and again to 7 MW_r in 2000-2001. The second, a 14 MW_t plant on the island of Amager started operating in 2005.

A project for a third plant in Sønderborg, southern Denmark, is currently under way and expected to become operational in 2011-2012.

Research has shown that the estimated geothermal resource in the area surrounding Copenhagen represents an output of 60 000 PJ.

Ecuador

Exploration of the Ecuadorean geothermal potential was begun during the 1970s in order to establish the extent of both high-temperature and low-temperature resources. Despite follow-up prefeasibility studies on the former and prefeasibility studies on the latter, plans for industrial and direct uses were found to be uneconomic.

At the present time geothermal power supplies only a small amount of energy for direct-use purposes. Some 5 MW_t of installed capacity is used for recreation and balneology. The country's energy supply is entirely satisfied by hydroelectricity and fossil fuels, but with Government plans to develop indigenous resources (both conventional and renewable), it has been stated that the role of geothermal is set to increase. Higher oil prices and increasing energy demand may well provide the impetus to completely survey, map and reassess the country's potential.

El Salvador

Like Costa Rica, El Salvador lies on the Central American volcanic belt and there is thus a plentiful geothermal resource. The main emphasis has been on using the resource for power generation although a potential exists for the direct use of geothermal in drying grains and fruit.

Of the 204.4 MW_e of geothermal capacity currently installed in El Salvador (95 MW_e at Ahuachapán, and 109.4 MW_e at Berlín), 183.8 MW_e is reported to be actually available (80 MW_e at Ahuachapán and 103.8 MW_e at Berlín). SIGET (Superintendencia General de Electricidad y Telecomunicaciones) reports that these capacities were unchanged as at June 2009.

Net geothermal electricity generation during 2008 increased by 10% over 2007 to 1 421 GWh, providing 25% of El Salvador's total generation.

For some time it has been reported that exploratory work in the San Vicente and Chinameca fields is taking place. During 2009, LaGeo, owner of the two existing geothermal plants, reported that initial research based on studies of the Chinameca field showed that it has the potential to be the site for a third power plant. Two wells have been sunk and two more will be during 2010.

Ethiopia

Ethiopia is one of a minority of African countries possessing geothermal potential. Considerable resources of both high- and low-enthalpy geothermal have been located in the Ethiopian Rift Valley – in the Main Ethiopian Rift and in the Afar depression. Exploration that began in 1969 has, to date, revealed a potential that could possibly generate more than 5 000 MW_e of electricity. Of the approximately 120 localities that are believed to have independent heating and circulation systems, about two dozen are judged to have potential for high enthalpy resource development, including for electricity generation. A much larger number are capable of being used directly for horticulture, animal breeding, aquaculture, agro-industry, health and recreation, mineral water bottling, mineral extraction, space cooling and heating etc.

Following exploratory drilling in the 1980s at Aluto, an 8.52 MW_e pilot power plant was installed in the Aluto-Langano geothermal field in 1999. It became the first geothermal power plant in Africa to use integrated steam and binary power technology. During the period 1993-1998 three deep and three shallow exploratory wells drilled at Tendaho were found to have geothermal fluids in the 200-600 m depth range.

The plan for expanding the geothermal sector is based on three fundamental criteria: technical (the degree to which exploration has been carried out); economic (the strategic location of exploration in respect to its proximity with the national grid); and demographic (the population density and thus the demand for electricity). In the light of these criteria, a number of areas have been selected for further exploration and study: Aluto-Langano, Tendaho, Corbetti, Tulumoye-Gedemsa, Doran, Fantale etc. It is estimated that the work on each field would take between 4 and 7 years to carry out the necessary investigations and studies prior to a total of some 390 MW_e being constructed.

It has been reported that in 2009 the first phase of expansion in the Aluto-Langano field began. The aim, following further investigative research and drilling of appraisal and production wells, is to increase the size of the installed power plant.

The country is heavily dependent on petroleum fuels for transport and some electricity generation, biomass for household cooking and lighting and an erratic hydro supply for the remaining electricity generation. Although geothermal is similar to, for example, hydro in that an installation requires a high initial investment cost, it has the advantage of having a possibly greater than 90% availability factor, perhaps double that of others of similar installed capacity. Recognising this, the Government has taken steps to implement changes to the legal and institutional framework in order for geothermal resources to compete with conventional energy systems and is committed to investigate and develop the country’s geothermal potential.

France

Low-enthalpy geothermal resources in metropolitan France are found in two major sedimentary basins: the Paris Basin and the Aquitaine Basin in the southwest. Other areas (Alsace and Limagne) have geothermal potential but it cannot be so readily utilised.

Although the first French geothermal district heating plant was constructed in 1969 in the Paris region, the main development of geothermal energy began following the oil crises of the 1970s. Development continued throughout the 1980s, culminating in nearly 100 exploration wells being brought into operation. However, the 1990s saw a diminution of interest in geothermal energy and approximately one-third of the plants were closed. The installed capacity is mainly used for space heating (80%+) but also greenhouse heating, fish farming and bathing and swimming.

By end-2008, it is estimated that installed thermal capacity for direct use was 307 MW_t and 1 300 MW_t for geothermal heat pumps.

For a considerable number of years France's low-enthalpy resources have been utilised by heat pump installations. In November 2008 le plan de développement des ENR (plan for the development of renewable energy) was unveiled by the Government. The law embodies the objectives that were first formulated in the 2007 Grenelle de l'environnement. It contains a framework to put the stated objectives into practice. Within the overall assistance given to the development of renewable energy, geothermal energy received various measures of support from financial incentives to R&D programmes.

The French WEC Member Committee reports the plan includes a 2020 objective of producing 2.4 mtoe of geothermal heat and equipping 2 million households with heat pumps.

Since the 1980s the French authorities have supported research into the potential of HDR. Work began at Soultz-sous-Forêts (northeastern France) in 1987 and based on the success of tests and drilling to a depth of 3 900 m (1987-1997), the next phase (1998-2001) was planned. During this period the drilling was extended to 5 000 m and further tests were conducted. Long-term circulation testing continued during Phase I (2001-2004). In June 2008 during Phase II (2005-2008) a 2.2 MW_e (1.5 MW_e net) power plant was installed. Electricity was generated for the first time in 2009.

Germany

Germany's hydrothermal resources, down to a depth of 5 000 m, are located in the North German Basin, the Molasse Basin in the south of the country and the Upper Rheingraben.

The hot dry rock (HDR) resource, at a depth of between 3 000 and 7 000 m, is thought to exist in the Crystalline Basement in the middle and south of the country, the Crystalline Basement in the Upper Rheingraben and the Rotliegend volcanites in the North German Basin.

An evaluation of the maximum recoverable potential for electricity generation from HDR technology has been estimated at 8 620 EJ and 90 EJ from hydrothermal resources.

As a result of the Renewable Energy Sources Act (EEG), and its 2008 amended version, deep geothermal energy has been able to significantly develop in recent years. Financial incentives already in place were strengthened in January 2009: a feed-in allowance of a maximum € 0.15/kWh (dependent on the plant capacity) was raised to € 0.16/kWh (or € 0.105/kWh for plants over 10 MW), together with an additional bonus of € 0.04/kWh for plants which become operational prior to 2015. Further incentives are in place for utilisation of waste heat and also technologies using the hot rock resource.

The first German geothermal power plant (230kW$_e$) was inaugurated at Neustadt-Glewe in November 2003 to provide electricity for 500 households and a second 3 MW$_e$ plant began operating in Landau in 2007. A third 3.4 MW$_e$ plant at Unterhaching first generated heat during 2007 and then electricity in late 2008. Output from the three plants during 2008 amounted to 18 GWh. Although this is a minute share of total electricity supply, there is an estimated 10 MW$_e$ of capacity currently under construction.

By end-2008 total installed capacity for direct thermal use was 1.6 GW$_t$, of which 91% was attributable to decentralised ground-coupled or groundwater source heat pumps. Output was 0.6 PJ for the former and 8.5 PJ for the latter.

Greece

Greece possesses both high- and low-enthalpy geothermal fields. The former occurs in the islands of Milos, Santorini, Nisyros, etc. located in the South Aegean volcanic arc. The latter are situated in the plains of Macedonia and Thrace and in association with the country's hot springs. At the present time the geothermal resource is not harnessed for electricity generation.

Low-temperature geothermal fields occurring in structurally active sedimentary basins have a considerable potential. A small proportion of this heat resource is currently utilised, with an installed capacity of about 135 MW$_t$ for space heating, greenhouse and soil heating, bathing and spas, industrial uses, fish farming, cultivation of spiroulina and geothermal heat pumps.

Although the number of heat pump installations in Greece does not equate with some other European countries, nevertheless there has been a strong rate of growth in recent years.

Guadeloupe

The double-flash plant at La Bouillante in the French Overseas Department of Guadeloupe is at present the only example of the island's geothermal energy being utilised for electricity production. The plant was commissioned in 1985 but was closed between 1992 and 1996.

The French Agency for Environment and Energy Management (ADEME) contributed to the development of the Bouillante high-enthalpy field by supporting 20% of the cost of drilling new wells.

Following the rehabilitation of Bouillante 1, a 5 MW$_e$ double-flash unit, in 1996, the plant was able to supply 2% of the island's electricity supply in 1998. Extensive exploration of the Bouillante field ensued and led to the drilling of three new production wells and a plan to construct Bouillante 2, an 11 MW$_e$ unit some 400 m from the original plant. Bouillante 2 was put into service in 2005 and currently some 10% of electricity generation is supplied by the geothermal resource.

An expansion to the generating capacity is currently planned for operation during 2013. Exploratory work will establish the capacity that could be constructed at Bouillante 3 but it is estimated that it will be between 20 and 40 MW$_e$.

Guatemala

Guatemala's Instituto Nacional de Electrificación (INDE) has five geothermal areas for development. All five (Zunil, Amatitlán, Tecuamburro, San Marcos and Moyuta) lie in the active volcanic chain in southern Guatemala. INDE has conducted both investigative work and development of geothermal power since 1972. It has been estimated that Guatemala's geothermal resource could supply 20% of the country's electricity supply.

The first geothermal power plant in the country was constructed in the Amatitlán area; electricity was produced from a 5 MW_e back-pressure plant for a period of three years (from October 1998), during which time the field was evaluated.

During 2007, a 20 MW_e binary plant was commissioned at Amatitlán, adding to the existing 5 MW_e back-pressure unit. However, the latter unit is currently out of service and INDE expects to transfer it to the next field - possibly Tecuamburro - to be developed some 2 or 3 years hence.

A second geothermal plant (in the Zunil I field) with a running capacity of 24 MW_e has been operating since July 1999. Following INDE's exploratory drilling work, a contract was signed with Orzunil I for the private installation and operation of the plant. Until 2019 the company will buy steam from INDE and sell power to the national grid.

INDE is planning to continue exploration and development of its other concessionary areas and hopes to install its next power plant in 2012 or 2013.

Direct use of geothermal heat is limited but the 1.6 MW_t Bloteca plant is used in the process of curing concrete construction blocks and in another instance Agro-Industrias La Laguna uses a 0.5 MW_t unit to dehydrate fruit.

Hungary

Hungary possesses very considerable geothermal resources and it has been estimated that the country has the largest underground thermal water reserves and geothermal potential (low and medium enthalpy) in Europe.

To date, there has been no utilisation of geothermal energy for the production of electricity. The principal applications of geothermal power used directly are for balneological purposes, greenhouse heating, space heating, industrial process heat and other uses.

Iceland

Geothermal energy resulting from Iceland's volcanic nature and its location on the Mid-Atlantic Ridge has been utilised on a commercial scale since 1930. The high-temperature resources are sited within the volcanic zone (southwest to northeast), whilst the low-temperature resources lie mostly in the peripheral area. A realistic assessment of Iceland's potential for electricity production has been put at 20 TWh annually, after taking into account economic factors, environmental considerations and technological elements.

The principal use of geothermal energy is for space heating, with about 89% of all houses heated by geothermal resources. There is a total of about 30 municipally-owned geothermal district heating systems located in the country, the largest of which is Reykjavik. In addition to the heating of houses, direct use of geothermal energy is made for swimming pools, snow melting, industrial use, greenhouse and fish farming.

Iceland's geothermal capacity for electricity generation has increased dramatically in recent years. By end-2009 total capacity of the seven installed plants stood at 573 MW_e, some 2.5 times the end-2005 capacity. Generation during 2009 rose to 4 553 GWh, representing 27% of total electricity generation. Geothermal accounted for 62% of Iceland's energy supply.

The policy of the Iceland Government is to expand the use of renewable energy to an even greater extent. With respect to utilising the country's geothermal resource, the licensing process has been completed for 180 MW_e in the Hengill area of southwest Iceland; Environment Impact Assessments (EIA) representing 325 MW_e capacity have been carried out at the Bjarnaflag field, in the Hengill area and at Reykjanes; EIAs in respect of 350 MW_e have been started on the Krafla and Theistareykir fields and some 2 000 MW_e additional capacity is thought to be feasible.

Direct use of geothermal power has not grown to the same extent as electricity generation but it remains of major importance, especially in the residential sector. It is estimated that during 2009, direct use amounted to 26.3 PJ, of which 19 PJ was for space heating.

The Iceland Deep Drilling Project (IDDP) began in 2000. The main purpose of the IDDP is to find out if it is economically feasible to extract energy and chemicals out of hydrothermal systems at supercritical conditions. Drilling will occur below areas that have already been exploited down to 4-5 km, with boreholes at Krafla, Nesjavellir and Reykjanes. Following a feasibility study undertaken by Deep Vision (a consortium of Sudurnes Regional Heating, the National Power Company, Reykjavik Energy and the National Energy Authority, representing the Government), the project became operational during 2003 and international partners sought. Drilling of the first well, IDDP-1, began at Krafla in early 2008 (down to 800 m). By mid-2009 it had reached 2 104 m but problems with magma intrusions occurred. Further research and testing is being undertaken prior to any decision regarding the progression of the project.

Iceland's economy has been seriously impacted by the global economic situation, which has slowed the pace of geothermal development. Reykjavik Energy has revised its projected drilling plans and although the company will continue with projects, they will take longer to come to fruition.

India

It has been estimated by the Geological Survey of India that the geothermal potential is in the region of 10 000 MW_e, widely distributed between seven geothermal provinces. The provinces, although found along the west coast in Gujarat and Rajasthan and along a west-southwest - east-northeast line running from the west coast to the western border of Bangladesh (known as SONATA), are most prolific in a 1 500 km stretch of the Himalayas.

Research has shown that there are 340 hot springs in India, most of which have a low-temperature resource and therefore only suitable for direct use. At the present time direct utilisation is almost entirely for bathing and balneological purposes. However, it is considered that greenhouse cultivation of fruit could be developed extensively in the future.

Investigative studies are being undertaken in order to establish the feasibility of developing the geothermal resource for power generation. The Ministry of New and Renewable Energy is supporting a RD&D programme for such studies. The State Governments of Jammu and Kashmir and Chhattisgarh have indicated their willingness to develop geothermal fields for commercial operation. The Government of Andhra Pradesh has initiated a resource assessment study and has proposed the demonstration and use of heat pumps in Gujarat.

An Action Plan for Indo-Iceland Geothermal Cooperation has been drawn up between the two Governments in order for Iceland’s geothermal expertise to assist in developing the Indian resource.

Indonesia

Having become a net oil importer early in the 21st century, Indonesia took the view that it was essential to harness the enormous geothermal resource at its disposal. The Government's National Energy Management Blueprint 2005-2025, contained a target of 9 500 MW_e geothermal capacity by 2025. The national geothermal potential has been estimated at 27.67 GW_e but at the present time only a tiny fraction of this has been realised. The island of Sumatra has in the region of 50% of geothermal potential.

In recent years the Indonesian Government has passed a raft of laws and regulations in order to better regulate both the upstream and downstream side of the sector and to better utilise its geothermal power. Additionally, the Japan International Cooperation Agency, at the request of the Government, was engaged to formulate a Master Plan Study for Geothermal Power Development. A period of 18 months in 2006/2007 was used to assess the fields and formulate a development plan.

By end-2008, a total of 1 054 MW_e geothermal capacity was installed, of which some 95% was based on the island of Jawa-Bali. The remaining 5% was located on Sumatera and Sulawesi. Of the total, Pertamina Geothermal Energy (PGE), a subsidiary of Pertamina, the state-owned oil and gas company, operates 252 MW_e, Chevron, 632 MW_e and other companies, 170 MW_e. Electricity production in 2008 amounted to 8.2 GWh.

In order to alleviate power shortages, the Government has prepared plans for 10 000 MW_e of electricity generating capacity to be installed. Of this it is expected that geothermal energy will provide a large portion. A planned programme of construction will gradually increase capacity so that by 2025 about 5% of national electricity demand will be satisfied by geothermal power. At end-2008 1 538 MW_e was reported to be under construction.

It was announced during the World Geothermal Congress 2010 that Indonesia plans to launch a 3 997 MW_e project to expand geothermal power.

A very small amount of geothermal energy is used directly for bathing, balneology and swimming and in the production of mushrooms, tea, silk and coconut sugar drying.

Iran (Islamic Republic)

Iran's geothermal potential is embodied in low- to medium-enthalpy resources found in provinces fairly widely distributed across the country. However, three regions, Damavand in the north-central area, and Maku-Khoy and Sahand in the northwest, are likely to be the most productive.

The Ministry of Energy currently has two projects under construction: power plants of 50 MWe and 3-5 MW_e in Meshkinshahr near Mount Sabalan (in the far northwest). Both projects began in 2005 and were expected to be operational in 2009. Generation from the former will be in the region of 370 GWh and the latter, 40 GWh.

Traditionally, geothermal heat has been used directly for recreational and balneological purposes.

The country is extremely well-endowed with low-cost fossil fuels and historically this has proved a disincentive to the development of the renewable energies. However, the Government is showing a growing interest in progressing renewable energy in order to meet fast-growing national energy demand. The Renewable Energy Organisation of Iran (SUNA), an affiliate of the Ministry of Energy was established in the 1990s. In recent years SUNA has studied the feasibility of, and given publicity to, using the heat for greenhouses, agriculture, aquaculture and heat pumps for cooling and heating purposes.

Ireland

There are no high-temperature geothermal resources in Ireland and all instances of low-temperature potential are only suitable for direct utilisation. To date, only one of the 42 warm springs located in the east and south of the country has been exploited, for heating a swimming pool.

The country does however possess an adequate supply of groundwater sources suitable for heat pumps. Since the late 1990s, the market has grown significantly so that now more than 9 500 domestically installed systems (typically, 15 kW) exist. This trend is expected to continue. Additionally, more than 270 large-scale heat pumps have been installed in commercial buildings. In total, heat pumps represent some 164 MW_t of installed capacity.

Israel

In recent years progress on the development of Israel's low-enthalpy resources has been relatively slow. A very small amount of geothermal heat is utilised directly for greenhouses.

Italy

Italy is one of the world's leading countries in terms of geothermal resources, lying fifth in terms of production of electricity from geothermal. The high-temperature steam-dominated reservoirs lie in a belt running through the western part of the country from Tuscany to Campania (near Naples). Commercial power generation from geothermal resources began in Italy in 1913 with a 250 kW_e unit. Subsequently the main emphasis has been on the production of power rather than on direct use of the heat.

The main geothermal fields in Italy are Larderello, the oldest and one of the most powerful in the world, with 200 production wells at depths of less than 1 000 to over 4 000 m, the Travale-Radicondoli, with 25 production wells at depths of between 1 500 and 3 500 m, and Bagnore and Piancastagnaio, with 16 production wells at depths of 2 500 - 4 000 m.

Following the limited development of resources during the first half of the 20th century, it was the second half of that century that saw rapid growth. By end-2008, 31 plants were in operation with a total installed capacity of 810 MW_e (711 MW_e operating capacity). All plants in operation are located in the region of Tuscany and over 45% in the Province of Pisa. Electricity generation during the year amounted to 5.5 TWh, reflecting a decrease of 0.9% over 2007. Although installed geothermal capacity represented only 3% of total renewable energy capacity, output accounted for 9.5% and Enel, the main Italian power company, already plans to increase capacity by installing a further 112 MW_e in the coming years. Expansion of capacity began in November 2009 when an additional highly-efficient facility was brought into operation.

Government and State support available for both geothermal plants and direct use of heat includes national mandatory quotas, tradable green certificates and financial incentives.

Although the country also utilises its low-enthalpy resources for direct purposes, it is considered that the market is still under-developed. Main applications for direct uses are thermal spas, space and district heating, fish farming, greenhouse heating, heat pumps and industrial process heat.

It was estimated that at end-2008 capacity of installed heat pumps totaled 150 MW_t, with an output in the region of 600 TJ. Heat pumps are being installed at a rate of some 500 per annum, most being groundwater types, with a smaller amount of closed-loop types. The growth potential of the direct use market is seen as greater than that of power generation. The Italian Position Paper foresees a potential capacity of 1 300 MW_e by 2020, while total use of geothermal heat might grow to 6 000 MW_t by 2020.

Japan

Japan has a long history of geothermal utilisation, both direct and for power generation. It is one of the world leaders in terms of generation of electricity. The first experimental power generation took place in 1925, with the first full-scale commercial plant (23.5 MW_e) coming on-line at Matsukawa, in the north of the main island of Honshu, in 1966. Following each of the two oil crises, development of Japan's geothermal resources was accelerated and technological improvements were made. By end-1996, installed capacity stood at 529 MW_e but in the following years economic constraints were imposed, financial incentives withdrawn and geothermal capacity grew only marginally, reaching 535 MW_e in 2006.The position was unchanged at the end of 2008. The existing 18 plants are located on the southern island of Kyushu, in northern Honshu, at Mori on Hokkaido and on the island of Hachijo, some 300 km south of Tokyo.

The country's geothermal potential is estimated to be in the order of 24.6 GW_e. Only a small fraction of this potential has been used to date and until ways of tapping Japan's deep resources can be developed, this situation will prevail. Geothermal energy was excluded from the Special Measures Law for the Promotion of Utilisation of the New Energy in 1997 and moreover, suffered when the electricity market was deregulated. In 2003 the Renewable Portfolio Standard Law did include geothermal energy but only insofar as binary cycle plants were concerned. The 2008 New Energy Law does include geothermal in the definition of New Energy and in January 2010, the Ministry of Economy, Trade and Industry (METI) presented measures for the promotion of renewable energy. METI is providing support by means of subsidies, tax incentives, an RPS and feed-in tariffs, appropriate to the energy source. However, although 2020 targets for other renewable energies are high, geothermal power generation is only expected to grow minimally.

By far the most important utilisation of geothermal hot water in Japan is for direct use. It can be classified into three categories: the thermal use of hot water; geo-heat pumps and hot springs for bathing. The last named has never until recently, been accurately quantified. Based on the consideration that there are more than 25 000 hot springs throughout the country, a figure of nearly 1 700 MW_t expressed in terms of fuel alternative energy was thought to represent this use in 2006. This estimate accounts for some 80% of total direct use. When recreational hot-spring bathing is excluded, the estimated 2006 total installed direct use capacity was 400 MW_t. Of this total, snow melting and air conditioning accounted for 38%; hot water supply and swimming pools, 31%; space heating, 19%; greenhouse heating, 9%; fish breeding 2%; and industrial and other uses, negligible. At the end of the year, some 13 MW_t of ground source heat pumps were estimated to be installed.

Kenya

The country has a high dependence on hydropower for electricity generation (approximately 60%), but the unreliability of the water resource poses a problem, particularly for the industrial sector's power supply and also more generally leads to the purchase of expensive and polluting fossil fuels. With its substantial geothermal resource, the Kenyan Government has expressed its commitment to support the further development of this potential, but in the past this has been impeded by financial constraints.

Twenty prospects lying in the Rift Valley have been identified as worthy of future study. However, to date wells have been drilled at only two sites: at Olkaria near Lake Naivasha (about 120 km northwest of Nairobi) and Eburru. Only the former has been exploited although there is a planned 2.5 MW_e power station at Eburru.

KenGen's Olkaria I was Africa's first geothermal power station when the first unit came into operation in mid-1981, with an initial installed net capacity of 15 MW_e. Two more 15 MW_e units were added in 1982 and 1985.

The 2 x 35 MW_e units of the Olkaria II plant (Africa's largest geothermal power plant, co-financed by the World Bank, the European Investment Bank, KfW of Germany and KenGen) were commissioned in late-2003.

Kenyan geothermal power output was increased by 12 MW_e in 2000 when the first two stages of Kenya's first private geothermal plant were installed at Olkaria III. The 35 MW_e third stage became operational at the beginning of 2009, bringing the total installed capacity to 48 MW_e.

In December 2009 drilling of new wells began at Olkaria. It is expected that 10 new wells will be drilled at Olkaria IV, increasing total capacity by 140 MW_e.

In mid-2008 the Government launched Kenya Vision 2030 and its first Medium Term Plan 2008-2012. The programme aims to transform all aspects of the Kenyan economy. Reforms in the energy sector will include for example, building a strong regulatory framework, encouraging more independent power producers and separating generation from distribution, and it is expected that the exploitation of the geothermal resource will progress. During 2009 the Government established the Geothermal Development Company (GDC) which has the express aim of developing geothermal energy and its contribution to national power production.

GDC reports that one of its objectives is to 'facilitate the realisation of at least 2 000 MW_e in 10 years and at least 4 000 MW_e by 2030 through an accelerated geothermal development program.'

The use of thermal waters for direct purposes is limited, although hot springs are being utilised by hotels to heat spas and there is some use of steam at Eburru for domestic purposes.

To date there has been one successful instance of a commercial direct-use application. Oserian began as a 5 ha vegetable-growing farm in 1969. Today it has grown to be a 210 ha farm specialising in floriculture with an annual output of 380 million stems. The Geothermal Rose Project covers an area of 84 ha. The greenhouse heating system is powered by a 2 MW_e binary-cycle power plant commissioned in September 2004, making the company self-sufficient in electricity needs.

Korea (Republic)

With its heavy reliance on fossil fuels and nuclear power for electricity generation, Korea's energy supply structure has only in recent years come to fully embrace the renewable energies. The 2008 First National Energy Master Plan encompassed the Third Basic Plan on New & Renewable Energy Technology Development, Utilization and Diffusion, 2009-2030. Within the Third Basic Plan, the share of renewable energy aims to satisfy 11% of primary energy supply and 7.7% of electricity generation by 2030. Although the main emphasis of the Plan is directed towards solar PV and hydrogen/fuel cells, development of the geothermal heat pump sector is expected to play its part. Additionally, the Mandatory Public Renewable Energy Use Act which came into force during 2004 states that more than 5% of the budget for any new public building larger than 3 000 m^2 must be used to install renewable energy. This legislation is hastening the growth of geothermal heat pumps.

It is estimated that by end-2008 the installed capacity of geothermal heat pumps amounted to 105.4 MW_t, some eleven times the 2004 level. A further 43.6 MW_t were installed for direct use, 75% of which was used for bathing and swimming. Other uses were for individual space heating and district heating. The latter, a scheme for 21 houses, was due to be expanded to several hundred during 2009. At the end of the year the first greenhouse heating scheme was inaugurated.

Lithuania

Lithuania's geothermal resource, lying in the west of the country, has been found to be significant. In 2000 the 41 MW_t (18 MW_t geothermal heat and 23 MW_t heat from absorption heat pump driven boilers) Klaipeda Geothermal Demonstration Plant (KGDP) was commissioned and began producing 25% of the heat required by the city of Klaipeda.

Much work has been undertaken on the thermal waters in Vilkaviskis, a city in the southwestern part of the country, with a view to developing balneological uses and also a district heating scheme.

To date, Lithuania's extensive low-temperature resource has been harnessed for an estimated 1 000 ground-source heat pumps, with an installed capacity of 17 MW_t.

Mexico

Reflecting the country's location in a tectonically active region, geothermal manifestations are particularly prevalent in the Mexican Volcanic Belt (MVB), as well as in the states of Baja California and Baja California Sur. Development has, in the main, been concentrated on electric power production, although there is a small amount of geothermal power used for direct purposes.

At the present time the country has four operational fields, with a total installed capacity of 958 MW_e:

- Cerro Prieto (northern Baja California), 720 MW_e (13 condensing units, ranging from 25 MW_e to 110 MW_e);

- Los Azufres, (MVB, 250 km west of Mexico City), 188 MW_e (14 condensing, back-pressure and binary units, ranging from 1.5 MW_e to 50 MW_e);
- Los Humeros, (MVB), 40 MW_e (8 x 5 MW_e back-pressure units);
- Las Tres Virgenes (Baja California Sur), 10 MW_e (2 x 5 MW_e condensing units).

During 2008, the four plants generated just over 7 TWh of electrical power, some 3% of national public utility generation.

The Comisión Federal de Electricidad (CFE) plans to develop geothermal power. In 2011 Cerro Prieto is due to have 2 x 37.5 MW_e units replaced by 2 x 50 MW_e condensing units. In the same year a 25 MW_e condensing unit at Los Humeros is due to come into operation; a further 25 MW_e is planned for 2013. The project planned for Los Azufres comprises replacing 7 x 5 MW_e back pressure units with 2 condensing units of 50 and 25 MW_e, raising total capacity to 225 MW_e by 2015. The 25 MW_e capacity Cerritos Colorados in the Jalisco field is scheduled for 2013 with an additional 50 MW_e coming into operation in 2014.

Exploration and feasibility studies of areas where the fields are considered to hold geothermal potential for power generation are currently being undertaking by CFE. It is estimated that in total these fields could be capable of supporting about 1 000 MW_e.

Geothermal heat used directly is predominantly utilised for bathing and swimming. The reported 156 MW_t installed capacity is widely distributed throughout the country. Minimal amounts of direct heat are utilised for space heating, greenhouse heating, agricultural drying and mushroom breeding. Geothermal heat pumps are virtually unknown.

Netherlands

Whilst the Netherlands has a similar geological situation to neighbouring countries, its geothermal potential (estimated to be a theoretical 90 000 PJ) has not been utilised to anywhere near the same extent. The country has access to indigenous low-cost natural gas and other forms of renewable energy that have resulted in a general lack of long-term support and publicity for geothermal power, unlike for example, Germany.

Heat pumps using vertical borehole heat exchangers have been and continue to be installed in private houses and small commercial buildings. Groundwater heat pumps are also used on a small scale, again mainly in small commercial buildings. However there is a significant market for medium to large-scale heat pumps combined with groundwater wells. Most of the systems in operation are installed in commercial buildings, industrial zones and housing developments to provide district heating and cooling schemes.

Development of the deep geothermal energy resource is now taking place. In late 2006 drilling began in Bleiswijk, near The Hague. In 2007 the 65^{o}C water, coming from a depth of 1 700 metres began to provide heating for 7.2 ha of tomato greenhouses. The utilisation of geothermal heat is obviating the need to use 3 million m^3 of natural gas. A second borehole was started in late-2008 in preparation for a doubling in the size of the greenhouses. It is expected that this application will encourage further use by horticulturists.

TNO, a Dutch research institute under contract to the Ministry of Economic Affairs, is currently mapping the deep heat resource in order to reassess the potential of the Netherlands. Analysis of deeper formations may demonstrate the feasibility of the resource for electricity generation.

New Zealand

New Zealand is exceptionally rich in geothermal fields, as well as in a large number of other geothermal features. Fluid temperatures range from 70°C to greater than 220°C in the 129 identified areas. Substantial capacity exists for both the generation of geothermally produced power and also for geothermal heat used directly.

A 2002 assessment of the high-temperature resource suggests that the total resource is estimated as equivalent to a median value of 3 600 MW_e of electrical generation, based on current technology.

With the country's rich geothermal resource, it has been estimated that there could be about an additional 1 500 MW_e capacity that is commercially viable.

Contained in the document New Zealand Energy Strategy to 2050 (published October 2007) is a governmental target that 90% of electricity is to be generated from renewable sources by 2025, with geothermal expected to supply approximately 20%.

Geothermal electricity generating plants have been operating in New Zealand since Wairakei, north of Lake Taupo (North Island) was brought into operation in November 1958. Wairakei was the second geothermal power station to be built in the world and the first to tap a hot pressurised water resource.

At end-2008, installed capacity was 632 MW_e according to the IEA Geothermal Implementing Agreement. However, the Ministry of Economic Development (MED) and the New Zealand Geothermal Assocation quote a level of around 585 MW_e which excludes turbines that have been decommissioned. The Kawerau field saw a 100 MW_e single condensing turbine commissioned in August 2008 and in September, an 8.3 MW_e binary plant. Development of the Ngawha field began in 1998 in a joint venture between Maori interests and Top Energy. The original capacity of 10 MW_e was expanded in October 2008 to bring capacity to 25 MW_e. Nationally, geothermally-generated electricity amounted to nearly 4 TWh during the year, just under 10% of total electricity generation.

Nga Awa Purua, a new 132 MW_e plant is currently being constructed in the Rotokawa field, and is due for completion in 2010. The 23 MW_e binary cycle Centennial Drive station in the Tauhara field (part of the Wairakei-Tauhara system) is also due to be commissioned during 2010.

In September 2008, consent for the initial phase of a replacement for the 51 year-old Wairakei station was granted. However plans for Te Mihi power plant have been postponed owing to the currently reliable service at Wairakei.

There are a considerable number of other electricity generation projects under consideration, ranging from those consented to those in the planning process.

Direct use of geothermal heat remains strong, with about 55% used in the 210 MW_t pulp and paper mill at Kawerau - the largest direct user in the world. In addition to horticulture, aquaculture and kiln drying facilities, heat is used for bathing, space heating and tourist attractions. Often tourist areas and commercial facilities are supplied by fluids and heat from areas associated primarily with generation. At end-2008 an estimated 385 MW_t were in operation, with an output of 9.5 PJ.

Although geothermal heat pumps have been virtually unknown in New Zealand in the past, it is reported that the market is showing signs of development. Some 39 TJ of output was estimated during 2008.

Nicaragua

Nicaragua is the Central American country with the greatest geothermal potential, in the order of several thousand megawatts. Reserves that can be estimated with a higher degree of confidence total about 1 100 MW_e. Medium- and high-temperature resources are associated with volcanoes of the Nicaraguan Depression, which parallels the Pacific Coast.

Geothermal exploration began at the end of the 1960s, focusing on the Momotombo and San Jacinto-Tizate geothermal fields. Studies increased after 1973, at a time when the oil crisis had a large impact on Nicaragua's economy. Geothermal electricity production started at Momotombo in 1983.

Exploitation of geothermal power in the Momotombo area, located at the foot of the volcano of the same name, began when the first 35 MW_e single-flash unit was commissioned in 1983. A second 35 MW_e unit was added in 1989. Thirteen years later following refurbishment by Ormat, the implementation of a new reservoir management plan and the installation of a 7.5 MW_e binary energy converter, the total nominal generation capacity stood at 77.5 MW_e (at end-2008 effective capacity was 28.5 MW_e.)

The San Jacinto-Tizate field was granted an exploitation licence in 2003. Stage 1 of Phase 1 came into operation during 2005 with a nominal 10 MW_e plant. Ram Power Corporation's subsidiary, Polaris Energy Nicaragua (PENSA), the operator of San Jacinto-Tizate began construction of Stage II of Phase I in December 2009. A 36 MW_e unit is expected to become operational by first quarter 2011. It is planned that Phase II will add an additional 36 MW_e unit by fourth quarter 2011, with the original 10 MW_e unit being decommissioned. The final stage would be the addition of a 10 MW_e

bottoming unit in place by third quarter 2012, bringing total capacity to 82 MW_e.

Nicaragua's net geothermal electricity output has been on a rising trend since 1999 and in 2008 totalled 289.8 GWh, just under 10% of total net generation.

Two of the ten identified areas of geothermal potential are currently being explored. GeoNico, a joint venture between the Italian company Enel and LaGeo of El Salvador, is exploring areas located in El Hoyo-Monte Galáan and Managua-Chiltepe.

Papua New Guinea

Positioned as it is in the same tectonic region as Indonesia and the Philippines, exploration has been undertaken to establish the geothermal potential of Papua New Guinea. Since 2002 activity has focused on the island of Lihir, off the northeast coast. In June 2002 a 6 MW_e back-pressure unit was approved by Lihir Gold Ltd (LGL), the owner of the island's gold mine, one of the largest in the world. Commissioning of the plant came just 10 months later and provided the mine with 10% of its power needs.

At end-July 2005 the plant was expanded with the addition of a 30 MW_e unit and in early 2007 a further 20 MW_e were added. The plant currently satisfies approximately 75% of current electricity demand.

During 2008 LGL approved a project to increase the annual processing capacity of its gold mining facility to approximately one million ounces per year, a rise of up to 240 000 ounces. The expansion is expected to be completed during 2012. Drilling is currently being undertaken to ascertain whether there are further reserves of geothermal steam that can be harnessed to supply the expanded facility with power.

Philippines

The Philippines archipelago is exceptionally well-endowed with geothermal resources. Today the country is the world's second largest user of geothermal energy for power generation. With only some 46% of the stated geothermal potential of 4 340 MW harnessed, there is much room for growth.

By end-2008 installed geothermal capacity stood at just under 2 GW_e. Of this figure 1.4 GW_e were considered dependable, representing about 11% of total electric generating capacity. Gross geothermal generation during the year amounted to 10.7 TWh which represented 17.6% of total electricity generation. Plants in the Visayas Islands generated 6.2 GWh; on the island of Luzon, 3.7 GWh and on the island of Mindanao, 0.8 GWh. Gross output in 2008 was 5% higher than in 2007, attributable to both the increased energy transfer from Leyte-Samar to Luzon via the Leyte-Luzon High Voltage Direct Current link – up from 720 GWh to 1 117 GWh and the unavailability of Luzon's coal-fired plants and thus the greater use of geothermal power.

The 2007 Update to the Philippine Energy Plan states the Government's determination to achieve a greater than 60% energy self-sufficiency beyond 2010. In December 2008 the Government legislated for a Renewable Energy Act to come into force at the end of January 2009. The objective of the Act is to accelerate the use of renewable energy so that the country will be able to raise its two-thirds self-sufficiency in electricity generation to possibly as high as 90%. To this end many market development incentives are being put in place. The target for additional geothermal capacity is 790 MW_e.

Direct use of geothermal heat is currently at a low level and is used for agricultural drying and bathing and swimming. The Government plans to further develop direct utilisation.

Poland

Poland has substantial resources of geothermal energy, but not at high temperatures. The available resource ranges from reservoir temperatures of 30°C to 130°C at depths of 1 to 4 km.

Although thermal water has been used for balneological purposes for many centuries, development of geothermal power for heating has only taken place during the past 15 years or so. Both the Strategy of Renewable Energy Resources Development which came into effect in 2000 and Polish membership of the European Union in 2004 have helped to encourage the growth of renewable energy use in general, but greater promotion of geothermal energy is needed.

Since 1992 seven geothermal heating plants have been brought on line: three in the Podhale region (Zakopane, Bukowina Tatrzańska and Bańska Niżna), in Stargard Szczeciński and Pyrzyce (both in the northwest) and in Mszczonów and Uniejow (both in central Poland). The plants are utilised for different purposes according to specific characteristics of the water at each location: some are used with gas peaking - the integrated units have a large contribution from gas, others have integrated absorption heat pumps with gas boilers.

Geothermal water is also used at eight balneological installations. It is estimated that there are about 10 000 compression heat pumps – mostly ground source – within the country with an installed capacity of at least 100 MW.

At the present time it is not foreseen that geothermal heat will be utilised for traditional electricity generation. However, there is an interest in studying binary plants which would be based on 90+°C water.

Portugal

The limited geothermal resources in mainland Portugal have been developed for direct use, whereas geothermal occurrences in the Azores are utilised for the production of electricity as well as being used directly.

Twelve areas with potential for developing geothermal electricity generation have been identified on the islands of Faial, Pico, Graciosa, Terceira and São Miguel in the Azores. Operation of the 3 MW_e Pico Vermelho on São Miguel began in 1981. A second plant came into operation in two phases in 1994 and 1997 and by end-2008 gross geothermal capacity had reached 28.2 MW_e, generating 192 GWh.

Research has shown that the island of Terceira has a high-temperature resource suitable for power generation. Construction of a 12 MW_e plant is planned.

Low-enthalpy occurrences are spread throughout the mainland and have been harnessed for small district heating schemes, greenhouse heating and bathing and swimming (including balneology). Direct use in the Azores excludes district heating. To date there has been little interest in geothermal heat pumps. At end-2009, total installed capacity stood at 27.8 MW_t of which 25.3 MW_t was for bathing and swimming, 1 MW_t for greenhouse heating and 1.5 MW_t for district heating.

Romania

Romania's low-enthalpy geothermal potential lies mainly along the western border with Hungary and in the south-central part of the country. Usage of the country's springs has been known since Roman times but it was only during the 1960s that energy-directed exploration began and then as an unexpected result of a hydrocarbon research programme. To date more than 250 exploration wells have been drilled. Completion and experimental exploitation of more than 100 wells during the past 25 years has enabled the evaluation of the heat available from this resource. The geological research programme is continuing, with a few new wells drilled each year, all being usually completed as potential production or injection wells.

The transition to a market economy, together with the run-up to membership of the European Union, have certainly assisted with the development of geothermal energy in Romania but for the full potential of the resource to be realised, access to adequate funding and the latest technology is required.

Currently geothermal heat is used only for direct purposes - there is no use for electricity generation. The installed capacity of 174 MW_t is utilised for space and district heating, bathing and swimming (including balneology), greenhouse heating, industrial process heat, fish farming and animal husbandry.

Near and mid-term plans include drilling of new production and reinjection wells, expansion of existing district heating schemes and development of some new ones, expansion of greenhouse heating and development of health and recreational bathing facilities. There is an evaluated potential in Romania of 20 MW_e for power generation and thus research will be undertaken into the possible use of binary plants.

Russian Federation

The Russian Federation has a significant geothermal resource, with thermal waters of 50-200°C having been identified in numerous areas from Kaliningrad in the west to the Russian Far East. In the Kamchatka Peninsula and the Kuril Islands the thermal water reaches 300°C. It has been estimated that the high-temperature resources defined to date in the Peninsula could ultimately support generation of 2 000 MW_e and 3 000 MW_t of heat for district heating. Exploration has shown that the discovered geothermal resource of Kamchatka could provide the peninsula's total demand for both heat and electricity for in excess of 100 years.

The country's energy sector has long been based on fossil fuels and the exploitation of hydroelectric and nuclear power. The contribution from geothermal energy represents a very small percentage. Considering the Federation's vast area and also the logistics of fuel transportation, the use of geothermal heat for power generation could be particularly important in the northern and eastern regions. However, the main thrust of Russian geothermal utilisation has been, and continues to be, for direct purposes.

The first plant using geothermal energy for power generation in Kamchatka was commissioned at Pauzhetka, south of Kamchatka in 1966. Four further plants were installed in 1999, 2002 and 2007 and by end-2008, total installed capacity stood at 81.9 MW_e. A 2.5 MW_e plant in Kamchatka and a 3.2 MW_e plant are currently under construction.

The use of geothermal heat for direct purposes is widespread and has mostly been developed in the Kuril-Kamchatka region, Dagestan and Krasnodar Krai. Many district heating and greenhouse heating schemes already exist, together with use of geothermal heat for industrial processes, cattle and fish farming, drying of agricultural products, and swimming pools and baths. There are plans for greater exploitation in Krasnodar Krai and the regions of Kaliningrad and Kamchatka.

There is much scope for the installation of heat pumps in Russia, but their use is presently at an early stage of development.

In January 2009 the Russian Prime Minister signed an Executive Directive for a greater use of renewable energy in order for the efficiency of the electric power sector to be improved. The targets for the share of renewable energy in electricity generation are 1.5% in 2010, 2.5% in 2015 and 4.5% by 2020. At the beginning of 2010 it was reported that a Ministerial MOU had been signed between Finland and Russia. The stated objective is that cooperation and shared knowledge will lead to greater energy efficiencies and improved utilisation of renewable energies.

Serbia

Exploration for geothermal resources in Serbia began in 1974: four provinces were discovered and preliminary drilling and pilot studies ensued. At the present time the main utilisation is at thermal spas for balneology and recreation. However, the 97 MW_t installed capacity is used for bathing and swimming, space heating, greenhouses, fish and other animal farming, industrial process heat and agricultural drying. In addition, about 22 MW_t of thermal water heat pumps are in use.

Slovakia

Slovakia's geothermal resources, first explored during the 1970s, have been located in areas covering 27% of the territory. The country has thermal waters ranging from low temperature (20-100^{o}C) to medium temperature (100-150^{o}C) to high temperature (>150^{o}C). At the present time, utilisation is only for direct purposes: bathing and swimming, district heating, greenhouse heating and fish farming.

Several projects are under development: a greenhouse heating scheme in Podhajska; a district heating scheme in Galanta and a space heating project in Slovakia's second city, Košice. The Košice scheme is in the final stage of preparation, having obtained the necessary permits and awaits the go-ahead prior to implementation.

Spain

Research has shown that a low-enthalpy geothermal resource is widely distributed across the Spanish mainland. The main areas are in the northeast, southeast, northwest and the centre. In the Canary Islands, it has been found that a high-temperature resource exists on Tenerife (but is not commercially viable) and that Lanzarote and La Palma have an HDR resource.

To date the geothermal resource has not had a major role in the Spanish energy economy. However, at the end of 2007, geothermal gained a higher profile within the Institute for the Diversification and Saving of Energy (IDEA) with the creation of the Hydroelectric and Geothermal Department, which together with the Instituto Geológico y Minero de España (IGME), will promote the technology and utilisation of geothermal energy. At the end of 2008, the country became a member of the IEA Implementing Agreement for Cooperation in Geothermal Research and Technology.

The main initiatives in the geothermal sector are: the development of the emerging market for geothermal heat pumps, the coming to fruition of various geothermal district heating schemes in 2011 and power generation projects in 2013 and the evaluation of high temperature resources.

There is a limited amount of capacity installed for direct purposes: - some 6 MW_t in 2008 utilised for individual space heating, greenhouse heating and swimming and bathing.

Sweden

Sweden's utilisation of deep geothermal heat is on a very limited scale. however, Lund, in the far south of Sweden, has two heat pumps totaling about 47 MW_t providing base-load heat to a district heating network. The plant was connected to the network in 1984 and started heat production in 1985.

There are many small ground-source heat pumps installed in the country. It is reported that more than 350 000 small heat pumps have been installed in residential and official buildings, providing an estimated 10% of heat demand.

The Swedish Deep Drilling Program began in 2007. The purpose of the Program is to ‘study fundamental problems of the dynamic Earth system, its natural history and evolution’. In 2009 a grant was awarded for a mobile truck-mounted drillrig that is capable of reaching a depth of 2 500 m. Supported by the International Scientific Drilling Program, drilling is planned to begin in 2011.

Switzerland

Switzerland's installed capacity for utilising geothermal energy has grown rapidly in recent years and the country now ranks among the world leaders in direct-use applications (there is no geothermal-based electricity at the present time). There are two main components to Switzerland's geothermal energy: the utilisation of shallow resources by the use of horizontal coils, borehole heat exchangers (BHE), foundation piles and groundwater wells, and the utilisation of deep resources by the use of deep BHEs, aquifers by singlet or doublet systems, and tunnel waters. In virtually all instances heat pumps are the key components.

Ground-source heat pumps are installed throughout the country. Total heat production from geothermal sources in 2008 was 5 729 TJ, Of this total, 1 046 TJ was used for balneological purposes and almost all the remainder involved the use of heat pumps, of which the majority used BHE technology.

Several hydrothermal projects are in the planning stage.

Research had shown that the area of Basle in northern Switzerland had the required criteria (a temperature of 200°C at about 5 km depth and an existing large heat distribution system) for the development of EGS. Following the start of the project in 1996 the first three wells were drilled. However, at the end of 2007 an induced earthquake caused by the drilling, resulted in the project being halted. At the end of 2009, it was announced that the Basle project has been stopped pending further study.

There remains substantial room for growth in Switzerland's geothermal sector. The annual growth-rate for heat pumps is estimated at 15% and the Government is actively supporting research and development into geothermal energy.

Tanzania

Preliminary studies conducted in different parts of Tanzania by surface geological exploration, magnetic and gravity data analyses and reconnaissance exploration have indicated that the country possesses high-temperature (exceeding 200°C) fluids beneath the volcanoes.

The presence of hot springs has provided a positive indication of the country's geothermal potential. Fifty hot springs have been sampled, with the majority having a surface temperature of 86°C and a reservoir temperature of 220-276°C.

Presently the country's geothermal resource is not utilised. However, and especially in the light of an increasing energy requirement, the National Energy Policy 2003 showed the need to assess the potential and establish its viability.

Thailand

Investigations of geothermal features in Thailand began in 1946 and subsequently more than 90 hot springs located throughout the country were mapped. However, it was not until 1979 that systematic studies of the resources began.

A small (0.3 MW_e) binary-cycle power plant was installed at Fang, in the far north near the border with Myanmar. Since commissioning in December 1989, this sole Thai geothermal plant has operated successfully, with an 85-90% availability factor. In addition, the Electricity Generating Authority of Thailand (EGAT) is using the 80^{o}C exhaust from the power plant to demonstrate direct heat uses to the local population. The exhaust can be used for crop drying and air conditioning (the latter not currently in use). A further example of utilising the heat directly is a public bathing pond and sauna that have been constructed by the Mae Fang National Park.

Turkey

A significant factor in Turkey's high geothermal potential is the fact that the country lies in the Alpine-Himalayan orogenic belt. It has been determined that Western Anatolia, containing the areas of most significance, accounts for about 78% of the 31.5 GW potential.

Geothermal exploration began during the 1960s, since when about 186 fields have been identified. Although some of these are high-enthalpy fields, 95% are low-medium enthalpy resources and thus more suited to direct-use applications.

Turkey has harnessed about 7% of the huge low-medium enthalpy resource at its disposal, utilising it mainly for district heating, greenhouse heating and balneological purposes. By end-2009, it was estimated that direct use installed capacity had risen to 2 084 MW_t, of which 1 011 MW_t was used for domestic space heating (including district heating), 483 MW_t for greenhouse heating and 552 MW_t for balneological purposes. The installed capacity of geothermal heat pumps was relatively small, at less than 40 MW_t.

Following research undertaken in 1968 into using geothermal resources for the production of electricity, a 0.5 MW_e pilot plant was installed in 1974 in the Kizildere field (near Denizli in southwestern Turkey). In 1984 the 20 MW_e single-flash Kizildere geothermal power plant came into operation. In addition to electricity generation, the plant has an integrated liquid CO_2 and dry-ice production factory that utilises the geothermal fluids.

By end-2008 installed electricity generating capacity totalled 34.2 MW_e. In February 2009 the 47.4 MW_e Ömerbeyli plant became operational and was grid-connected by the end of March 2009. By the end of 2010, capacity is expected to have reached nearly 100 MW_e, with the completion of two additional geothermal power plants.

Uganda

Uganda's power sector relies heavily on indigenous hydroelectricity. The country is particularly well-endowed with a hydro resource but large losses due to long transmission lines, together with the possible effects of climate change on the supply of water, has ensured that the Government recognises the importance of diversification. The 2007 Renewable Energy Policy for Uganda states that modern renewable energy should increase from the current 4% to 61% of total energy consumption by 2017.

Research has established that three areas in particular, lying in the west of the country near the border with the Democratic Republic of Congo, have considerable geothermal potential. Assessments have shown that the three prospects, Katwe-Kikorongo, Buranga and Kibiro have an estimated potential of 450 MW and if the temperatures of 140-200°C, 120-150°C and 200-220°C respectively are confirmed, then production or electricity and direct use in industry and agriculture could follow. Further investigative work is to be undertaken on these known prospects and in other areas of the country.

United Kingdom

There is no recorded high-temperature resource in the UK and although the country possesses a low- and medium-enthalpy resource it is, unlike some of its European neighbours, very under-utilised.

Historically there has been no direct Government support for geothermal energy and the only application of low-enthalpy geothermal energy is the scheme, launched in 1986 in the city of Southampton. The scheme now supplies more than 40 GWh/yr of heat, 26 GWh of electricity from the combined heat and power plant and over 7 GWh of chilled water for air conditioning.

Again, historically there have only been isolated instances of ground-source heat pumps in existence. However, the Government's Low Carbon Transition Plan and the Renewable Energy Strategy both include heat pumps in the list of technologies that the UK must adopt if renewable energy targets are to be met. It has become evident that this technology is gradually gaining in acceptance. In April 2007, the Code for Sustainable Homes came into operation as the national standard for sustainable new build homes and as such encourages the integration of ground source heat pumps where feasible.

The Government has also stated that it will provide GBP 6 million to explore the potential for deep geothermal power in the UK. Past research has shown the southwest region of England to be an area particularly rich in this resource.

An ambitious plan to regenerate the site of a cement works which closed in 2002 will hopefully lead to a renewable energy village in Upper Weardale, County Durham. The area, which was formerly mined for lead and fluorspar, is known to possess a source of geothermally-heated water (46°C at a depth of 1 000 m). The Weardale Task Force's Master Plan for the eco-friendly village envisages that the heat will be utilised for a public hot-springs spa and fish-breeding ponds. Additionally, the development will include environmentally-friendly commercial and residential property and a range of tourist and leisure activities based on the use of biomass (for a district heating scheme), wind, solar and hydro technologies.

A planning application for the village gained first stage approval in September 2009. Final approval has still to be granted but it is hoped that construction could start in 2011.

The 2008 Energy Act provided the wherewithal for the Government to introduce feed-in tariffs (FIT). From 1 April 2010 renewable energy electricity-generating technologies qualify for generation and export tariffs. FITs will work alongside the Renewables Obligations. The Renewable Heat Incentive, applicable to renewable systems generating heat, will come into force on 1 April 2011 to work alongside the feed-in tariffs for electricity.

United States of America

The USA possesses a huge geothermal resource, located largely in the western half of the country. Research has shown that geothermal energy has been used in North America for many thousands of years but the first documented commercial use was in 1830 in Arkansas. In 1922 an experimental plant began generating electricity in California but, proving to be uneconomic, it soon fell into disuse. Another 38 years were to pass before the first large-scale power plant began operations at The Geysers, north of San Francisco, California. The USA is the world's largest producer of electricity generated from geothermal energy.

The U.S. Department of Energy (DOE) reports that at end-2008 installed geothermal power capacity was 3 277 MW_e, although a proportion of this is on standby or at least operating below the nameplate level, net electrical capacity is thus considerably lower. By early 2010, gross installed capacity was 3 168 MW_e, with net running capacity put at 1 748 MW_e.

Nine States: Alaska, California, Hawaii, Idaho, Nevada, New Mexico, Oregon, Utah and Wyoming harness their geothermal resource for electricity, but at the present time it is California that has the majority share at 83%. Nevada follows with 14% and at the other end of the spectrum, New Mexico, Oregon and Wyoming each have less than 0.01%. In the case of Oregon, a 280 kW_e binary unit provides power for the campus of the Oregon Institute of Technology.

The DOE states that an additional capacity totaling 80 MW_e is under construction and a further 234 MW_e is planned. Geothermal systems, with a potential capacity of 9 057 MW_e have been identified in 13 western States, approximately 5 800 MW_e more than that currently operating. Based on Geographic Information Systems statistical models, the mean estimated undiscovered resources in the 13 States is more than 30 GW_e.

The DOE's Geothermal Technologies Program is focused on Enhanced Geothermal Systems (EGS) technology, with activities ranging from site selection for future development to site characterisation, reservoir creation and validation, interwell connectivity, reservoir scale-up and reservoir sustainability. On the assumption that this technology is successfully implemented, models yield an estimated mean electric power resource on private and accessible public land of 517 800 MW_e in the 13 States. Development of an EGS R&D demonstration project at Desert Peak, Nevada is already under way.

Geothermal heat suitable for direct utilisation is far more widespread, ranging from New York State in the east to Alaska in the west. Data reported to the 2010 World Geothermal Congress (WGC) estimates that direct use capacity at end-2009 was 611 MW_t. Geothermal is used directly for fish and animal farming (142 MW_t), greenhouse heating (97 MW_t), bathing and swimming (113 MW_t), district heating (75 MW_t), space heating (140 MW_t), agricultural drying (22 MW_t), industrial process heat (17 MW_t), snow melting (3 MW_t) and air conditioning (2 MW_t).

The report to the WGC 2010 also reports that the number of geothermal heat pumps has grown rapidly in recent years. It is estimated that total installed capacity at end-2009 was some 12 000 MW_t.

The Emergency Economic Stabilization Act (ESSA) of 2008 and the American Recovery and Reinvestment Act (the Recovery Act) have both been instrumental in the development of geothermal power. The ESSA extended Production Tax Credits (PCT) for geothermal until end-2010 and introduced a 30% individual tax credit for heat pumps, capped at US$ 2 000.

The US$ 787 billion Recovery Act passed into law in early 2009 and provides the wherewithal to promote an economic recovery following the recession. The Act has allotted US$ 16.8 billion for the Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE). Specifically US$ 350 million is designed to support four areas of research into geothermal technologies: geothermal demonstration projects; Enhanced Geothermal Systems R&D; innovative exploration techniques; and a National Geothermal Data System, Resource Assessment and Classification System. The Recovery Act has further extended the geothermal PCT until end-2013, improved the conditions applying to the various tax credits and grants available and removed the US$ 2 000 cap on heat pumps.

Vietnam

The government-supported exploration and evaluation of the country's geothermal resource has shown that there is a total of 269 prospects of which 30 sites, with a capacity of 340 MW_e have been identified as being capable of power generation. The south-central, north-western and northern regions are the areas of Vietnam with the greatest potential.

At the present time there is no geothermal power generation. Although it is considered that large power plants would be infeasible, six locations have been chosen for units totaling some 97 MW_e.

Direct utilisation is limited to the provision of industrial process heat (iodide salt production) and bathing and swimming. The theoretical capacity of direct use has been estimated at 472 MW_t, of which 200 MW_t could be in operation by 2020.

12. Wind Energy

COMMENTARY

Resource and Potential

Wind energy has been utilised by man for thousands of years, initially to provide mechanical energy and now to provide electricity. It is available virtually everywhere on earth, although there are wide variations in wind strengths. The total resource is vast; one estimate (Cole, 1992) suggests around a million GW 'for total land coverage'. If only 1% of the area was utilised, and allowance made for the lower load factors of wind plant (15-40%, compared with 75-85% for thermal plant) that would still correspond, roughly, to the total worldwide capacity of all electricity-generating plant. Another estimate (Archer and Jacobson, 2005) suggests that the global wind resource, exploiting only the best sites (with wind speeds above 6.9 m/s at 80 m) could cover world electricity needs seven times over. The offshore wind resource is also vast, with European resources, for example, capable of supplying all the European Union's electricity needs, without going further than 30 km offshore.

The location of the 'best' onshore wind resources, based on maps by Czisch (2001), and the analysis of Archer and Jacobson (2005) is summarised in Fig. 12.1, which shows that wind energy resources are well distributed.

Figure 12.1 Summary of locations of the most attractive regions for wind energy (Source: Czisch, 2001)

Region	Location
Europe	North and west coasts of Scandinavia and the UK, some Mediterranean regions
Asia	East coast, some inland areas, Pacific Islands
Africa	North, southwest coast
Australasia	Most coastal regions
North America	Most coastal regions, some central zones, especially where mountainous
South America	Best towards the south, coastal zones in east and north

The rapid growth of wind energy may be demonstrated by noting that the projection for 2010 set out in the European Commission's White Paper on renewable energy (EC, 1997), was 40 GW. That was 16 times the capacity in 1995, but the target was realised by 2005 and by late 2009, European capacity was over 72 GW.

World wind energy capacity has been doubling about every three and a half years since 1990 as shown in Fig. 12.2. It is doubtful whether any other energy technology is growing, or has grown, at such a rate. Total capacity at the end of 2008 was over 120 GW and annual electricity generation around 227 TWh, roughly equal to Australia's annual consumption. The United States, with about 25 GW, has the highest capacity but Denmark with over 3 GW, has the highest level per capita, and production there corresponds to about 20% of Danish electricity consumption.

Wind energy is being developed in the industrialised world for environmental reasons and it has attractions in the developing world as it can be installed quickly in areas where electricity is urgently needed. In many instances it may be a cost-effective solution if fossil fuel sources are not readily available. In addition there are many applications for wind energy in remote regions, worldwide, either for supplementing diesel power (which tends to be expensive) or for supplying farms, homes and other installations on an individual basis.

Most wind capacity is located onshore but offshore wind sites have been completed, or are planned, in China, Denmark, Ireland, Sweden, Germany, the Netherlands, the UK and elsewhere. By end-2009, over 1 500 MW was operational. Offshore wind is attractive in locations where pressure on land is acute and winds may be 0.5 to 1 m/s higher than onshore, depending on the distance from the coast. The higher wind speeds do not presently compensate for the higher construction costs, but the chief attractions of offshore are its large resource and low environmental impact.

Types of Modern Wind Turbine

Early machines - 25 years ago - were fairly small (50-100 kW, 15-20 m diameter) but there has been a steady growth in size and output power. Several commercial types of wind turbine now have ratings over 3 MW and diameters around 60-80 m; machines for the offshore market have outputs up to 6 MW and diameters up to 126 m. The way in which sizes have increased is shown in Fig. 12.3; the average rating of turbines installed in Germany in 1992 was 180 kW and in 2008 it was just under 2 000 kW – over ten times as much.

Machine sizes have increased for two reasons. They are cheaper and they deliver more energy. The energy yield is improved partly because the rotor is located higher from the ground and so intercepts higher-velocity winds, and partly because they are slightly more efficient. Energy yields, in kWh per square metre of rotor area, are

Figure 12.2 Growth of world wind capacity
(Source: Milborrow and 'Windpower Monthly')

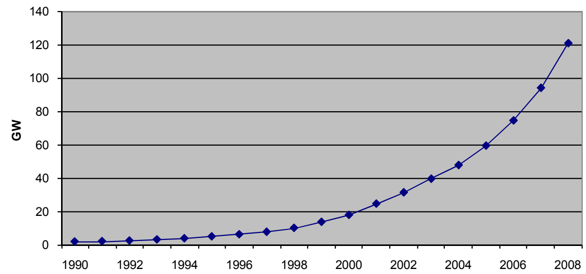
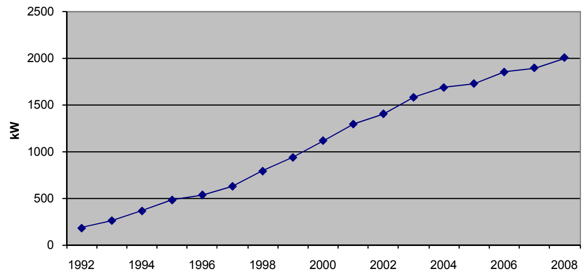


Figure 12.3 Average size of wind turbines installed in Germany, 1992-2008
(Source: German Wind Energy Institute [DEWI])



now double those of 1990 (Welke and Nick-Leptin, 2006). In 2008, data from the Danish Energy Agency showed that the most productive machines delivered around 1 500 kWh per square metre of rotor area. Reliability has also improved steadily and availabilities of 95% or more are common.

The majority of the world's wind turbines have three glass-reinforced plastic blades. The power train includes a low-speed shaft, a step-up gearbox and an induction generator, either four- or six-pole. However, the market is evolving and there are numerous other options. Wood-epoxy is an alternative blade material and some machines have two blades. Variable-speed machines are becoming more common and many generate power using an AC/DC/AC system, but double-fed induction generators are becoming established. These also allow variable-speed operation, which brings several advantages - it means that the rotor turns more slowly in low winds (which keeps noise levels down), it reduces the loadings on the rotor, which can operate with higher efficiency, and the generators are usually able to deliver current at any specified power factor. Direct drive systems are becoming increasingly common. These eliminate the gearbox and are usually of the variable-speed type, with power conditioning equipment.

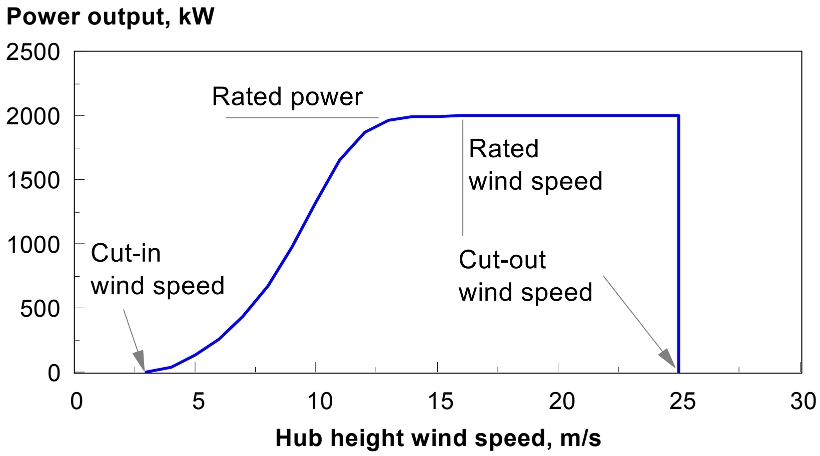
Towers are usually made of steel and the great majority are of the tubular type. Lattice towers, common in the early days, are now rare, except for small machines in the range 100 kW and below. Recent increases in the price of steel have re-awakened interest in concrete towers but there are relatively few examples yet.

As the power in the wind increases with the cube of the wind speed, all wind turbines need to limit the power output in very high winds. There are two principal means of accomplishing this, with pitch control on the blades or with fixed, stall-controlled blades. Pitch-controlled blades are rotated as wind speeds increase so as to limit the power output and, once the 'rated power' is reached, a reasonably steady output can be achieved, subject to the control system response. Stall-controlled rotors have fixed blades which gradually stall as the wind speed increases, thus limiting the power by passive means. These dispense with the necessity for a pitch control mechanism, but it is rarely possible to achieve constant power as wind speeds rise. Once peak output is reached the power tends to fall off with increasing wind speed, and so the energy capture may be less than that of a pitch-controlled machine. The merits of the two designs are finely balanced and until recently roughly equal numbers of each type were being built. Since the turn of the century, however, pitch-controlled machines have become much more popular.

Energy Production

Contrary to popular opinion, energy yields do not increase with the cube of the wind speed, mainly because wind energy is discarded once the rated wind speed is reached. It does not make economic sense to build turbines with very high ratings that will only be reached on rare occasions. To illustrate the key parameters and the concept of rated output, a typical power curve for a 2 MW machine, 80 m in diameter, is shown in Fig. 12.4. Most machines start to generate at a similar speed -

Figure 12.4 Power curve and key concepts for a 2 MW wind turbine
(Source: Vestas Wind Systems A/S)



around 3 to 5 m/s - and shut down in very high winds, generally around 20 to 25 m/s.

Annual energy production from the turbine whose performance is charted in Fig. 12.4 is around 2 457 MWh at a site where the wind speed at 78 m height is 5 m/s, 5 629 MWh at 7 m/s and 6 725 MWh at 8 m/s. Wind speeds around 5 m/s can be found, typically, away from the coastal zones in all five continents, but developers generally aim to find higher wind speeds. Levels around 7 m/s are to be found in many coastal regions and over much of Denmark; higher levels are to be found on many of the Greek Islands, in the Californian passes - the scene of many early wind developments - and on upland and coastal sites in the Caribbean, Ireland, Sweden, the UK, Spain, New Zealand and Antarctica. Offshore wind speeds are generally higher than those onshore – around 8 m/s in European coastal waters, for example.

Wind Energy Costs

The cost of wind energy plant fell substantially during the period from 1980 to 2004. Prices in the 1980s were around US$ 3 000/kW, or more, and by 1998 they had come down by a factor of three. During that period the size of machines increased significantly - from around 55 kW to 1 MW or more - and manufacturers increased productivity substantially. In 1992, for example, one of the major manufacturers employed over seven people per megawatt of capacity sold, but by 2001 only two people per megawatt were needed. The energy productivity of wind turbines also increased during this period. This was partly due to improved efficiency and availability, but also due to the fact that the larger machines were taller and so intercepted higher wind speeds. A further factor that led to a rapid decline in electricity production costs was the lower operation and maintenance costs.

With capital costs halving between 1985 and the end of the century, and productivity doubling, it could have been expected that electricity production costs would fall by a factor of four. This general trend has been confirmed by data from the Danish Energy Agency; these suggest that generation costs fell from DKK 1.2/kWh in 1982 to around DKK 0.3/kWh in 1998 (Danish Energy Agency, 1999).

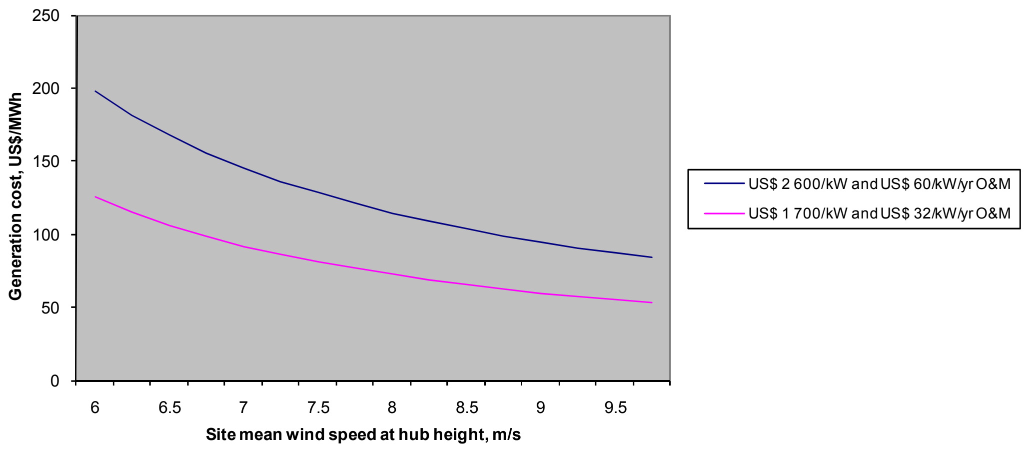
Shortly after the turn of the century, the downward trend in wind turbine and wind farm prices halted and prices moved upwards. This was partly due to significant increases in commodity prices and partly due to shortages of wind turbines. Prices appear to have peaked in 2008, with complete wind farms averaging just under US$ 2 200/kW and wind turbines at just under US$ 1 600/kW. Prices may now be falling, based on data available to the autumn of 2009.

Generation costs

No single figure can be quoted for the installed cost of wind farms, as much depends on the difficulty of the terrain, transport costs and local labour costs. Generation costs depend, in addition, on the wind speed at the wind farm site - since this determines the energy productivity - and on the financing parameters. The latter depend on national institutional factors which influence whether wind

Figure 12.5 Generation costs for onshore wind

(Source: Milborrow)



farm investments are seen as high or low risk. Although there is a broad consensus that wind turbines are now sufficiently reliable to enable depreciation over a 20-year period, the 'weighted average cost of capital' (WACC) may lie between 5% and 11%. (The WACC is a weighted average interest rate that takes into account the cost of both bank loans and equity investments).

Typical generation costs are shown in Fig. 12.5, using installed costs between US$ 1 700/kW and US$ 2 600/kW, an 8% interest rate and a 20-year amortisation period. Operating costs, which cover the costs of servicing, repairs, management charges and land leases have been set at US$ 32/kW/yr for the lower capital cost and US$ 60/kW/yr for the higher capital cost. The link between wind speed and energy productivity has been established by examining the performance characteristics of a number of large wind turbines that are currently available. Although there is not a unique link between wind speed and capacity factor, the spread is quite small. All wind speeds refer to hub height. The estimates suggest that generation costs at US$ 2 600/kW range from just under US$ 200/MWh at 6 m/s, falling to US$ 84/MWh at 9.75 m/s. At US$ 1 700/kW, the corresponding range is US$ 125/MWh to US$ 53/MWh, respectively.

Wind Farms

The way in which wind energy has developed has been influenced by the nature of the support mechanisms. Early developments in California and subsequently in the UK, for example, were mainly in the form of wind farms, with tens of machines, but up to 100 or more in some instances. In Germany and Denmark the arrangements favoured investments by individuals or small cooperatives and so there are many single machines and clusters of two or three. By building wind farms, economies of scale can be realised, particularly in the civil engineering and grid connection costs and possibly by securing ‘quantity discounts’ from the turbine manufacturers.

Offshore Wind Farms

The attractions of offshore wind are the availability of a huge resource, low environmental effects and good wind speeds - often exceeding 8 m/s - which are only found on limited numbers of onshore sites. The downsides are the need to protect the wind turbines from salt spray, the higher foundation and installation costs and the additional expenses of organising operation and maintenance activities.

Offshore wind installations have been built in the waters around Belgium, China, Denmark, Germany, Ireland, the Netherlands and the United Kingdom. A number of projects are being planned in Canada and the USA. The UK Government has recently awarded concessions that allow the development of up to 32 GW of offshore wind; when this is added to awards from licensing rounds, the UK is set to host up to 40 GW in total.

Economies of scale deliver more significant savings in the case of offshore wind farms and many of the developments involve large numbers of machines. Fig. 12.6 gives an indication of typical parameters for offshore and onshore wind farms. The strength of the offshore wind may be gauged by noting that the offshore wind farm is half the capacity of the onshore farm, but delivers well over half the energy output.

Figure 12.6 Key features of an onshore and an offshore wind farm

	Onshore	Offshore
Project name:	Hadyard Hill, Scotland	Alpha Ventus, Germany
Project location:	72 km south of Glasgow, in the Southern Highlands of Scotland	45 km from the coast
Site features:	moorland, 250 m above sea level	water depth 30 m
Turbines:	52 x 2.3 MW	12 x 5 MW
Project rating:	120 MW	60 MW
Turbine size:	58 and 68 m hub height, 82 m diameter	90 m hub height, 116 m diameter (6) 92 m hub height, 126 m diameter (6)
Energy production (annual):	320 000 MWh	220 000 MWh
Construction completed:	2005	2009
Source:	Scottish and Southern Energy	E.ON Climate and Renewables, EWE and Vattenfall Europe

Small Wind Turbines

Although the largest wind turbines tend to attract most interest, there is a wide range of sizes available commercially, from small battery-charging machines with ratings of a few Watts, up to, say 100 kW for farm use. A recent review of this market (Frey, 2010) found 124 manufacturers and suggested the term 'micro SWTs' be used for machines up to 1 kW output, 'mini' up to 10 kW output and 'midi' up to 100 kW output. Although such turbines are relatively more expensive than their larger counterparts, they are generally not competing with electricity from large thermal power stations and may be the only convenient source of power - possibly in conjunction with batteries or diesel generators. In developing countries small wind turbines are used for a wide range of rural energy applications, and there are many 'off-grid' applications in the developed world as well - such as providing power for navigation beacons and road signs. Since most of these are not connected to a grid, many use DC generators and run at variable speed. A typical 100 W battery-charging machine has a shipping weight of only 15 kg.

A niche market, where wind turbines often come into their own as the costs of energy from conventional sources can be very high, is in cold climates. Wind turbines may be found in both polar regions and in northern Canada, Alaska and Finland.

Environmental Aspects

No energy source is free of environmental effects. As the renewable energy sources make use of energy in forms that are diffuse, larger structures, or greater land use, tend to be required and attention may be focused on the visual effects. In the case of wind energy, there is also discussion of the effects of noise and possible disturbance to wildlife - especially birds. It must be remembered, however, that one of the main reasons for developing the renewable sources is an environmental one - to reduce emissions of greenhouse gases. Several studies have shown that wind plants 'repay' the energy used during construction by about 6 months or less, and so electricity generated after that time realises substantial emission savings. In many cases wind generation displaces coal-fired plant, so 1 kWh of wind saves about 0.8-1 kg of carbon dioxide.

Noise

Almost all sources of power emit noise, and the key to acceptability is the same in every case - sensible siting. Wind turbines emit noise from the rotation of the blades and from the machinery, principally the gearbox and generator. At low wind speeds wind turbines generate no noise, simply because they do not generate. The noise level near the cut-in wind speed (Fig. 12.4) is important since the noise perceived by an observer depends on the level of local background noise in the vicinity, and this has a masking effect. At very high wind speeds, on the other hand, background noise due to the wind itself may be higher than noise generated by a wind turbine. The intensity of noise reduces with distance and it is also attenuated by air absorption. The exact distance at which noise from turbines becomes ‘acceptable’ depends on a range of factors, especially local planning guidelines.

Television and radio interference

Wind turbines, like other structures, can sometimes scatter electro-magnetic communication signals, including television. Careful siting can avoid difficulties, which may arise in some situations if the signal is weak. Fortunately it is usually possible to introduce technical measures - usually at low cost - to compensate.

Birds

The need to avoid areas where rare plants or animals are to be found is generally a matter of common sense, but the question of birds is more complicated and has been the subject of several studies. Problems arose at some early wind farms that were sited in locations where large numbers of birds congregate - especially on migration routes. However, such problems are now rare, and it must also be remembered that many other activities cause far more casualties to birds, such as the ubiquitous motor vehicle. In practice, provided investigations are carried out to ensure that wind installations are not sited too near large concentrations of nesting birds, there is little cause for concern. Most birds, for most of the time, are quite capable of avoiding obstacles and low collision rates are reported where measurements have been made.

Visual effects

One of the more obvious environmental effects of wind turbines is their visual aspect, especially that of a wind farm comprising a large number of wind turbines. There is no measurable way of assessing the effect, which is essentially subjective. As with noise, the background is important. Experience has shown that good design and the use of subdued neutral colours – ‘off-white’ is popular - minimises these effects. The subjective nature of the question often means that extraneous factors come into play when acceptability is under discussion. In Denmark and Germany, for example, where local investors are often intimately involved in planning wind installations, this may help to ensure that the necessary permits are granted without undue discussion. Sensitive siting is the key to this delicate issue, avoiding the most cherished landscapes and ensuring that the local community is fully briefed on the positive environmental implications.

Integration into Supply Networks

Electricity systems in the developed world have evolved so as to deliver power to the consumers with high efficiency. One fundamental benefit of an integrated electricity system is that generators and consumers both benefit from the aggregation of supply and demand. On the generation side, this means that the need for reserves is kept down. In an integrated system the aggregated maximum demand is much less than the sum of the individual maximum demands of the consumers, simply because the peak demands come at different times.

Wind energy benefits from aggregation; it means that system operators cannot detect the loss of generation from a wind farm of, say, 20 MW, as there are innumerable other changes in system demand which occur all the time. Numerous utility studies have indicated that wind can readily be absorbed in an integrated network at modest cost. Several studies have been reviewed by the International Energy Agency (2005). More recent estimates suggest 10% wind energy is likely to incur extra costs in the range GBP 2.5-5/MWh (US$ 4-8/MWh) and 20% wind energy in the range GBP 3-6/MWh (US$ 5-10/MWh), approximately (Milborrow, 2009). Beyond 20%, some wind power may need to be curtailed on a few occasions if high winds coincide with low demand, but there are no 'cut-off' points. Practical experience at these levels is now providing a better understanding of the issues involved.

Future Developments

The very rapid growth in Denmark and Germany, up to around 2003/4, has now slowed, but Spain, India, China and the United States are now forging ahead and there are plans for further capacity in Canada, the Middle East, the Far East and South America. The future rate of development will depend on the level of political support from national governments and the level of commitment, internationally, to achieving carbon dioxide reduction targets.

Projections of future capacity vary. The International Energy Agency's Reference Scenario (IEA, 2009) suggests 422 GW by 2020, but other studies suggest higher values. The European Wind Energy Association (EWEA, 2009) suggests there will be 230 GW in Europe by 2020, of which 40 GW will be offshore. The technology has developed rapidly during the past 20 years, is still maturing and further improvements are expected both in performance and cost.

Taking the IEA's cautious estimate of 422 GW for the installed capacity in 2020 and assuming an installed cost of US$ 2 000/kW suggests investments of around US$ 522 billion will be required over the next 10 years.

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TABLES

Table 12.1 Wind energy: capacity and generation in 2008

	Installed capacity	Annual output *
	MW_e	GWh
Algeria	N	N
Cape Verde Islands	3	5
Egypt (Arab Rep.)	365	900
Eritrea	1	2
Kenya	N	N
Mauritius	N	N
Morocco	114	298
Namibia	N	1
Nigeria	2	4
Réunion	10	10
Senegal	N	N
South Africa	9	18
Tunisia	19	39
Uganda	N	N
Total Africa	**523**	**1 277**
Canada	2 369	6 200
Costa Rica	74	140
Dominica	N	N
Dominican Republic	N	N
Guadeloupe	35	63
Jamaica	21	40
Martinique	1	2
Mexico	88	254
Netherlands Antilles	12	23
Nicaragua	N	N
United States of America	25 410	55 363
Total North America	**28 010**	**62 085**

Table 12.1 Wind energy: capacity and generation in 2008

	Installed capacity	Annual output *
	MW_e	GWh
Argentina	30	62
Bolivia	N	N
Brazil	338	557
Chile	20	38
Colombia	20	54
Cuba	7	14
Ecuador	4	8
Falkland Islands	1	2
Guyana	14	26
Peru	1	1
Uruguay	21	40
Total South America	**456**	**802**
Armenia	3	2
Bangladesh	1	2
China	12 210	18 000
Cyprus	N	N
Hong Kong, SAR	1	2
India	9 645	17 500
Indonesia	1	2
Japan	1 880	2 919
Kazakhstan	1	2
Korea (Democratic People's Rep.)	N	N
Korea (Republic)	236	421
Mongolia	2	5
Nepal	1	2
Pakistan	6	12
Philippines	25	61
Sri Lanka	3	3

Table 12.1 Wind energy: capacity and generation in 2008

	Installed capacity	Annual output *
	MW_e	GWh
Taiwan, China	252	589
Thailand	1	2
Turkey	458	847
Vietnam	1	3
Total Asia	**24 727**	**40 374**
Austria	995	2 100
Belarus	1	2
Belgium	384	622
Bulgaria	113	122
Croatia	60	40
Czech Republic	150	245
Denmark	3 166	6 928
Estonia	78	130
Faroe Islands	4	13
Finland	142	261
France	3 506	5 710
Germany	23 903	40 400
Greece	990	1 661
Hungary	127	205
Ireland	1 028	2 410
Italy	3 538	4 861
Latvia	28	58
Lithuania	54	129
Luxembourg	35	61
Netherlands	2 149	4 260
Norway	429	917
Poland	482	790
Portugal	3 030	5 757

Table 12.1 Wind energy: capacity and generation in 2008

	Installed capacity MW_e	Annual output * GWh
Romania	10	11
Russian Federation	17	30
Slovakia	6	6
Spain	16 689	31 313
Sweden	1 021	2 000
Switzerland	14	16
Ukraine	90	170
United Kingdom	3 406	7 097
Total Europe	**65 645**	**118 325**
Iran (Islamic Rep.)	74	143
Israel	6	12
Jordan	1	3
Lebanon	N	N
Syria (Arab Rep.)	N	1
Total Middle East	**81**	**159**
Australia	1 306	3 285
New Caledonia	24	36
New Zealand	322	1 047
Total Oceania	**1 652**	**4 368**
TOTAL WORLD	**121 094**	**227 390**

Notes:

1. Sources: WEC Member Committees, 2009/10; national and international published sources; *IEA Wind Energy Annual Report 2008*; World Wind Energy Association; European Wind Energy Association.
   * Where data on wind energy output are not available, estimates have been calculated by assuming 2 000 hours annual utilisation, applied to the estimated mid-2008 installed capacity

COUNTRY NOTES

The Country Notes on Wind Energy have been compiled by the Editors. In addition to national and international Wind Energy Associations' web sites and government publications/web sites, numerous national and international sources have been consulted, including the International Energy Agency's *IEA Wind Energy Annual Report 2008*. Information provided by WEC Member Committees has been incorporated as available.

Albania

Historically wind energy has been used in isolated areas by traditional windmills and for water pumping; however, in recent years attention has turned to utilising the resource for power generation.

The areas of Albania best suited for wind installations have been found to be the mountainous regions of the northeast, the hilly areas of the south and southeast and the coastal strip.

It is considered that by 2020 4% of the country's electricity could be generated by wind power (some 400 GWh/yr). If priority is given to the construction of 20 coastal wind turbines adjacent to water pumping stations, the areas lying beside the Adriatic can be safeguarded from flooding. Pumping stations located in the coastal lowlands take around 30 GWh/yr (some 0.7% of domestic power generation). Studies conducted by the National Agency of Energy have shown that these areas have a sufficient wind resource for them to be considered as suitable sitings for turbines.

Average annual wind speed is around 4-6 m/s at a height of 10 m (with an average annual energy density of 150 W/m^2).

During 2009 it was reported that one of the objectives of an updated Energy Strategy for Albania would be for the greater use of renewable energy for power generation. An ambitious plan for the harnessing of the country's wind resource includes a 250-turbine, 500 MW wind farm project with the Italian company, Moncada Energy. As well as the onshore turbines, located in the District of Vlorë, an undersea cable to Brindisi, Italy would be constructed for the export of electricity. In addition, plans for many hundred megawatts of further capacity have been cited.

Argentina

Argentina has a long tradition of using wind energy. It is estimated that even today the plains of the pampas have the largest concentration of farm windmills in the world, with over 400 000 in place. Windpower has certainly played an important role in the agricultural development of the country.

As regards electricity generating capacity, Argentina presently possesses more than a dozen wind parks, located in six different provinces, with an aggregate installed capacity of 29.76 MW. Many of these parks have been developed with the assistance of the Régimen Nacional de la Energía Eólica y Solar, under Law 25019/98, which (amongst other fiscal benefits) subsidises electricity generated from wind or solar and fed into the public networks.

The current exploitation of wind energy is not commensurate with its enormous potential. It has been estimated that Patagonia's wind potential south of the 42nd parallel represents tens of times that contained in the whole of Argentina's annual crude oil production. Moreover, it is not just the southern extremity of the country that possesses favourable conditions for the installation of wind farms. Numerous suitable areas exist in almost the whole of the Río Negro and Neuquén provinces, in various upland and coastal zones of Buenos Aires province, and in many other localities in the interior.

The Plan Nacional de Energía Eólica, entrusted by the Federal planning ministry to the regional wind energy centre (CREE) of Chubut province, lays the foundations for the first large-scale national development in this field. The Plan involves the compilation of a national wind map as well as the construction of numerous wind farms, with an aggregate capacity of around 300 MW to be installed by about three years' time.

The first stage of the plan consists of the implementation of the 'Winds of Patagonia' project, which involves the construction of a wind park of 50-60 MW in the vicinity of Comodoro Rivadavia, Chubut; later stages envisage the erection of similar parks in the provinces of Santa Cruz, Buenos Aires, Río Negro, Neuquén, La Rioja and San Juan. In the long term, the public and private projects identified so far have an aggregate capacity of approximately 2 000 MW.

Australia

The development of the wind energy sector got off to a slow start in Australia. The resource had been used historically for water pumping in isolated locations but there existed no comprehensive wind industry. The situation began to change at the end of the 1980s (when the first 20 kW grid-connected turbine was installed in Victoria) and gathered momentum during the 1990s. By end-1999, total installed capacity stood at just over 10 MW (wind-diesel hybrid and grid-connected schemes) and the Australian Wind Energy Association (AusWEA) had just been formed.

The Renewable Energy (Electricity) Act of 2000 established the Mandatory Renewable Energy Target (MRET) which came into effect in April 2001. This piece of legislation, the founding of the AusWEA and the establishment of an indigenous wind turbine manufacturing sector are considered to have been fundamental in transforming the country's wind industry. By end-2008 1 306 MW had been installed across all states, an increase of 37% over 2007. By November 2009, the total had risen to 1 668 MW, representing 49 wind farms with 962 operational turbines.

Apart from the wind installation at the Australian Antarctic Base, the two Tasmanian installations and the two installations in northern Queensland, most of the turbines are located in the coastal regions in the southern half of the country. South Australia, with ten wind farms has approximately 44% of the total capacity. Although Western Australia has 14 projects it has 12% of the sector whereas Victoria with 8 projects has 23%.

The MRET scheme 'places a legal liability on wholesale purchasers of electricity to proportionally contribute to an additional 9 500 GWh of renewable energy per year by 2010' and 'sets the framework for both the supply and demand of renewable energy certificates (RECs) via a REC market'. The Scheme has been successful but in order to achieve the Government's objective of 20% renewable energy in the electricity supply by 2020, a national Renewable Energy Target (RET) of 45 000 GWh has been set for that year.

It is estimated that at the current time there are wind energy projects across the country totalling some 6 GW. Planning permission has been granted for many, and seven projects - totalling nearly 560 MW - are already under construction. Commissioning of five of the projects is expected during 2010.

Brazil

Brazil has a great potential and the necessary structure for viable and economic use of wind power, although costs will still have to be drastically cut before it can compete with other renewable options. The *Atlas do Potencial Eólico Brasileiro* (2001) indicates the existence of a 143 000 MW potential (a little more than the total generation park currently in operation). The areas with median wind propitious for the installation of wind farms are mainly in the northeast (144 TWh/yr) and in the south and southeast of the country (96.04 TWh/yr). It is, however, estimated that the potential could be much greater. In a preliminary assessment, projections for wind at a height of 100 m (as opposed to wind at a height of 50 m considered in the Atlas) point to a significant increase in Brazil´s energy potential. There is also the median capacity factor of the wind farms in operation, which amounts to 34%, much superior to the percentages observed in Europe.

One of the main incentive measures for this technology was PROINFA (Programme of Incentive to Alternatives for Electric Power) established by Law 10,438/2002. It was instrumental in contracting 3 300 MW from alternative energy undertakings, of which 54 (1 422 MW) were wind. As at late 2009, 23 (385 MW) of them were already in operation, 11 (382 MW) were projected to enter into operation by the end of the year, and the remaining 20 (655 MW) to start up during 2010, the last year of the programme.

However, the wind farm undertakings of PROINFA are not the only ones implemented in Brazil. According to the Generation Database, BIG, of ANEEL (the national electric power agency), which stores information on all current schemes in operation, under construction or granted, 35 wind farms are in operation, which corresponds to an installed capacity of 548 MW.

The average cost of wind generation remains high in comparison with other sources and wind power is therefore not viable for direct participation in public bids. Owing to the strategic interest in a greater diversity of renewables in the energy matrix, a differentiated economic treatment in the form of specific bids for wind farms has been proposed.

The first specific public bid for contracting power reserves from wind sources was due to be held in November 2009 and attracted the interest of a significant number of generators. Registrations for the contest comprise 441 projects. Together, they amount to 13 341 MW of installed capacity. The wind farms taking part in the bid originate from 11 states and 3 regions.

Brazilian industry has the capacity to meet a demand of approximately 650 MW of wind generators per year. However, 200 MW are already committed in finalising PROINFA. Discounting possible external demand, production commitments already contracted for and installed capacity expansion projects, available figures show that the indigenous industry would have a maximum capacity to supply 450 MW in 2010 and 650 MW in 2011. It should be noted that Brazilian industry is well-placed to supply wind equipment and can compete on an international level, meeting the needs of both domestic and foreign markets.

Thus, wind power is on the way to become a viable option for the national energy matrix, considering that it is a strategic energy source for greater security of supply. Especially in the northeast, the operation of new large wind farms contracted via PROINFA proves that it is a viable complement. The generation forecasts for this energy source have been exceeded by the operation of more recent systems. When considering the possibility of economies of scale in Brazil - owing to a larger share of wind power in the energy matrix - it is expected that in the medium term installation costs will improve, reflecting positively on the cost of wind energy.

Inserting wind power into Brazil´s electricity matrix meets the objectives of the Plano Nacional sobre Mudança do Clima (National Plan for Climate Change) which is a summary of the actions and measures in effect or being drawn up by the Government for combating global warming. It involves a significant participation of renewable sources in the electricity matrix and furthermore can contribute to an increase in greater energy supply security and reduce dependence on fossil fuels.

Bulgaria

Bulgaria's wind energy resources are quite modest. The territory can be divided into four zones according to their wind potential. However, only two of them are of interest with regard to electricity generation: 5-7 m/s and > 7 m/s. The area where the annual average wind speed is in the region of 6 m/s or above is about 1 430 km^2.

A National Programme for the Promotion of the Use of Renewable Energy Sources 2005-2015 states that the available wind potential is approximately 280 ktoe.

In recent years there has been an increasing level of interest in the installation of wind turbines and at the present time more than 1 000 MW have been granted preliminary agreement for connection to the grid.

Canada

Canada's wind energy capacity has grown significantly since 2000. In that year the country had just 137 MW installed wind capacity. By end-2005 it had risen to 684 MW; and by end-2008, to 2 369 MW. Wind generators produced an estimated 6.2 TWh of electricity in 2008.

The Canadian Wind Energy Association reports that capacity grew by 40% during 2009, bringing the year-end figure to 3.3 GW. There are in the region of 4.4 GW projects with either signed power purchase agreements and/or are under construction.

Although to date the western provinces have utilised some of their respective wind resources, with more than 30 wind farms located in Alberta, Saskatchewan, Manitoba, Yukon and British Columbia, it is the eastern provinces where wind power has been mostly harnessed. Ontario has the highest number of wind farms installed, followed by Nova Scotia. Together with Quebec, Prince Edward Island, New Brunswick and Newfoundland, there are nearly 70.

As a result of the Federal Government's Wind Power Production Incentive greatly assisting in the development of wind power generation, the 14-year ecoEnergy for Renewable Power program was launched in 2007. This program will provide nearly CDN$ 1.5 billion in support of renewable energy, including wind. Additionally, there are many provincial incentives for the development of wind energy.

- Alberta – a target to increase the renewable and alternative energy portion of total electricity generating capacity by 3.5% by 2008 was met and to date no new target has been set. The Province's micro-generation regulation allows small producers with a capacity of less than 1 MW to receive credit for any power they can send to the grid.

- British Columbia - in early 2007, The BC Energy Plan: A Vision for Clean Energy Leadership was announced. The Plan looks to all forms of alternative energy to help in meeting the needs of British Columbia, and has a specific pledge of renewable energy continuing to account for at least 90% of electricity generation. BC has a renewable energy target of 50% of new generation by 2012.

- Manitoba – the Province has a voluntary target of 1 000 MW of new wind installed capacity by 2015. It uses requests for proposals to achieve this target.

- New Brunswick – legislation provides for a Renewable Portfolio Standard (RPS) of 10% by 2016. NB Power offers a net metering program for small renewable energy producers of up to 100 kW of installed capacity.

- Newfoundland and Labrador – there is a plan to install 80 MW of new wind capacity by 2010.

- Nova Scotia – legislation provides for an RPS of 5% by 2011 and 10% by 2013. The Provincial Government has recently extended by a year, to 31 December 2011, the target for obtaining 5% of its electricity supply from renewable energy resources, citing the global credit crisis as having prevented some energy projects from obtaining financing. Nova Scotia Power offers a net metering program for small renewable energy producers of up to 100 kW of installed capacity.

- Ontario – the Province has a target of 10% new renewable energy capacity by 2010 and it is committed to double its renewable power capacity by 2025. The Green Energy and Green Economy Act includes a new Feed-in Tariff (FIT) program that replaced the Renewable Energy Standard Offer Program. Ontario also offers a net metering program for small renewable energy producers of up to 500 kW of installed capacity.

- Prince Edward Island – legislation provides an RPS of 30% by 2016. A net metering program is offered to small renewable energy producers of up to 100 kW of installed capacity.

- Quebec – as part of its Energy Strategy, Quebec plans to install 4 000 MW of wind capacity by 2015. With a focus on local economic development, its requests for proposals have mandatory requirements on local content, a clause that has spurred manufacturing capabilities in remote regions of the province. There is a net metering program offered to small renewable energy producers of up to 50 kW of installed capacity.

- Saskatchewan - the Government is investing more than CDN$ 500 million in a suite of sustainable and renewable energy programs as part of the Province's Green Strategy and Energy and Climate Change Plan. The Plan includes a voluntary renewable energy target of 30% by 2020. A net metering program is offered for small renewable energy applications of up to 100 kW of installed capacity.

China

Although the use of the Chinese wind resource for water pumping is many hundreds of years old, it is only in recent years and with the country's rapid economic growth that attention has turned to utilising wind power by means of modern turbines.

The country not only has an enormous energy/electricity generation requirement, an historical reliance on coal and limited indigenous oil resources, but also severe environmental problems. To address these issues, the Government has targeted renewable energy to supply an increasing share of power output from green energy.

The provinces of Inner Mongolia and Hebei and the eastern coastal areas are well blessed with wind energy. The theoretical potential of the country as a whole has been estimated to be over 3 000 GW, but the Chinese Meteorology Research Institute states that the practical potential is in the region of 250 GW onshore (at 10 m) and 750 GW offshore (at 50-100 m).

The China Renewable Energy Law, issued at the end of February 2005, became effective on 1 January 2006. The legislation was intended to provide the basis for favourable long-term financial arrangements in order to encourage private investors and hence to expedite the development of the wind industry. This policy has proved to be extremely successful and, with the added benefit of UN Clean Development Mechanism (CDM) funding, the actual installed capacity has far exceeded the target set.

Since they were first set by the Energy Bureau of the National Development and Reform Commission (NDRC) the strategic targets have been raised 3 times, so that by the beginning of 2007 it was reported that the 2010 target for wind had been set at 8 GW. By end-2007, actual installed capacity stood at 5.9 GW. During 2008 this figure was more than doubled with 6.2 GW of new capacity being added to reach a total of 12.2 GW by year-end, surpassing the 2010 target by over 50%.

At the end of 2008 the area with the highest concentration of wind turbines was the Autonomous Region of Inner Mongolia (nearly 31% of the national capacity), followed by the Provinces of Liaoning, Hebei and Jilin with 10.3%, 9.1% and 8.8% respectively.

By end-September 2009, Chinese wind capacity stood at 15.9 GW, with a plan for 35 GW by end 2011.

Despite the high level of installed wind capacity in some regions, for example Inner Mongolia, there is not always a high population density and thus a high demand for power. The lack of a highly-developed transmission system has meant that in some areas wind-generated electricity has not found a ready outlet.

It was announced during 2009 that the CDM funding for Chinese wind projects was being withdrawn, whilst at the end of the year new legislation decreed that grid operators would be required to purchase electricity produced from renewable energy. Both actions will necessarily encourage the wind sector to focus on developing an efficient distribution network and also improving the competitiveness of wind, especially when in competition with inexpensive coal-generated electricity.

The country's first offshore wind power plant, installed (late 2007) on the China National Offshore Oil Corporation’s Bohai Suizhong 36-1 oil platform, had by end-2008 generated some 3.3 million kWh.

Chinese manufacturing of wind turbines has grown very rapidly in recent years, to the extent that the largest companies rank amongst the world’s biggest. It is reported that within five years Sinovel Wind Co Ltd. aims to lead the world in terms of turbine production.

Costa Rica

Costa Rica is reputed to have a better wind regime than California and some of the highest average wind speeds in the world. In addition to using the country's geothermal and biomass resources, the Government is demonstrating its commitment to the utilisation of its wind resource in an effort to develop sustainably and reduce GHG emissions. It has been reported that ultimately the nation aims to be the first carbon-neutral country on earth.

In 1993 the Costa Rican Government issued a tender for a 20 MW (30 x 660 kW) grid-connected wind plant near the town of La Tejona. The project was designed for the installation of between 40 and 100 turbines on two parallel ridges to the northwest of Lake Arenal. However, many problems were encountered, which delayed the project until the late 1990s. It was not until September 2001 that the turbines were shipped and installation could begin.

A further project, also near Lake Arenal, financed by private and public loans, various banks and the Danish International Development Agency, has been developed. The 24 MW Tierras Morenas wind farm sells approximately 70 000 MWh/yr electricity to the Instituto Costarricense de Electricidad (ICE), the state-owned national electric utility, under a 15-year power purchase agreement.

In September 2006 Econergy International announced that ICE had awarded the company and its partners a 20-year contract to build, own, operate and transfer a 49.5 MW project. The 55 turbine Proyecto Eólico Guanacaste, known as 'La Gloria', was connected to the grid at the end of 2009. The wind farm, sited near a volcano, utilises a 12 m/s wind speed resource and is expected to supply approximately 240 GWh per annum.

Denmark

With the utilisation of wind energy featuring in each Danish energy strategy, the country has made use of its wind resource since the early 1980s. The installed wind turbine capacity grew slowly but steadily until the mid-1990s when growth became very rapid. This situation continued to end-2002, when capacity totalled some 2 900 MW. At that point further onshore expansion ceased, owing to a substantial rise in the investment risks incurred by the turbine owners selling production on the electricity market. This was caused by a set of complicated regulations and a reduced environmental premium paid to wind power.

The wind energy market was influenced during 2004 by a political agreement that encouraged the establishment of offshore wind turbines, together with the introduction of a market-orientated pricing system for wind, leading to increased R&D. In the same year a second re-powering scheme was launched for replacing wind turbines sited in unfavourable positions with new installations in more suitable locations. Following on, in June 2005, the Government published its Energy Strategy 2025 in which economically viable on- and offshore wind power will both play a role. Environmental considerations are central to the Strategy and within six months the Danish Energy Agency (DEA) had begun to formulate a plan for the siting of offshore wind turbines in the period 2010-2025, taking these into consideration.

At end-2008 total installed wind power stood at 3 166 MW, supplying 6 928 GWh (19.9% of Denmark's total net electricity production). Of this total, offshore wind parks accounted for 422 MW with 214 turbines. Output in 2009, at 6 721 GWh, was slightly lower than the previous year.

After the UK, the country is the second largest developer of offshore wind installations. The 160 MW (80 x 2 MW) Horns Rev installation in the North Sea was commissioned during 2002. It is located 14-20 km offshore from the western Danish coast, off Blaavands Huk. During 2003, a sister farm (Nysted or Rødsand I) was installed in the Baltic Sea, south of the island of Lolland. Nysted consists of 72 x 2.3 MW turbines. The 91-turbine, 209 MW Horns Rev II, located about 10 km to the west of the Horns Rev I became operational during September 2009.

At the end of November 2009 and replacing 12 old wind turbines, two 3.6 MW turbines became operational in the Avedøre Holme district of

Copenhagen. The timing was to coincide with the UN Climate Change Conference COP15. These 3.6 MW machines are about 160 times larger than the first turbines installed in Denmark in the late-1970s.

Future wind farms expected to come into operation in late 2011 and late 2012 respectively are the 200 MW Rødsand II and the 400 MW Anholt. The former is to be located 3 km west of the existing Rødsand I, south of Lolland and the latter in the Kattegat between Djursland on the mainland and the island of Anholt.

The 2007 report, Future Offshore Wind Turbine Locations – 2025 suggested areas in which a total of 4 600 MW could be constructed. If these projects come to fruition, then in the region of 50% of Danish electricity consumption could be supplied from wind energy.

In addition to supplying the home market, Denmark is a major supplier of wind turbines to the world. Both Vestas and Siemens manufacture MW-size turbines whilst Gaia Wind Energy produce small household-size turbines. There are also many Danish companies specialising in wind turbine component manufacture.

With the highly significant role that Denmark plays in the world wind industry, R&D is of the utmost importance. Eight Danish organisations are numbered amongst the 40 European partners of the UpWind project. The aim of UpWind, to last for five years from March 2006 and funded by the EU's Sixth Framework Programme, is to undertake research into all design aspects of the 8-10 MW turbines that are considered to be necessary for the wind farms of the future – both on and off-shore.

Along with nine other European governments (Belgium, France, Germany, Ireland, Luxembourg, the Netherlands, Norway, Sweden and the UK), Denmark is part of the European Offshore Supergrid® project. The aim is to establish a renewable energy electricity grid, in which the wind turbines belonging to the participant countries would be fully integrated.

Egypt (Arab Republic)

Egypt is endowed with an excellent wind energy potential, especially in the Red Sea coast area where a capacity of 20 000 MW could be achieved, as the annual average wind speed is around 10 m/s.

The Wind Atlas for the Gulf of Suez, published in March 2003, identified the areas of greatest suitability for wind farm projects. It included data for 13 sites covering the period from 1991 to 2001 and was undertaken with the assistance of the Danish Government. The extension of the Wind Atlas in 2005 covering the whole of the country determined that the wind resource in the desert regions on either side of the River Nile and parts of Sinai is potentially suitable for development.

Since 1992, 5 MW wind capacity has been in service at Hurghada. At end-2008 there was 360 MW of installed capacity at Zafarana on the Red Sea coast, developed in cooperation with Denmark, Germany and Spain. The multi-station wind farm has gradually been brought into service since Zafarana 1 became operational in April 2001. By end-2010 capacity is expected to total 545 MW.

The area of Gabal El-Zayt on the Suez Gulf, some 150 km south of Zafarana, has been identified as being suitable for the installation of some 3 000 MW of wind farms. Feasibility studies have been undertaken for two plants - one of 80 MW with German assistance and another of 220 MW with Japanese assistance.

Egypt's national energy planning incorporates a target of 1 050 MW wind capacity to be installed by the end of the Sixth Five-Year Plan period (2007-2012). Longer term, the Government envisages 20% of electricity to come from renewable energy by 2020. To meet this target, it is expected that 12% will be satisfied by wind power.

Ethiopia

It has been found that Ethiopian wind speeds suitable for electricity generation vary across the territory.

A study undertaken in 2005 with the assistance of GTZ of Germany, as part of the TERNA programme (Technical Expertise for Renewable Energy Application) has shown that high wind speed sites are located in the Mekelle Region at Ashegoda with 8 m/s and Harena 6.84 m/s and Nazareth and Gondar with 6.64 m/s and 6.07 m/s respectively. Wind speeds at around 4 m/s were recorded in Harar, Debre Birhan and Sululta.

Medium wind speeds of between 3.5 and 5.5 m/s (energy values between 500 and 1 500 Mcal/m^2) exist over most of the eastern part of the country and the central rift valley zone. Such winds provide a promising potential for water lifting in the rift valley settlements, where water is scarce both for irrigation and domestic uses. A Catholic Mission in the Meki-Zeway area uses wind turbines to pump water for schools and villages.

The Ethiopian Electric Power Corporation (EEPCO) has a project to generate 120 MW in the northern region of Tigray. It has been reported that the Ashegoba wind plant will be operational in 2011. EEPCO is also studying the wind prospects in the Oromiya and Somali regional states.

Finland

Finland’s wind energy potential is located mostly in coastal areas. There is a huge technical potential offshore, with ample shallow sites available. Wind energy deployment has been very slow, but a new target of 6 TWh/yr for 2020 (2 000-3 000 MW) and an anticipated feed-in tariff system have led to a rush for the best sites.

Two new turbines totalling 4 MW were installed in 2009, bringing total capacity to 146 MW at the end of the year. There is ever increasing interest in offshore projects, as good sites for larger wind farms in coastal areas are scarce. The first semi-offshore projects were built in 2007: 6 x 2.3 MW turbines on small islands in Åland Båtskär, and in 2007-08: 10 x 3 MW turbines in Kemi, of which 24 MW is offshore. A 90-100 MW demonstration project in Pori is planned but probably needs some demonstration funding in order to be realised.

The 12 MW Hamina and 9.2 MW Raahe wind farms are being constructed during 2010 and the

18 MW Eckerö wind farm is planned for erection during summer 2010. One pilot offshore turbine is to be built in 2010 in Pori and about 40 MW more have received investment subsidy decisions and could be implemented during the year. In total there are 1 400-2 200 MW wind power projects in various phases of planning onshore, and 4 000 5 800 MW announced for offshore.

The 6 TWh/yr target, announced in the Climate and Energy Strategy would represent about 6% of total electricity consumption in Finland. A new subsidy system is proposed to start in 2010 and a new wind energy research programme (Cleen WIPO) is planned to start at the beginning of 2011.

Wind power technology exports from Finland amount to about € 1 billion. Wind turbine manufacturer Winwind has developed an ice prevention system for 3 MW turbines in collaboration with VTT; Moventas is developing its gearboxes for larger turbines, and ABB and the Switch are developing generator and frequency converter solutions for wind power.

France

In 2003 the wind sector in metropolitan France began to grow substantially, albeit from a very low base and after many years of little interest in renewable energy. Between 2005 and 2006 installed capacity virtually doubled. The years 2007 and 2008 saw increases of 46% and 43% respectively, bring the total grid-connected capacity at end-2008 to just over 3 500 MW.

L'Association France Energie Eolienne (FEE), representing the wind sector of the Syndicat des Energies Renouvelables, reports that wind installations are widely distributed throughout the country, with the heaviest concentration in the north, northwest and northeast.

As at 15 December 2009, the objective of the Programmation pluriannuelle des investissements de production d'électricité was for 25 000 MW of wind capacity to be installed by 2020, of which 19 000 MW would be onshore and 6 000 offshore.

At end-2009, an offshore project of 105 MW was out for tender, whilst onshore projects totalling some 4 300 MW were in the pipeline.

Along with nine other European governments (Belgium, Denmark, Germany, Ireland, Luxembourg, the Netherlands, Norway, Sweden and the UK), France is part of the European Offshore Supergrid® project. The aim is to establish a renewable energy electricity grid, in which the wind turbines belonging to the participant countries would be fully integrated.

Germany

The Electricity Feed-in law (Stromeinspeisungsgesetz) was the progenitor of German wind power development in 1991. But the country's growth in wind capacity from just 110 MW at end-1991 to the present day, when it ranks amongst the world leaders, is due to further legislation in the subsequent years. In 1997, the Federal Building Code included wind turbines as 'privileged building projects'; April 2000 saw the adoption of the Renewable Energy Sources Act (EEG); March 2001 saw the feed-in tariff model complying with the European State Aid and

Competition Law, while in August 2004 the EEG was amended.

During 2008 the law was again amended with an 'initial tariff' fixed for between 5 and 20 years, reducing to a 'basic tariff', linked by comparison to a 'reference yield' and dependent on whether the installation is located in a productive wind area (tariff paid for no less than 5 years) or in a not so productive area (paid for up to 20 years). From the beginning of 2009 the onshore 'initial tariff' was increased to € 0.092/kWh and, for new installations will decrease every year by 1%. The 'basic tariff' is set at € 0.0502/kWh.

Offshore wind turbines will attract remuneration of € 0.13/kWh plus an additional € 0.02/kWh for projects coming into operation prior to the end of 2015. This tariff is payable for a period of 12 years, after which it will fall to € 0.035/kWh. Post 2015 new turbines will attract the € 0.13/kWh tariff but it will decrease by 5% per annum.

In order to reverse the limited amount of re-powering in past years, a special tariff was retained for replacing older turbines (greater than 10 years) with turbines at least double the capacity in the same or neighbouring county.

The wind industry has been so successful that the German Wind Energy Association (BWE) estimates that nearly 100 000 people are employed.

By the end of 2008 German installed wind capacity represented some 20% of the global total. The number of turbines stood at 20 301, totalling 23 903 MW, generating 40.4 TWh and accounting for 7.5% of electricity consumption. By end-2009 the German Wind Energy Association was reporting that the number of turbines had risen to 21 164 and capacity to 25 777 MW.

During 2009 the State of Brandenburg continued to lead the way with new turbines but it is the State of Niedersachsen that heads the ranking of total installed capacity - 6 407 MW - some 54% higher than Brandenburg.

The States of Sachsen-Anhalt, Mecklenburg-Vorpommern, Schleswig-Holstein and Brandenburg obtained 47, 41, 40 and 38% respectively of their net electricity consumption from wind during 2009.

With a national requirement for wind capacity to increase, the BWE has suggested that it could reach 45 000 MW onshore with another 10 000 MW offshore. The Government has indicated that by 2030, offshore capacity could be as high as 20 000 – 25 000 MW. However, there have been obstacles to the requisite expansion in the transmission system. Passing the Power Line Expansion Law will facilitate the necessary construction of cabling to accommodate the additional capacity.

At the present time there are 9.5 MW of installed offshore wind parks operating in the North Sea and 2.5 MW operating in the Baltic. There are numerous projects in both areas that are either in the first stages of construction or are in the process of approval.

Along with nine other European governments (Belgium, Denmark, France, Ireland, Luxembourg, the Netherlands, Norway, Sweden and the UK), Germany is part of the European Offshore

Supergrid® project. The aim is to establish a renewable energy electricity grid, in which the wind turbines belonging to the participant countries would be fully integrated.

Hong Kong, China

Hongkong Electric's (HEC) 800 kW Lamma Island wind turbine, in operation since early 2006, with an associated exhibition centre, continues to provide a public showcase for renewable energy.

The CLP Group is planning the construction of an 800+ kW wind turbine pilot/demonstration plant and also the inclusion of two wind turbines as part of stage two of the Town Island Renewable Energy Power Station. The latter units are due to be completed in early 2011.

Due to the scarcity of suitable land in Hong Kong, both HEC and CLP are conducting feasibility and environmental impact studies for 100 and 200 MW offshore wind power in Hong Kong waters.

Hungary

Even though Hungary lies in the Carpathian Basin and thus does not have as strong a wind resource as say, Poland, the prevailing north-westerly winds provide a potential resource that can be harnessed. If the Government is able to make improvements to the system for permitting wind turbines and also grid access for renewable energy then wind could assist Hungary in meeting its EU-mandated target of 13% renewable energy in the energy mix by 2020.

At the end of 2008 windpower capacity stood at 127 MW, generating over 200 GWh. The Hungarian Wind Energy Association reports that by end-2009, capacity had risen to 201 MW.

India

Estimates of the Indian wind resource were firstly put at about 45 GW. The onshore wind potential has now been assessed by the Centre for Wind Energy Technology (C-WET) - and officially adopted - as 48.5 GW (assuming 1% land availability for wind farms requiring 12 ha/MW, at sites having a wind power density in excess of 200 W/m^2 at 50 m height). However, the Indian Wind Turbine Manufacturers Association has estimated that at increased heights (55-65 m) and with improved technology, the resource could be as high as 65-70 GW. A total resource of 100 GW has been suggested by the World Institute for Sustainable Energy, India, given both greater turbine capacity and land provision. The States of Karnataka, Gujarat and Andhra Pradesh possess approximately 24%, 22% and 18% respectively of India’s presently identified wind resource, with Kerala, Madhya Pradesh, Maharashtra, Orissa, Rajasthan and Tamil Nadu possessing the remaining 36%.

The C-WET, established by the Indian Government and working in association with the State Nodal Agencies, private companies and Denmark’s Risø National Laboratory, is conducting a Wind Energy Assessment Programme. More than 1 000 wind monitoring stations in 25 States have been supplying data for inclusion in a wind atlas, under preparation for publication.

At end-2008 India had installed grid-connected wind capacity of 9 645 MW, placing it 5th in the world ranking, behind USA, Germany, Spain and China. By end-2009 grid-interactive capacity had grown to 10 925 MW and by end-March 2010 to 1 1 807 MW. About 90% is located in just four states, of which Tamil Nadu, at 42%, has the largest share.

A common feature of un-electrified areas or locations with poor supply is the use of small (1-10 kW) wind-solar hybrid systems – over 1 000 kW had been installed by end-March 2010.

By the end of the 11th Five Year Plan (2007-2012) it is foreseen that some 17 500 MW will have been installed. However, the target of 1 500 MW during the 10th Five Year Plan was exceeded by a factor of 3.6, so it is possible that the 11th Five Year Plan will also be exceeded.

Although India possesses a coastline in excess of 7 500 km, research has shown that the wind resource at the majority of the locations studied is not sufficient for offshore wind turbines. The one area that does have promising potential is the southern tip of the sub-continent, from Kanyakumari, northeast to Rameshwaram. Further investigation and data collection are required in order to establish the feasibility of establishing a demonstration offshore wind farm.

India has built a wind turbine manufacturing industry which is now capable of exporting, as well as supplying the home market. In FY 2009-10 (up to end-2009) turbines worth some US$ 600 million had been exported to the USA, Australia, Nicaragua, Bulgaria and Brazil.

Many Governmental and State-led financial incentives together with promotional policies are expected to assist in further strong growth in the Indian wind energy market.

Ireland

Ireland has a minimum target for renewable electricity of 40% by 2020 (15% by 2010) one of the highest in the world and possibly the most ambitious, considering the relative isolation of the grid and the lack of new large hydro-electricity options. Almost all of the required capacity will be wind energy. Ireland has a practicable resource of approximately 1 900 000 GWh.

Wind farm connection rates have recovered to pre-2007 levels with 207.7 MW being connected in 2008, bringing the total installed to 1 028 MW. During the year wind generation produced approximately 2.4 TWh of electricity, increasing its share of electricity consumption from 6.7% in 2007 to 8.1% in 2008 and displacing almost 1.28 million tonnes of CO_2 emissions.

The contribution from wind energy to electricity supply continues to rise: by the end of 2009 total installed wind capacity had risen to 1 264 MW.

Ireland's EU apportioned target is to supply 13.2% of electricity demand from renewable sources by 2010. Added to other renewable generation stock, an estimated 1 350 MW of wind capacity is required to meet this target. Annual additions to wind capacity have improved recently and it appears likely that the 2010 target will be met.

As outlined in the 2007 Energy White Paper, Ireland had aimed to supply 33% of its electricity demand from renewable sources by 2020. This target has been increased to 40% and it has been emphasised by Government that it is to be seen as a minimum rather than a ceiling. Approximately 280 MW of new renewable capacity is required each year from 2009 to 2020 if the target is to be met.

EirGrid, Ireland's transmission system operator (TSO) has published its strategy for the development of the grid. It will be necessary for the capacity of the transmission system to double by 2025. Following on from Grid25 the TSO has begun more detailed studies to identify specific reinforcement needs and their environmental, economic and system impacts.

Current support mechanisms for renewable generation in Ireland take the form of a Renewable Energy Feed-in Tariff (REFIT). REFIT is a Public Service Obligation (PSO) backed power purchase agreement (PPA).

Along with nine other European governments (Belgium, Denmark, France, Germany, Luxembourg, the Netherlands, Norway, Sweden and the UK), Ireland is part of the European Offshore Supergrid® project. The aim is to establish a renewable energy electricity grid, in which the wind turbines belonging to the participant countries would be fully integrated.

Italy

The Italian wind resource is most prolific in the southern regions of Campania, Puglia and Molise and on Sardinia, Sicily and the minor islands.

Technically exploitable capability for onshore wind farms has been assessed at around 7 000 MW for wind velocity higher than 5 m/s and 90 m hub height. There is a limited potential for offshore development owing to the considerable depth of the coastal waters, although there are possibilities in the seas surrounding Sicily.

In the period 2004-2008 the number of wind plants more than doubled, increasing from 120 in 2004 to 242 by end-2008. The largest numbers of wind farms were concentrated in four southern Regions (Puglia, Sicily, Campania and Sardinia).

By mid-2009 total wind capacity in service had reached 4 128 GW. In the same period, the total new capacity authorised or under construction reached 3 494 MW. It was expected that of the total of 7 622 MW, about 5 000 MW would be available at end-2009. Although Italy is not exposed to strong and regular winds, the Italian Wind Energy Association (ANEV) aims to achieve 9 600 MW capacity by 2013 and 16 200 MW by 2020 (with annual generation of 27 TWh). However, the Italian Position Paper presented by the Ministry of Economic Development states that the potential for wind power capacity is foreseen as 12 000 MW by 2020.

Terna, the Italian grid operator, is planning a number of projects in readiness for an expanded wind energy sector. They include a submarine cable link between Sardinia and the mainland, various power lines linking different Regions and eight new transformer stations. These projects are timed to become operational between end-2010 and 2013.

Japan

Although the wind resource of Japan is large, located mostly in the far north and far south of the country, there are impediments to utilising it to the full. The areas of high wind (Tohoku, Hokkaido and Kyushu regions) do not match the areas of high population density and the national, privately-owned grids have limited capacity to accommodate wind generated power.

Owing to the deep waters surrounding the country, offshore wind turbines have not been installed. However, investigative studies are now under way.

As a result of the UN Climate Change Conference in Kyoto in 1997, Japan agreed to reduce its output of GHG by 6% by 2010, compared to the 1990 level. In order to meet this target, the Government set an objective of 3 000 MW wind capacity. To assist in meeting the renewable energy contribution, the Government passed legislation in 2003 for a Renewables Portfolio Standard – RPS. Reviewed every four years, the 2007 RPS set a target of 16 TWh of electricity supply to be met by renewable energy.

By end-2007 total installed power stood at 1 538 MW. During 2008 342 MW were added bringing the total by year-end to 1 880 MW, from 1 508 turbines. Various factors, including changes in the 2007 Japanese Building Code, meteorological conditions and a lack of land availability, contributed to a decrease in incremental capacity from the higher rates in earlier years.

Although the wind sector's recent performance would suggest that the 2010 target might be difficult to meet, the Government is taking steps to improve the prospect. Support and field test programmes, demonstration projects, subsidies, R&D are all being implemented.

Jordan

Studies on Jordan's wind potential have been conducted over a period of years and have shown that the country has a rich wind energy resource. The average annual wind speed exceeds 7 m/s in some areas. A wind atlas has been prepared, based on an assessment of the available resource, which demonstrates the existence of a potential for several hundred megawatts of wind-power installations.

There are two operational wind farms in Jordan: Al-Ibrahimiya, with a capacity of 320 kW (4 x 80 kW), established in 1988 in co-operation with a Danish firm and considered as a pilot project; the other, in Hofa, has a capacity of 1 125 kW (5 x 225 kW), established in 1996 in co-operation with the German Government under a programme called Eldorado. Both wind farms are operated and maintained by the Central Electricity Generating Company (CEGCo). During 2008 generation from the two plants totaled 2.92 GWh.

Jordan, now actively promoting renewable energy, intends to strengthen the role of the National Energy Research Center in order to develop the exploitation of new and renewable energy resources, promote energy conservation and establish suitable regulatory frameworks to manage these resources. The new Energy Law has established the wherewithal to introduce a fund to provide the necessary investment for the development of renewable energy, while the Jordan Renewable Energy and Energy Efficiency Fund (JREEF) has been established as a legally independent entity with the authority to achieve such objectives. The Government has stated that wind power capacity will total 600 MW by 2015.

Korea (Republic)

It has been reported that Korea's potential wind resource could amount to 186.5 TWh/yr onshore and 460.5 TWh/yr offshore.

The Third National Basic Plan for New and Renewable Energy R&D and Deployment (Third Basic Plan for NRE), established by the Government in 2008, replaced the Second National Plan for NRE and now sets a target of 4.3 GW wind capacity by 2015 and 7.3 GW by 2030.

The utilisation of the country's wind resource has historically not been rapid. Following capacity additions of 50 MW, 30 MW, 77 MW and 18 MW in 2004-2007, 43 MW were installed during 2008, bringing the total by year-end to 236 MW. An estimated 421 GWh electricity was generated from the wind in 2008.

One particular problem with the siting of turbines is the lack of suitable locations. The mountainous countryside beyond the centres of population lacks the necessary infrastructure and has other constraints, thus causing capital costs to be higher; moreover obtaining authorisation to build in such areas is often impossible. However, to achieve the Government's ambitious wind capacity plan, a number of measures have been implemented: a well-supported R&D programme, a 15-year guaranteed feed-in tariff, tax incentives and subsidies. Furthermore, a Renewable Portfolio Standard is due to come into effect in 2012 and a study of offshore areas is being undertaken.

Lithuania

Following the installation of a second-hand wind turbine, wind energy production began in Lithuania during 2002. The first new turbine was installed in Vydmantai in 2004 and in 2006 the largest Lithuanian wind park (30 MW), in the vicinity of the villages of Kiauleikiai, Kviecia and Rudaicia. By end-2009, a total of 91.2 MW had been installed, generating 156.7 GWh.

The coastal areas of the Baltic States have a good wind energy potential but are, at the present time, under-utilised. The Governments of Lithuania, Latvia and Estonia have agreed to cooperate in a UNDP/GEF project to study the wind resource of the region with a view to removing any barriers to its development.

Lithuania plans for aggregate wind capacity to reach 200 MW by end-2010. The new wind power development programme could lead to further construction, particularly off-shore and should provide appropriate regulation and more favourable planning requirements.

Mexico

The present resource estimate is of the order of 5 000 MW. A number of zones with potential for exploiting wind for electricity generation have been identified in (amongst others) the isthmus of Tehuantepec (in the state of Oaxaca) and La

Rumorosa in Baja California, in the states of Zacatecas, Hidalgo, Veracruz, and Sinaloa, and in the Yucatán Peninsula.

The year 2008 saw a massive increase in installed wind capacity. From just 2.6 MW at end-2007, the total leapt to nearly 88 MW by end-2008.

In September 2009 the national electric utility (CFE) was conducting a bidding round for La Venta III and Oaxaca I, each with a capacity of 101 MW. Oaxaca II, III and IV (total capacity 303 MW) were at the feasibility stage.

The energy regulatory commission (CRE) has granted permission for the construction of about 2 500 MW of private wind power plants, including 80 MW for Parques Eólicos de México and 35 MW for Eurus.

Morocco

Study has shown that the best wind resources in Morocco are found in the north (particularly in the Atlantic coastal regions) and in the south. The former experiences annual average wind speeds of between 8 m/s and 11 m/s and the latter of between 7 m/s and 8.5 m/s. The wind potential is estimated at 6 000 MW.

There are two large wind parks in service, the 50.4 MW Abdelkhalak Torres, located 40 km east of Tanger and brought into service in August 2000, and the 60 MW Amougdoul, located 15 km south of the city of Essaouira and brought into service in April 2007. Additionally a 3.5 MW experimental wind park, in the vicinity of Abdelkhalak Torres, came into operation in October 2000.

Two large wind projects that were due to be completed by end-2009 were the 140 MW park at Tanger and the 100 MW Touahar, 12 km from Taza.

The National Office of Electricity (ONE) has two major renewable energy schemes:

- Energipro will offer inducements to industrial firms for the installation of wind generators, with the provision of grid-connection facilities and an assurance of surplus power purchase.
- In order to assist with the objective of using more than 10% renewable energy in the supply of electricity by 2012, the 'Initiative 1000 MW' has been launched by the ONE. This ambitious development plan covers 14 project sites, mostly located along the coast, with 2 to be constructed inland in the north of the country. It is expected that one of the sites, Tarfaya, with a capacity of 200 MW (expandable to 300 MW) will be in service during 2010. The others are expected to be operational in 2012.

Namibia

A full study has been conducted in order to determine the feasibility of wind farms situated on the coastal areas of Namibia. At Luderitz the average wind speed is 7.5 m/s while at Walvis Bay it has been found to be slightly above 7.5 m/s.

A 220 kW wind turbine was installed at Walvis Bay in late 2005 and is to date the largest such installation in the country. There are several other stand-alone 1 kW turbines located around the country used for electricity generation and water pumping for farms, totalling in the region of 70 kW.

The Ministry of Mines and Energy states that at the present time no wind energy projects are planned but with a plentiful wind resource available, there are opportunities for investment.

Netherlands

During 2001 the Dutch Government set new renewable energy targets in order to comply with its obligations under the Kyoto Protocol. These targets were confirmed during 2005 but have been subsequently amended so that currently the objective is for renewable energy to provide 20% of total energy supply in 2020. To achieve this target approximately 4 GW onshore and 6 GW offshore wind capacity must be installed. It is still expected that in 2010 9% of electricity generation will be met by renewable energy.

Until 2001, wind capacity had been increasing only slowly, with just 485 MW being installed by year-end. Thereafter, additions to capacity accelerated, averaging some 250 MW each year between 2002 and 2008. However, after a certain amount of decommissioning the net increase to capacity in 2008 was approximately 400 MW. At year-end total installed capacity stood at 2 149 MW of which 1 921 MW was onshore. At 4 260 GWh, wind supplied 47.5% of electricity generation during 2008.

Early in 2002 the consortium Noordzeewind (Nuon Renewables and Shell Wind Energy) was chosen to build a demonstration Near Shore Wind Farm (NSW) off the coast at Egmond aan Zee. The NSW is designed to have a life span of 20 years, at the end of which it will be dismantled. The intention is that the experience gained will greatly assist the development of further offshore installations, both larger in size and located in deeper waters. The first electricity from the 36 x 3 MW wind farm was supplied in October 2006. The research programme will last until 2012.

In order for the Government to double the onshore wind capacity and to commit 450 MW offshore wind, both by 2011, it will be necessary to remove barriers and to put in place various conducive measures. The former will involve government departments working together through the 'Administrative Agreement National Development Wind Energy' to solve the historical environmental problems of siting the turbines. The latter will involve Ministries applying the environmental and financing aspects of a Scenario Plan published in mid-2008.

Along with nine other European governments (Belgium, Denmark, France, Germany, Ireland, Luxembourg, Norway, Sweden and the UK), the Netherlands is part of the European Offshore Supergrid® project. The aim is to establish a renewable energy electricity grid, in which the wind turbines belonging to the participant countries would be fully integrated.

New Zealand

A wealth of indigenous renewable energy (in particular hydro and geothermal) already supplies some 31% of total energy demand and about 65% of electricity supply. With an excellent resource – supplying about 2.5% of electricity during 2008 –

wind will be increasingly harnessed in the future. New Zealand has assessed its wind resource as potentially able to generate over 125 000 GWh/yr. However, in reality some 2 500 – 3 000 MW will possibly be installed by 2025, supplying 15-20% of power generation.

At end-2008 total installed capacity stood at 322 MW, generating 1 047 GWh in the year. During 2009 the first 15 turbines of Project West Wind, the Horseshoe Bend wind farm and Stage 2 of the Te Rere Hau wind farm came into operation. By end-year total capacity had reached 496 MW, with a further 80 MW under construction.

Norway

Norway's electricity production is virtually entirely based on hydropower but as there are physical limitations to new schemes, attention has turned to wind energy, albeit with some major obstacles to overcome (financing, public acceptance, grid-limitations, etc.).

Although the country has a tremendously high wind resource, in some remote areas the prohibitively high cost of grid connection would make installation of wind turbines uneconomic. Until 2002 installed capacity was extremely small but incremental capacity added between 2003 and 2008 brought the year-end total to 429 MW. Wind turbines at 18 sites generated 917 GWh in 2008.

Ambitious plans to harness the wind resource are not yet being put into practice despite targets being set and project approvals made. The Government has a goal for 2010 renewable energy production and energy savings to be 12 TWh higher than in 2001. For this to be met, it is foreseen that wind will have to supply more than 3 TWh. For 2016 the overall level is set at 30 TWh higher than 2001.

Enova, an enterprise owned by the Norwegian Ministry of Petroleum and Energy came into operation on 1 January 2002. Its mission is to 'contribute to environmentally sound and rational use and production of energy, relying on financial instruments and incentives to stimulate market actors and mechanisms to achieve national energy policy goals'. Since its inception, 14 wind projects have received Enova's support, with an expectation that they will annually contribute in the region of 1 600 GWh. This support will continue until it joins with Sweden in creating a joint electricity certificate market in 2012. The agency plans for renewable energy and energy conservation to contribute some 18 TWh by the end of 2011. To this end Enova currently has a NOK 1 million budget for the development of wind. A round of applications for investment support of wind was launched in November 2009, with a closing date of end-January 2010. A second round of applications will open in the latter part of 2010, closing in early 2011.

Along with nine other European governments (Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Sweden and the UK), Norway is part of the European Offshore Supergrid® project. The aim is to establish a renewable energy electricity grid, in which the wind turbines belonging to the participant countries would be fully integrated.

Peru

Peru has a large wind energy resource, with a theoretical potential of some 77 000 MW, and a technologically feasible potential estimated at 22 000 MW. The Government published a national wind atlas in November 2008, which showed that the best wind regimes are to be found in the northern coastal departments of Piura and Ancash, Cajamarca in the northern Andes and the Ica department south of Lima.

After a slow start, utilisation of this source of renewable energy is beginning to accelerate. Two small pilot plants were installed in the 1990s: Malabrigo (250 kW) in the department of La Libertad and Marcona (450 kW) in Ica. A Government tender for renewable energy plants was held in 2009; three 20-year contracts were awarded for wind projects, with an aggregate capacity of 142 MW. Two of the wind parks are planned for northern Peru, 80 MW in Cupisnique, La Libertad and 30 MW at Talara, Piura. The third installation will be built at Marcona, site of one of the pilot plants.

Poland

The highest wind velocities in Poland are found along the Baltic coastal region (5-6 m/s annual average wind speed at 30 m above ground level) and in northern and central areas (4.0-5.5 m/s): it is therefore these areas that are the most favoured for development. Wind turbines have been installed, mostly in the northern coastal region but also throughout the western and central parts of the country and the Carpathians, ranging from less than 1 MW capacity to many tens of MW. The Polish Wind Energy Association has estimated that the potential for wind energy capacity amounts to 10-13 GW. However, there is land available for the installation of 19-23 GW but this would prove problematical for the Polish transmission grid as it exists at the present time.

By end-2008, installed wind capacity had reached 482 MW, generating 790.2 GWh. According to the Energy Regulatory Office, by end-2009 over 700 MW of wind capacity was in operation.

The Polish Government plans that by 2010 wind energy capacity will total 2 000 MW and wind power will contribute 2.3% of energy consumption. In November 2009 it was reported that over 350 MW of capacity was under construction.

Portugal

Portugal's considerable technical wind potential (estimated to be approximately 700 GWh/yr) was, until the beginning of the 21st century, fairly under-utilised. Total installed wind capacity stood at 125 MW at end-2001. However, because of a lack of indigenous energy resources and a high dependence on imported fuels, the Government legislated for electricity to be increasingly produced from renewable energies and in particular wind. Capacity approximately doubled in 2004 and 2005 and then increased by 60%, 45% and 23% in 2006, 2007 and 2008. By the end of this period it had reached 3 030 MW.

The Atlantic archipelagos of the Azores and Madeira both have a high wind energy potential and it was in these islands that the first wind parks were established at the end of the 1980s/beginning of the 1990s. Today, the majority of capacity is located on the mainland but the Azores and Madeira each have a small number of wind turbines. At end-2008 Portuguese wind-generated electricity amounted to 5.8 TWh, representing 12.5% of total electricity production and just over 37% of generation from renewable energy.

The Portuguese Government aims for 59% of electricity generation to be met by renewables in 2020. To achieve this objective it will be necessary for there to be 5 100 MW of wind capacity installed in 2010 and 8 500 MW in 2020.

By end-2009, mainland capacity had risen to 3 566 MW and by March 2010, 1 956 wind turbines, representing 3 725 MW capacity, had been installed in 204 wind parks.

To assist future development various incentives have been put in place: fixed feed-in tariffs, subsidies, tax benefits and a green-certificate support mechanism. Additionally, during 2008 the Portuguese Science and Technology Foundation launched a financing call for RD&D projects.

Romania

At 14 000 MW, Romania has the highest wind potential in southeastern Europe, which could result in an extra 23 000 GWh produced annually. However, from an economic point of view only 12 000 MW is feasible. A study of Erste Bank places Romania and especially the Dobrogea Region with Constanţa and Tulcea counties as the second best place in Europe to construct wind farms, owing to its large wind potential. Investors have already requested grid connection for 12 000 MW, although the national electricity transport company Transelectrica has offered permits for only 2 200 MW.

In Romania there are five distinct wind zones, depending on the existing potential of wind energy, climate and terrain. The Romanian wind map was developed taking into consideration the wind potential at an average height of 50 m and also all the meteorological information gathered since 1990.

By end-2008, 16 units with a total capacity of 9.5 MW had been installed, generating 11.02 GWh/yr. There were only 13 wind companies that had an E-SRE licence (a certificate for electricity produced from renewable sources) given by the Romanian Energy Regulatory Authority (ANRE).

A study by the Romanian Energy Institute (REI) stated that by 2020 wind farms could contribute 13 GW to national power generation capacity, and between 2009 and 2017, 4 000 MW of wind farm capacity is planned for installation, with an investment of US$ 5.6 billion. With regard to the European Commission’s targets for renewable energy, Romania aims to produce 24% of its gross final consumption of energy from renewable sources in 2020.

At end-2009 the status of Romania’s wind farm projects (larger than 10 MW) was as follows: 1 419 MW were under construction, 5 006 MW had been approved and 45 MW had been proposed. The cost of the 6 470 MW was some US$ 10.6 billion. The first offshore wind farm (100 x 5 MW), to be located in the Constanţa County sector of the Black Sea, is expected to be commissioned in 2011.

The Romanian WEC Member Committee further reports that at this time the national electricity grid cannot support all planned projects. It will therefore be necessary, by 2025, to make investments in the grid by upgrading and building power stations and a series of new 400 kV lines.

Russian Federation

Russia has used its high wind resource for many hundreds of years, mainly mechanically for water pumping. However, despite an enormous potential, commercial large-scale utilisation has never occurred and development has generally been restricted to agricultural uses in areas where a grid connection was infeasible. The areas of greatest resource are the regions where the population density is less than 1 person per km^2.

The coastal areas of the Pacific and Arctic Oceans, the vast steppes and the mountains are the areas of highest potential. Estimates suggest that the European part of Russia has a gross wind energy resource of 29 600 TWh/yr (37%) and the Siberian and Far East part, 50 400 TWh/yr (63%). The technical resource for each is reported to be 2 308 and 3 910 TWh/yr, respectively.

It has been suggested that large-scale wind energy systems might be applied in areas where the resource is particularly favourable and there is an existing power infrastructure and major industrial consumers. These would include various locations in Siberia and the Far East (east of Sakhalin Island, the extreme south of Kamchatka, the Chukotka Peninsula in the Magadan region, Vladivostok), the steppes along the Volga river, the northern Caucasus steppes and mountains and the Kola Peninsula. Additionally, offshore wind parks could be considered in some of these areas, especially in the Magadan region and in the Kola Peninsula where existing hydropower stations could be used to compensate for the intermittent wind power.

The country’s wind resource is severely under-developed. Generally, during the past decade, Russia's economic constraints have not assisted in the development of large renewable energy projects. However, in 2000, the European Union and Russia began the mutually beneficial Energy Dialogue dealing with a wide range of energy issues, from security of supply to energy efficiency to discussions regarding an interconnected electricity network. Soon after Russia's ratification of the Kyoto Protocol in October 2004, the EU began providing technical assistance through its TACIS programme. The Kyoto Protocol requires the promotion of renewable energy and, as far as wind is concerned, the manufacture of wind energy equipment and the development of wind plants in Russia.

In January 2009 the Russian Prime Minister signed an Executive Directive for a greater use of renewable energy in order for the efficiency of the electric power sector to be improved. The targets for the share of renewable energy in electricity generation are 1.5% in 2010, 2.5% in 2015 and 4.5% in 2020. At the beginning of 2010 it was reported that a Ministerial MOU had been signed between Finland and Russia. The stated objective is that cooperation and shared knowledge will lead to greater energy efficiencies and improved utilisation of renewable energies.

The Russian Association of Wind Industry (RAWI) was established in the early years of the 21st century and the first of its stated aims is to help the formation, growth and development of the wind power market in the Russian Federation. The President of RAWI has stated that as at March 2010, 4 134 MW of wind capacity sites had been identified, of which 1 793 MW were 'being prepared for project work'.

JSC RusHydro and the state corporation Rostechnologii are developing a 1 GW wind farm project in the Volgograd region. The project will proceed with a 1-year planning and 4-year construction period, assuming that the Government implements the necessary measures for the support of renewable energy-generated electricity.

Spain

For many years Spain has had an ambitious wind energy policy. From a capacity of just 75 MW in 1994 the wind sector has grown enormously and far outstripped the country's official programmes and forecasts.

The main impetus behind wind energy's strong position in the Spanish energy market has been the Spanish Renewable Energy Plan (PER) 2005-2010, issued by the Instituto para la Diversificación y Ahorro de la Energía (IDAE) in July 2005. The Plan specified that renewable energy (including large hydro) should supply 29.4% of electricity demand by end-2010 and at least 12% of total energy use. The target for wind capacity, which had been set at 13 000 MW, was raised to 20 155 MW by end-2010.

According to the Spanish Wind Energy Association (AEE), between end-2006 and end-2007 Spain added just over 3 500 MW to its installed wind capacity, bringing the total to 15 104 MW. By end-2008, a lower but still impressive 1 585 MW had been added, bringing the net total to 16 689 MW, representing over 16 800 turbines in over 733 wind farms. In terms of capacity Spain ranks second within Europe and third in the world (behind Germany and the USA).

The 30% increase in 2007 was largely because the level of government subsidies was lowered in 2008. A Royal Decree (RD 661 of 25 May 2007) specified that wind farms coming into operation before 1 January 2008 could choose to receive (until end-2012) the more favourable level of subsidy previously in force.

The AEE reports that the wind sector increased by 14.7% in 2009, adding 2 459 MW and bringing the net total national capacity to 19 149 MW and generating some 36 GWh.

All but two of the 17 Spanish Autonomous Communities (SAC) have installed wind power. Planned projects and regulatory confirmation for both Extremadura and Madrid will, in due course, result in every SAC possessing wind power. During 2009 the region of Andalucia saw the largest absolute increase of 1 077 MW, equivalent to an increase of 61% over 2008. Three regions (Castilla-La Mancha, Castilla y León and Galicia) now each have in excess of 3 000 MW.

The current level of Spanish wind capacity is likely to ensure that the target of 20 155 MW by end-2010 set by the PER, 2005-2010 will be met.

Although there is general agreement that wind capacity should reach 40 000 MW by 2020, in fact each SAC has its own target, aggregating to in excess of 41 000 MW. Moreover the EU has set a target for 20% of final energy consumption to be met by renewable energy in 2020 – wind will undoubtedly play a major role in reaching this objective.

Royal Decree 1028/2007 established the process necessary for the authorisation of offshore wind turbines, with the further Royal Decree 1029/2007 requiring that environmental studies be undertaken to establish the suitability of offshore sites.

National incentive programmes (payment plan, feed-in tariff, market option) have all played their part in providing support for the strong development of the Spanish wind industry, as well as R&D plans – the latest being drawn up by the Government during 2008 for implementation between 2008 and 2011.

Indigenously-owned manufacturers account for over 70% of wind turbines installed in the country. Whilst there are several foreign manufacturers participating, the national company Gamesa leads the home market.

Sweden

The wind energy resource in Sweden is very high but although Sweden was one of the early pioneers in modern wind power development, embarking on a wind energy programme in 1975, bureaucratic procedures have meant that deployment has been fairly slow.

In 2002 the Parliament set a national planning target of 10 TWh for electricity production from wind power (4 TWh onshore and 6 TWh offshore) by 2015. However, a complex planning permission process had resulted in only 788 MW being installed by end-2007. During 2008 a net 233 MW was installed, bringing the total at year-end to 1 021 MW. At 2.0 TWh, wind-generated electricity was 40% higher than in 2007 and accounted for 1.5% of total electricity output.

In February 2009 the Swedish Government set out its new energy and climate policy. It is intended that wind power should play a significant role in the increasing use of renewable energy. To this end, the policy included the establishment of 30 TWh of wind power by 2020, of which 10 TWh would be offshore. A number of factors, not least the limitations of the national grid - designed to transmit power from the northern hydroelectric plants to the south – will probably result in a more realistic figure of 25 TWh by 2020 (15 TWh onshore, 10 TWh offshore). This latter total concurs with an earlier proposal by the Swedish Energy Agency. With a support system from the Agency and taking into account that permission can be more expeditiously granted (than for onshore locations), it is likely that a number of offshore wind plants in the south of the country will become operational.

The construction of the Utgrunden II offshore plant was due to begin in 2007. However, the developer (E.ON) has postponed the project. The Kriegers Flak offshore plant has received support for ongoing development studies. The 110 MW Lillgrund (48 x 2.3 MW) offshore development is located in the Öresund between Malmö and

Copenhagen. It came into operation at the end of 2007.

The 30 MW (10 x 3 MW) Vindpark Vänern was inaugurated in May 2010. Located in the northern part of Sweden's largest lake, it is the first 'inland offshore' wind power project.

Along with nine other European governments (Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway and the UK), Sweden is part of the European Offshore Supergrid® project. The aim is to establish a renewable energy electricity grid, in which the wind turbines belonging to the participant countries would be fully integrated.

Taiwan, China

Taiwan's coastal areas, particularly the west coast and the island of Penghu receive annual average wind speeds of 5-6 m/s, with strong northwest winds for six months in the year. The total wind power potential (onshore and offshore) is at least 3 000 MW.

Utilisation of the wind resource began in 2000 with the installation of small demonstration turbines by private industry, under the Ministry of Economic Affairs (MOEA)'s 5-year demonstration project. Taipower's project on Penghu followed in 2001 and in total some 8.5 MW was installed.

In 2007 the MOEA set a 2025 target of 3 000 MW for wind power, including 1 700 MW offshore.

The MOEA's Bureau of Energy has stated that renewable energy will play an increasing role in electricity generation, with wind providing the major share. In mid-2009, the Legislative Yuan set a goal in its Renewable Energy Act of increasing Taiwan's electricity generating capacity from renewable energy by 6.5 GW to 10 GW within 20 years. A series of incentive mechanisms will be initiated in order to assist development.

The Executive Yuan has also ratified the first stage of an offshore wind power programme. The objective will be to develop 300 MW offshore.

Taipower has a long-term three-phase wind development project. The first phase occurred between January 2003 and end-2008. In this period 60 units totalling 99 MW were installed, including 9 turbines at the 1st and 3rd NPPs. The second phase began at the beginning of 2005 and will run until mid-2010. This phase represents a further 116 MW. The 69 MW third phase runs between the beginning of 2007 and mid-2011, with commercial operation of the units scheduled for 2010 and 2011.

By end-2008, a total of 252 MW wind capacity had been installed, divided approximately 50% Taipower/50% IPP. Electricity generation from wind in 2008 totalled 589 GWh.

Tunisia

Two small experimental wind projects: Aquaria (10 kW) and Jabouza (12 kW) (both now closed) had been commissioned during the 1980s by SEN (Société d'Energies Nouvelles). STEG (Société Tunisienne de l'Electricité et du Gaz) took over the wind turbines when SEN closed in 1994. An early-1990s feasibility study undertaken by STEG led to the 10.56 MW grid-connected wind plant at Sidi Daoud becoming operational in August 2000. An 8.72 MW expansion to Sidi Daoud became operational in 2003 and it was intended that a 34.32 MW 3rd stage would come on line during 2007, but Tunisian total installed capacity was still only 19 MW at end-2008.

In September 2008 Gamesa, the Spanish wind turbine manufacturer, reported that it had signed an agreement with STEG to supply 91 wind turbines for a 120 MW scheme. The generators will supply the Metline and Kechabta wind farms in the Bizerte region in what will become the country's largest wind project.

Turkey

During 2007 the Turkish Wind Energy Potential Atlas established that in regions where wind speed was in excess of 8.5 m/s, the potential was 5 000 MW, but that it was as high as 48 000 MW where the wind speed was a minimum of 7 m/s.

By end-2004 total installed capacity stood at only 18 MW and thus at that time the resource was very little utilised. The Turkish Parliament's legislation for the increased use of renewable energy in electricity production came into force in 2005 and by end-2008, installed wind capacity had increased some 25 times to reach 458 MW. Electricity generation from wind turbines amounted to 847 GWh in 2008. At end-2009, capacity was estimated to be 78% higher than the previous year and had reached 813 MW. In May 2010 some 1 030 MW was under construction, of which 429 MW is expected to be commissioned during the year. Construction of 644 MW is expected to be started during 2010.

The Strategic Plan 2010-2014 of the Turkish Ministry of Energy and Natural Resources (MENR) states that wind energy capacity is forecast to reach up to 10 000 MW by 2015. The MENR has set a 2020 wind energy target of up to 20 000 MW. At the present time the main obstacle to an increased wind park is the limitations of the national grid.

United Kingdom

The Utilities Act (2000) made substantial changes to the regulatory system for electricity in Great Britain. The Act replaced the Non-Fossil Fuel Obligation Orders (NFFO) by the Renewables Obligation and the Renewables Obligation (Scotland), which came into force in April 2002. These consist of four key strands: all electricity suppliers must supply a specific proportion of electricity from renewable sources; electricity generated from all renewable sources (excluding hydro plants over 10 MW) will be exempted from the Climate Change Levy; renewable energy will be supported by a programme which includes capital grants and an R&D programme; and renewables will benefit from a regional strategic approach to planning. The 2001 EU's Renewables Directive set a target for the UK for 10% of electricity consumption to be met from renewable energy by 2010. During 2008 a new Renewables Directive set a target for the UK for 15% of final energy consumption to be met from renewable energy by 2020.

By end-2008 installed wind capacity in the UK stood at 3 406 MW, of which 2 820 MW was onshore and 586 MW offshore. Electricity generation during 2008 totaled 7.1 TWh, of which 5.8 TWh came from onshore plants and 1.3 TWh from offshore. The 4 GW mark for total installed wind capacity was passed before end-2009 and the UK now holds the position of world leader in installed offshore wind capacity.

In October 2009 there was 1.2 GW onshore and 0.9 GW offshore wind capacity under construction; 3.2 GW onshore and 4.0 GW offshore awaiting construction and 5.9 GW onshore and 3.6 GW offshore applications being considered.

In order for the renewable energy targets to be met, the Government has formulated policies designed to support the industry during the forthcoming decade. The official UK Low Carbon Transition Plan states that the Government is providing up to GBP 120 million worth of investment for developing the offshore wind industry. In conjunction with Ofgem (Office of the Gas and Electricity Markets) a new regulatory framework for offshore electricity transmission, involving GBP 15 billion worth of grid connections, was put into effect in June 2009. In the period to 2020, and in addition to the planned 8 GW offshore wind, it was estimated that a further 20 GW was feasible. However, following a full Strategic Environmental Assessment, the UK Renewable Energy Strategy, published in July 2009, indicates that new capacity could be as high as 25 GW. These estimates relate to the UK Renewable Energy Zone and the territorial waters of England and Wales, in water up to 60 m deep. The Scottish Executive is studying the potential for an additional 6.4 GW in its own territorial waters.

The Planning Act 2008, which built on the objectives set out in the Planning White Paper of May 2007, now ensures that the approval process for new capacity will be conducted more speedily and smoothly. The planning process in Scotland comes under the jurisdiction of the Scottish Executive but after review in 2006 it also now ensures a degree of expeditiousness.

The 2008 Energy Act provided the wherewithal for the Government to introduce feed-in tariffs (FIT). From 1 April 2010 renewable energy electricity-generating technologies, up to a maximum of 5 MW, qualify for generation and export tariffs. FITs will work alongside the Renewables Obligations. In the case of new wind schemes, where both the product and installer are certificated, the generation tariffs are on a decreasing scale from GBP 0.345/kWh for up to 1.5 kW capacity to GBP 0.045/kWh for installations of 1.5-5 MW. These rates will remain the same for a period of 20 years (although adjusted for inflation through a link to the Retail Price Index). The rates are subject to variation for new installations after 31 March 2012. The tariff payable for electricity exported to the grid is GBP 0.03/kWh, regardless of the size of the installation.

The London Array is an offshore project developed by partners E.ON, Dong Energy and the Abu Dhabi investment company Masdar. Environmental impact studies were begun in 2001 and the required permissions were granted in 2006 and 2007. Ultimately the wind farm will be the largest in the world and also the first with a capacity of 1 GW.

By end-2009 the consortium had signed contracts with suppliers for the 175 turbine, 630 MW first phase. Offshore work is scheduled to begin in early 2011 with a completion date of end-2012. The second phase, if approved, would add a further 370 MW. The scheme is designed to satisfy the electricity requirements of 750 000 homes in the Greater London area.

Along with nine other European governments (Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway and Sweden), the UK is part of the European Offshore Supergrid® project. The aim is to establish a renewable energy electricity grid, in which the wind turbines belonging to the participant countries would be fully integrated.

United States of America

The land-based wind potential of the USA has been estimated at 8 000 GW. However, the sector was slow to develop, with just 1.8 GW of installed wind capacity in place in 1990. By 2000 annual growth in wind capacity had averaged approximately 3% and it was only in the last decade that spectacular growth has occurred. Between 2000 and 2006, capacity grew rapidly, at nearly 30% per annum but the following two years saw unprecedented growth: an increase of 46% during 2007 and a further increase of 50% in 2008, bringing the end-year capacity to 25 410 MW. Seven states (Texas, Iowa, California, Minnesota, Washington, Colorado and Oregon) each had in excess of 1 000 MW.

The Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) states that growth in installed capacity during 2009 was 37%. About 9.5 GW were added, bringing the total by year-end to nearly 35 GW. Thirty seven states have wind power capability with Texas having approximately 2.6 times the capacity of the next biggest state: Iowa. During 2009, Texas installed nearly 2.3 GW. Fourteen states now have in excess of 1 000 MW.

Various policies and programmes have helped or are helping to expand the US wind sector:

The Federal tax credits have played a significant role in the growth of wind power. The Wind Energy Production Tax Credit (PTC) of an inflation-adjusted US$ 0.021/kWh for the production of electricity from utility-scale turbines has been particularly important. The credit was due to expire at end-2008 but in October Congress extended it for one year. In February 2009 the incentives were expanded and again extended to 2012.

The Emergency Economic Stabilization Act of 2008 and the American Recovery and Reinvestment Act (the Recovery Act) have both been instrumental in the development of wind power. The US$ 787 billion Recovery Act passed into law in early 2009 and provides the wherewithal to promote an economic recovery following the recession. The Act has allotted US$ 16.8 billion for the EERE. The Recovery Act specifically includes provisions for stimulating the wind power sector and by year-end, over US$ 1.5 billion had supported nearly 40 wind projects.

A Renewable Portfolio Standard (RPS) has been adopted by a majority of States and the District of Columbia. Some States have RPS with nonbinding goals. Feed-in tariffs offered during 2008 are gradually being adopted on a State and city basis. RPS policies can be adopted at both Federal and State level and use market mechanisms to ensure that renewable energy is increasingly used for the production of electricity.

Individual States also have policies for the encouragement of small wind systems These include tax credits, net metering, rebates, production incentives, etc.

The U.S. Department of Energy's Wind Energy Program focuses its research on two primary areas. The first is increasing the technical viability of wind systems by pursuing large wind technology, distributed wind technology and supporting research and testing (wind-technology-specific research targeted to help industry improve the performance of components and fully integrated turbine systems). The second is increasing the technology application (the use of wind power in the marketplace). It does this by sponsoring research into both systems integration and technology acceptance.

Following the 2006 Advanced Energy Initiative, which suggested that areas of good wind resources had the potential to supply up to 20% of electricity consumption, the report, *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to US Electricity Supply*, was published in 2008. A collaborative effort by the U.S. Government and industry, it contained one scenario examining the challenges associated with achieving the 20% goal, whilst another looked at no further increase in wind capacity. The report concluded that the U.S. had wind potential far in excess of that needed for the 20% goal to become a reality. However, to be implemented it would be necessary to overcome the challenges that were identified and for the rate of installation of turbines to increase from 2 000/yr in 2006 to around 7 000/yr in 2017.

Until recently, problems - largely due to competing claims for jurisdiction over territorial waters - have hampered the utilisation of the offshore wind resource potential. The U.S. thus lags behind Europe in its use of its offshore resource. However, in April 2010, it was announced that Government approval had been given for the first offshore project. The 130 turbine wind farm will be located in a 25 square mile area in Nantucket Sound. It has been reported that further offshore wind schemes are being planned for other northeastern States.

13. Tidal Energy

COMMENTARY

The Tides

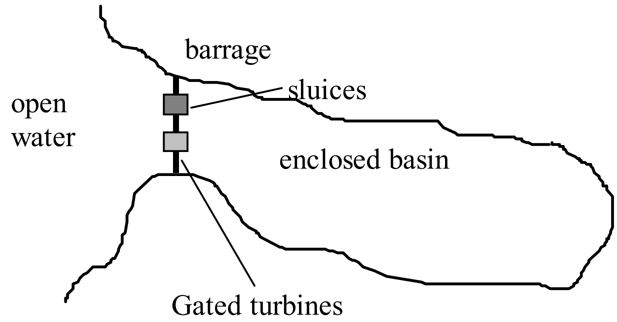
Using the tides as energy sources is not a new idea. Small tidal 'mills' were used in Southern England and Northern France in the Middle Ages. Tidal flows in bays and estuaries offered the potential to drive cereal-grinding apparatus in areas that were too low-lying to allow the use of conventional water wheels. The Eling Tide Mill, for example, (Fig. 13.1) is still operational, largely as an educational and tourist facility. This is a very early example of a tidal entrainment system, i.e. an artificial barrier or barrage used to interfere with the natural movement of water under tidal influences. Entrainment is a more general term than 'barrage', as it allows consideration of alternative engineering methods such as lagoons.

In the 20th century, tides were seriously re-examined as potential sources of energy to power industry and commerce and it is this activity that forms the subject of most of this commentary. If the technical progress achieved in the 20th century is continued, then it is likely that the 21st century will see ongoing large-scale development and implementation of tidal energy.

The explanation for the existence of tides represented one of the greatest challenges to early oceanographers, mathematicians and physicists. It was not until Newton developed his theories of gravitation and the mechanics of motion that a satisfying theory emerged to explain at least some of the properties of the tides. The physics of the 'Newtonian Tidal Theory', which is sometimes

Figure 13.1 The Eling Tide Mill (Source: Eling Tide Mill)

Figure 13.2 Hypothetical tidal barrage configuration (Source: Bryden)



referred to as ‘Equilibrium Tidal Theory’, gives a partial description of tidal behaviour for an abstract planet Earth, which is entirely covered by water, and is outlined in most introductory texts on oceanography (Bearman, 1997). In effect, the tides represent the terrestrial manifestation of the potential and kinetic energy fluxes present in the Earth-Moon-Sun system. These fluxes are complicated by the presence of continents and other landmasses, which modify the form and phase of the tidal wave. This results in some regions of the world possessing substantially higher local fluxes than others. The Bay of Fundy in Canada and the Bristol Channel between England and Wales are two particularly noteworthy examples, which possess exceptionally high tidal ranges.

Although tides originate from mechanistic astronomic effects and tidal influences can be predicted centuries in advance, the sea surface is also subject to weather-related effects of which waves are, of course, the most obvious. Pressure effects and wind-driven currents also superimpose unpredictable perturbations upon the tides but these can be forecast from meteorological information over periods of days.

Harnessing the Energy in the Tides

Approaches to exploitation

There are two fundamentally different approaches to the exploitation of tidal energy. The first is to exploit the cyclic rise and fall of the sea level through entrainment. This includes ‘traditional’ barrage methods as well as tidal lagoons and fences. The second approach is to harness local tidal currents in a manner somewhat analogous to wind power.

Tidal barrages

Principles and history:

There are many places in the world in which local geography results in exceptionally large tidal ranges. Sites of particular interest include the Bay of Fundy in Canada, which has a mean tidal range of 10 m; the Severn Estuary between England and Wales, with a mean tidal range of 8 m and northern France with a mean range of 7 m. A tidal barrage power plant has, indeed, been operating at La Rance in Brittany since 1966 (Banal and Bicon, 1981). This plant, which is capable of generating 240 MW, incorporates a road crossing of the estuary. It has recently undergone a major ten-year refurbishment programme.

Other operational barrage sites are at Annapolis Royal in Nova Scotia (18 MW), The Bay of Kislaya, near Murmansk (400 kW) and at Jangxia Creek in the East China Sea (500 kW) (Boyle, 1996). Schemes have been proposed for the Bay of Fundy and for the Severn Estuary but have never been built. The prospect of generating electricity in the Severn Estuary has excited engineers and planners since the end of the 19th century, even before there was a significant demand for electricity. A serious proposal for an 800 MW generation scheme was made in 1925 (Hansard, 1926) and this particular option continued to be examined seriously into the 1950s. The UK government is presently considering options for the commercial development of the Severn Estuary and a decision on future progress will be made during 2010.

Figure 13.3 Water levels in an ebb generation scheme (Source: Bryden)

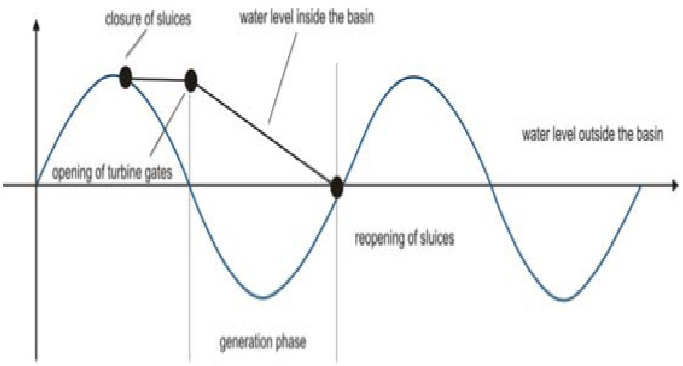
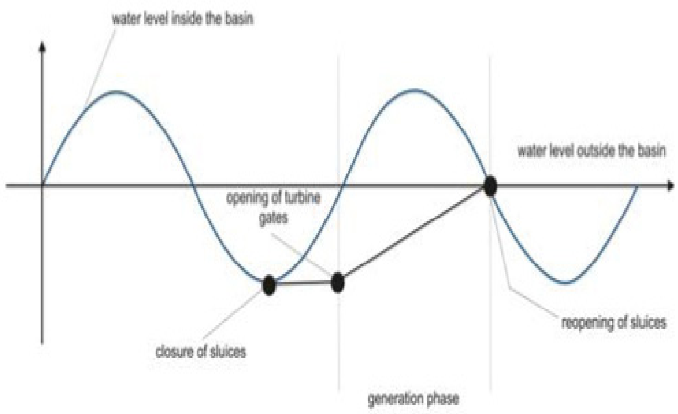


Figure 13.4 Water levels in a flood generation scheme (Source: Bryden)



In South Korea the Sihwa Lake Power should be completed in 2010 with a preliminary capacity of 254 MW, thus replacing La Rance as the largest tidal entrainment development. The plant will use ten 25.4 MW submerged bulb turbines. Unlike La Rance and most of the Severn proposals, the plant will operate in flood mode rather than ebb mode, in order to minimise specific environmental effects in the site.

Tidal Barrages can operate in a variety of modes. These can be broken down initially into Single Basin Schemes and Multiple Basin Schemes. The simplest of these are the Single Basin Schemes:

Single Basin Tidal Barrage Schemes. These schemes, as the name implies, require a single barrage across the estuary (Fig. 13.2). There are, however, three different methods of generating electricity with a single basin. All of the options involve a combination of sluices which, when open, can allow water to flow relatively freely, through the barrage and gated turbines, the gates of which can be opened to allow water to flow through the turbines to generate electricity.

Ebb generation mode. During the flood tide, incoming water is allowed to flow freely through sluices in the barrage. At high tide, the sluices are closed and water retained behind the barrage. When the water outside the barrage has fallen sufficiently to establish a substantial head between the basin and the open water, the basin water is allowed to flow out though low-head turbines and to generate electricity. The system can be considered as operating in phases. Fig. 13.3 shows the periods of generation associated with stages in the tidal cycle.

Typically the water will only be allowed to flow through the turbines once the head is approximately half the tidal range. This method will generate electricity for, at most, 40% of the tidal range.

Flood generation mode. The sluices and turbine gates are kept closed during the flood tide to allow the water level to build up outside of the barrage, as shown in Fig. 13.4. As with ebb generation, once a sufficient head has been established the turbine gates are opened and water can, in this case, flow into the basin generating electricity.

This approach is generally viewed less favourably than the ebb method, as keeping a tidal basin at low tide for extended periods could have detrimental effects on the environment and shipping. However, the special circumstances in the Korean Sihwa project have made flood mode the preferred option.

Two-way generation. It is possible, in principle, to generate electricity in both ebb and flood. Unfortunately computer models do not indicate that there would be a major increase in the energy production. In addition, there would be additional expenses associated with having a requirement for either two-way turbines or a double set to handle

Figure 13.5 Hypothetical two-basin system
(Source: Bryden)

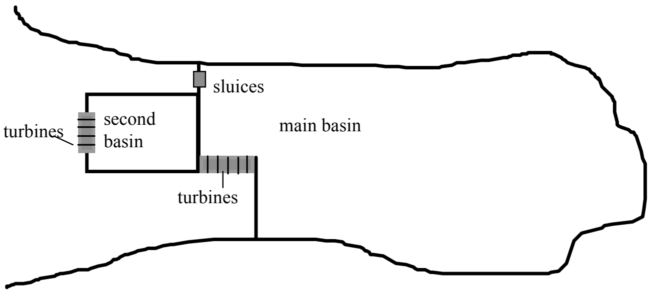


Figure 13.6 Possible sites for future tidal barrage developments (Source: Boyle)

Site	Mean tidal range (m)	Barrage length (m)	Estimated annual energy production (GWh)
Severn Estuary (UK)	7.0	17 000	12 900
Solway Firth (UK)	5.5	30 000	10 050
Bay of Fundy (Canada)	11.7	8 000	11 700
Gulf of Khambhat (India)	6.1	25 000	16 400

the two-way flow. Advantages include, however, a reduced period with no generation and the peak power would be lower, allowing a reduction in the cost of the generators.

Double Basin Systems. All single-basin systems suffer from the disadvantage that they only deliver energy during part of the tidal cycle and cannot adjust their delivery period to match the requirements of consumers. Double-basin systems (Fig. 13.5) have been proposed to allow an element of storage and to give time control over power output levels.

The main basin would behave essentially like an ebb-generation single-basin system. A proportion of the electricity generated during the ebb phase would be used to pump water to and from the second basin to ensure that there would always be a generation capability.

It is anticipated that multiple-basin systems are unlikely to become popular, as the efficiency of low-head turbines is likely to be too low to enable effective economic storage of energy. The overall efficiency of such low head storage, in terms of energy out and energy in, is unlikely to exceed 30%. It is more likely that conventional pumped-storage systems will be utilised. The overall efficiency of these systems can exceed 70% which is, especially considering that this is a proven technology, likely to prove more attractive financially.

Possible sites for future tidal barrage developments:

Worldwide there is a considerable number of sites technically suitable for development, although whether the resource can be developed economically is yet to be conclusively determined (Boyle, 1996). Although not a definitive list, Fig. 13.6 shows some of the possible sites:

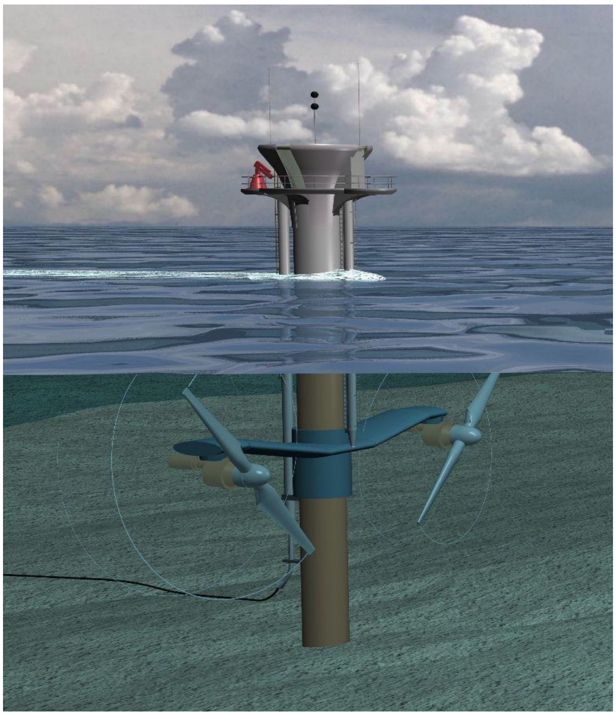
Tidal lagoons

Tidal barrage systems are likely to cause substantial environmental change. Ebb generation results in estuarial tidal flats being covered longer than in a natural estuary. This might not be acceptable. A barrage, even with locks, will cause obstruction to shipping and other maritime activity. Artificial lagoons (tidalelectric.com) have been proposed as alternatives to estuarial barrages. Electricity would be generated using sluices and gated turbines in the same manner as 'conventional' barrage schemes.

The principal advantage is that the coastline, including the intertidal zone, will be largely unaffected. Careful design of the lagoon could also ensure that shipping routes would be unaffected. A much longer barrage would, however, be required for the same surface area of entrainment. Some preliminary studies do, however, suggest that, in suitable locations, the costs might be competitive with other sources of renewable energy. There has yet to be in-depth peer-reviewed assessments of the tidal lagoon concept, so estimates of economics, energy potential and environmental impact should be treated with caution. The Severn

Figure 13.7 SeaFlow with the nacelle raised
(Source: Marine Current Turbines)

Figure 13.8 Artist's impression of SeaGen
(Source: Marine Current Turbines)



Estuary and the mouth of the Yalu River, China have both been suggested as potential locations for lagoon-style development.

Tidal current technology

Principles and history:

The development of a tidal entrainment system represents a substantial investment of time and money, and many planners and engineers favour the development of tidal current systems which could be developed incrementally. Indeed, it is possible that a step-by-step development of the tidal current resource might allow subsequent advances in technology or understanding of the resource to be incorporated in later stages. The most thoroughly documented early attempt to prove the practicality of tidal current power was conducted in the early 1990s in the waters of Loch Linnhe in the Scottish West Highlands (itpower.co.uk). This scheme used a turbine held mid-water by cables, which stretched from a sea-bed anchor to a floating barge.

The mid to late 1990s was primarily a time of planning and development as far as tidal current power was concerned and it was not until the beginning of the 21st century that further systems became ready to test. In 2000 a large vertical-axis floating device (the ENERMAR project [Pontediarchimede.com]) was tested in the Strait of Messina between Sicily and the Italian mainland. Between May 2003 and October 2009, Marine Current Turbines (MCT) Ltd. (marineturbines.com) of Bristol, England, demonstrated a 300 kW pillar-mounted prototype system, called SeaFlow, in the Bristol Channel.

Fig. 13.7 shows the SeaFlow system with its nacelle raised into the 'maintenance position'.

The Canadian Clean Current project involved the testing of a ducted horizontal-axis machine at Race Rocks, British Columbia, between July and September 2006 before being removed in May 2007 and subsequently re-installed after modification in October 2008.

MCT installed their commercial-scale prototype (SeaGen) in Strangford Narrows in Northern Ireland in 2008. Although having some similarities with SeaFlow, it is equipped with two rotors and has a rated capacity of 1.2 MW. An artist's impression is shown in Fig. 13.8 and the operational system in Fig. 13.9. There is presently one other grid-connected tidal current device under test in UK waters. This was built by the Irish company OpenHydro and installed in 2007 in one

Figure 13.9 Photograph of SeaGen in operation (Source: Marine Current Turbines)

Figure 13.10 The OpenHydro system installed at EMEC (Source: OpenHydro)

of the tidal test berths made available by the European Marine Energy Centre (EMEC) in Orkney.

In Norway, the Hammerfest Strøm system (tidevannsenergi.com) demonstrated between 2003 and 2007 that a 300 kW pillar-mounted horizontal-axis system could operate in a Fjord environment. The company now has ongoing plans for a larger (1 MW) system, which is intended to be available for commercial installation from 2012.

In the USA, Verdant Power Ltd. successfully demonstrated an array of six 5 m diameter horizontal-axis tidal turbines in New York's East River from 2006 to 2008 (verdantpower.com). The company now has detailed plans for a substantially larger development, using more advanced technology.

In Korea, the UK-based company Lunar Energy (lunarenergy.co.uk) announced in 2008 that they had an agreement with Korean Midland Power Co. (KOMIPO), to develop a 300-turbine array of their ducted, horizontal-axis devices off the South Korean coast to supply 300 MW by the end of 2015.

In 2007, EMEC (emec.org.uk), established in 2004 to allow the testing of full-scale marine energy technology in a robust and transparent manner, became fully equipped for the testing of tidal, as well as wave energy technology. The tidal test berths are located off the southwestern tip of the island of Eday, in an area known as the Fall of Warness. The facility offers five tidal berths at depths ranging from 25-50 m in an area 2 km across and approximately 3.5 km in length. Each berth has a dedicated cable connecting to the local grid. At the time of writing, there is one fully operational device (openhydro.com) installed. This is operated by OpenHydro and is a novel annular turbine system held by twin vertical pillars. The system can be seen in its maintenance position in Fig. 13.10. There is presently an additional device, developed by Tidal Generation Ltd. (TGL), in the process of being installed. This is a frame-mounted horizontal-axis device as shown in Fig. 13.11.

The physics of the conversion of energy from tidal currents is superficially very similar, in principle, to the conversion of kinetic energy in the wind. Many of the proposed devices have, therefore, an inevitable, though superficial, resemblance to wind turbines. There is, however, no total agreement on the form and geometry of the conversion technology itself. Wind power systems are almost always horizontal-axis rotating turbines. In these systems, the axis of rotation is parallel to the direction of the current flow. Many tidal developers also favour this geometry. Vertical-axis systems, in which the axis of rotation is perpendicular to the direction of current flow, have not, however, been rejected. It is of interest to note that ENEMAR used a novel Kobold vertical-axis turbine.

The environmental drag forces on any tidal current energy conversion system are very large, when compared with wind turbines of the same capacity. This poses additional challenges to the designer. Designs exist for devices which are rigidly attached to the seabed or are suspended from floating barges, such as the early Loch Linnhe device. It is generally accepted that fixed systems will be most applicable to shallow water sites and moored

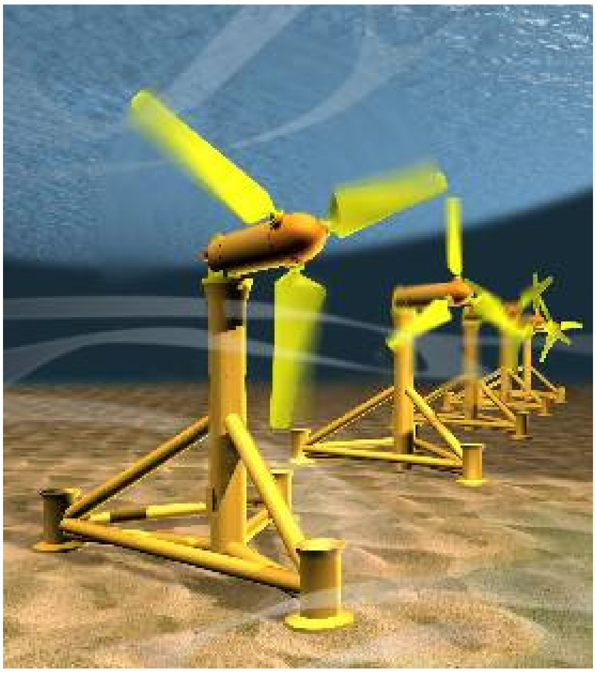


Figure 13.11 Artist's impression of the TGL systems being installed at EMEC
(Source: Energy Technologies Institute)

systems for deep water. There may, however, be exceptions to this.

The Pentland Firth, discussed earlier, is widely believed to be one of the world's most energetic tidal channels and, in November 2008, The Crown Estate, which owns the sea bed, invited initial proposals from developers for sites located in the Firth and surrounding waters (thecrownestate.co.uk). Its Round 1 leasing programme has been aimed at delivering 700 MW of new offshore wave and tidal power. The challenges of this exploitation must not be underestimated. The very resource, which makes it attractive, also makes it dangerous and unpredictable. However, even 700 MW represents a small proportion of the potential capacity, which makes it an appetising target for ambitious developers. What form the technology for economic exploitation of this resource might be is not yet clear but some existing technology concepts might already be capable of delivering from some of the less challenging areas of the Firth.

Energy available in tidal currents:

The energy available from tidal currents has been a matter for considerable conjecture. It is usual in marine renewable energy to consider the theoretical, technical and practical resource. The theoretical resource is that which could in principle be extracted, without consideration of technology or constraints. Even this concept can prove elusive for tidal current assessment. The 'Technical' resource is that proportion of the theoretical resource that could be exploited using reasonably available technology options. Even more restrictive is the 'Practical' resource, which represents the proportion of the technical resource that could be exploited after consideration of external constraints, for example grid accessibility, competing use (shipping lanes, etc.) and environmental sensitivity.

Marine charts and tidal atlases have, for many years, given considerable information on the distribution of energetic tidal flows. Maps, such as those published in the Atlas of UK Marine Renewable Energy Resources (renewables-atlas.info) which detail tidal current speeds and distributions, are already available for some areas of potential interest. Fig. 13.12, for example, shows the distribution of average peak spring tide current speeds around the Scottish coastline. The resolution of the map hides many very energetic sites, although the speeds in the Pentland Firth can be clearly seen. High speed sites tend to be geographically compact, although the energy flux densities can be considerable.

It is very tempting to draw analogies between wind power and tidal current power. In both, it is possible to calculate the kinetic energy carried by a moving

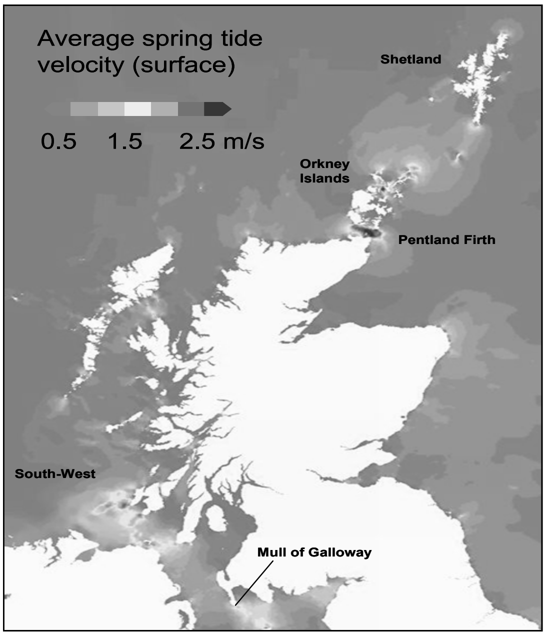


Figure 13.12 Average spring peak speeds around Scotland
(Source: University of Edinburgh)

fluid and to relate this to an energy flux density. This would represent, however, only part of the energy in a tidal current. In any tidal environment, energy is being dissipated through 'friction' between the moving water and the boundaries. The surface of the sea in a high energy tidal environment cannot be considered as level and changes should be expected in the potential energy of the water as it flows through a site. In many situations, the changes in potential energy and the frictional dispersion of energy can dwarf the kinetic flux. In addition, the sea surface is in close proximity to the technology and any analysis cannot ignore the influence of energy extraction on the boundary itself.

A full analysis of the energy potential of a tidal current development site should also consider the complexity of flow in terms of temporal and spatial variation and the impact of extraction on the underlying flow patterns. This would generally require the use of significant numerical modelling of the tidal environment and the technology being introduced, to allow assessment of the impact of extraction scenarios. This in turn would require the availability of high quality data on the tidal/hydraulic environment.

The *'Theoretical'* resource can be difficult to interpret for all but the simplest environment. In most cases, it will be more reasonable to estimate the *'Practical'* resource directly through agreement with environmental and other bodies as to what would be acceptable changes in the tidal flow environment and subsequently using numerical modelling techniques to determine how much energy could be extracted without exceeding these constraints. The challenge would then be to determine, from knowledge of the technology concepts available: how these devices affected the local flow environment; how many devices would be necessary and in what configurations they could be deployed. Given sufficiently sophisticated modelling capability, it would be advantageous to simultaneously determine the energy extraction and device deployment configurations from knowledge of the environmental and other constraints.

Individual prospective tidal sites, either estuaries or high flow-speed areas, need site-dependent consideration. This makes the production of high-level resource assessments very difficult. Knowledge of the processes is now sufficient to allow robust estimates of the practical resource, provided sufficiently detailed data are available to describe the environment and the constraints. Such analysis is now being applied to candidate sites across the world. Once sufficient analyses have been conducted, the experience will aid the processes necessary for high-level resource assessments of national resources based upon less detailed data.

Development options for tidal currents:

The environment that tidal devices will operate in is very different from that experienced by wind turbines and there are some rather difficult problems associated with installation, survivability and maintenance, which need to be solved before true commercial exploitation can be achieved.

Proposed development options often involve the use of dedicated installation and maintenance vessels, which suggests that tidal currents might only be economically developed in large sites, where major development can be installed, justifying the use of an expensive infrastructure.

Small sites could perhaps be developed, however, using technology which can be installed and maintained using less expensive techniques. The Sea Snail (Owen and Bryden, 2005), which can be installed using a small seagoing tug, could be one such option. This sea-bed located device is held to the sea bed using variable position hydrofoils which generate substantial down force, thus reducing the need to use substantial ballast.

Many industrial, commercial and public bodies have suggested that there is a high degree of synergy between the development of a tidal current generation industry and the offshore oil and gas industry. This offers the intriguing prospect of a new renewable industry developing in partnership with the petroleum industry and could, perhaps, result in accelerated development, as a result of the availability of expertise and technology, which would otherwise have to be developed from scratch.

Unlike the wind, tides are essentially predictable as they derive from astronomic processes discussed earlier in this commentary. Wind power systems are dependent upon random atmospheric processes, which result in it being difficult to integrate large wind power developments into strategic electricity distribution networks. The predictability of the tides will make this integration much easier for tidal power.

Although prototype tidal current devices are now available and have mostly proved successful in their operation, there are still issues requiring resolution before the resource can be fully exploited. With the exception of the New York development referred to above, knowledge of the performance of devices in arrays is somewhat limited, although theoretical models are at last becoming available. It is also becoming obvious that turbulence levels in high-energy tidal flows can be considerable. Turbulent amplitudes exceeding 15% of the time-averaged flows have been measured (Norris and Bryden, 2007). This will prove challenging to systems designers. Similarly there is an ongoing need for enhanced understanding of the behaviour of tidal current devices in the presence of incident waves. These gaps in understanding should not, however, prevent ongoing deployment of pre-commercial, or even early-stage commercial technology, provided that technology developers are aware of the design constraints that knowledge gaps impose, and recognise that they themselves are part of the research process which will ultimately allow cost-effective exploitation of the tidal current resource.

The Future of Tidal Power

The high capital costs associated with tidal barrage systems are likely to restrict development of this resource in the near future. What developments do proceed in the 21st century will most probably be associated with road and rail crossings, in order to maximise the economic benefit. There is, however, more interest in entrainment systems now than at any time in the past thirty years and it is increasingly likely that new barrage and lagoon developments will be seen, especially in those locations which offer a combination with transport infrastructure. In a future in which energy costs are likely to rise, assuming that low-cost nuclear fusion or other long-term alternatives do not make an unexpectedly early arrival, then tidal barrage schemes could prove to be a major provider of strategic energy in the late 21st century and beyond. The technology for tidal barrage systems is already available and there is no doubt, given the experience at La Rance, that the resource is substantial and available. The ongoing development of the Korean resource and renewed interest in the Severn and Fundy resource also suggest that future development is possible.

In the near future it is likely that tidal current systems will continue to appear in experimental form in many places around the world. If these schemes prove successful, then the first truly commercial developments will appear in the second decade of the 21st century. Already, commercial scale prototypes are being tested and may prove to be the technical basis for true commercial development. Tidal current systems may not presently have the strategic potential of barrage systems but, in the short term at least, they do offer opportunities for supplying energy in rural coastal and island communities. In the longer term, massive sites such as the Pentland Firth could become strategically important.

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COUNTRY NOTES

The Country Notes on Tidal Energy have been compiled by the Editors, drawing upon a wide range of sources. National, international and governmental publications/web sites have all been consulted.

Canada

Embayments at the head of the Bay of Fundy between the maritime provinces of New Brunswick and Nova Scotia have some of the largest tidal ranges in the world. The most promising prospects for tidal power have centred on two sites in this region: the Cumberland Basin (an arm of Chignecto Bay) and the Minas Basin (both at the head of the Bay of Fundy). However, the only commissioned tidal power plant is located at Annapolis Royal, further down the Bay in Nova Scotia. The 20 MW plant came into operation in 1984: the barrage was primarily built to demonstrate a large-diameter rim-generator turbine. Annapolis uses the largest Straflo turbine in the world to produce more than 30 million kWh per year.

In view of the large tidal energy resource of the two basins, estimated to be 17 TWh per year, different options for energy storage and integration with the river hydro system have been explored. Following an application for funding in late-2006, Nova Scotia Power announced in January 2007 that the company planned to establish a tidal stream demonstration project in the Minas Passage, Bay of Fundy.

The harnessing of the tidal energy resource in the Minas Passage is one of the commitments the Government of Nova Scotia made in response to the Strategic Environmental Assessment for offshore renewable energy in the Bay of Fundy. The Fundy Tidal Institute was established to facilitate the work of the three companies appointed by the Government of Nova Scotia, allowing them to test their respective technologies and to share costs, potential impact and testing conditions.

The three companies are employing different techniques in the demonstration pilot-scale project: Clean Current Power Systems of Canada is using a Clean Current Mark III Turbine; Minas Basin Pulp and Power is using Marine Current Technology's SeaGen turbine and NSPI has chosen an Irish OpenHydro turbine.

Following a scientific marine survey, data analysis, environmental studies and consultations with interested parties during 2008 and 2009, it was announced in November 2009 that NSPI/OpenHydro had deployed their 1 MW turbine at the demonstration site. After further testing the plan for Spring 2010 is that the cable connection onshore will be made. Ultimately, the capacity of the grid-connected tidal plant is expected to total 4 MW.

The province of New Brunswick which borders the landward side of the Bay of Fundy also conducted a Strategic Environmental Assessment of In-Stream Energy Generation Development during 2008. At the present time a tidal energy development policy is being considered.

Verdant Power of the USA is developing its Cornwall Ontario River Energy (CORE) scheme on the St Lawrence River. Phase 1 - Demonstration Pilot (2007-2010) will be followed by Phase 2 - Commercial Field Build-Out (2010-2012). The project could ultimately generate up to 15 MW of electricity.

China

The southeastern coastal areas of Zhejiang, Fujian and Guangdong Provinces are considered to have substantial potential for tidal energy. China's utilisation of tidal energy with modern technologies began in 1956: several small-scale tidal plants were built for pumping irrigation water. Thereafter tidal energy began to be used for power generation. Starting in 1958, 40 small tidal plants (total capacity 12 kW) were built for the purpose of generating electricity. These were supplemented from around 1980 by much larger stations, of which the 3.2 MW Jiangxia and the 1.3 MW Xingfuyang schemes were the largest. The majority of the early plants have been decommissioned for a variety of reasons, including design faults, incorrect location, etc. Currently there are seven tidal power stations (plus one tide flood station) with a total capacity of 11 MW.

Since the end of the 1970s emphasis has been placed on optimising the operations of existing plants to improve their performance. Additionally, a feasibility study for a 10 MW level intermediate experimental tidal power station has been undertaken.

It was announced in November 2006 that China had signed a joint venture with the Italian engineering company Ponte di Archimede International for the application of its patented Kobold turbine to a site in the Strait of Jintang, in the Zoushan Archipelago.

France

Relatively few tidal power plants have been constructed in the modern era. Of these, the first and largest is the 240 MW barrage on the Rance estuary in northern Brittany. The 0.8 km long dam also serves as a highway bridge linking St. Malo and Dinard. The barrage was built as a full-scale demonstration scheme between 1961 and 1966 and has now completed 40 years of successful commercial operation. Annual generation is some 640 million kWh.

Originally the barrage was designed to generate on both flood and ebb tides; however, this mode of operation proved to be only partially successful. The barrage is now operated almost exclusively on ebb tides, although two-way generation is periodically instigated at high spring tides.

In 1988 the plant became fully automated, requiring the integration of complex operational cycles imposed by variable heads, and the necessity for continuous regulation of the turbines to optimise energy conversion. A 10 year programme for refurbishing its 24 turbines was begun in 1996, on the plant's 30th anniversary.

Despite its successful operation, no further tidal energy plants are planned for France, which is now dominated by generation from nuclear stations.

It was announced during 2008 that EDF, the leading electricity producer in France, plans a pilot tidal turbine system off the coast of Brittany. The project, consisting of 4 to 10 turbines, with a total capacity of between 2 and 4 MW will be sited at Paimpol-Bréhat (Côtes d'Armor). In October 2008, EDF stated that the company had appointed OpenHydro of Ireland to equip the demonstration tidal farm, which is scheduled to be connected to the grid from 2011 onwards.

India

The tidal ranges of the Gulf of Kutch and the Gulf of Khambhat, both in the western state of Gujarat, are 5 and 6 m, the theoretical capacities 900 and 7 000 MW, and the estimated annual output approximately 1.6 and 16.4 TWh, all respectively.

The Indian Ministry of Non-Conventional Energy Sources intends to harness the power potential of the Sundarbans area of the Gangetic delta in the eastern state of West Bengal. To this end, the West Bengal Renewable Energy Development Agency (WBREDA) has prepared a project report and an environmental impact assessment study for a 3.75 MW demonstration single-basin, single-effect tidal power plant at Durgaduani Creek, adjoining Gosaba Island. WBREDA has engaged the National Hydroelectric Power Corporation to implement the estimated Rs 500 million (approximately US$ 11 million) project.

It was announced in November 2009 that Atlantis Resources Corporation would work with the State Government of Gujarat to assess the viability of developing in excess of 100 MW of tidal turbine power plants in the Gulfs of Kutch and Khambhat.

Korea (Republic)

After a four-year construction period, the country's first tidal project on the Uldolmok Strait off Jindo Island, South Jeolia Province, was inaugurated in May 2009. The 1 MW tidal current pilot plant is expected to generate 2.4 GWh/yr but it is planned that by 2013 the plant will be expanded to 90 MW.

As part of the Government's plan for increasing the use of renewable energy, further tidal power plants are either nearing completion or in the planning stage.

The Ministry of Land, Transport and Maritime Affairs has announced that the world's largest tidal energy plant – the 254 MW tidal barrage project at Sihwa Lake - is scheduled to be completed by end-2010. The Sihwa-Lake project, located 25 km southwest of Seoul in Ansan, Gyeonggi Province on the western coast of the Peninsula is being developed by the Korea Water Resources Corporation.

The artificial lake at Sihwa was created between 1987 and 1994 to provide water for agricultural purposes. A dam curtailing the tidal currents was constructed but the quality of the water deteriorated, becoming heavily polluted following a rise in local industry and a consequent increase in factory wastes. The plan was subsequently abandoned and instead the power plant will utilise the head between high tide on one side and the level of the lake on the other. The scheme will not only provide generation of electricity but also environmental improvements and tourist attractions. Annual power generation is expected to be in the region of 550 GWh.

A number of other potential tidal power sites have been identified and several very large projects proposed.

New Zealand

The country has a good marine resource with a coastline in excess of 15 000 km and an estimated tidal energy potential of 1 000 MW. In recent years a drive towards an increased use of renewable energy has moved the utilisation of the tidal resource nearer to fruition.

The New Zealand Energy Efficiency and Conservation Authority (EECA) established the *Marine energy deployment fund* in order to support the advancement of marine energy in general. For the period 2008-2012, a sum of NZ$ 8 million in total has been made available for distribution as grants. The funds are intended to assist the development of pre-commercial projects.

It was announced in May 2008 that a grant of NZ$ 1.85 million from the first round of the *Marine energy deployment fund* had been awarded to Crest Energy Ltd. Subject to the necessary consents being granted, the company intends to eventually install two hundred 1 MW turbines in Kaipara Harbour, one of the largest in the world, located on the north-western coast of North Island. The first stage of this project is the installation of three turbines, grid-connected on land via a converter station.

The third round of the *Marine energy deployment fund*, worth NZ$ 2 million, opened on 31 July 2009, closing on 23 November 2009; decisions on any grants are awaited. A fourth round will be held in the second half of 2010.

Norway

A 300 kW prototype tidal power plant was installed in September 2003 in the Kval Sound in the far north of Norway. The world's first grid-connected offshore underwater turbine, located at Kvalsundet, close to Hammerfest, was successfully tested for a period of four years prior to being removed during 2008 for inspection. In order for further research to be conducted the turbine was reinstalled *in situ* during the summer of 2009.

During 2008 Hammerfest Strøm AS collaborated with ScottishPower to form Hammerfest Strøm UK. The 100% owned subsidiary was established with the intention of licensing and developing the Norwegian technology. In February 2010, the new company, based in Scotland, received a GBP 3.9 million grant from the Carbon Trust for the construction and testing of a 1 MW full-scale demonstration turbine (HS1000™) in Scottish waters at EMEC, prior to commercialised deployment.

A 1.5 MW floating tidal power plant - the MORILD demonstration project - is planned for deployment during 2010 in the Gimsøystraumen tidal current in the Lofoten Islands. It has been reported that connection to the grid is planned for end-2010.

Russian Federation

Design studies for tidal power development have been conducted in Russia since the 1930s. As part of this work, a small pilot plant with a capacity of

400 kW was constructed in Kislaya Bay on the Barents Sea and commissioned in 1968. The location has now become an experimental site for testing new tidal power technologies.

Early in 2007, GidroOGK, a subsidiary of the Russian electric utility, Unified Energy Systems (UES), began the installation of a 1.5 MW orthogonal turbine alongside the original Kislaya Bay tidal facility. The experimental turbines will be thoroughly tested as part of a pilot project to assist in the design of large-scale tidal power plants.

There are currently two ambitious projects for TPPs in the Federation:

- Mezenski Bay (on the White Sea, in northern Russia): proposed capacity 15 GW, annual output 40 TWh;
- Tugurki Bay (on the Sea of Okhotsk in the Russian Far East): 7.98 GW, 20 TWh annual output.

If the 1.5 MW experimental installation at the Barents Sea location proves successful, UES intends to embark on a programme for constructing giant-size TPPs such as those projected.

GidroOGK reported at end-2008 that Russia's tidal energy potential was some 250 TWh/yr and although at the present time the contribution of tidal power is very small, by 2015 Russia plans to have installed 12 MW of capacity, generating some 24 GWh and by 2020, 4 500 MW capacity, generating some 2.3 TWh.

In January 2009 the Russian Prime Minister signed an Executive Directive for a greater use of renewable energy in order for the efficiency of the electric power sector to be improved.

United Kingdom

The large tidal range along the west coasts of England and Wales provides some of the most favourable conditions in the world for the utilisation of tidal power. If all reasonably exploitable estuaries were utilised, annual generation of electricity from tidal power plants would be some 50 TWh, equivalent to about 15% of current UK electricity consumption.

The four principal islands of the Channel Islands group: Alderney, Jersey, Guernsey and Sark have all been shown to possess a tidal resource that could be harnessed at some time in the future. Study has shown that Alderney has tidal ranges estimated to have a power potential of between 750 MW and 3 GW. The other three islands are all at the stage of studying the possibilities of utilising their tidal potential.

Another area of the UK that could, if tidal technology is employed, provide an estimated 5% of the UK's electricity, is the northwest region of England. The Solway Firth, Morecambe Bay, and the Mersey and Dee estuaries are all potential sites for tidal schemes. Peel Energy, working with the Northwest Regional Development Agency, is currently undertaking a feasibility study on the estuary of the River Mersey. It has also been reported that the councils of West Cumbria (England) and Dumfries and Galloway (Scotland) are studying the potential of the Solway Firth.

The possibilities for utilising the tidal resource of both the north coast of Wales and the Teign estuary in Devon, England are presently being studied.

The European Marine Energy Centre's (EMEC) Tidal Test Facility is located off the southwestern coast of the island of Eday, Orkney. As the world's only purpose-built open-sea area where demonstration tidal devices can be tested *in situ* prior to deployment of full-scale turbines, it now advises other countries intent on learning how to develop their own marine energy resource.

2008 saw the first UK grid-connected 250 kW tidal turbines. In May, the Irish company OpenHydro began producing electricity for national consumption at EMEC. Later in the year, also at EMEC, OpenHydro installed the world's first specialist barge for deployment of full-scale seabed-mounted tidal turbines.

In October 2009 Atlantis Resources Corporation announced that it was planning to test its 1 MW AK-1000 tidal current turbine at EMEC in summer 2010.

In December 2009, it was announced that EMEC was undertaking a search for further sites that could be used for sea trials.

The UK's Energy Act 2008 became law in November 2008 and will implement the legislative aspects of the 2007 Energy White Paper: *Meeting the Energy Challenge*. In part, the Act will strengthen the Renewables Obligation to drive greater and more rapid deployment of renewable energy in the UK. In December 2008 a draft Renewables Obligation Order 2009 was published.

Both *The UK Renewable Energy Strategy* and the White Paper: *The UK Low Carbon Transition Plan* were published in mid-2009. They are intended to provide the direction for the country to meet its share of the EU's 20% renewables target by 2020, thereby reducing national carbon emissions.

The Government also launched a *Marine Action Plan* in September 2009 which provides a "Vision" to 2030 (with reference to 2020). The Plan, together with increased investment, will provide furtherance of the marine energy technologies, building on both the UK's excellent marine resource and the offshore expertise gained through the oil and gas sectors.

For the successful deployment of an enhanced marine sector, the wide-ranging Plan will address all aspects of the financing, environmental, industrial, economic, planning issues etc. prior to the publication of the draft Action Plan, expected in Spring 2010. There will thereafter be a period of public consultation.

In October 2007 the Sustainable Development Commission (SDC), on behalf of the Government, published the results of a year-long study looking at the full range of tidal power technologies available. The Commission was charged with examining the sustainable use of the UK's tidal resource, in particular how the power of the Severn Estuary, with its British and European legal conservation protection, could be used.

It will be necessary for any ensuing development of the Severn Estuary to first clear the hurdles of the many environmental concerns.

In late January 2009 the Government announced that it was halfway through a feasibility study looking at all aspects of a tidal plant in the Severn Estuary. After a three-month period of public consultation and studying 10 possible schemes for a tidal plant, a short list of five proposals was drawn up using a range of options: three using a barrage scheme and two, a lagoon:

- Beachley Barrage
- Bridgewater Bay lagoon
- Cardiff-Weston Barrage
- Fleming lagoon at Welsh Grounds
- Shoots Barrage

The impact of any one or a combination of these schemes, the possibility of installing a tidal fence and the consequence of not developing the Severn Estuary at all are to be studied prior to a decision, expected to be made in 2010.

Work on surveying the waters surrounding the island of Alderney and the preparation of environmental studies have taken place over a period of three years and involved OpenHydro and Alderney Renewable Energy Ltd. (ARE). This cooperation resulted in 2008 in OpenHydro acquiring a 20% shareholding in ARE. Moreover, ARE received an exclusive 65-year licence from the States of Alderney for electricity generation from tidal (and wave) energy in the island's territorial waters.

Following Marine Current Turbines' (MCT) development of its SeaFlow turbine and the experience gained from its deployment offshore from Lynmouth, Devon, the next-generation SeaGen turbine achieved a world first during 2008. In May a 1.2 MW, 16 m diameter, twin rotor system was installed in Strangford Narrows, Northern Ireland. After a period of testing, the world's first commercial-scale tidal stream project achieved power generation at maximum capacity in December 2008.

It was announced in July 2009 that SeaGen had been accredited by OFGEM (Office of the Gas and Electricity Markets) as a UK power station, making it the first tidal project to receive Renewable Energy Certificates (ROCs) and thereby permitting it to sell the generated power.

By September 2009 SeaGen was operating without on-the-spot close supervision of its environmental impact and output was greater than originally anticipated. It is currently operating remotely without environmental supervision and will, in due course, be able to operate on a 24-hour basis. The Irish company ESB Independent Energy has signed a five-year power purchase agreement to buy the electricity generated, sufficient for approximately 1 000 homes.

Early in 2008, MCT joined in partnership with npower renewables to develop a tidal stream project under the management of a newly-created company, SeaGen Wales. The plan is for a 10.5 MW farm to be located in The Skerries, off the northwest coast of Anglesey. The farm will consist of seven 1.5 MW SeaGen turbines. If planning permission is granted and financing is in place, then commissioning could take place in 2011/2012. It is expected that electricity generated would feed into the national grid.

In November 2008 The Crown Estate, owner of the UK's seabed, began the process of inviting proposals to develop marine energy projects in the Pentland Firth and Orkney Islands. The area off the northeast coast of Scotland is particularly well-endowed with a marine resource and Round 1 of the leasing programme is designed for the installation of 1.2 GW of tidal (and wave) power by 2020. The tender period for pre-qualified organisations lasted until May 2009. Negotiations with twenty prospective developers then ensued. In March 2010 the names of the successful bidders were announced. Leases for the installation of 600 MW have been signed as follows:

- SSE Renewables Developments, 200 MW, Westray South (Orkney);
- SSE Renewables Holdings and OpenHydro, 200 MW, Cantick Head (Orkney);
- Marine Current Turbines, 100 MW, Brough Ness (Orkney);
- ScottishPower Renewables, 100 MW, Ness of Duncansby (Pentland Firth).
- One further site, Inner Sound, also in the Pentland Firth, was re-tendered, with expressions of interest closing at end-May 2010.

The ScottishPower Renewables scheme plans to use up to 95 Hammerfest Strøm 1 MW turbines.

United States of America

Many locations on both the east and west coasts are being studied for the possible installation of tidal energy schemes.

Following Phase 1 Prototype Testing (2002-2006), of Verdant Power's Roosevelt Island Tidal Energy Project (RITE), Phase 2 Demonstration (2006-2008) of the 35 kW project was successfully completed in New York City's East River. From 9 000 hours of operation, the six turbines produced 70 MWh for delivery to two consumers on Roosevelt Island. Phase 3 (2009-2012) will represent commercial development: in May 2009 Verdant applied to the Federal Energy Regulatory Commission (FERC) for a commercial licence to enable the project to progress. Once complete, the RITE Project will consist of 30 x 35 kW, 5 metre diameter, axial-flow Kinetic Hydropower System turbine-generator units, generating between 1 680 and 2 400 MWh.

During 2008 and 2009 Ocean Renewable Power Company (OPRC) successfully tested its OCGen™ turbine generator unit (TGU) in the waters of Cobscook Bay, Maine, near the mouth of the Bay of Fundy. Following the acquisition of FERC pilot process licences, it is hoped that grid-connected schemes will be put in place in Maine by end-2010. In addition, ORPC plans to construct TGUs for both tidal and river currents for deployment in 2011 in Cook Inlet and the Tanana River, Alaska.

At end-2009 it was reported that Tidewalker Associates was investigating the possibility of locating a tidal energy project in the Half-Moon Cove area of Cobscook Bay.

The U.S. Department of Energy, under its 2008 Advanced Water Power Program has agreed funding of approximately US$ 600 000 for the proposed 1.5 MW Nantucket-Edgartown tidal scheme in the vicinity of Martha's Vineyard. A two-year evaluation, beginning in December 2009 is being coordinated by the University of Massachusetts Marine Renewable Energy Center and managed by Harris Miller Miller & Hanson Inc.

Puget Sound in the north west of Washington State is being considered by the U.S. Navy, Tacoma Power and the Public Utility District Number 1 of Snohomish County as the possible location of tidal energy schemes. The three entities have proposed seven projects and are currently making site selections and undertaking feasibility studies.

14. Wave Energy

COMMENTARY

COMMENTARY

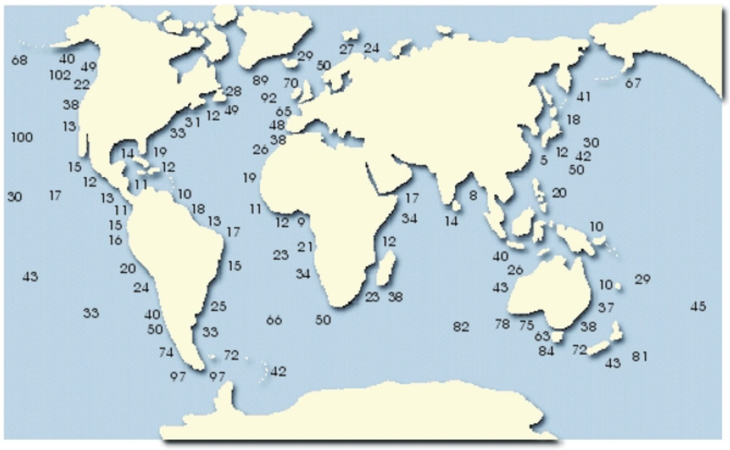
Introduction

The first serious study of wave energy took place in the 1970s and early 1980s when several governments undertook national R&D programmes as a response to the emerging oil crises. In many countries this research was greatly curtailed or stopped altogether throughout most of the 1980s and 1990s. Over the past decade a number of small companies have tried to develop and commercialise a range of different wave energy technologies as a non-polluting source of energy. In some countries, these initiatives have been accompanied by government-funded activities, as well as developments in international organisations such as the European Commission and the International Energy Agency.

The Resource

Wave energy can be considered as a concentrated form of solar energy, where winds generated by the differential heating of the earth pass over open bodies of water, transferring some of their energy to form waves. The amount of energy transferred and, hence, the size of the resulting waves, depends on the wind speed, the length of time for which the wind blows and the distance over which it blows (the 'fetch'). Hence, solar energy can be 'stored' in waves so that original solar power levels of typically ~100 W/m^2 can be magnified into waves with power levels of over 1 000 kW per metre of wave crest length.

Figure 14.1 Average annual wave power levels as kW/m of wave front (Source: Pelamis Wave Power)



Waves lying within or close to the areas where they are generated (storm waves) produce a complex, irregular sea. These waves will continue to travel in the direction of their formation even after the wind dies down. In deep water, waves lose energy only slowly, so they can travel out of the storm areas with minimal loss of energy as regular, smooth waves or 'swell' and this can persist at great distances from the point of origin. It is these 'swell waves' that are utilised by most wave energy devices and coasts with exposure to the prevailing wind direction and long fetches tend to have the most energetic wave climates, such as the western coasts of the Americas, Europe, Southern Africa and Australia/New Zealand as shown in Fig. 14.1.

The global wave power resource in deep water (i.e. 100 m or more) is estimated to be ~ 8 000–80 000 TWh compared to global electricity production of 19 855 TWh in 2007 (IEA, 2009). The economically exploitable resource varies from 140-750 TWh/yr for current designs of devices when fully mature (Wavenet, 2003) and could rise as high as 2 000 TWh/yr (Thorpe, 1999), *if* all the potential improvements to existing devices are realised. Some confirmation of these values can be derived from the more recent wave power maps from Cornett (2008); these indicate a value for the exploitable resource (i.e. with wave power levels ≥ 20 kW/m) of approximately 800 GW corresponding to ~ 2 000 TWh.

The Challenges

A successful wave energy device faces a number of design challenges:

Design Waves. To operate its mechanical and electrical plant efficiently, a wave energy device must be rated for wave power levels that occur much of the time (e.g. in the UK this would be 30-70 kW/m). However, the device also has to withstand extreme waves that occur only rarely and these could have power levels in excess of 2 000 kW/m. This poses a significant challenge because it is the lower power levels of the commonly occurring waves that produce the normal output of the device (and hence the revenue) while the capital cost is driven by the civil structure that is designed to withstand the high power levels of the extreme waves – unless the device designer is cunning.

Variability of Wave Power Levels. Waves vary in height and period from one wave to the next and also from storm to calm conditions. The average wave power levels can be predicted in advance by using satellites to observe the waves far out to sea, which will arrive near to the shore in the next 24-48 hours. However, the short term variation (over periods of minutes) has to be converted to a smooth electrical output if it is to be accepted by the local electrical utility. This usually necessitates some form of energy storage or smoothing.

Variability in Wave Direction. Normally, offshore waves travel towards a wave energy device from a range of directions, so it has to be able to cope with this variability either by having compliant moorings (which allow the device to point into the waves) or by being symmetrical. Another approach is to place the wave energy device close to the shore, because waves are diffracted as they approach a

Figure 14.2 Summary of the types and status of wave energy development (as at January 2010)

Company	Technology	Web site	Type	Status
Abencis Seapower		http://abencis.com/energia-marina.php	2	1
Able Technologies L.L.C.	Electric Generating Wave Pipe	http://www.abletechnologiesllc.com	2	1
Advanced Wave Power	Nautilus	http://www.advancedwavepower.com	1*	3
Applied Technologies Company Ltd	Float Wave Electric Power Station	http://www.atecom.ru/wave-energy	2	2
Finevara Renewables	Aqua Buoy	http://finavera.com/en/wavetech	2	4
Aquamarine Power	Oyster	http://www.aquamarinepower.com/	3	4
Arlas Invest	MAUI	http://www.capricornioct.com/tuvalu6.htm	2	2
Atmocean	Atmocean	http://www.atmocean.com/	2	4
AW-Energy	WaveRoller	http://www.aw-energy.com/	3	3
AWS Ocean Energy	Archimedes Wave Swing	http://awsocean.com	2	4
Balkee Tide & Wave Generator	TWPEG	r.balkee@yahoo.com	2	3
BioPower Systems Pty Ltd	bioWAVE	http://www.biopowersystems.com/	3	4
Bølgevingen	Crest Wing	http://www.waveenergyfyn.dk	4	2
Bourne Energy	OceanStar ocean power system	http://www.bourneenergy.com	6	2
Brandl Motor	Brandl Generator*	http://brandlmotor.de/	2	3
Carnegie Wave Energy	CETO	http://www.carnegiecorp.com.au/	2	4
Checkmate Seaenergy UK Ltd.	Anaconda	http://www.checkmateuk.com/seaenergy	4	2
College of the North Atlantic	Wave Powered Pump	http://www.cna.nl.ca/news/newsletters/Fall %202006.pdf	2	3
Columbia Power Technologies	Generator Buoy	http://www.columbiapwr.com	2	3
C-Wave	C-wave	http://www.cwavepower.com/	3	2
Daedalus Informatics Ltd	Wave Energy Conversion Activator	http://www.daedalus.org	1	2
Delbuoy	Wave Powered Desalination	http://www.solutions-site.org/artman/publish/printer_60.shtml	2	1
DEXA Wave UK Ltd	DEXA Wave Energy Converter	http://www.dexawave.com/	4	2
C-Energy	Wave Rotor	http://www.c-energy.nl	6	3
Ecole Centrale de Nantes	SEAREV	http://www.ec-nantes.fr	2	2
Edinburgh University	Sloped IBS Buoy	http://www.mech.ed.ac.uk/research/ wavepower	2	2
ELGEN Wave	Horizon Platform*	http://www.elgenwave.com	2*	1
Embley Energy	Sperboy	http://www.sperboy.com/	1	2
Energias de Portugal	Foz do Douro breakwater	http://www.edp.pt & http://hidrox.ist.utl.pt/doc_fct/FozDouro.pdf	1	4
Euro Wave Energy	Floating absorber*	http://www.eurowaveenergy.com	2	1
Float Inc.	PSP	http://www.floatinc.com	1*	1
Floating Power Plant ApS	Poseidon's Organ	http://www.poseidonorgan.com/	2*	4
Fobox AS	FO^3	http://www.seewec.org	2*	3
Grays Harbor Ocean Energy	Titan	http://www.graysharboroceanenergy.com/	1*	1
Green Wave Energy Corp	Syphon Wave Generator	http://www.gweconline.com	6	3
Green Wave Energy Corp	Green Wave Bottom Generator	http://greenwaveenergycorp.com	2	4
Green Ocean Energy Ltd	Ocean Treader & Wave Treader	http://www.greenoceanenergy.com/	4	2
Greencat Renewables	Wave Turbine	http://www.greencatrenewables.co.uk	6	1
GyroWaveGen	GyroWaveGen	gyrowavegen@sbcglobal.net	6	1
Gyro Energy Limited	Gyrotorque	http://www.gyroenergy.co.nz/	6	2
Hydam Technology	McCabe Wave Pump		4	4
Hidroflot s.l.	Multi cell platforms	http://www.hidroflot.com/	2*	4
Independent Natural Resources	SEADOG	http://inri.us	2	2
Indian Wave Energy Device	IWAVE	http://waveenergy.nualgi.com/	2	3
Inerjy	WaveTork	http://inerjy.com	4	3
Ing Arvid Nesheim	Oscillating Device	http://www.anwsite.com/	2	1
Instituto Superior Tecnico	Pico OWC	http://www.pico-owc.net/	1	4
Interproject Service (IPS) AB	IPS OWEC Buoy	http://www.ips-ab.com/	2	4
JAMSTEC	Mighty Whale	http://www.jamstec.go.jp/jamstec/ /	1	3
Jospa Ltd	Irish Tube Compressor (ITC)	http://www.jospa.ie/	4	2

Key:

Types: 1 -OWC; 2 - point absorber; 3 - surge/flap; 4 - attenuator/contouring; 5 overtopping; 6 other; * multiple units on one platform

Status: 1 - theoretical; 2 - wave tank tests on model; 3 - small scale tests in sea; 4 -demonstration prototype; 5 - commercial deployment

Figure 14.2 Summary of the types and status of wave energy development (as at January 2010)

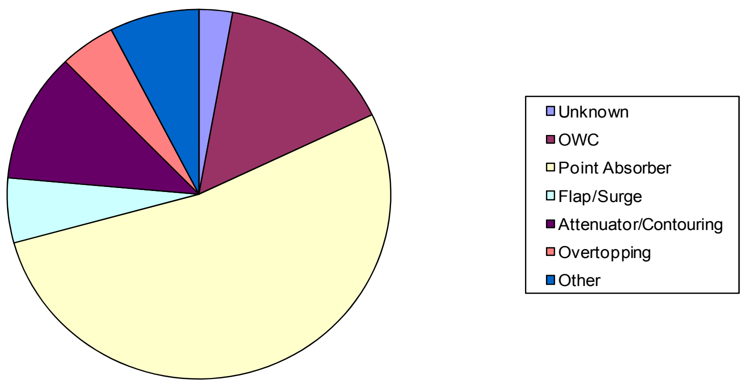
Company	Technology	Web site	Type	Status
Kinetic Wave Power	PowerGin	http://www.kineticwavepower.org	5	1
Kobe University		http://ci.nii.ac.jp/naid/110007085589	2	2
Lancaster University	WRASPA	http://www.lancs.ac.uk/fas/engineering	2	2
Langlee Wave Power	Langlee System	http://www.langlee.no/	3	2
Leancon Wave Energy	MAWEC	http://www.leancon.com/	1*	2
Manchester Bobber	Manchester Bobber	http://www.manchesterbobber.com/	2*	2
Motor Wave	Motorwave	http://www.motorwavegroup.com	6	3
Muroran Institute of Technology	Pendulor	http://www.muroran-it.ac.jp	3	4
Nautilus	Wave Energy Convertor	http://nautiluswaveenergy.com	2	3
Neptune Renewable Energy Ltd	Triton	http://www.neptunerenewableenergy.com	2	3
Neptune Systems	MHD Neptune		2	1
Norwegian Uni of Sci. & Tech.	CONWEC		1	2
OceanEnergy Ltd	Ocean Energy Buoy	http://www.oceanenergy.ie/	1	4
Ocean Harvesting Technologies	Ocean Harvester	http://oceanharvesting.com/	2	2
Ocean Motion International	OMI WavePump	http://www.oceanmotion.ws/	2*	2
Ocean Navitas	Aegir Dynamo	http://www.oceannavitas.com/	2	2
Ocean Power Technologies	PowerBuoy	http://www.oceanpowertechnologies.com/	2	4
Ocean Wave Energy Company	OWEC	http://www.owec.com/	2*	2
Ocean Wavemaster Ltd	Wave Master		4	2
Ocean Wind and Wave Energy	Hybrid Wave Power Rig		1*	2
Oceanic Power		http://www.oceanicpower.com		2
Oceanlinx (formerly Energetech)	Denniss-Auld Turbine	http://www.oceanlinx.com.au	1*	4
Oceantec Energías Marinas, S.L.	OCEANTEC WEC	jpablo@robotiker.es	2	4
Offshore Islands Limited	Wave Catcher	http://www.offshoreislandslimited.com	2	1
Offshore Wave Energy Ltd	(the Grampus)	http://owel.co.uk/owel.htm	6	2
RECon	MRC 1000	http://www.orecon.com/	1*	3
Pelagic Power AS	PelagicPower	http://pelagicpower.com	2*	3
Pelamis Wave Power	Pelamis	http://www.pelamiswave.com/	4	5
Protean Power	Protean	http://www.proteanpower.com	2	3
Renewable Energy Pumps	Wave Water Pump (WWP)	http://www.renewableenergypumps.com/	2*	1
Resolute Marine Energy	AirWec & SurgeWec	http://www.resolute-marine-energy.com/	2	3
Sara Ltd	MWEC	http://www.sara.com/rae/ocean_wave.html	2	1
SDE	S.D.E	http://www.sde.co.il/	2	3
Sea Power International AB	Streamturbine	http://www.seapower.se/	5	2
Seabased AB	Linear generator	http://www.seabased.com/	2	4
SEEWEC Consortium	FO^3 device/ Buldra	http://www.seewec.org/index.html	2	4
SeWave Ltd	OWC	http://www.sewave.fo/	1	1
SRI International	EPAMT	http://www.hyperdrive-web.com	2	3
Straumekraft AS	Winch operated buoy	http://www.straumekraft.no	2	3
SurfPower	SurfPower	http://www.surfpower.ca/	2	2
Swell Fuel	Lever Operated Pivoting Float	http://swellfuel.com	2	3
SyncWave	SyncWave	http://www.syncwavesystems.com	2	2
Tonchev	Coastline Wave Power Plant	http://www.tonchev.org	2	1
Trident Energy Ltd	The Linear Generator	http://www.tridentenergy.co.uk	2*	3
Wave Dragon	Wave Dragon	http://www.wavedragon.net	5	3
WAVEenergy AS	Seawave Slot-Cone Generator	http://waveenergy.no	5	3
Wave Energy Centre	Pico plant	http://www.pico-owc.net	1	4
Wave Energy Technologies Inc.	WET EnGen™	http://www.waveenergytech.com	2*	3
Wave Energy Technology	(WET-NZ)	http://www.wavenergy.co.nz/		
Wave Star Energy ApS	Wave Star	http://www.wavestarenergy.com/	4	4
Waveberg Development	Waveberg	http://www.waveberg.com	2*	3
Wavebob Limited	Wavebob	http://www.wavebob.com	2	3
Wavegen	Limpet & Breakwater Turbine	http://www.wavegen.com/	1, 1*	4
WavePlane Production	Wave Plane	http://www.waveplane.com	5	4
WindWavesAndSun	WaveBlanket	http://www.windwavesandsun.com	4	1

Key:

Types: 1 -OWC; 2 - point absorber; 3 - surge/flap; 4 - attenuator/contouring; 5 overtopping; 6 other; * multiple units on one platform

Status: 1 - theoretical; 2 - wave tank tests on model; 3 - small scale tests in sea; 4 -demonstration prototype; 5 - commercial deployment

Figure 14.3 Breakdown of current wave energy devices by type



coastline, so that most end up travelling at right angles to the shoreline.

Wave Movement. To produce useful electricity, the relatively slow oscillation of waves (typically at ~ 0.1 Hz) has to be transformed into a unidirectional output that can turn electrical generators at hundreds of rpm, which requires a gearing mechanism or the use of an intermediate energy transfer medium.

Reliability. As has been found in the offshore wind industry, maintenance and repair at sea is an expensive undertaking. In addition, many devices cannot be repaired at sea, necessitating return to harbour. This entails considerable expense and loss of production, in part because the ships used are those employed by the offshore oil and gas industry, which can command high costs. This leads some developers to consider deploying a purpose-built vessel, thus ameliorating the situation. Nevertheless, to be successful, wave energy devices will have to achieve high levels of reliability.

Technologies

There are several significant reviews of wave energy (Thorpe, 1992 and 1999; Clément et al., 2002; Brooke, 2003; IEA, 2003; Wavenet, 2003; Previsic et al., 2004; Falcão, 2006) and two excellent books (McCormick, 2009; Cruz, 2008). These show that a wide range of wave energy devices have been developed to meet the challenges outlined above.

At least 100 separate technologies are represented by the wave energy devices currently being developed (Fig. 14.2). There are various ways of categorising these devices but the one shown in the breakdown of device types in Fig. 14.3 is self-evident and expanded upon below.

Oscillating Water Column (OWC): an OWC comprises a partially submerged structure forming an air chamber, with an underwater aperture (Fig. 14.4). This chamber encloses a volume of air, which is compressed as the incident wave makes the free surface of the water rise inside the chamber. The compressed air can escape through an aperture above the water column which leads to a turbine and generator. As the water inside falls, the air pressure is reduced and air is drawn back through the turbine. Both conventional (i.e. unidirectional) and self-rectifying air turbines have been proposed. OWC devices have several benefits: they have been extensively researched; they have been deployed in their hundreds (as small navigational buoys); they have effectively one moving part thereby increasing reliability; their mechanical and electrical (M&E) plant can be easily accessed in service, because they are shore-based or the M&E equipment lies well above the waves. Even with this commonality of operating principles, the examples of oscillating water column actually deployed vary considerably, e.g.

- Wavegen deployed a single, bottom-standing, shoreline-based concrete device in Scotland, which has functioned with great reliability since 2002 (Fig. 14.5);

Figure 14.4 Outline of the operating principles of an OWC (Source: Wavegen)

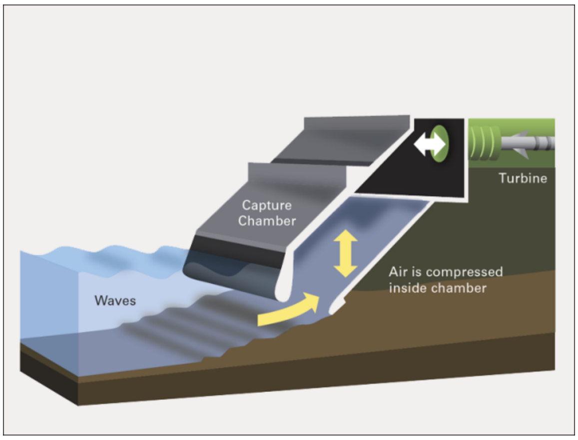


Figure 14.5 Shoreline OWC – the Limpet (Source: Wavegen)

- a multiple unit, floating offshore steel device to be deployed by Oceanlinx in Australia following proof of concept with their nearshore 400 kW device;

- a floating single unit OWC where the mouth of the OWC points away from the waves towards the shore (thereby significantly reducing mooring loads) to be built in Ireland by OceanEnergy;

- an OWC to be tunnelled into a cliff in the Faeroe Islands by SeWave;

- an increasingly popular option is to build a number of OWCs into *new breakwaters*, thereby defraying their high structural costs, either as a few large OWCs (as with the 3 x 250 kW OWCs in the breakwater at the mouth of Douro river in Portugal) or as multiples of smaller OWCs (such as Wavegen's 16 x 18.5 kW OWCs in Mutriku, Spain).

Point Absorber: this is a buoy that is small in size compared to the length of the waves, which floats at or near the surface. It can usually absorb energy in all directions by following the movements of water at or near the sea surface (like a float) or, for subsea devices, move up and down under the influence of the variations in subsea pressure as a wave moves by. Energy is generated by reacting these movements against some kind of resistance, which can take a number of forms, depending on the configuration of resistance, the power take-off (PTO) and the type of device-to-shore transmission, for instance:

- Ocean Power Technologies' PowerBuoy is a vertical float that uses a heave plate attached to connecting spar as resistance (its large surface area reduces the heave plate movement through water). The relative motion between the float and the heave plate drives a hydraulic and mechanical PTO that generates electricity on the device (Fig. 14.6). The output from up to 10 PowerBuoys is linked via an Underwater Substation Pod (USP), where it is transformed to a higher voltage for transmission to shore. Several 20-40 kW demonstration buoys have been deployed and a larger 150 kW system awaits deployment in 2010 in the USA and Scotland.

- Carnegie Wave Energy's CETO uses an underwater buoyant float attached via a flexible mooring line to a simple pump (Fig. 14.7), which is fixed on the sea bed via a gravity anchor or steel pile. The movement of float with respect to the pump is used to pressurise seawater and the output from an array of these devices is collected for onward transmission to the shore where it drives a Pelton turbine to produce electricity. The first buoy in a 5 MW scheme will be deployed in early 2010 in Western Australia.

Figure 14.6 Ocean Power Technologies' PowerBuoy lying horizontal prior to deployment – the heave plate (left), the float (right) (Source: Ocean Power Technologies)

Figure 14.7 CETO Float and Pump Unit prior to deployment (Source: Carnegie Wave Energy)

- Seabased's Linear Generator has a buoyant surface float attached via a flexible connector to a unit on the sea bed (Fig. 14.8). The movement of the float is converted directly into electricity using a linear generator (such a generator has been used in other devices, such as the most powerful device yet deployed, AWS Ocean Energy's Waveswing). A pilot project of up to 10 x 10 kW devices has been under way in Sweden since 2002.

- Other developments have occurred regarding point absorbers, such as:

  - *Encapsulated Devices*, which have all the PTO within the body of the float so as to avoid equipment coming into contact with seawater. Some of these devices follow the inspiration of Professor Stephen Salter, the father of wave energy, by using internal gyroscopes to provide the resistance to movement (e.g. devices from Oceantec Energías Marinas and Kobe University);

  - *Multi-unit Platforms* comprising a number of point absorbers on an offshore platform in an attempt to simplify installation and allow easier access for repair and maintenance (e.g. devices from Hidroflot and Floating Power Plant).

Surge Devices: these extract energy from the horizontal to-and-fro movements of water particles within waves. They are situated in shallower water close to shore, because it is only in shallow water that the circular movement of water particles in deep water then becomes elongated into horizontal ellipses (surge). These devices usually take the form of wide flaps that are pivoted about a rotor. Again, despite the same operating principle, the examples of surge devices actually deployed vary considerably, e.g.:

- Aquamarine Power's Oyster is a large (2.4 MW), single-flap device whose movements activate hydraulic rams to pressurise seawater, which is then pumped ashore to drive a turbine and generate electricity (Fig. 14.9). A demonstration 315 kW prototype device was installed in Scotland in 2009;

- AW-Energy's WaveRoller is a device with several flaps mounted on a single sea-bed platform, where the movements of each flap activate piston pumps that drive an on-board hydraulic motor and generator (Fig. 14.10). A

Figure 14.8 Outline of Seabased's Point Absorber and Linear Generator (Source: Seabased AB)

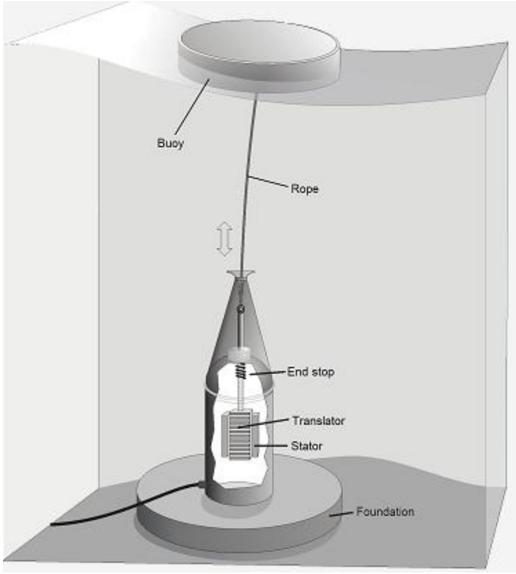


Figure 14.9 The prototype Oyster undergoing construction (Source: Aquamarine Power)

13 kW prototype was deployed in Portugal in 2007 and 2008;

- Other devices have been designed to have flaps mounted on floating platforms, e.g. C-wave and Langlee Wave Power, whilst one other imitates the motions of subsea flora (Biopower Systems).

Attenuator/Contouring Devices: these are elongated floating devices that extend parallel to the wave direction and so effectively 'ride' the waves. As the incoming wave passes along the device, it generates movements within the device that are used to produce energy. The types of device under development are very varied, e.g.:

- Pelamis Wave Power's Pelamis is a series of floating cylindrical hollow steel segments that are connected to each other by hinged joints. As waves run down the length of the device, the segments move with respect to each other and actuate hydraulic cylinders incorporated in the joints between sections to pump oil to drive a hydraulic motor/generator via an energy-smoothing system (Fig. 14.11). A 750 kW prototype device was deployed in Scotland in 2004, followed by a prototype production device and a three-device wave farm in Portugal in 2008.

- Wave Star Energy's Wave Star has a series of floats either side of a long connecting structure. (Fig. 14.12). As the wave passes down the length of the structure, it raises and lowers the independent floats, each driving a hydraulic pump that is connected to a common hydraulic motor and generator. A 1/10th scale system has been running in Denmark since 2006 and the first section of the 500 kW device was installed in September 2009.

- Checkmate Seaenergy's Anaconda comprises a distensible rubber tube, filled with sea water. It is anchored to a mooring post and floats just beneath the surface, head to sea (Fig. 14.13). Passing sea waves produce a succession of bulges in the tube, which travel down its length, producing pressure fluctuations ahead of the bulge. These are smoothed out in an accumulator at the end of the tube and used to drive a hydraulic turbine and generator in the stern of the device.

Overtopping Devices: these rely on using a ramp on the device to elevate part of the incoming waves above their natural height in order to fill a raised reservoir, from which the seawater is allowed to return to the sea via low-head turbines:

- The Wave Dragon is a floating device using a pair of large curved reflectors to gather waves into the central portion where they flow up a ramp and over the top into a raised reservoir on the device, from which the water is allowed to return to the sea via a large number of low-head turbines. A quarter-scale, 20 kW prototype was

Figure 14.10 The WaveRoller

(Source: AW-Energy)

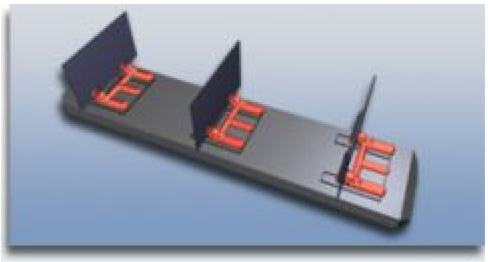


Figure 14.11 The Pelamis demonstration device

(Source: Pelamis Wave Power)

deployed in a Danish inlet in 2003 (Fig. 14.14). Activities are under way for installation of full-scale devices in Denmark (1.5 MW in 2011) and Wales (7 MW in 2012). Wave Energy AS has plans for a 300 kW multi-reservoir, shoreline device in Denmark during 2011;

- Wave Energy has developed a multiple-stage overtopping device that can be used as a breakwater or as a floating or fixed offshore island (Fig. 14.15). It utilises a total of three reservoirs placed on top of each other, in which the potential energy of the incoming wave can be stored, until it is allowed to run through their multi-stage turbine. Using multiple reservoirs is hoped to increase the overall efficiency compared to single overtopping devices.

Benefits

In addition to the large size of the resource and the lack of associated greenhouse gas emissions, wave energy has several important advantages:

- outside the tropics, storms are usually more intense and frequent during winter, which results in wave power levels being higher in that season. Therefore, wave energy provides good seasonal load-following for those regions where peak electricity demand is produced by winter heating and lighting requirements (e.g., northern Europe, western Canada and northwest USA);
- wave energy is predictable for one to two days ahead, because satellites can measure waves out in the ocean that will later impact on devices around the coast. This predictability will allow for less spinning reserve that is often required to support more intermittent renewable energy sources;
- most studies on the environmental aspects of wave energy (e.g. Wavenet, 2003) concluded that the environmental impacts are likely to be low, provided developers show sensitivity when selecting sites for deployment and key stakeholders are consulted;
- several wave energy developers are seeking to use their technology for producing potable water by reverse osmosis (RO), thereby helping to address a major environmental crisis – the lack of clean drinking water for many millions of people. The fact that the vast majority of the world’s population lives within 30 km of the coast makes wave energy a suitable technology for providing water close to where it will be consumed.

Figure 14.12 Artist's impression of the Wave Star demonstration scheme
(Source: Wave Star Energy)

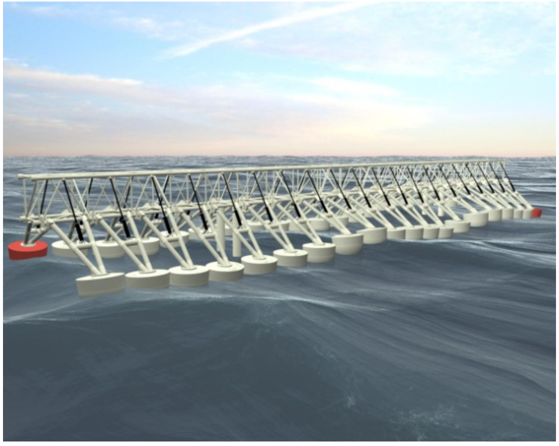


Figure 14.13 A model of the Anaconda undergoing tests
(Source: Checkmate Seaenergy)

Status

The range of device types outlined above and the large variations in configuration within each type indicate that wave energy is currently an immature technology, without a clear consensus on which are likely to eventually prove the successful devices.

Since the technology is immature, the predicted generating costs for the first wave energy devices are high (all the high fixed costs associated with a wave energy scheme - permits, surveys, grid connection, R&D, etc. - are defrayed against the output of a single device, and everything is a 'one off'). Follow-on schemes should benefit from improved savings in costs (through design optimisation and mass production) as well as increases in the device performance.

Thorpe (1991) estimated the generating costs for the *initial* designs of a range of wave energy devices and followed this with estimates for the generating costs for *mature* devices (Thorpe, 1998). The Carbon Trust (2006) undertook a similar assessment and the results of these studies agreed well, after adjustment for project lifetime (15 years) and discount rate (10%). Fig. 14.16 shows a wide range of predicted costs for initial designs with average values about GBP 250/MWh, reducing to GBP 50-100/MWh for mature schemes (taken to be for a cumulative deployment of 1 GW of a particular device). This would bring the costs close to that of offshore wind energy and several countries (Ireland, Portugal and Scotland) have high premium payments for initial wave energy devices that will reduce over time to support a wave energy industry from its initial phase to maturity.

Conclusions

This is a most interesting time for wave energy. Every effort has been made to obtain information regarding the type and status of development from wave energy organisations as shown in Fig. 14.2. Of the various wave energy devices listed, many will remain uneconomic and some will not work reliably. This observation applies to devices of *all* types and status, including some devices that have received considerable investment (both public and private) or that have achieved 'demonstration prototype status'. Hence, over the next few years there will be some spectacular 'failures' as the false promise of a number of devices will be laid bare.

That said, there are some technologies that show considerable promise and these will require support in order to realise their full potential, at which point wave energy could start to make a significant contribution to energy supply and the provision of potable water.

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Figure 14.14 The Wave Dragon prototype
(Source: Wave Dragon)

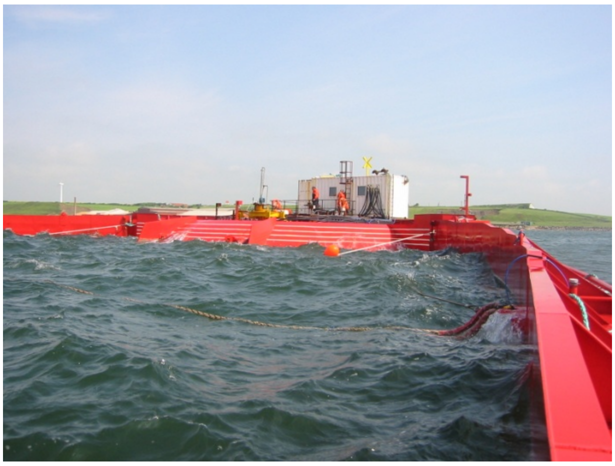


Figure 14.15 Outline of WAVEenergy's Seawave Slot-Cone Generator concept
(Source: Wave Energy)

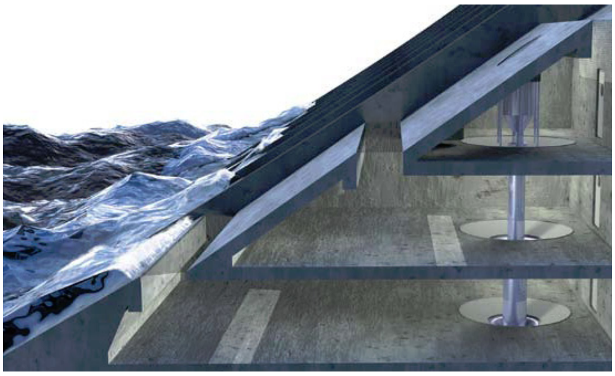
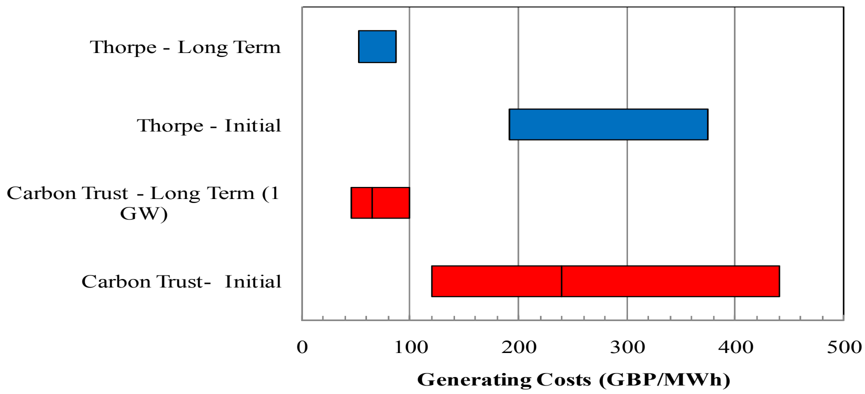


Figure 14.16 Comparison of predicted generating costs for initial and mature wave energy devices



COUNTRY NOTES

The following Country Notes have been compiled by Tom Thorpe. Every effort has been made to be comprehensive by contacting all known wave energy developers. Nevertheless, it is not an exhaustive list because information is difficult to obtain on some countries and new wave energy devices are being continually conceived. Inclusion of a technology in these notes does not indicate endorsement of that technology. Indeed, there are numerous technologies under development, including some at a very advanced stage or which have received significant investment, that are likely to be uneconomic or unreliable.

Wave energy is an immature technology and therefore, there are only a few 'commercial' devices installed worldwide, some of which are precursors to installation of a 'farm' of devices. These Country Notes focus on wave energy activities within each country, with no reference to the levels of deployment. The large number of devices under development and the reluctance of some developers to provide detail on their technologies make it impossible to provide detailed descriptions of them all. Thus the reader is referred to Fig. 14.2, which contains a web address for virtually all the developers.

International Bodies

A number of important international bodies have been involved in ocean energy, including wave energy.

The European Commission

This body has been an active sponsor of wave-related activities in a number of areas for many years, including:

- cooperation between leading organisations and institutes, via the European Wave Energy Thematic Network (www.wave-energy.net/index3.htm) and the Coordinated Action on Ocean Energy (www.ca-oe.net);
- direct contributions towards developing particular technologies, including: shoreline OWC at Pico in the Azores, the Wave Dragon, the Wave SSG, SEEWEC, Project ALDA and others;
- studies of the non-technological barriers to wave energy through Wave Energy Planning and Marketing, WAVEPLAM (www.waveplam.eu);
- a collaborative programme focusing on new components and concepts for ocean energy converters, CORES (http://hmrc.ucc.ie/cores/index.html);
- supporting the European Ocean Energy Association, which has been formed from all stakeholders in ocean energy (both within and outside Europe) to act as the central network for its members on information exchange and EU financial resources, as well as promoting the ocean energy sector by acting as a single EU voice (www.eu-oea.com).

The International Energy Agency

In 2001, the International Energy Agency (IEA) formed an Implementing Agreement on Ocean Energy (www.iea-oceans.org), which is the IEA's mechanism for providing a framework for international collaboration in energy technology R&D, demonstration and information exchange.

It has grown from the original three Members (Denmark, Portugal and the UK) to nineteen - in order of joining: Denmark, Portugal, United Kingdom, Ireland, Japan, Canada, European Commission, United States of America, Belgium, Germany, Mexico, Norway, Italy, New Zealand, Spain, Sweden, Australia, Korea, and South Africa. This growth reflects how ocean energy is increasingly seen as a viable and important future energy source.

It has four important activities denoted by its 'Annexes':

- Annex I: Review, exchange and dissemination of information;
- Annex II: Development of recommended practices for testing and evaluating OES;
- Annex III: Integration of ocean energy plants into electrical grids;
- Annex IV: Assessment of environmental effects and monitoring efforts for ocean wave, tidal, and current energy systems.

Australia

The Australian Government, through its Renewable Energy Deployment Fund has started to support wave energy, as evidenced by its grant to Victorian Wave Partners (subject to successful offer negotiations) for Ocean Power Technologies (Australasia) and its partner Leighton Contractors to construct a 19 MW Victorian Wave Power Demonstration Project using Ocean Power Technologies' PowerBuoy technology off Portland, Victoria.

Support is also available from State Governments, for instance Carnegie Wave Energy has received an AUD 12.5 million grant from the Western Australian Government for a commercial-scale CETO unit for Carnegie's commercial demonstration project.

There are several indigenous wave energy companies in Australia, but only three at the large-scale demonstration stage:

BioPower Systems

BioPower Systems is undertaking a pilot project for King Island, Tasmania, based on its bioWAVE™ technology. This 250 kW project is undertaken in collaboration with Hydro Tasmania and will deploy and test a bioWAVE™ device in 2010.

Carnegie Wave Energy

Carnegie Wave Energy has started development of its 5 MW Perth Wave Energy Project with the initial deployment of one of its 200 kW CETO buoys.

Oceanlinx

Building on the ocean test experience gained with its full-scale OWC prototype at Port Kembla and its 1/3rd scale test of its Mk2 device, Oceanlinx is scheduled to deploy in 2010 its Mk3 Pre-Commercial Device, a floating platform containing an array of OWCs.

Canada

Canada has not traditionally been thought of as having an interest in wave energy. However, there have been several important developments in recent years. In April 2008, the Canadian Federal Program of Energy Research and Development allocated funding for three years to support ocean energy R&D conducted by federal and provincial governments, in partnership with industry and academia. The Government of Canada continues to work on the regulatory framework for the management of offshore renewable energy resources (including ocean energy) in areas under federal jurisdiction.

A recent report issued by Natural Resources Canada, *Review of Marine Energy Technologies and Canada's R&D Capacity*, confirmed that Canada was currently well positioned to provide R&D within its existing R&D facilities or as part of demonstration projects.

A number of organisations have set up the Ocean Renewable Energy Group to promote wave and tidal energy in Canada by addressing common issues (resource assessment, permitting, supply chain) as well as including a number of individual device developers, including a number from outside Canada (http://oreg.ca). Wave and especially tidal current are seen as a promising energy source, with a number of Provinces actively supporting development projects such as that by BC Hydro for Vancouver Island, where a number of wave and tidal energy developers are seeking to install devices. This activity is starting to be matched at a national level, with the Government undertaking work that will benefit all potential developers (e.g. looking into permitting processes).

Much of the interest in Canada has been in tidal current energy, because of the large resource in the Bay of Fundy. However, several initiatives in wave energy have taken place, including:

Wave Energy Technologies

Wave Energy Technologies has tested a 20 kW WET EnGen™ at Sandy Cove, Nova Scotia, as a pre-commercial demonstration project – the current status is unclear.

SyncWave

SyncWave plans to develop its first-generation demonstration Power Resonator off the west coast of Vancouver Island in 2011.

China

Since the beginning of the 1980s China's wave energy research has concentrated mainly on fixed and floating oscillating water column devices. In 1995, the Guangzhou Institute of Energy Conversion of the Chinese Academy of Sciences successfully developed a symmetrical turbine wave-power generation device for navigation buoys rated at 60 W. Over 650 units have been deployed along the Chinese coast, with a few exported to Japan.

Other wave energy projects in China include:

- a shoreline OWC at Shanwei in Guangdong province, consisting of a two-chambered device with a total width of 20 m, rated at 100 kW began operating in September 1999;
- a 5 kW Backward Bent Duct Buoy (a floating OWC with the opening to the OWC chamber pointing towards the land) in association with Japan;
- a shoreline pivoting flap device (Pendulor) developed by Tianjin Institute of Ocean Technology of the State Oceanic Administration;
- an experimental 3 kW shoreline OWC, installed on Dawanshan Island in the Pearl River estuary is being upgraded with a 20 kW turbine.

Denmark

Although Denmark does not have a good wave energy resource, it had one of the best Government-sponsored wave energy programmes between 1998 and 2004. The Government continues to support individual devices alongside private investment. As a result, interest in developing wave energy technology continues to grow in Denmark, as evidenced by the Danish Wave Energy Association (www.waveenergy.dk), and the fact that Denmark is hosting seven demonstration plants at sea, based on five different concepts:

- Floating Power Plant's Poseidon's Organ Demonstration Project;
- Wave Star Energy's half-scale 500 kW (a sub unit) and 500 kW demonstration;
- Wave Dragon's 237 tonne, 1/10th scale prototype project in Nissum Bredning;
- WavePlane's full-scale, 200 kW prototype;
- Dexa Wave Energy's 5 kW demonstration unit;
- LEANCON Wave Energy's 1/40th scale experimental manifolded OWC unit;
- Waveenergyfyn's half-scale model under construction for testing at sea.

In addition, the European Commission is supporting SeWave in a novel OWC concept in the Faeroes, which is an OWC tunnelled into a cliff – Project ALDA.

France

With its heavy investment and large production from nuclear technologies, France used to show little interest in wave energy. However, this has started to change in recent years:

- the first wave energy converter test site (named SEM-REV) is being built on the Atlantic coast in the Pays de la Loire region and will be operational by summer 2010;

- in 2009, an industrial consortium started to conduct a feasibility study for the deployment of Pelamis technology in Réunion Island;
- several government agencies and universities are involved in R&D on wave energy including:

  - ADEME - the French Environment and Energy Management Agency;

  - Ifremer – the French Research Institute for Exploitation of the Sea;

  - Ecole Centrale de Nantes – a university with a long-standing contribution to wave energy.

It would be accurate to say that, with these exceptions, French interest is mainly in tidal not wave energy.

Germany

The country has a very strong public, commercial and national interest in renewable energies but because of its relatively small resource and low wave power levels, the main wave energy work undertaken in Germany has previously been in universities. There is a large amount of public funding in the national energy research programme for renewable energies and a feed-in tariff for electricity from wave energy similar to the tariff for small hydropower.

Currently there is only one German manufacturer of ocean energy devices, Voith Hydro, which acquired the Scottish company Wavegen in 2005. Under this leadership, Wavegen has gone on to significant projects in the UK and Spain. Other German suppliers, such as Bosch Rexroth and Contitech, build components and parts for a number of wave devices. The German utility RWE has created a new operating company for all of its European renewable energy activities - RWE Innogy; the UK subsidiary of this business, RWE npower renewables, has invested in Wavegen's technology in the UK. E.ON is investing in a scheme using the Pelamis in Scotland.

India

The Indian wave energy programme started in 1983 at the Institute of Technology (IIT) under the sponsorship of the Department of Ocean Development, Government of India. Initial research identified the OWC as most suitable for Indian conditions: a 150 kW pilot OWC was built onto the breakwater of the Vizhinjam Fisheries Harbour, near Trivandrum (Kerala), with commissioning in October 1991. The scheme operated successfully, producing data that were used for the design of a superior generator and turbine. An improved power module was installed at Vizhinjam in April 1996 that in turn led to the production of new designs for a breakwater comprised of 10 caissons with a total capacity of 1.1 MW. The National Institute of Ocean Technology succeeded IIT and continued to research wave energy including the Backward Bent Duct Buoy (a variant of the OWC design). However, little activity now seems to be going on in this area.

Ireland

In recent years, the Irish Government has become more active in ocean energy. The Marine Institute and Sustainable Energy Ireland prepared the *National Strategy for Ocean Energy* to introduce ocean energy into Ireland's renewables portfolio *and* to develop an ocean energy sector by supporting national developers of wave energy devices:

- Phase 1 (2005-2007), an offshore test site for ¼ scale prototypes;
- Phase 2 (2008-2010), enhanced support for demonstration of pre-commercial single devices and development of a grid-connected test site;
- Phase 3 (2011-2015), pre-commercial small-array testing of promising devices;
- Phase 4 (2016 onwards), development of strategies for commercial deployment of wave devices.

More recently, the Irish programme has changed, with challenging targets for the use of ocean energy in Ireland of 75 MW by 2012 and 500 MW by 2020. To achieve these objectives, the Government has a three-year (2008-2010) financial package of about € 27 million, which is administered by the Ocean Energy Development Unit (OEDU). This package covers support for device developers, enhancement of test facilities at the Hydraulics and Maritime Research Centre (University College Cork), development of grid-connected test facilities (€ 2 million). There is also an important buy-in tariff of € 22/MWh for electricity produced from wave and tidal devices.

Much of the Irish Government's activities are focused through The Marine Institute and Sustainable Energy Ireland.

The academic centres involved in wave energy are the Hydraulics and Maritime Research Centre in University College Cork, the University of Limerick and the Electricity Research Centre in University College Dublin.

This support for wave energy and the fact that Ireland has one of the best wave resources in the world has stimulated some developments, including:

- Swedish power utility Vattenfall and Irish wave-energy developer Wavebob announced plans in 2009 to build a commercial-scale wave-energy project off the west coast of Ireland;
- the OceanEnergy OE Buoy has been tested in Galway Bay at a ¼-scale machine and is now moving on to a ¾-scale;
- Hydam Technology has developed the McCabe Wave Pump, tested at full size in 2003;
- the Electricity Supply Board, Ireland's premier utility, has started a project to reinforce the lines to the western coast to cope with new generating capacity from ocean renewables.

Japan

Despite having low wave power levels, extensive research on wave energy has been undertaken in Japan, which deployed one of the first wave energy devices (the floating OWC, 'Kaimei') followed by another floating OWC, the 'Mighty Whale', in 1989. Particular emphasis has been placed on the development of air turbines and on the construction and deployment of prototype devices (primarily OWCs), with numerous schemes having been built:

- 1983 - a 40 kW OWC was deployed on the shoreline structure at Sanze;
- 1989 - a five-chambered 60 kW OWC as part of the harbour wall at Sakata Port;
- 1988 to 1997 - 10 OWCs installed in front of an existing breakwater at Kujukuri;
- 1996 - a 130 kW OWC in a breakwater in Fukushima Prefecture;
- 1987 - a floating OWC known as the Backward Bent Duct Buoy.

In addition, the Pendulor wave energy device was investigated for over 15 years by the Muroran Institute of Technology. However, the only significant wave energy device studied recently is an OWC deployed at Niigata in 2005.

As a result, despite having made such significant contributions to wave energy in the past, ocean energy was not included in the sources of new energy listed in the Law Concerning Special Measures to Promote the Use of New Energy (New Energy Law). As a result, financial assistance for promoting wave energy is not available in Japan.

Nevertheless, Ocean Power Technologies has signed an agreement with a consortium of three Japanese companies (Idemitsu Kosan, Mitsui Engineering & Shipbuilding, and Japan Wind Development) to develop a demonstration wave power station in Japan with up to three of the company's PowerBuoys. Such a trial plant would provide the basis for the proposed building of a commercial-scale wave power station with an initial capacity of 10 MW.

Mexico

Historically, the only wave energy activity in Mexico has been the development of a wave energy driven sea-water pump at the Instituto de Ciencias del Mar y Limnología, U.N.A.M. Unidad Académica Mazatlán. This is to be used to improve the state of ecologically-distressed isolated coastal areas by flushing them out with fresh seawater. A prototype has been successfully tested on the Pacific coast of the state of Oaxaca and a project has been approved to build and install a pump to flush out the port of Ensenada, on the Baja California Peninsula.

More recently, the Federal Electricity Commission (CFE) has studied a possible joint test of a wave electricity generator with Oceanlinx (Australia) and sea-bed wave generator with Mexican inventor, Antonio Bautista.

New Zealand

New Zealand provides funding from the Marine Energy Deployment Fund to promote marine energy by offering NZ$ 2 million per annum between 2008 and 2012 for the deployment of prototypes in New Zealand waters. To date this has been awarded mainly to tidal energy developers apart from the Wave Energy Technology – New Zealand (WET-NZ) consortium, which comprises two Crown Research Institutes (Industrial Research Limited (IRL) and the National Institute for Water and Atmospheric Research (NIWA) and a private company, Power Projects Limited. This has deployed small-scale devices (~2 kW) in the sea.

Norway

Norway has an attractive wave energy resource and there are several national programmes and targets for renewable energy in Norway, but none are specific for ocean energy. Similarly, there are several government support mechanisms for technology development, prototype and full-scale test devices for renewable energy, but no specific support exists for ocean energy. Nevertheless, some companies have received significant funding, (e.g. Langlee Wave Power received a grant from the Research Council of Norway in 2009).

The Norwegian University of Science and Technology in Trondheim (NTNU) has long been involved in several research and development projects relating to wave, including the EU-sponsored SEEWEC project. Statkraft, the state-owned utility, has allocated € 10 million over a period of four years for an ocean energy university programme for focusing on offshore wind, wave and tidal energy in three Nordic universities (NTNU, Norway; University of Uppsala, Sweden; and the Technical University of Denmark); the universities will have to match the projects financed by the programme.

There is some commercial activity in Norwegian wave energy:

- Tussa Kraft and Vattenfall are testing 40 kW Seabased technology devices outside Runde on the west coast of Norway;
- The Fred. Olsen company was actively involved for three years of testing (with the research rig 'Buldra') of 'FO^3' multiple point absorbers on a single vessel. This was a part of SEEWEC, a consortium involving 11 partners from 5 EU-members (Belgium, The Netherlands, Portugal, Sweden and the UK) and 1 associated country (Norway). Its final report indicated that arrays of single point absorbers would be better;
- WAVEenergy is presently working to build its own test 300 kW SSG unit at Svåheia on the coast near Egersund for 2011 and has recently started a feasibility study for Hanstholm Harbour for a 10 MW project in January 2010;
- Langlee Wave Power has conducted R&D on a 1/20th scale model of its floating wave energy device and is currently looking to deploy a prototype device in 2010. It is reported to have an agreement with the Turkish renewable energy company Ünmaksan for a 24 MW commercial facility to be deployed in Turkish waters, presumably in the form of a combined wind-wave system.

Portugal

The Portuguese Government was the pioneer in seeing the type of support needed for wave energy in its early stages of development and it introduced a special tariff for wave energy in 2007 (Decree-law 225/2007) of € 260/MWh for the first 20 MW, with decreasing prices for additional installed capacity.

The Government established a Wave Energy Pilot Zone 2008 for device demonstration & pre-commercial wave farms, with a cumulative output of up to 250 MW. REN (the Portuguese National Grid) is expected to sign a Pilot Zone concession contract with the Government, with 16 MW connection available in the first phase; 80 MW in the second phase and 250 MW in the third phase.

Academic wave energy research is concentrated at the Instituto Superior Técnico (the School of Engineering of Technical University of Lisbon) and Instituto Nacional de Engenharia, Tecnologia e Inovação (INETI). In addition to undertaking in-house research, they are participants in several European Commission Programmes; also IST and Massachusetts Institute of Technology have a collaborative programme funded by the Portuguese Government.

The other technical focus in Portugal is the Wave Energy Centre (WavEC). This is a private non-profit association created in 2003 for the development and promotion of wave energy utilisation through technical and strategic support to companies and public bodies. Currently it comprises 15 associates working on a wide range of topics on ocean energy, including a number of European programmes, and it has responsibility for the 400 kW OWC pilot plant in the Azores. It has come to play an increasingly important role for marine energy, not just in Portugal but internationally and WavEC may expand to become the Institute of Offshore Energy with support from companies and public.

Commercial interest in wave energy is very much in evidence in Portugal, for instance:

- the Portuguese utility, Energias de Portugal, SA (EDP) has played an important role in ocean energy, having invested in the Azores. It is promoting a Portuguese wave energy cluster through the ‘Ondas de Portugal’ initiative (OdP), which included the first demonstration, pre-commercial wave farm in the world – the Pelamis – in 2008. With other Portuguese companies, it has plans to deploy a further 20 MW of Pelamis devices;

- Energias Renováveis e Ambiente, Eneólica and WavEC helped deployment of a half-scale prototype of the AW-Energy’s WaveRoller; AW-Energy is leading a consortium (including its earlier partners and Grupo Lena, Bosch-Rexroth and ABB) for a 300 kW for Portugal;

- Kymaner, a small company working in consultancy and engineering of wave energy conversion, has carried out refurbishment of the Azores OWC plant;

- Martifer Energia, a company within the Martifer Group (large manufacturers of metal structures), has been developing its own wave energy technology in conjunction with the Certification Authority, Det Norske Veritas);

- the Wavebob prototype is expected to be tested in Portugal with EU and commercial funding by a consortium called ‘Standpoint’, led by Wavebob but including Vattenfall (Sweden), Generg Novos Desenvolvimentos (Portugal), Germanischer Lloyd (Germany), Hydac (Germany) and Wedge Global (Spain);

- Wave Dragon has formed a project development company, TecDragon, with the purpose of developing an initial 50 MW wave energy project in Portuguese waters.

Spain

The Spanish Government supports wave energy with feed-in tariffs for ocean power of € 0.0689/kWh for the first 20 years and € 0.0651/kWh thereafter. Regional governments promote the installation of demonstration plants in different ways, e.g.:

- the Governments of the Basque Country and Cantabria intend to set up infrastructures on their coasts during the coming years to test different technologies of wave energy conversion and hold stocks in wave energy projects under construction in their territories;
- the Basque Country Government is at the design and licensing stage for a wave energy test facility - the Biscay Marine Energy Platform, BIMEP - to allow full-scale prototype testing and the installation of demonstration and pre-commercial wave power plants up to 20 MW;
- the Canary Islands have funded the cost of developing a wave energy atlas to promote the installation of wave power plants.

In comparison with the 2007 edition of the *Survey*, there is now significant wave energy activity in Spain:

- the Nereida Project in Mutriku (Basque Country) is an OWC integrated in a breakwater and involves a € 6 million investment. The plant consists of 16 turbines each of 18.5 kW;
- in Santoña (Cantabria), Iberdrola Energías Marinas de Cantabria S.A. has installed the first 40 kW PowerBuoy from Ocean Power Technologies. After finishing a testing stage and a detailed analysis of investment costs, a second phase could be undertaken, including the installation and grid connection of 9 buoys of 150 kW each;
- a research project for the development of three wave energy converters called PSE-MAR was coordinated by the Tecnalia Technology Corporation for a consortium formed by the three technology developers: Hidroflot, Pipo Systems and Tecnalia. The winning technology, the Oceantec Wave Energy Converter, will undergo further sea trials in 2010-2011. Iberdrola and Tecnalia are supporting development of the full-scale device at BIMEP in 2012;
- OWC technologies are to be trialled in several locations, including A Guarda, Galicia, and Granadilla, Tenerife;
- several other private initiatives exist from Abencis Seapower, Hidroflot, Norvento and Sea Energy, but the situation regarding these is not clear.

Sweden

Swedish governmental support of ocean energy renewable sources is by means of the electricity certificate system, which provides a market place where sellers and purchasers of certificates can meet.

There is a wave energy test facility called Islandsberg in the municipality of Lysekil on the west coast of Sweden, where testing of the Seabased wave energy device will run to 2013-2014.

United Kingdom

The UK has become a positive regime in which to develop renewable ocean energy technologies, because of the various types of support offered. This includes:

- the Renewables Obligation (RO), the UK Government's main support mechanism for the expansion of emerging technologies in renewable electricity generation in the UK, operates through the use of renewable obligation certificates (ROCs). The incentive offered by ROCs will vary with the market but is of the order of GBP 50/MWh. In 2008, the UK Government introduced banding by technology of the ROC in order to provide better support for emerging technologies, with wave receiving 2 ROCs/MWh of eligible generation. Scotland, like Portugal and Ireland, recognised the need for enhanced support for emerging technologies like wave and introduced 5 ROCs/MWh for wave energy;

- the UK Government's Marine Renewables Proving Fund of GBP 22 million for R&D to take marine devices successfully from initial prototype development through to early–stage commercial generation, where they are then eligible for funding from the Marine Renewables Deployment Fund (MRDF). The MRDF contains the Wave and Tidal Energy Demonstration Scheme, with a total of GBP 42 million to be committed over 3 years, with a maximum of GBP 9 million per project, a 25% capital grant (with a maximum of GBP 5 million) and GBP 100/MWh for 7 years once a scheme is commissioned;

- UK Government support for R&D in marine technologies from fundamental research (the SuperGen Marine programme) through to pre-commercial deployment. This comprises a consortium of about 33 organisations including energy companies, utilities, research laboratories, commercial companies, government bodies, ocean energy developers and universities;

- the Scottish Government runs the Saltire Prize scheme offering an international prize of GBP 10 million aimed at inspiring significant technological advances in the marine renewables sector. It also continues to invest in infrastructure at the European Marine Energy Centre (EMEC) in Orkney, an institution that provides much of the necessary infrastructure for wave (and tidal current) developers to test their demonstration devices, including subsea electrical cables to test stations. EMEC has produced a number of guideline documents for the marine energy sector as precursors to becoming standards (www.emec.org.uk/national_standards.asp);

- EMEC will be joined in the near future by the 'Wave Hub' infrastructure project off the Cornish coast (SW England) pioneered by the South West Regional Development Agency. This will provide a 20 MW capacity electrical connection from a subsea facility to the national grid, to test small farms of wave energy devices as the next step to commerciality;

- there is also a facility for large wave tanks and dry-dock testing of large-scale devices at the New and Renewable Energy Centre (Narec, Blythe, Northumberland);

- the Government has also introduced a Marine Bill, which addresses all users of the marine environment to ensure a sustainable approach to the use of the sea and aims to streamline the consenting process. In support of this, work is nearly complete on developing revised Environmental Impact Assessment guidance for offshore renewables.

Given this level of support, together with other marine energy initiatives such as the UK's Energy Technologies Institute's development of subsea cable connectors for ocean energy, there is a great deal of interest from wave energy companies in the UK and, perhaps more importantly, support from utilities and other commercial organisations, for instance:

- Wavegen's Siadar Wave Energy with RWE npower renewables will generate up to 4 MW from a number of OWCs in a breakwater on the Isle of Lewis;

- Pelamis Wave Power will deploy a 3 MW scheme off Orkney with ScottishPower Renewables;

- Pelamis Wave Power and Vattenfall will develop a 20 MW wave power project off the Shetland Islands in a joint venture, called Aegir Wave Power;

- EMEC will enable testing of a number of devices, including: Aquamarine Power's Oyster, Ocean Power Technologies' PowerBuoy, Pelamis (with E.ON); Ocean Navitas' Aegir Dynamo;

- Wave Hub has selected a number of technologies for its wave farm: Ocean Power Technologies' PowerBuoy, Pelamis Wave Power's Pelamis and others.

In November 2008 The Crown Estate, owner of the UK's seabed, began the process of inviting proposals to develop marine energy projects in the Pentland Firth and Orkney Islands. The area off the northeast coast of Scotland is particularly well-endowed with a marine resource and Round 1 of the leasing programme is designed for the installation of 1.2 GW of wave (and tidal) power by 2020. The tender period for pre-qualified organisations lasted until May 2009. Negotiations with twenty prospective developers then ensued. In March 2010 the names of the successful bidders were announced. Leases for the installation of 600 MW have been signed as follows:

- SSE Renewables Developments, 200 MW, Costa Head (Orkney);

- Aquamarine Power and SSE Renewables Developments, 200 MW, Brough Head (Orkney);
- SSE Renewables Holdings and OpenHydro, 50 MW, Marwick Head (Orkney);
- E.ON, 50 MW, West Orkney South;
- E.ON, 50 MW, West Orkney Middle South;
- Pelamis Wave Power, 50 MW, Armadale (Pentland Firth).

United States of America

Since 2007, when the U.S. Department of Energy (DOE) was first authorised to establish a research programme in marine and hydrokinetic energy (including wave), there has been a continued increase in activity and interest in ocean energy, with DOE spending slowly increasing so that US$ 14.6 million was awarded in 2009 to support development of advanced water power technologies. This has been matched by other activities such as a Presidential announcement of a new initiative to lease federal waters for the purpose of generating electricity from wind and ocean currents. In addition, the DOE has provided in-kind assistance through its national laboratories, National Renewable Energy Laboratory and Sandia National Laboratory, to two cooperative research and development projects. Technologies relevant to wave energy have also benefited from grants under the DOE's Small Business Innovative Research initiative. The DOE, in collaboration with two other U.S. federal agencies, the National Oceanic and Atmospheric Administration and the Department of the Interior, has helped to prepare a report summarising what is currently known about the environmental impacts of marine and hydrokinetic energy. It also aims to identify device-specific marine energy technologies and projects as they develop and store them in a database that provides 'up-to-date' information on ocean energy conversion (see www1.eere.energy.gov /windandhydro/hydrokinetic/default.aspx).
Work has also taken place to coordinate the interests of Federal stakeholder agencies (e.g. the Fish and Wildlife Service, the National Park Service, the U.S. Army Corps of Engineers, the Environmental Protection Agency, etc.). Finally, The American Recovery and Reinvestment Act of 2009 enabled wave energy to become eligible for the renewable energy production tax credit (PTC), at a rate of US$ 0.01/kWh until 2013.

The U.S. Navy has continued its support of specific ocean energy projects, under its Naval Facilities Command (NAVFAC), while the two U.S. agencies charged with regulating marine and hydrokinetic energy facilities, the Federal Energy Regulatory Commission and the Department of the Interior's Minerals Management Service, have focused on improving their understanding of the technologies and their social and environmental effects, and each continues to refine its regulatory processes.

Individual states have also continued or begun to pursue ocean energy related projects through a number of organisations, including the Oregon Wave Energy Trust, the West Coast Governors Agreement, and the Pacific NorthWest Economic Region with plans for specific ocean energy schemes such as San Francisco seeking to develop a 30 MW wave energy farm. In addition, federal grants have supported companies and institutions active in ocean energy, with several focusing on wave energy.

A number of U.S. universities and research organisations are active in ocean energy research and development, and their efforts continue to increase in scope and depth. Three have been named as part of two National Marine Renewable Energy Centers, designed to integrate research, development and open water testing facilities:

- Oregon State University and the University of Washington have combined to form the Northwest National Marine Renewable Energy Center;
- the University of Hawaii's Natural Energy Institute will lead a second centre, the National Marine Renewable Energy Center.

In the private sector, a number of companies in the USA are currently in the process of researching and/or developing wave energy devices but only a few have reached the stage of full-scale deployment and testing:

- Ocean Power Technologies (OPT) has been very active on the wave energy scene in the USA (and elsewhere):
    - In December 2009, OPT deployed a 40 kW PowerBuoy at the U.S. Marine Corps Base Hawaii (MCBH) at Kaneohe Bay;
    - OPT has accrued 25 months in-service experience for an earlier version of its 40 kW PowerBuoy at Atlantic City, New Jersey;
    - OPT is developing a wave park near Reedsport, Oregon that will use ten of its new 150 kW PowerBuoys;
    - OPT is proposing to develop a wave park at Coos Bay, Oregon of up to 100 MW using 200 of the 500 kW PowerBuoys under development.
- Resolute Marine Energy has conducted ocean testing of a prototype wave energy converter that produces compressed air for offshore aquaculture operations. In 2010, Texas Natural Resources intend to deploy an offshore wave power station in the Gulf of Mexico near Freeport, Texas, using Independent Natural Resources' SEADOG® wave pump;
- PG&E is proposing an ocean wave energy pilot study (WaveConnect™) to be conducted off the coast of Humboldt County, California to give wave energy device manufacturers the opportunity to test their devices on a common site. The scheme should be ready to accept devices in about 2013 and PG&E intends to use the most effective wave energy converter technologies for future ocean wave energy projects.

15. Ocean Thermal Energy Conversion

COMMENTARY

The Resource

Ocean Thermal Energy Conversion (OTEC) is a means of converting into useful energy the temperature difference between the surface water of the oceans in tropical and sub-tropical areas, and water at a depth of approximately 1 000 metres, which comes from the polar regions. Fig. 15.1 shows the temperature differences in various parts of the ocean, and for OTEC a temperature difference of 20°C is adequate, which embraces very large ocean areas, and favours islands (Gauthier & Lennard, 2001) and many developing countries (Lennard 2007).

Whilst the ocean thermal resource is relevant, particularly to many developing countries, there are a multitude of other factors to be considered before it can be said that a particular country or location is suitable for an OTEC installation. These include: distance from shore to the thermal resource; depth of the ocean bed; depth of the resource; size of the thermal resource within the Exclusive Economic Zone (EEZ); replenishment capability for both warm and cold water; currents; waves; hurricanes; sea bed conditions for anchoring; sea bed conditions for power cables of floating plants; present installed power, and source; installed

Figure 15.1 The area available for OTEC and the temperature difference (Source: Xenesys Inc.)

power per head; annual consumption; annual consumption per head; present cost per unit - including any subsidy; local oil or coal production; scope for other renewables; aquaculture potential; potable water potential; and environmental impact - to name but a few. For completeness it would be useful to seek whole-life nuclear-power costings so that comparative capital and generating costs for all energy sources are clearly indicated.

Types of OTEC Plant

Depending on the location of the cold and warm water supplies, OTEC plants can be land-based, floating, or - now not such a longer-term development - grazing. Floating plants have the advantage that the cold water pipe is shorter, reaching directly down to the cold resource, but the power generated has to be brought ashore, and moorings are likely to be in water depths of, typically, 2 000 metres. The development of High Voltage DC transmission offers substantial advantage to floating OTEC, and the increasing depths for offshore oil and gas production over the last decade mean that mooring can now be classed as 'current technology' - but remains a significant cost item for floating OTEC. Land-based plants have the advantage of no power transmission cable to shore, and no mooring costs. However, the cold water pipe has to cross the surf zone and then follow the seabed until the depth reaches approximately 1 000 metres - resulting in a much longer pipe which has therefore greater friction losses, and greater warming of the cold water before it reaches the heat exchanger, both resulting in lower efficiency.

The working cycle of an OTEC plant may be closed or open, the choice depending on circumstances. All these variants clearly develop their power in the tropical and sub-tropical zones (Fig. 15.1), to the benefit of countries in those parts of the world, but a grazing plant would allow OTEC energy use in highly-developed economies which lie in the world's temperate zones. In this case, the OTEC plant is free to drift in areas of ocean with a high temperature difference, the power being used to split sea water into liquid hydrogen and liquid oxygen. The hydrogen, and in cases where it is economic, also the oxygen, would be offloaded into shuttle tankers which would take the product to energy-hungry countries, where the infrastructure for liquid hydrogen distribution is now being initiated - for example in California. Also, the hydrogen may be an intermediate product, being used in turn to produce ammonia. At present, use of ammonia fertilisers is determined in part by production capacity from natural gas; the use of such fertilisers in the developing world - much of it in the tropical and sub-tropical zones where OTEC processes are available - could make a major contribution to world food production.

The Market for OTEC

There has been a significant resurgence of interest in the development of commercial-scale OTEC systems in the last few years. This resurgence has come about as a result of several interrelated factors.

The first of these factors is the ongoing economic crisis which is in no small part related to the high price of oil. As global energy demand rises, due

Figure 15.2 Less developed countries with adequate ocean thermal resources, 25 km or less from shore
(Source: Cogeneration Technologies)

Country / Area	Temperature Difference (^{o}C) of Water Between 0 and 1 000 m	Distance from Resource to Shore (km)
Africa		
Benin	22-24	25
Gabon	20-22	15
Ghana	22-24	25
Kenya	20-21	25
Mozambique	18-21	25
São Tomé and Príncipe	22	1-10
Somalia	18-20	25
Tanzania	20-22	25
Latin America and the Caribbean		
Bahamas	20-22	15
Barbados	22	1-10
Cuba	22-24	1
Dominica	22	1-10
Dominican Republic	21-24	1
Grenada	27	1-10
Haiti	21-24	1
Jamaica	22	1-10
St Lucia	22	1-10
St Vincent & the Genadines	22	1-10
Trinidad & Tobago	22-24	10
U.S. Virgin Islands	21-24	1
Indian and Pacific Oceans		
Comoros	20-25	1-10
Cook Islands	21-22	1-10
Fiji	22-23	1-10
Guam	24	1
Kiribati	23-24	1-10
Maldives	22	1-10
Mauritius	20-21	1-10
New Caledonia	20-21	1-10
Pacific Islands Trust Territory	22-24	1
Philippines	22-24	1
Samoa	22-23	1-10
Seychelles	21-22	1
Solomon Islands	23-24	1-10
Vanuatu	22-23	1-10

primarily to the robust growth of the Chinese and Indian economies, global energy supplies from conventional sources do not have the same upward potential. As the global economy recovers and energy demand in the developed world grows, the upward pressure on the price of the limited supplies of fossil fuel - especially oil - could well lead to another economic crisis. Timely development of renewable energy resources can provide an alternative path to this anticipated economic spiral.

Among alternative energy sources OTEC has several advantages. It taps directly into the largest energy resource on the surface of the earth – the tropical ocean surface layer. The solar energy flux through this layer is roughly 10 000 times greater than the present rate of energy use by all of human society. OTEC systems take their energy out of the heat stored in the surface layer of the ocean and hence have an availability factor that is essentially 100%. This means that there is a more efficient use of capital resources in an OTEC system than in almost all other renewable energy resources (which are intermittent). With the heating of the ocean surface layer due to global warming, OTEC systems are also becoming more efficient in a thermodynamic sense.

In order to convey the energy produced by floating OTEC platforms to countries outside of the tropics, it has to be changed into a transportable form such as liquefied hydrogen (LH2). OTEC systems have a significant synergy with the production and liquefying of hydrogen, in that the pure water needed for hydrogen production can be produced as part of the OTEC power production by using the Open Cycle OTEC process. Liquefying the hydrogen can be done much more efficiently on the OTEC platform than conventionally, because of the availability of the cold water heat sink. Finally, the OTEC production platform is already floating in the most efficient transport medium (the ocean) so that delivery of the LH2 product can be executed with the minimum number of stages.

The OTEC resource is largely located on the High Seas and is therefore available to all countries for the price of building and operating the required production platforms under their own flag. This means that even countries outside of the tropical zone and having no oceanic coastline (e.g. Switzerland or Mongolia) can become energy self-sufficient in perpetuity.

The second important factor related to the resurgence of interest in the development of OTEC systems is the growing global environmental crisis resulting from the burning of fossil fuels. There is now broad consensus that the increase in anthropogenic greenhouse gases in the atmosphere has reduced the outflow of long-wave radiation from the earth and has thereby increased the amount of heat stored in the earth system (primarily in the surface layer of the ocean). This has led directly to a rise in sea level, to more intense tropical cyclones, and globally, more extreme weather events. In addition, the majority of the anthropogenic CO_2 is eventually dissolved in the ocean surface layer where it reduces the pH and thereby significantly damages the coral reefs of tropical zones.

Tropical islands, especially atolls, are very susceptible to such environmental damage and it is therefore no surprise that these island communities are in the forefront of the current effort advocating large-scale development of OTEC systems. While all renewable energy systems reduce the emission of CO_2 by reducing the use of fossil fuel, only OTEC has three additional mechanisms for reducing the damage that is related to our use of fossil fuels:

- OTEC directly converts some of the heat of the surface layer of the ocean to useful energy;
- by returning the slightly cooled (and hence denser) surface layer water to below the top of the thermocline, the additional CO_2 contained in that water is sequestered in a layer which no longer interacts with the atmosphere;
- by discharging the slightly warmed deep seawater (along with its component nutrients) the primary productivity of the tropical ocean is increased. This means that some of the CO_2 is incorporated in biological material which sinks and is thereby sequestered in the deep ocean.

An effort is currently under way by some of the tropical island nations (initiated by the Republic of the Marshall Islands) to team up with one or more industrial nations (such as the USA; the Republic of Korea; Taiwan, China or Germany) to deploy 125 MW OTEC platforms. Their purpose would be to supply the electricity and fresh water requirements of the island population, as well as producing significant amounts of LH2 (and liquefied oxygen, LO2) for export to the industrial partners.

The third important factor in the resurgence of interest in the development of OTEC systems is the realisation that advances have been made, not only in the technology directly involved in the OTEC process (concrete floating platforms, improved heat exchangers, more reliable subsea systems), but also in the technology related to the use of the energy product (highly efficient and reliable alkaline fuel cells, better hydrogen storage systems). Additionally, global interest rates for capital-intensive projects such as OTEC platforms continue to be generally low.

Further OTEC Applications

An especial benefit of OTEC is that, unlike most renewable energies, it is base-load - the thermal resource of the ocean ensures that the power source is available day or night, and with only modest variation from summer to winter. It is environmentally benign, and some floating OTEC plants would actually result in net CO_2 absorption. And a further unique feature of OTEC is the additional products which can readily be derived - food (aquaculture and agriculture); pharmaceuticals; potable water; air conditioning; etc. Many of these arise from the pathogen-free, nutrient-rich, deep cold water. OTEC is therefore the basis for a whole family of Deep Ocean Water Applications (DOWA), which can additionally benefit the cost of generated electricity. Potable water production alone can reduce electricity generating costs by up to one-third, and is itself in very considerable demand in most areas where OTEC can operate.

Large-scale development of OTEC systems will create numerous high-quality jobs in marine construction as well as in a wide range of manufacturing industries. The funding of such projects could be facilitated by an eventual reduction in the cost of importing fossil fuels.

Hans Krock
The University of Hawaii

with contributions from the OTEC commentary, SER 2007 written by the late Don Lennard

COUNTRY NOTES

The Country Notes on OTEC compiled for previous editions of the *Survey of Energy Resources* have been revised, updated and augmented by the Editors, using national sources, other information and personal communications.

American Samoa

In mid-2006 it was reported that the country's Power Authority was being supported by the U.S. Department of the Interior in an investigation into using its available OTEC resource to replace fossil fuel-generated electricity.

Antigua

At the beginning of 2006 the Chief Environment Officer of Antigua announced that an MOU for an OTEC feasibility study was being prepared with an American organisation.

Australia

At an ocean energy workshop held in Townsville, northern Queensland in September 2005, discussion concentrated on developing OTEC energy in the region. It was suggested that the city could act as the 'launch pad' for plants in the South Pacific and also, in time, become a centre of excellence in the technology.

To date the plans have not progressed owing to environmental concerns for any such scheme and also a greater interest in other alternative energy sources.

Barbados

With the high petroleum product prices of recent years, Barbados has considered substituting a fossil fuel-based power supply for one utilising the renewable energies. In late-2004, an American developer announced that it was interested in helping Barbados establish an OTEC plant for electricity generation and mariculture purposes.

Cayman Islands

Caribbean Utilities Company (CUC) stated during 2006 that it was exploring the possibilities of utilising the country's ocean thermal resource for the production of electricity and fresh water. An American developer would plan for a prototype plant to be installed but purchase agreements between CUC, Cayman Water Authority and/or Cayman Water Company would need to be settled prior to any deployment.

Côte d'Ivoire

A French project to build two open cycle onshore OTEC plants of 3.5 MW each in Abidjan was proposed in 1939. The experimentation was eventually undertaken after World War II, with the main research effort occurring during 1953-1955. The process of producing desalinated water via OTEC proved to be uneconomic at that time and the project was abandoned in 1958.

Cuba

This was the site of the first recorded installation of an OTEC plant and the island remains a very desirable location in terms of working temperature difference (in excess of 22^{o}C). Georges Claude, a French engineer, built an experimental open cycle OTEC system (22 kW gross) at Matanzas in 1929-1930. Although the plant never produced net electrical power (i.e. output minus own use) it demonstrated that the installation of an OTEC plant at sea was feasible. It did not survive for very long before being demolished by a storm.

It was reported that in 2006 the Cuban National Energy Program included details of the development of OTEC demonstration plants. The following year investigative studies were carried out by Xenesys (a private Japanese company). In early 2008, Xenesys reported that the company together with the Ministries of Basic Industry, and of Science, Technology and Environment and the University of Matanzas were working together to further the project.

Fiji

This group of islands has been the subject of OTEC studies in the UK and in Japan. In 1982 the UK Department of Industry and relevant companies began work on the development of a floating 10 MW closed cycle demonstration plant to be installed in the Caribbean or Pacific. The preferred site was Vanua Levu in Fiji.

At end-1990 a Japanese group undertook an OTEC site survey on the Fijian island of Vitu Levu. Design work on an integrated (OTEC/DOWA) land-based plant was subsequently undertaken.

The studies have not given rise to any firm construction project. However, when the tourist industry grows further, the Vanua Levu site will again be ideal, with cold deep water less than 1 km from shore. The development of the tourist industry will require substantial electrical power, potable water and refrigeration.

French Polynesia

Feasibility studies in France concluded that a 5 MW land-based pilot plant should be built with Tahiti as the test site. An industrial grouping, Ergocean and Ifremer (the French institute for research and exploitation of the sea) undertook extensive further evaluation (of both closed and open cycle) and operation of the prototype plant was initially expected at the end of the 1980s, but the falling price of oil caused development to be halted. Ifremer continues to keep the situation under review and has been active in the European Union.

Specifically, Ifremer with various partners has examined DOWA desalination, since a much smaller (1 m diameter) cold water pipe would be needed. Techno-economic studies have been completed but further development is on hold.

As has been demonstrated, the ocean thermal energy resource of the region is suitable for harnessing. To this end the Japanese company Xenesys reported early in 2008 that it had signed an MOU with Pacific Petroleum Company (PPC) to develop OTEC in French Polynesia, New Caledonia and Vanuatu. Later in 2008, a joint venture between Xenesys and PPC was established to carry out the necessary research into the project and in March 2010, a full feasibility study was reported to be under way.

Guadeloupe

Experimental studies on two open cycle plants were undertaken by France between the mid-1940s and the mid-1950s in Abidjan, Côte d'Ivoire. The results of these studies formed the basis of a project to build an OTEC plant in Guadeloupe (an Overseas Department of France) in 1958. This onshore 3.5 MW OTEC plant was intended to produce desalinated water but the process proved to be uneconomic at that time and the project was abandoned in 1959.

India

Having an extremely long coastline, a very large EEZ area and suitable oceanic conditions, India's potential for OTEC is extensive.

Conceptual studies on OTEC plants for Kavaratti (Lakshadweep Islands), in the Andaman-Nicobar Islands and off the Tamil Nadu coast at Kulasekharapatnam were initiated in 1980. In 1984 a preliminary design for a 1 MW (gross) closed Rankine Cycle floating plant was prepared by the Indian Institute of Technology in Madras at the request of the Ministry of Non-Conventional Energy Resources. The National Institute of Ocean Technology (NIOT) was formed by the governmental Department of Ocean Development in 1993 and in 1997 the Government proposed the establishment of the 1 MW plant of earlier studies. NIOT signed a Memorandum of Understanding with Saga University in Japan for the joint development of the plant near the port of Tuticorin (Tamil Nadu).

During 2001 the Department of Ocean Development undertook an exercise to determine the actions required to maximise the country's potential from its surrounding ocean. The result was a Vision Document and a Perspective Plan 2015 (forming part of the 10th 5-year plan) in which all aspects of the Indian Ocean will be assessed, from the forecasting of monsoons through the modelling of sustainable uses of the coastal zone to the mapping of ocean resources, etc.

It has been postulated that most of India's future fully-commercial OTEC plants will be closed cycle floating plants in the range 10-50 MW (although 200-400 MW plants are not ruled out). Working with Saga University, NIOT had planned to deploy the 1 MW demonstration plant in March/April 2003. However, mechanical problems prevented total deployment and the launch was delayed. Following testing, it was planned to relocate the plant to the Lakshadweep Islands for power generation prior to full commercial operation from scaled-up plants. No further progress has been reported.

In late 2008, the Indian press reported that a 1 MW floating OTEC plant had been piloted off the coast of Tamil Nadu. The plant was designed in collaboration with Saga University of Japan, and the Japanese company Xenesys is also actively working on the project. The unit, situated 60 km from Tuticorin, is installed on a 68.5 m barge, the Sagar Shakthi, which houses a Rankine Cycle-based power plant.

Indonesia

Although a Dutch study suggested that Bali was a suitable site for an OTEC plant, none has ever resulted. However, in late 2008 a projected 100 MW plant off the coast of Indonesia was publicised. The plan was for hydrogen to be produced in order to power zero-emission vehicles.

Jamaica

In 1981 it was reported that the Swedish and Norwegian Governments, along with a consortium of Scandinavian companies, had agreed to provide the finance required for feasibility studies towards an OTEC pilot plant to be located in Jamaica.

In a reference to OTEC, the National Energy Plan (circa 1981) stated that 'a 10 MW plant was envisioned in the late 1980s'. Although this project never came to fruition, a plan remains in place for an offshore 10 MW plant producing energy and fresh water. For implementation to take place, purchasing agreements from the power and water utility companies need to be in place.

There was further discussion regarding Jamaica's ocean thermal resource at the beginning of 2005 and the Ministry of Industry, Technology, Energy and Commerce continues to list OTEC as a possible energy supply to the island, but to date there has been no development.

Japan

Research and development on OTEC and DOWA has been carried out since 1974 by various organisations (Ocean Thermal Energy Conversion Association of Japan; Ocean Energy Application Research Committee, supported by the National Institute of Science and Technology Policy; Japan Marine Science and Technology Center, Deep Seawater Laboratory of Kochi; Research Institute for Ocean Economics and Toyama prefectural government; Saga University; Electrotechnical Laboratory and Shonan Institute of Technology).

Saga University conducted the first OTEC power generation experiments in late-1979 and in early-1980 the first Japanese experimental OTEC power plant was completed in Imari City.

During the summer months of 1989 and 1990 an artificial up-welling experiment was conducted on a barge anchored on the seabed at 300 m offshore in Toyama Bay.

With the establishment in 1988 of the OTEC Association of Japan, now the Japan Association of Deep Ocean Water Applications (JADOWA), the country has placed greater emphasis on products that use deep ocean water in the manufacturing process. Such products (food and drink, cosmetics and salt) have all proved commercially successful.

In March 1996, a Memorandum of Understanding was signed between Saga University and the National Institute of Ocean Technology of India. The two bodies have been collaborating on the design and construction of a 1 MW plant to be located off the coast of Tamil Nadu in India.

In mid-2003 Saga University's Institute of Ocean Energy (IOES) inaugurated a new research centre for the study of OTEC.

During 2003 it was reported that Saudi Arabia had shown great interest in working with Saga University to develop the Kingdom's OTEC potential.

If the OTEC projects the university is helping to implement are proved to be viable, the enormous potential of Japan's own EEZ could be exploited in the future.

Kiribati

During late-1990, an OTEC industrial grouping in Japan undertook detailed research (including the water qualities of the ocean, seashore, lagoon and lakes) on Christmas Island. Following on from this research, the basic concepts were improved but no developments have ensued.

Kuwait

In May 2007 Kuwait National Petroleum Company signed an MOU with Xenesys of Japan for the application of OTEC technology to power generation and water desalination, using waste heat from KNPC refineries.

Marshall Islands

In the early 1990s the Republic of the Marshall Islands invited proposals from U.S. companies to undertake a detailed feasibility study for the design, construction, installation and operation of a 5-10 MW (net) OTEC power plant to be located at Majuro. The contracted study was carried out by Marine Development Associates of California between April 1993 and April 1994 but no project resulted.

At a forum convened prior to the World Water Forum (Kyoto, March 2003) by Japan's Saga University and the Government of Palau (a group of Pacific Islands to the east of the Marshall Islands), interest was renewed in the possibility for

OTEC installations. The success of the planned project in Palau could well prove to be the impetus required for development in the Marshall Islands and other Pacific Islands.

Mauritius

With its heavy dependence on imported fossil fuels for energy supply, Mauritius has increasingly been looking at developing the renewable energies available to the Republic. In 2005 Xenesys, and Saga University, both of Japan and working on the development of OTEC systems, were represented at the UN conference for Small Island Developing States held in Mauritius. Although much interest was shown in utilising the Republic's ocean thermal resource, there has to date been no development.

The Republic's Long-Term Energy Strategy 2009-2025, published in October 2009, includes a provision for the introduction of OTEC technology. However, it is stated that the Government will only adopt the technology once its commercialisation has been tested by other countries.

Nauru

In 1981, the Tokyo Power Company built a 100 kW shore-based, closed cycle pilot plant on the island of Nauru. The plant achieved a net output of 31.5 kW during continuous operating tests. This plant very effectively proved the principle of OTEC in practical terms over an extended period, before being decommissioned.

Netherlands Antilles

A feasibility study carried out by Marine Structure Consultants of the Netherlands and funded by the Dutch Government for the Netherlands Antilles Government examined the competitiveness of a 10 MW floating OTEC plant. No development ensued.

New Caledonia

Ifremer (the French institute for research and exploitation of the sea) has re-examined a previous proposal to establish a test site for OTEC/DOWA in New Caledonia.

Towards the end of 2009, Makai Ocean Engineering Inc., on behalf of Génie & Technologies Industriels of Noumea reported that it had undertaken a pre-design evaluation of the possibility of utilising OTEC technology for the new coastal resort of Gouaro Deva.

See French Polynesia.

Northern Marianas

Using the islands' ocean thermal resource for power generation continues to be considered. A Memorandum of Understanding was signed in 2003 for the future development of a 10 MW plant, but to date the plan has not progressed.

Palau

In Spring 2001 the Government of Palau, Japan's Saga University and Xenesys Inc. (a Japanese private company) entered into an agreement that resulted in research and feasibility studies being undertaken for the identification of suitable sites for OTEC installations. Seven such sites were located on the biggest island in Palau (Babeldaob). It was stated that a pilot project would have a capacity of 3 000 kW that could ultimately reach 30 000 kW, an increase in excess of 50% from the current diesel-generated supply.

In addition to the production of power, the by-products of salt and fresh water could be used for organic farming.

It was reported that under the ACP-EU Partnership Agreement, the European Commission and the Government of Palau had drawn up a Country Strategy Paper and an Indicative Programme for the period 2002-2007. The EU was to provide financial assistance to Palau in order to expand the utilisation of renewable energy sources. However, to date no development has taken place.

Palau depends heavily on fossil-fuel generated electricity and in order to decrease this dependence, a plan for an OTEC plant has once again been mooted. In early 2008 a request was made to the U.S. Trade and Development Agency to finance a feasibility study for a plant to produce both electricity and fresh water.

Philippines

The aim of the New and Renewable Energy Program (NRE) of the Department of Energy (DOE) is to accelerate the development, promotion and commercialisation of new and renewable energy systems. The Philippines is well-endowed with a range of renewable energies and the Philippine Energy Plan (2005-2014) plans to utilise them in an effort to reduce fossil fuel consumption. To this end the DOE, working with Japanese scientists, has identified sixteen areas that could be suitable for the development of OTEC systems.

Puerto Rico

Although in 1979-1980 Puerto Rico was found to have suitable conditions for harnessing its ocean thermal energy resource, the proposed Punta Tuna 40 MW prototype plant never received funding. However, during 2008 the subject of an OTEC installation was raised again, as part of the country's move away from fossil-fuel generated electricity. In July 2008 it was reported that the Puerto Rico Electric Power Authority had signed a letter of intent with a developer for a 75 MW unit. A viability study for this plant, to be located in the southeast of the island, has been completed.

Réunion

Région Réunion has stated that by 2025 the island will be self sufficient in its sources of energy for generation of electricity. In April 2008 a study financed by Le Port, a city in the north west of the island and led by the Agence Régionale de l'Energie de la Réunion, was undertaken by the Agence pour la Recherche et la Valorisation Marine. The study established that the marine area offshore from Le Port would be suitable for the utilisation of open-cycle OTEC technology.

In April 2009 DCNS Groupe, the naval defence company, signed an agreement with Région Réunion to analyse the feasibility of installing OTEC technology. It has been suggested that an OTEC unit could be aligned with an existing power plant replacing, in the long-term, the use of fossil fuel. In October 2009, a second agreement was signed which allows for DCNS to establish optimal integration with existing generating capacity.

Saudi Arabia

It was reported in early 2003 that there had been high level governmental discussions between Japan and Saudi Arabia with a view to OTEC technology being utilised for water desalination and electricity production. To date, there has been no development.

Sri Lanka

Interest in OTEC and DOWA has been revived by the National Aquatic Resources Agency in Colombo, in the context of making use of Sri Lanka's EEZ, which is some 27 times its land area.

Three submarine canyons (Panadura, Dondra and Trincomalee) have been identified as highly suitable sites for OTEC plants and the production of electricity. The results of successful experiments conducted during 1994 were presented to the Government but political unrest in the area of Trincomalee resulted in unsafe working conditions.

The Oceanography Division of the National Aquatic Resources Research & Development Agency (NARA) maintains contact with Japan's Institute of Ocean Energy (Saga University) and the Mitsui Corporation. Following the announcement in January 2007 of the establishment of an Alternative Energy Authority, it is hoped that in the future OTEC will play a significant role in Sri Lanka.

St. Lucia

In 1983, as a part of a commitment to develop alternative energy systems, the Government of St. Lucia welcomed the opportunity to be part of an OTEC initiative that included the design and construction of a 10 MW closed cycle floating OTEC demonstration plant off Soufriere. Hydrographic surveys in 1985 confirmed that the 1 000 m contour was less than 3 km from shore, with cold water in the volcanic canyon adjacent to Petit Piton and Gros Piton. This landfall was also close to the electrical grids. The surface temperature of the sea on that part of the west coast never falls below 25^{o} C, reaching 27/28^{o} C in summer.

The UK-designed plant was provided with a fully costed proposal by a merchant bank, which showed that with construction commencing in 1985, and operation from 1989, the OTEC plant would show a cost benefit over oil-fired plant from 1994, the higher capital cost of OTEC being balanced by the 'free fuel', whereas there were ongoing fuel costs for the diesel plant. However, the final decision was to go for a diesel plant, with the whole of the capital cost being funded by another country.

Taiwan, China

The seas off eastern Taiwan are considered to be highly favourable for OTEC development. Following preliminary studies during the 1980s, three nearshore sites were selected and the steeply shelving east coast was thought to be able to accommodate an onshore OTEC plant. However, only one site (Chang-Yuan) was deemed suitable for further investigation by the Institute of Oceanography.

In 1989, the Pacific International Center for High Technology Research in Hawaii prepared a development plan for the Taiwanese Multiple Product Ocean Thermal Energy Conversion Project (MPOP). The intention of the MPOP was to construct a 5 MW closed cycle pilot plant for generating power and also the development of mariculture, desalinated water, air conditioning, refrigeration and agriculture. It was thought that the operating data obtained from the pilot plant could be used in the building of a 50-100 MW commercial plant. In 1993 it was assumed that 6 years would be required for site preparation and 5 years for construction, with the plant having a 25-year life cycle.

During the 1990s the concept of MPOP changed to a Master OTEC Plan for R.O.C. (MOPR), with the objective of ultimately establishing eight 400 MW floating OTEC power plants.

With its positive interest, Taiwan was the initiator, in 1989, of the International OTEC/DOWA Association (IOA). Until around 2004 a permanent Taiwanese secretariat worked to ensure a higher international profile for OTEC/DOWA but both the organisation and plans for OTEC within the country have, at present, somewhat stagnated.

United States of America

Hawaii remains the focus of U.S. activity in OTEC/DOWA, primarily through work carried out at the Natural Energy Laboratory of Hawaii (NELHA) facility at Keahole Point.

In 1979 'Mini-OTEC', a 50 kW closed cycle demonstration plant, was set up at NELHA. It was the world's first net power producing OTEC plant, installed on a converted U.S. Navy barge moored 2 km offshore: it produced 10-17 kW of net electric power.

In 1980 the Department of Energy constructed a test facility (OTEC-1) for closed cycle OTEC heat exchangers on a converted U.S. Navy tanker. It was not designed to generate electricity.

In the early 1980s a 40 MW OTEC pilot plant was designed. It was to be sited on an artificial island off the Hawaiian coast. However, funding was not forthcoming and the plant was not constructed.

An experimental 210 kW (gross electrical) open cycle OTEC plant was designed and operated by the Pacific International Center for High Technology Research (PICHTR) at Keahole Point. It produced a record level of 50 kW of net power in May 1993, thus exceeding the 40 kW net produced by a Japanese OTEC plant in 1982. The plant operated from 1993 until 1998 and its primary purpose was to gather the necessary data to facilitate the development of a commercial-scale design. Following the experiments, the plant was demolished in January 1999.

A further PICHTR experiment at NELHA employed a closed cycle plant to test specially developed aluminium heat exchangers. It used the (refurbished) turbine from 'Mini-OTEC' to produce 50 kW gross power. During initial operation in May 1996, corrosion leaks developed in the heat exchanger modules; the plant had to be shut down and the units re-manufactured. From October 1998, when the new units were received until end-1999 - the end of the project - data were collected on the heat exchange and flow efficiencies of the heat exchangers and thus on the economic viability of competing types of heat exchangers.

In addition to research into ocean thermal energy, NELHA has established an ocean science and technology park at Keahole Point. Cold deep seawater is pumped to the surface and utilised for the production of energy, air-conditioning, desalination, fish farming, agriculture, etc.

As part of its plan to use renewable energy to power the Natural Energy Laboratory of Hawaii Authority (NELHA), the Laboratory has created a Green Energy Zone whose goal is to develop a range of projects using a variety of renewable energies. One such project is the installation of a 1 MW offshore OTEC plant, which NELHA continues to work towards. In July 2009 NELHA reported that the 1 MW pilot plant is scheduled to be in operation in 2013 and it is hoped that it will lead to a 100 MW OTEC plant, in operation in 2017.

As part of the U.S. Military's requirement to reduce its fossil-fuel consumption, the U.S. Navy is working closely with the U.S. DOE, NOAA and private industry in order to progress the speed at which OTEC technology is commercialised and deployed. Initially the Navy is looking to implement OTEC technology at its base in Pearl Harbor, Hawaii.

In September 2009, it was announced that the Naval Facilities Engineering Command (NAVFAC) had awarded Lockheed Martin a US$ 8.1 million contract to develop the components necessary for an OTEC pilot plant. Lockheed Martin has teamed up with Ocean Engineering & Energy Systems (OCEES) International Inc. and Makai Ocean Engineering of Honolulu to work on this project.

Vanuatu

See French Polynesia.

Virgin Islands

The island of St. Croix has been found to be a suitable site for the development of OTEC-produced electricity and desalinated water.

In the early 1990s an agreement was drawn up between the U.S. company GenOtec and the Virgin Islands Water and Power Authority (WAPA). The plan was to obtain 5 MW of OTEC-produced electricity and 1.5 million gallons/day of desalinated water from a land-based, closed cycle OTEC plant. Additionally, various mariculture industries were planned. The project did not come to fruition.

Abbreviations and Acronyms

10^3	kilo (k)
10^6	mega (M)
10^9	giga (G)
10^{12}	tera (T)
10^{15}	peta (P)
10^{18}	exa (E)
10^{21}	zetta (Z)
ABWR	advanced boiling water reactor
AC	alternating current
AHWR	advanced heavy water reactor
API	American Petroleum Institute
APR	advanced pressurised reactor
APWR	advanced pressurised water reactor
b/d	barrels per day
bbl	barrel
bcf	billion cubic feet
bcm	billion cubic metres
BGR	Bundesanstalt für Geowissenschaften und Rohstoffe
billion	10^9
BIPV	building integrated PV
BNPP	buoyant nuclear power plant
boe	barrel of oil equivalent
BOO	build, own, operate
BOT	build, operate, transfer
bpsd	barrels per stream-day
bscf	billion standard cubic feet
Btu	British thermal unit
BWR	boiling light-water-cooled and moderated reactor
C	Celsius
CBM	coal-bed methane
cf	cubic feet
CHP	combined heat and power
CIS	Commonwealth of Independent States
cm	centimetre
CMM	coal mine methane
CNG	compressed natural gas
CO_{2e}	carbon dioxide equivalent
COP3	Conference of the Parties III, Kyoto 1997
cP	centipoise

CSP	centralised solar power
d	day
DC	direct current
DHW	domestic hot water
DOWA	deep ocean water applications
ECE	Economic Commission for Europe
EIA	U.S. Energy Information Administration / environmental impact assessment
EOR	enhanced oil recovery
EPIA	European Photovoltaic Industry Association
EPR	European pressurised water reactor
ESTIF	European Solar Thermal Industry Federation
ETBE	ethyl tertiary butyl ether
F	Fahrenheit
FAO	UN Food and Agriculture Organization
FBR	fast breeder reactor
FID	final investment decision
FSU	former Soviet Union
ft	feet
g	gram
gC	grams carbon
GEF	Global Environment Facility
GHG	greenhouse gas
GTL	gas to liquids
GTW	gas to wire
GW_e	gigawatt electricity
GWh	gigawatt hour
h	hour
ha	hectare
HDR	hot dry rocks
hm^3	cubic hectometre
HPP	hydro power plant
HTR	high temperature reactor
Hz	hertz
IAEA	International Atomic Energy Agency
IBRD	International Bank for Reconstruction and Development
IEA	International Energy Agency
IIASA	International Institute for Applied Systems Analysis

IMF	International Monetary Fund
IMO	International Maritime Organization
IPP	independent power producer
IPS	International Peat Society
J	joule
kcal	kilocalorie
kg	kilogram
km	kilometre
km^2	square kilometre
kPa	kilopascal
ktoe	thousand tonnes of oil equivalent
kV	kilovolt
kW_e	kilowatt electricity
kWh	kilowatt hour
kW_p	kilowatt peak
kW_t	kilowatt thermal
lb	pound (weight)
LNG	liquefied natural gas
LPG	liquefied petroleum gas
l/s	litres per second
l/t	litres per tonne
LWGR	light-water-cooled, graphite-moderated reactor
LWR	light water reactor
m	metre
m/s	metres per second
m^2	square metre
m^3	cubic metre
mb	millibar
Mcal	megacalorie
MJ	Megajoule
Ml	megalitre
mm	millimetre
MOU	memorandum of understanding
MPa	megapascal
mPa s	millipascal second
MSW	municipal solid waste
mt	million tonnes
mtpa	million tonnes per annum
mtoe	million tonnes of oil equivalent

MW	megawatt
MW_e	megawatt electricity
MWh	megawatt hour
MW_p	megawatt peak
MW_t	megawatt thermal
N	negligible
NEA	Nuclear Energy Agency
NGLs	natural gas liquids
NGO	non governmental organisation
Nm^3	normal cubic metre
NPP	nuclear power plant / net primary productivity
OAPEC	Organization of Arab Petroleum Exporting Countries
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
OTEC	ocean thermal energy conversion
OWC	oscillating water column
p.a.	per annum
PBMR	pebble bed modular reactor
PDO	plan for development and operation
PFBR	prototype fast breeder reactor
PHWR	pressurised heavy-water-moderated and cooled reactor
ppm	parts per million
ppmv	parts per million by volume
psia	pounds per square inch, absolute
PV	photovoltaic
PWR	pressurised light-water-moderated and cooled reactor
RBMK	reaktor bolchoi mochtchnosti kanalni
R&D	research and development
RD&D	research, development and demonstration
R/P	reserves/production
rpm	revolutions per minute
SER	Survey of Energy Resources
SHS	solar home system
SWH	solar water heating
t	tonne (metric ton)
tb/d	thousand barrels per day

tC	tonnes carbon
tce	tonne of coal equivalent
tcf	trillion cubic feet
tcm	trillion cubic metres
toe	tonne of oil equivalent
tpa	tonnes per annum
TPP	tidal power plant
tpsd	tonnes per stream day
tscf	trillion standard cubic feet
trillion	10^{12}
ttoe	thousand tonnes of oil equivalent
tU	tonnes of uranium
TWh	terawatt hour
U	uranium
U_3O_8	uranium oxide
UN	United Nations
UNDP	United Nations Development Programme
vol	volume
W	watt
WEC	World Energy Council
W_p	watts peak
WPP	wind power plant
wt	weight
WTO	World Trade Organization
WWER	water-cooled water-moderated power reactor
yr	year
—	unknown or zero
~	approximately
<	less than
>	greater than
≥	greater than or equal to

Conversion Factors and Energy Equivalents

Basic Energy Units

1 joule (J) = 0.2388 cal

1 calorie (cal) = 4.1868 J

(1 British thermal unit [Btu] = 1.055 kJ = 0.252 kcal)

WEC Standard Energy Units

1 tonne of oil equivalent (toe) = 42 GJ (net calorific value) = 10 034 Mcal

1 tonne of coal equivalent (tce) = 29.3 GJ (net calorific value) = 7 000 Mcal

Note: the tonne of oil equivalent currently employed by the International Energy Agency and the United Nations Statistics Division is defined as 10^7 kilocalories, net calorific value (equivalent to 41.868 GJ).

Volumetric Equivalents

1 barrel = 42 US gallons = approx. 159 litres
1 cubic metre = 35.315 cubic feet = 6.2898 barrels

Electricity

1 kWh of electricity output = 3.6 MJ = approx. 860 kcal

Representative Average Conversion Factors

1 tonne of crude oil = approx. 7.3 barrels

1 tonne of natural gas liquids = 45 GJ (net calorific value)

1 000 standard cubic metres of natural gas = 36 GJ (net calorific value)

1 tonne of uranium (light-water reactors, open cycle) = 10 000–16 000 toe

1 tonne of peat = 0.2275 toe

1 tonne of fuel wood = 0.3215 toe

1 kWh (primary energy equivalent) = 9.36 MJ = approx. 2 236 Mcal

Note: actual values vary by country and over time.

Because of rounding, some totals may not agree exactly with the sum of their component parts.

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