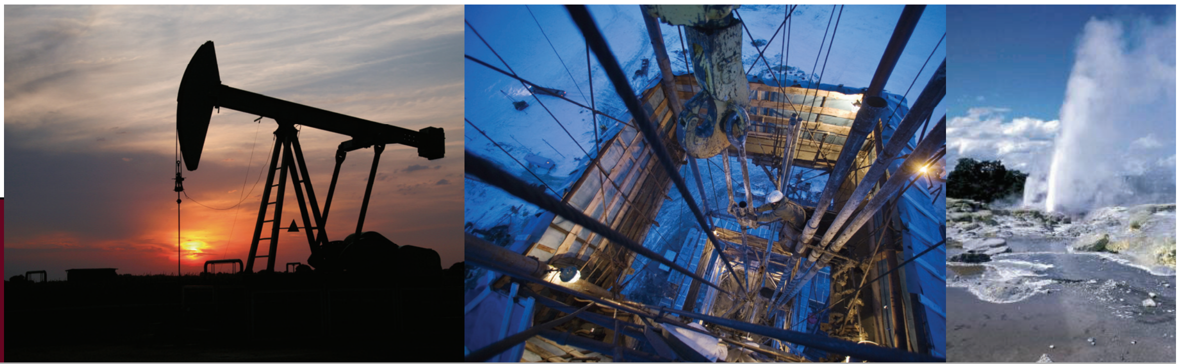
ENERGY RESOURCES 2009



Reserves, Resources, Availability

Crude Oil
Natural Gas
Coal
Nuclear Fuels
Geothermal Energy

BGR

Energy Resources 2009

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Crude Oil, Natural Gas, Coal, Nuclear Fuels, Geothermal Energy

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Preface by the President of the BGR

Germany is an energy dependant country. The industrial revolution in Germany relied as early as in the middle of the 19th century on energy from hard coal. Also the first oil discoveries in our country can be dated back to that time: When, in the year 1859, Prof. Georg Hunäus searched for coal in Wietze north of Hannover, one borehole struck oil at a depth of 36 m. Therefore, today, in the year 2009, we celebrate 150 years of oil in Germany! For a start, in this country the big oil boom failed to appear. Not before the end of World War II domestic crude oil and natural gas became important components of our energy supply and have remained so to this day.

Presently, Germany is world leader in the usage of soft brown coal, concerning the quantity of produced lignite as well as power plant technology. Germany holds a cutting-edge position in the development of the environmentally and climate friendly CCS technology (CCS, *Carbon Capture and Storage*) which focuses on the minimizing of carbon dioxide emissions, especially in coal-based power generation.

By now, renewable energy sources are inseparable components of our energy mix and they will gain further importance. For the Federal Institute for Geosciences and Natural Resources (BGR) the use of geothermal energy is of special importance. Here, one-borehole concepts, like they are just being tested with the pilot project GeneSys in the Geozentrum Hannover could lead to a breakthrough for the broad use of deep geothermal energy.

Also in the future, energy will define our economy and our lives altogether. During the past decades, growing energy demand and the increasing exhaustion of the domestic reserves of crude oil and natural gas have turned Germany more and more into an import country for energy resources. This development was accompanied, especially in recent years, by major fluctuations in energy resource prices and increasing technological effort for the development of new fields and the production of crude oil and natural gas.

In this situation, there is an urgent need for research and development: possible future reserves of energy resources have to be explored and innovative technologies for the exploration and development of the new deposits have to be worked out. Here, the BGR is acting prior to industrial activities, especially in the exploration of the energy resource potential of so far hardly noticed regions like the deep-water areas of the oceans.

Also in the coming years, fossil fuels will bear the major burden of the energy supply. Therefore, basic information on the worldwide situation of reserves, resources and availability is absolutely essential for the orientation of Germany's future energy supply. With the present study, BGR presents on behalf of the Federal Ministry for Economy and Technology an analysis of the status quo and of future developments in the field of energy resources.

Prof. Dr. Hans-Joachim Kümpel

President of the BGR

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1 The Availability of Energy Resources – An Overview

In this study reserves, resources, output, and consumption of the energy resources oil, natural gas, coal, nuclear fuel as well as geothermal energy are globally analyzed and evaluated in a regional context by year end 2007. Thus, this is the first time after the study based on the year 2002 (BGR, 2003, data status at the end of 2001) that the BGR gathers, collects and evaluates the global energy resource situation in detail. The period after the publication of the last study has been characterized in particular by significant increases of the prices for raw materials, which has also resulted in an increased perception of the subject raw materials in politics and the general public.

The **reserves** of non-renewable energy resources corresponded to approximately 38 700 EJ in total (Tab. 1.1) at the end of 2007. The increase of 2220 EJ in comparison to 2001 was particularly due to increases of soft brown coal and the conventional hydrocarbons, crude oil and natural gas.

Coal is still the dominant energy resource as measured by its recoverable energy content. Its proportion of the reserves of all non-renewable energy resources is approximately 55 % (Fig. 1.1). Crude oil with nearly 23 % (conventional and unconventional with 17 % and 6 %, respectively) ranks second. Natural gas follows at nearly 19 %, the nuclear fuels add up to app. 4 %.

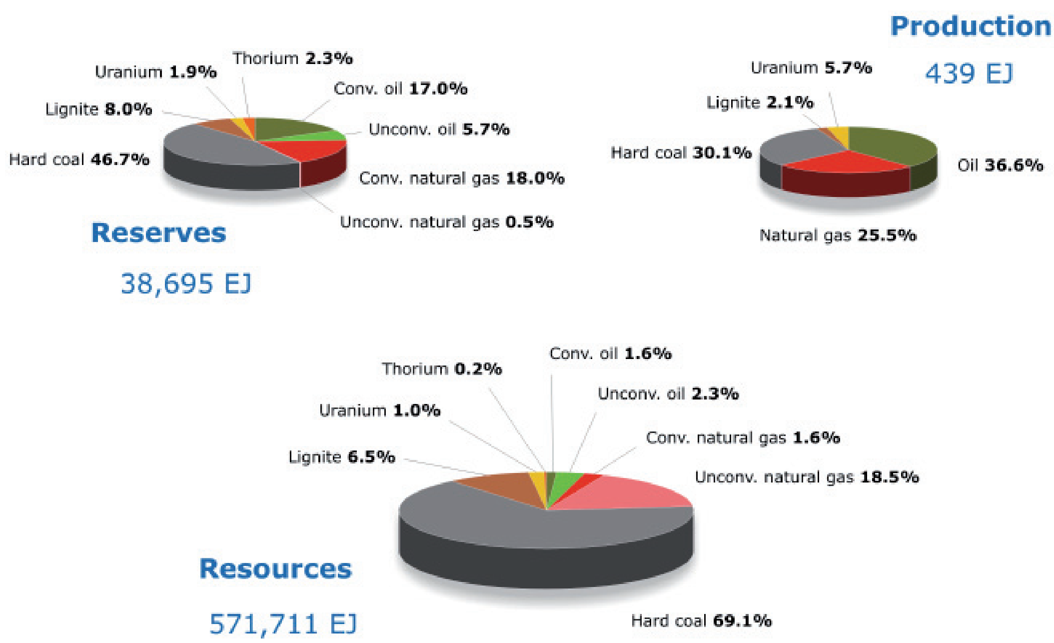


Figure 1.1: Annual production, reserves and resources of the individual non-renewable fuels in 2007.

The resources of the non-renewable energy resources were estimated at approximately 571 700 EJ (Tab. 1.1) by the end of 2007. There is a significant increase by approximately one-and-a half times in comparison to 2001. This is due to a different assessment of coal, to the hitherto not considered resources and unconventional natural gas deposits in tight reservoirs and coalbed methane.

Table 1.1: Reserves and resources of non-renewable fuels at the end of 2007 in the common unit for the individual fuels (left column each) and in EJ (right column each).

Fuels	Unit of measurement	Reserves (dimension see left column)	Reserves EJ	Resources (dimension see left column)	Resources EJ
Crude oil	Gt	157	6 575	92	3 829
Natural gas	Tcm	183	6 947	239	9 098
Conventional hydrocarbons	Gtoe	323	13 522	309	12 927
Oil sand / extra heavy oil	Gt	52	2 183	190	7 918
Oil shale	Gt	-	-	119	4 970
Unconventional oil	Gtoe	52	2 183	309	12 919
Tight reservoir	Tcm	3	103	666[6)]	25 312
Coal bed methane	Tcm	2	82	254[6)]	9 652
Aquifer gas	Tcm	-	-	800	30 400
Gas hydrates	Tcm	-	-	1 000	38 000
Unconventional natural gas	Tcm	5	184	2 720	103 364
Unconventional hydrocarbons	Gtoe	57	2 369	2 779	116 210
Hydrocarbons total	Gtoe	280	15 889	3 088	129 210
Hard coal	Gtce	616	18 060	13 195	386 718
Soft brown coal	Gtce	106	3 113	1 671	48 977
Coal total	Gtce	722	21 173	14 866	435 695
Fossil fuels total			37 062		564 905
Uranium[1)]	Mt U	2[2)]	725[2)]	6[3)]	2 654[3)]
				8[4)]	3 188[4)]
Thorium[5)]	Mt Th	2	908	2	964
Nuclear fuel total			1 633		6 806
Non-renewable fuels total*			38 695		571 711

Totals can differ due to rounding

1) 1 t U = 14 000 – 23 000 tce, lower value used or 1 t U = 0,5 x 10^{15} J
2) RAR recoverable up to USD 40/kg U
3) Sum of RAR producible from USD 40-130/kg U and IR
4) Speculative resources
5) 1 t Thorium used the same tce-value as for 1 t U
6) in-situ amount

In relation to the energy content, the dominant position of coal amongst the resources at a proportion of about 76 % is even more significant than for the reserves. At nearly 20 % the aggregated resources of conventional and unconventional natural gas range second, at 1.6 % and 18.1 % respectively. Crude oil follows at 3 % ahead of nuclear fuel at a little more than 1 %.

For the **production** of non-renewable energy resources a significant increase was observed, from 335 EJ in the year 2001 to 439 EJ in 2007. This increase was reported for all energy resources, but especially for hard coal, the production of which increased from 82 to 124 EJ/a. With the exception of Europe, all regions showed increases in production. In Austral-Asia these were particularly high, because of hard coal, with an increase from 71 to 124 EJ/a. Major increases also occurred in the CIS and in the Middle East.

The **consumption** of non-renewable fuels also underwent a significant increase from 346 to 451 EJ/a. With the exception of uranium, the consumption increased for all resources, in particular for coal from 94 to 145 EJ/a. Increases were noted in all regions. The consumption in Austral-Asia increased from 98 to 191 EJ/a. The proportion of the OECD was significantly lowered from 63 to 50 %.

If the global annual production of all energy resources in total for 2007 at 439 EJ, the reserves at 38 700 EJ and the resources at 571 700 EJ are compared, a ratio of approximately 1 : 90 : 1300 results. The global reserves of energy resources with the exception of conventional oil can thus ensure a sufficient cover of the energy demand.

Based on the analysis of the data, the following key statements result for the individual energy resources:

The use of **geothermal energy** has developed rapidly over the past years. Globally, the power generation rates for geothermal energy have increased nearly linearly by 200 to 250 MW_e annually since 1980. The direct use of heat increased simultaneously even out of proportion due to the massive growth of local heating systems with heat pumps. In 2005 the worldwide existing geothermal systems had an installed capacity of 27 825 MW_{th} of thermal energy and 8933 MW_e of electrical energy. At an installed capacity of 2504 MW_e for power generation and 7817 MW_{th} for the direct use of heat, the US stand out from the other countries as largest user of geothermal energy world-wide.

The exploitation of geothermal energy by development schemes for regenerative energies and for the reduction of CO_2 emissions will continue to increase considerably, not only in Germany but also in other countries such as the USA, Australia and Kenya.

Regarding the supply with **nuclear fuel**, from a geological point of view no shortage is to be expected in the foreseeable future. All over the world increasing reserves and resources are noted. The concentration of the global output as well as the known reserves and resources in a few countries continue unabatedly. In 2007, only seven mining companies produced 85 % of the global production. Here, the production occurs in politically stable countries with inexpensive deposits. The upturn of the market resulted in a significantly increased growth of the exploration activity in the past few years, even in countries without prior production. Thus, in future a higher degree of diversification of the producing countries is to be expected.

The gap between the annual production and the consumption continues to exist. As before, the additional demand for uranium is being satisfied from civil stock previously amassed, and from strategic stock. After massive increases in prices in the past years, ever since 2007 an adaptation of the markets concerning the spot market prices has started with a simultaneous increase of the prices for long-term supply contracts. In spite of the current crisis affecting the financial markets all over the world, the market prices are above those before 2006. All over the world, a number of countries has announced the construction of new power plants for the coming decade. These projects are frequently coupled with the development of alternative and more efficient technologies, also using Thorium.

Coal is the energy resource with the greatest geological availability. Soft brown and hard coal together have the greatest potential of all non-renewable energy resources at a percentage of about 55 % (722 trillion tce) of the reserves and about 76 % (14 866 trillion tce) of the resources. This is sufficient to satisfy the foreseeable demand for many decades. Coal ranks second after crude oil amongst the non-renewable energy resources with a global PEV-percentage of about 30 % (hard coal 28 %, soft brown coal about 2 %) as far as consumption is concerned. For the global power generation (gross), coal was the most important energy resource at a percentage of 40 % (7620 TWh) in 2006 (IEA, 2008a). Due to its widespread and plentiful occurrences it is regarded as a most important element of security of supply in the energy resource sector.

Just like its predecessors, the Annual Reports of the BGR of the preceding years, this study also documents an increase in resources. In future, further changes in reserves as well as in resources have to be taken into account, as the high price of coal in the past years has caused a noticeable extension of the exploration and also developing activities.

The results of the currently conducted pilot project for the reduction of CO_2-emissions such as carbon capture and storage (CCS), in particular for the power generation from coal, will influence decision which role the immense supply of coal will play in future in the global energy supply. In addition, coal could moderate possible future bottlenecks in oil supply by means of coal liquefaction.

Natural gas has sufficient potential to take over the part of a bridging energy carrier towards renewable energies for the next decades. Traditional reserves of natural gas show a strong regional concentration. Thus, the three leading countries possessing most of the natural gas, Russia, Iran and Qatar harbor more than half of the reserves. The high specific transportation costs of natural gas are disadvantageous in comparison to crude oil and coal.

The proportion of liquefied natural gas (LNG) in transportation will continue to rise. Owing to long-term obligations of delivery and regional markets for natural gas, no dominant world market comparable to crude oil will develop.

Unconventional natural gas, in particular natural gas from tight reservoirs gas, shale gas and coal bed natural gas will assume greater importance in satisfying the demand for tight gas. The production of natural gas from gas hydrate is still in the testing stage.

Crude Oil is the most important energy resource and will remain so in future. Based on the current degree of depletion of the reserves, conventional oil will not be available in the foreseeable future at the previous amounts.

Based on the existing general requirements of the oil market for an optimum use of the reserves and resources, the global maximum of the production of conventional crude oil will be reached around 2020. If, in addition, increases in reserves from producing deposits and the possible production of oil from oil sands are taken into account, based on the mentioned prerequisites, an increase of the production until 2035 is possible (Fig. 1.2). According to the projections conducted in the course of this study, the future production of oil will not exceed 4.7 Gt per year. Just as for natural gas, the remaining reserves are increasingly concentrated in the strategic ellipse. National state-owned oil companies are increasingly forcing international trusts into the background, where access to the reserves and production are concerned.

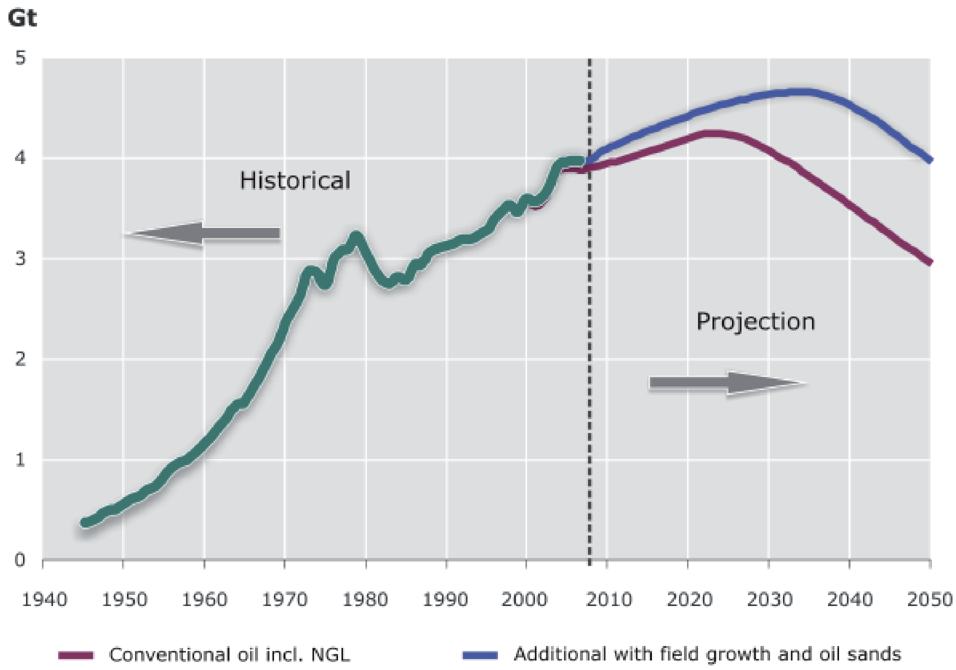


Figure 1.2: Historic development of oil production and projected course of production for conventional oil including condensate (NGL) and additionally taking into account the oil sand production and increases in reserves (Field Growth).

Unconventional oil, in particular from oil sands, shall play an increasingly important part in the future. The expected maximum in production for oil, however, cannot be delayed for long. Significant additional oil - but also potential for natural gas is expected in the frontier areas of the Arctic and the deep-water areas of the edges of the continents. In particular, due to the more effective oil recovery of producing fields, additional increases in reserves will occur.

The particular situation of oil is also demonstrated by the synopsis of reserves and resources of the non-renewable energy resources (Fig. 1.3). This impression is even further intensified in comparison with the cumulative consumption in the period from 2008 to 2030 in accordance with the reference scenario of the IEA (2008b). Whereas coal has the greatest potential by far, a still relaxed image emerges for natural gas and uranium. Crude oil is the energy resource, whose deposits have been depleted most on a global scale.

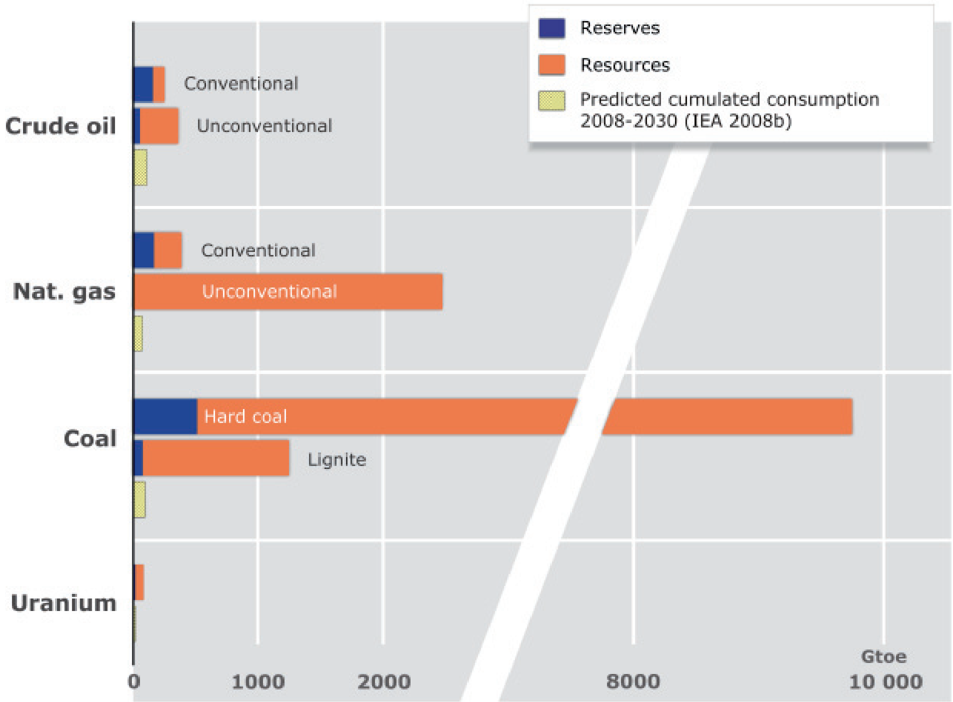


Figure 1.3: Supply situation (reserves and resources) of non-renewable energy resources in comparison with a demand scenario by the IEA (2008) to 2030.

1.1 References on the Availability of Energy resources - An Overview

BGR (Bundesanstalt für Geowissenschaften und Rohstoffe) (2003): Rohstoffwirtschaftliche Länderstudien XXVII: Reserven, Ressourcen und Verfügbarkeit von Energierohstoffen 2002. – 426 p; Hannover.

IEA (International Energy Agency) (2008a): Electricity Information 2008. – 760 p; Paris.

— (2008b): World Energy Outlook 2008. – 569 p; Paris.

2 Energy Resources — Definitions and Classifications

2.1 Energy Resources of the Earth

Non-renewable energy resources include the fossil energy resources **oil**, **natural gas** and **coal** as well as the **nuclear fuels uranium** and **thorium**. The total sum of these energy resources constitutes the backbone of the global energy supply at a percentage of 87 % of the total primary energy supply in 2006 (Fig. 2.1).

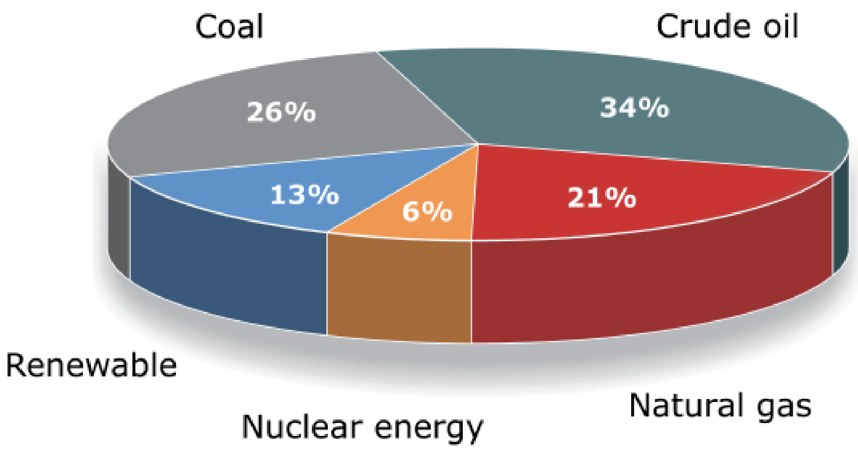


Figure 2.1: Proportion of the individual energy resources on the total primary energy supply in 2006 worldwide (IEA, 2008).

The energy resources are widespread as natural resources and occur in great amounts and in varied form in the earth crust.

Crude oil, natural gas and coal are remains of organic life forms, differing according to their origins: During certain geological conditions in the course of the Earth's history, large amounts of dead organic material were incorporated into sediments. These rocks enriched in organic material sunk into deeper and hotter zones of the earth crust due to geological processes. During these processes, the dead organic material continuously kept changing due to the high temperatures. The different stages of the so-called coalification are representative of this change: Anthracite coal as fossil organic material has been submerged deeper in its geological history and was thus exposed to higher temperatures than lignite. In the course of this conversion of organic material, hydrocarbon molecules have also developed, which migrate into the cavities and pores of the rock. Depending on the kind of the hydrocarbon molecule and on the pressure and temperature of the individual rock, these mixtures of hydrocarbon occur either as a liquid – crude oil - or as a gas - natural gas.

The nuclear fuels uranium and thorium are also natural components of the rock of the earth crust. Due to natural radioactive decay, they continuously generate energy in form of heat in the rock. The fact that the earth's temperature rises with increasing depth can about half be attributed to the radioactive decay of these substances.

There are considerable amounts of thermal energy present inside the earth. This geothermal energy exceeds the usable energy from non-renewable energy resources many times over. Even if its proportion in the global energy extraction is still minimal, this study will treat geothermal energy as geogenic source of energy. Geothermal energy is generally considered as a renewable energy and differs from oil, natural gas, coal and the nuclear fuels in that no primary production of raw materials in the sense of mining precedes. Thus, there is no material aspect in geothermal energy in the original sense of the word. This involves specific technical features of production and technical use of geothermal energy (Chapter 7). In this respect, geothermal energy maintains a special status in the following explanations, which also becomes apparent in a deviating classification of deposits (Chapter 2.5).

2.2 From the Occurrence of Energy Resources to Mineral Deposits

Only few occurrences of energy resources are economically exploitable. If the resource is present in sufficient concentration, the recoverability of a known occurrence is possible, if it is technically feasible to develop the occurrence, if the production is economically profitable and if there are no other higher-level reasons, e.g. social or economic considerations, which argue against the usage. Occurrences which can be exploited under these conditions are called deposits.

In view of the types of the energy resource occurrences, of the economically usable amounts of resources, of the technical feasibility of production and also of the security of supply of energy resources, a number of terms such as availability, reserves and resources, reach, conventional and non-conventional resources have been formed. These terms can be used to designate different aspects of the availability of the energy resources. They are omnipresent in professional circles as well as in the general language use. There is not, however, a definition that has been recognized either globally or even only for a branch of an industry. The terms shall be defined below to make this study more easily comprehensible. Individual energy resources are also classified this way.

2.3 Classification of Energy Resources by Types

For crude oil, natural gas and uranium a subdivision into **conventional and unconventional occurrences** is standard. For oil and natural gas, conventional occurrences are the ones for which a production based on classic exploration, production and transport methods is possible. In view of these classic methods, flowing oil and freely flowing natural gas can be used. According to this soft definition, the development and use of unconventional occurrences requires alternative technologies. Aspects of economic efficiency and the fact, whether the individual deposit is already used for production, are not considered for this definition. A classification of the energy resources in this sense has been depicted in Figure 2.2. For coal, a subdivision into conventional and unconventional occurrences is not customary (Chapter 2.3.3).

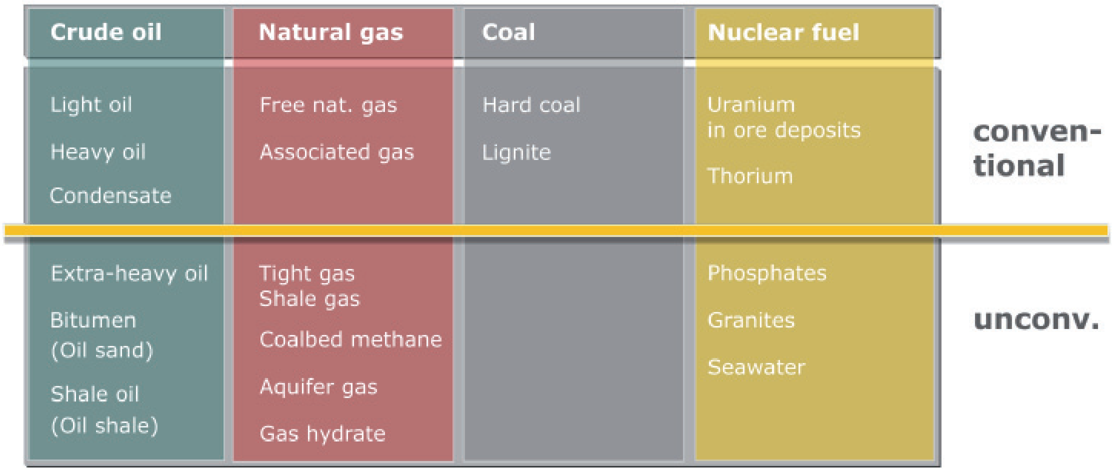


Figure 2.2: Classification of the non-renewable energy resources.

2.3.1 Conventional and Unconventional Oil

Oil is subdivided into conventional occurrences together with liquid hydrocarbons, the so-called natural gas liquids (NGL), which are extracted in the course of the production of natural gas such as condensate or liquefied gas, as well as heavy oil. Among unconventional oil, extra heavy oil is numbered, which is barely capable of flowing due to its high viscosity as well as bonded oil in oil sands and oil shale. This way, conventional oil can also be defined physically, based on density: Oil with a density of less than 1.0 g/cm³ (or greater 10°API) belongs to conventional oil (Fig. 2.3).

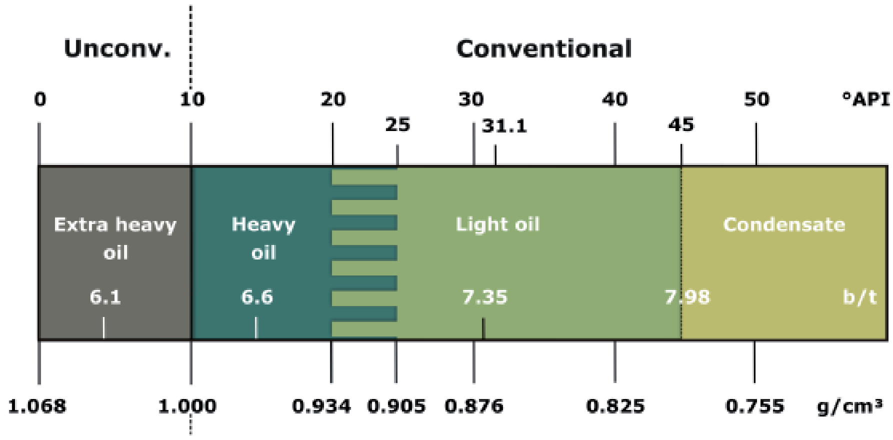


Figure 2.3: Classification of crude oil according to its density.

Different classifications for oil include aspects of the conditions of the incidence of the occurrences. Some authors designate offshore-occurrences, occurrences below a certain depth of water or in certain regions as unconventional. Campbell (1997, 2002, 2006) includes offshore-oil in water depth greater than 500 m (deep water) and oil in arctic regions as well as condensate in spite of the above-mentioned conventional technologies for production among unconventional oil. This procedure excludes occurrences of crude oil, for which the assessment of resources is still rather difficult, from scenarios of future availability of oil. As a consequence the global reserves and resources (Chapter 2.4) of conventional oil are considerably underestimated.

Other authors, such as Schollnberger (1998) include all crude oils amongst conventional oil, which can be economically produced, independently of their physical properties, the type of the occurrences and the technology necessary for production. This definition is based on the perception that consumer are mainly interested in the price of the energy resource. This subdivision between conventional and unconventional is, however, very close to the one described in Chapter 2.4.2 into reserves and resources and is thus not recommended. Oil statistics are also inconsistent where the terms conventional and unconventional are concerned. Some countries report amounts of reserves including unconventional occurrences, for most countries the production data contain unconventional oil.

2.3.2 Conventional and Unconventional Natural Gas

Just as for oil, occurrences of natural gas are usually called conventional if exploitation using classic production technologies is possible. According to Figure 2.2, this includes free gas in natural gas deposits or gas condensate deposits as well as associated gas, which is dissolved in oil accumulations.

Unconventional natural gas does not flow in sufficient amounts towards a production well without further technical measures, as it either does not occur in free gas-phase in the rock or as the reservoir rock is not sufficiently permeable. These unconventional occurrences of natural gas comprise shale gas, tight gas, coalbed methane, aquifer gas and gas hydrate.

For shale gas and tight gas, the permeability of the reservoir rock is very small. For the production of natural gas from tight rocks, technical measures have to create pathways in the reservoir rock. Therefore, the rock is broken up (fractured) via drill holes applying high hydraulic pressure.

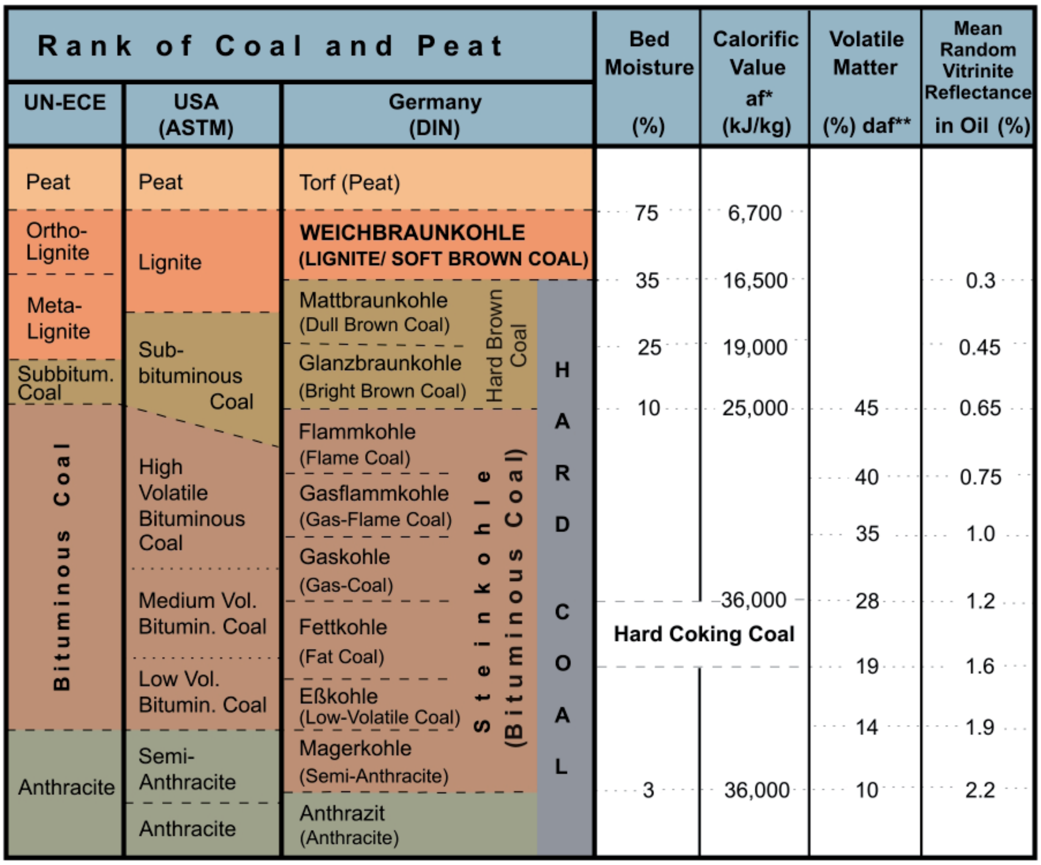
Coalbed methane, CBM, is natural gas which occurs in coal bearing basins in coal seams in absorbed form or in micro-fissures and micropores. It is also extracted through drill holes and the influx is stimulated by cracking open the coal seams using artificial fractures.

Aquifer gas is the term for natural gas that is dissolved and dispersed in the groundwater and can be released by pressure relief, when the water is brought to the earth’s surface.

Gas hydrate is an ice-like, solid bonding of methane and water, which can develop at low temperature and high-pressure conditions (stability zone). Gas hydrate occurs in polar permafrost areas and in certain water depths at the continental margins of the oceans.

2.3.3 Classification of Coal

A subdivision of coal deposits into conventional and unconventional occurrences is not customary. Several of the coal producing countries also have their own classification of coal. This complicates the comparability of the different types of coal and the associated different classifications into classes of resources (BGR, 2003). Important distinctive features of coal deposits used for classification refer to physical properties of coal such as the energy content (calorific value) and the vitrinite reflectance as well as to the chemical composition using parameters such as the moisture content (bed moisture) or the proportion of volatile matters (Fig. 2.4).



UN-ECE: Ortho-Lignite max. 15,000 kJ/kg
Meta-Lignite max. 20,000 kJ/kg
Subbituminous Coal max. 24,000 kJ/kg
Bituminous Coal max. mean random vitrinite reflectance of 2 %

USA: Lignite max. 19,300 kJ/kg

* af = ash-free, daf** = dry, ash-free

Figure 2.4: Comparison of the BGR-coal-classification with the systems of the UN-ECE (in-seam coals) and the USA.

In the German-speaking area, the types of lignite are generally distinguished according to their moisture content and the associated strength and color. In contrast, the types of hard coal as well as anthracite have been classified according to their proportion of volatile matters and energy content as well as in accordance with the composition of the so-called coking residues (Pohl, 1992).

The BGR lists the coal reserves and coal resources divided into lignite and hard coals in their studies of energy resources (Fig. 2.4). All coals with an energy content of less than 16 500 kJ/kg are allocated to lignite; all coals with an energy content above 16 500 kJ/kg are considered hard coals. As internationally no delimitation between hard coal and lignite has been established, the combination of resource data from different countries can cause allocation problems. The World Energy Council (WEC) subdivided in its coal classification bituminous coal including anthracite, sub-bituminous coal and lignite. Exact limit values for the classification of coals have not been specified by the WEC. The WEC reasons that there is no universally accepted system for the classification of coals. Thus, the allocations to these three coal groups may differ from one country to another and in particular the data relating to the sub-bituminous coals cover bituminous coals and also lignite in a number of countries (WEC, 2004).

2.3.4 Conventional and Unconventional Uranium

Uranium deposits are called conventional, if they have a traceable production history, for which uranium is the main product or a major by-product. Uranium enrichments in rocks can be based on very different geological processes. This results in numerous types of conventional uranium deposits (Chapter 6.1.1). Occurrences with low contents, where uranium is only recoverable as a minor by-product or only in very low concentration are considered unconventional deposits accordingly (Fig. 2.2). These unconventional occurrences consist of seawater, granite, phosphorite and black shale.

2.4 Reserve Classification of the Energy Resources

2.4.1 The Quantification of Resources

Occurrences of oil, natural gas, coal, uranium and thorium as components of the earth crust elude, in general, the direct observation. Large areas of the earth, such as great parts of the Arctic or the deep-water areas of the continental margins have been little explored, thus statements concerning possible deposits of resources are based on arbitrary observations or assumptions. The actual amounts of energy resources in the earth's crust are hence presently not known.

It is also impossible to specify, with satisfactory accuracy, the extent of the **usable** amounts of energy resources of the earth. Information about enrichments of these resources can be gathered for known occurrences from conclusions from observations at the surface of the earth, from spot-wise information of drill holes, by mining or by indirect exploration, such as the seismic sound transmission through the underground. In the course of the development and during production of a deposit, geological data and production data are collected continuously. This information has to be interpreted geo-scientifically to obtain an assessment of the actually recoverable amount of the reserves in the deposit. But usually it is not possible to estimate the exact volume of the deposit and the quality of the energy resource.

Even at the time the production at a deposit is terminated, it is often not known, how much of the resource remains in the ground, because only in very rare cases a deposit is completely depleted when the production is ceased. Thus, production is ceased, when the operating company or the consortium decides to stop further investments in the expansion and the continued production of this deposit and the remaining production is no longer sufficiently profitable. Reasons for such decisions are frequently of a geological or technical kind, but can also be due to the changing political and economic conditions. In the global average, for instance, the production of oil deposits is stopped after about a third of the originally existing oil in-place has been extracted; two thirds remain in the reservoir. With increasing production of oil reservoirs, the proportion of produced water increases and the pressure gererally decreases. Even if large amounts of oil remain in the reservoir, production will become uneconomical at a certain point.

Information concerning the amount of the producible and usable resources thus always depends on the geological conditions of the deposits, the state of the scientific and technical knowledge, the technological potential of the development and production as well as on the economic and political requirements. Correspondingly, the intentions and methods to assess the amounts of energy resources vary.

Companies producing resources are interested in data that are as accurate as possible concerning the contents of their individual deposits and conduct the evaluation of the deposit contents with high accuracy. These data constitute the base of the business for these companies and significantly influence their investment decisions. Ultimately, the resource volumes are estimated in accordance with the individual data status for every individual reservoir. To what extent the information shall be made available to the public depends on the legislation and the habits of the company and of the corresponding country.

Economic and energy policy also need numbers relating to supplies of energy resources as planning basis. A direct relation to individual petroleum deposits is frequently not necessary; statistics are prepared for producing areas, countries or continents. These statistics, for instance, are gathered by national geological services or by international organizations, such as the IEA. There is one general distinction that applies to all resource statistics, the one between those resource amounts, whose exploitation is regarded as proven (reserves) and those resources, whose existence is only assumed or whose production is currently not assumed possible (resources).

2.4.2 BGR-Definition of Reserves

Reserves are those amounts of energy resources, which have been accurately recorded and which can be economically extracted using the current technical possibilities.

Synonymously used expressions are recoverable (coal) as well as proved recoverable amounts/resources. The definition mentioned above means that the amount of reserves depends on the level of knowledge about the deposit, on the commodity prices and the present state of the technology. This dependence on the price is particularly pronounced for uranium, the only energy resource whose reserves and resources have been for a long time subdivided in accordance with the production costs. For uranium the BGR equals reserves in the sense of the above-mentioned definition with production costs for secure reserves of less than USD 40/kg in accordance with the definition of NEA and IAEA.

Resources are those amounts of an energy resource, which have been geologically proven, but which cannot be extracted economically at that time and the amounts, which have not been proven, but which can be expected for geological reasons in the area concerned.

Only the expected and potentially economically extractable amounts of the resources of oil, natural gas and uranium have been taken into account. For coal these are, generally, in-situ amounts, i.e. the total amounts independent of their recoverability.

The **estimated ultimate recovery** (EUR) is the total extractable amount for hydrocarbons, i.e. the sum of the amounts extracted up to now, plus the reserves and the resources.

The **remaining potential** is the still extractable amount of energy resources, i.e. the sum of the reserves and resources. For coal and uranium the term “total resources” has been used as a synonym. It has to be noted that reserves are not part of the resources.

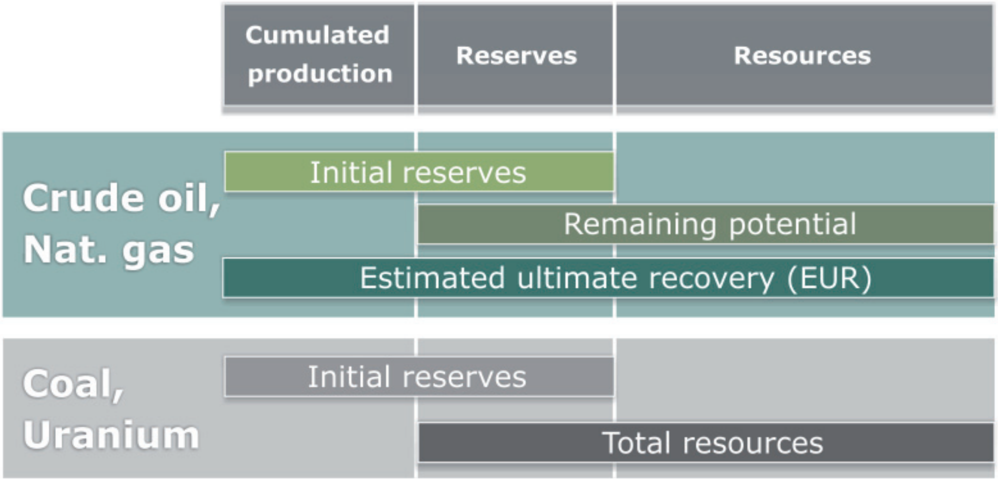


Figure 2.5: Reserve classification of the energy resources

The **initial reserves** are the total hitherto proven reserves of energy resources, i.e. the sum of the hitherto produced total amounts and the reserves known today. Figure 2.5 provides an overview over the delimitation of the reserve/resource terms for the energy resources. Besides this BGR-definition, there is a great number of different classifications, depending on the resource and the country, the most important of these shall be dealt with below.

2.4.3 Other Classification Systems for Energy Resources

Crude oil and natural gas
The Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) compared a number of different common national and international classification systems for oil and natural gas in 2005 (SPE, 2005). These comprise three different views: The rules issued by stock exchange supervision such as the United States Securities and Exchange Commission (SEC) contained definitions for secure reserves up to now. In 2009 the SEC started to include probable and possible reserves as well. Government institutions such as the Norwegian Petroleum Directorate (NPD) cover the complete spectrum of the reserves and resources referring to the specifications of their own countries. The United Nations Framework Classification (UNFC) and the classification of the SPE/WPC/AAPG/SEEC (World Petroleum Congress, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers) can be regarded as the only worldwide standards with universal applicability.

For the purposes of the BGR, i.e. a worldwide registration of the reserves/resouces, the third category is of particular importance. The SPE/WPC/AAPG/SEEC-classification developed historically from different classifications, which have been created amongst others by the WPC and in parallel by the SPE and which have successively been combined to a joint classification, the Petroleum Resource Management System (PRMS), starting in 1990. The latest version of this system was published in 2007 by the two organizations together with the AAPG and the SEEC as joint classification system (SPE, 2007). The PRMS is the most common system in the oil industry. It comprises the complete spectrum, from reserves to resources. Important parameters for the subdivision of reserves and resources are the economic efficiency of the exploitation of a deposit and the degree of uncertainty of the estimated amount of the resource (Fig. 2.6). The latest version has already incorporated current trends such as the increasing use of unconventional energy resources. Depending on how reliable the detection is considered, reserves are subdivided into proved (P1), probable (P2) and possible reserves (P3) (Fig. 2.6). The labels 1P for proved, 2P for the sum of proved and probable and 3P for the sum of proved, probable and possible reserves (Fig. 2.6) are also in use. For resources, the PRMS distinguishes contingent resources (discovered but subcommercial) and prospective resources (undiscovered).

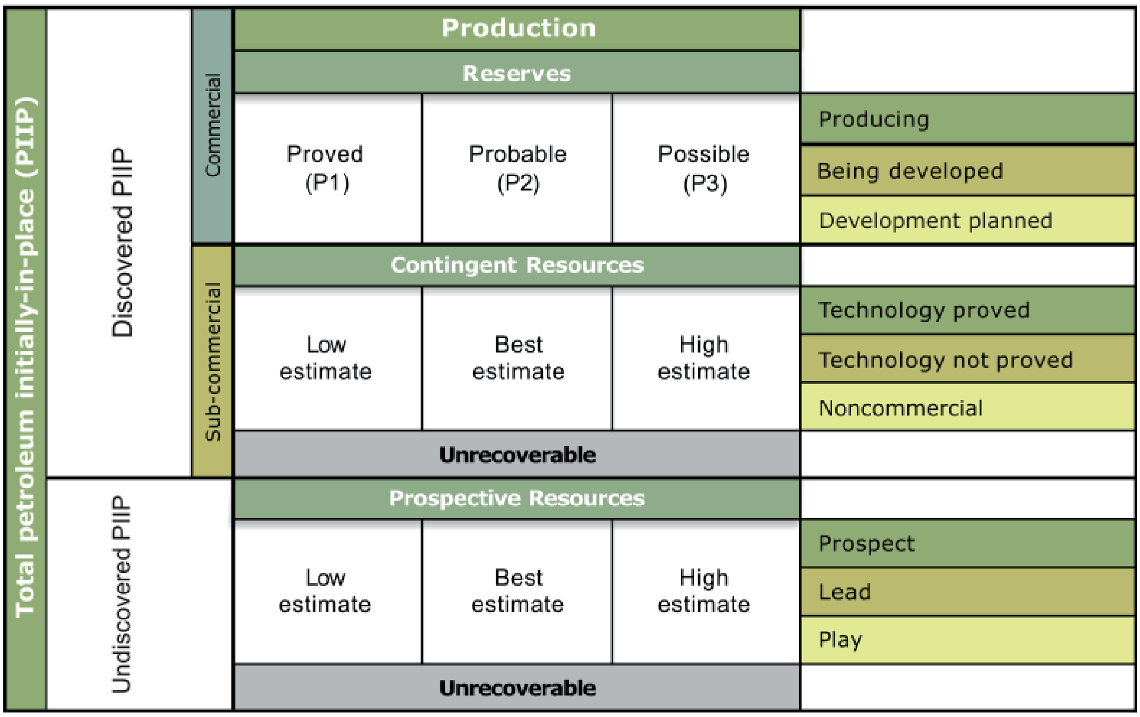


Figure 2.6: Petroleum resource management system SPE/WPC/AAPG/SPEE (SPE, 2007).

The frame classification UNFC has been developed by order of the UN-ECE in collaboration with BGR. Originally created for coal and other mineral resources, in 2003 an extension to include oil and natural gas was suggested (UN, 2003). Object of the classification is to make reserves and resources comparable, which have been analyzed according to different national classifications and regulations. The system is based on a three-dimensional structuring of the deposits in accordance with the factors geological stage of investigation (G), feasibility/project status (F) and economy (E) (Tab. 2.1). A combination of three key numbers can thus be assigned to every deposit regarded.

In spite of a uniform classification, the numbers referring to reserves are not very transparent. For this reason, the IEA has requested more transparency in the assessment of reserves and the disclosure of the required data. From this perspective, the ongoing activities towards harmonization of these two classifications are considered promising. For the purposes of the BGR, both classifications, PRMS and UNFC, have turned out to be too detailed. Due to the very different data sources and data qualities, the globally researched reserve data by BGR cannot be integrated with sufficient reliability into the complex structures of the UNFC and of the PRMS. For this reason, the simpler system mentioned above has been selected.

Table 2.1: Classification of Oil and Natural Gas Deposits According to the UNFC (UN, 2003).

Coding scheme	E Profitability	F Feasibility (Project status)	G Geological degree of exploration
10	Profitability (commercial)	confirmed (committed)	proved (proved)
20	conditionally profitable (contingent commercial)	possible (contingent project)	explorated and described (explored and delineated)
30	Not profitable (not commercial)	Exploration	discovered (discovered)
40			expected (prospective)

Coal

The WEC keeps, just like the BGR, a statistic of the worldwide inventories of coal, which is also based on a somewhat coarse classification system due to insufficient data. The two systems are similar, but differ slightly with regard to the details. For instance, the WEC (2004) does not subdivide coal inventories into reserves and resources, but in proved amounts in-place and estimated additional amounts in-place.

The proved amounts comprise the total remaining amounts in known deposits, which have been carefully investigated and which are recoverable under current as well as under expected economic conditions with existing and available technology. These amounts are listed, if available, with data on the minimum seam thickness as well as the maximum depth of the recorded resources in the deposits. The proved recoverable reserves form a subset of the proved amounts, which can be extracted in future under current as well as expected local economic conditions using existing and available technology.

As estimated additional amounts, the WEC lists the indicated and inferred amounts, which will be of economic interest in the foreseeable future in addition to the proved amounts. This includes resources in unexplored parts of deposits or in undiscovered deposits in known coal bearing areas carbonaceous as well as assumed amounts in areas with favorable geological conditions. Speculative amounts are not included. The estimated additionally recoverable reserves are listed as sub-quantity of the estimated additional amounts (Estimated Additional Reserves Recoverable), for which the geological and technical information suggests that there is sufficient reason to believe that they could be produced in future.

There is no direct comparability of the data of WEC and BGR, as in addition to the differing subdivision of the inventories, both institutions use their own classifications of coal.

Uranium

In uranium producing countries, a multitude of individual classifications for the supply of conventional uranium has evolved (Fig. 2.7). These subdivisions are, in general, based on the degree of knowledge about the recoverability of uranium amounts in deposits. Every two years, the OECD Nuclear Energy Agency (NEA) together with the International Atomic Energy Agency (IAEA) reports on the uranium resources of the world in their 'Red Book'. This statistic is considered the standard work on the reserves estimates of uranium and is thus also the base of this BGR-study. Though, NEA and IAEA have introduced a classification system, which, in addition to the standard parameters, specifies the expected production costs in four categories based on USD/kg uranium (<USD 40/kg, <USD 80/kg, <USD 130/kg and costs unknown).

In accordance with NEA and IAEA, identified resources are separated from undiscovered resources (Fig. 2.7). The identified resources comprise the Reasonably Assured Resources (RAR), and the Inferred Resources (IR), which can be produced at costs of less than USD 130/kg. The proven reserves refer to uranium in explored deposits with known tonnage, contents and configuration. These RAR have a high probability of existence and are accordingly considered proven reserves. The inferred reserves comprise uranium deposits derived from direct geological knowledge, but for which there are no specific data concerning the supply situation and contents as well as knowledge about the deposit characteristics.

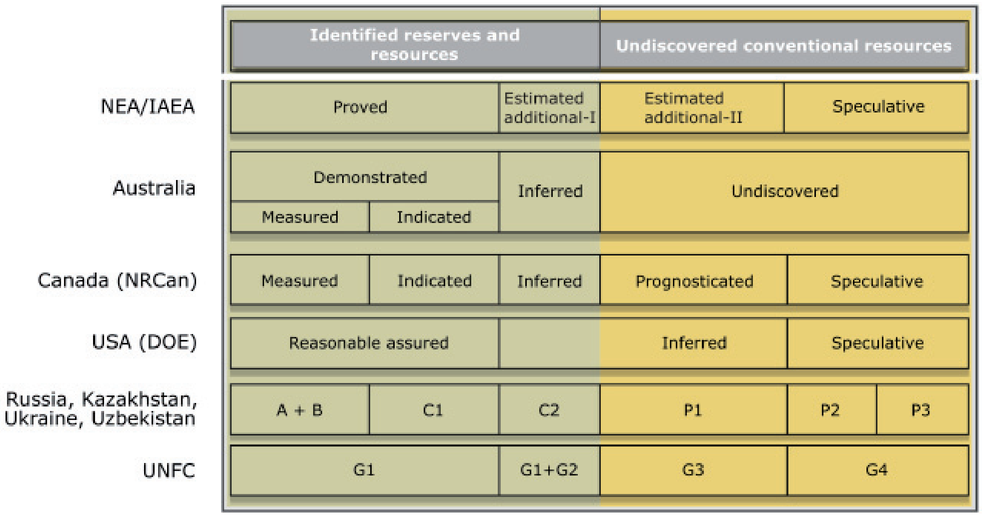


Figure 2.7: Comparison of common resource classifications for uranium deposits (NEA, 2005).

The undiscovered resources consist of the Prognosticated Resources and the Speculative Resources (SR). The existence of prognosticated resources is derived indirectly from the knowledge of geological prospectivity in well-defined geological formations and areas with known deposits. Assessments of the tonnage, the contents as well as the exploration and total production costs are based on the comparison with known deposits in the same or even in comparable geological areas. SR refer to uranium occurrences whose existence can be assumed based on geological conditions and extrapolation.

For the resource classification of the BGR (Chapter 2.4.2), the assured reserves of the NEA and IAEA at production costs of less than USD 40/kg are called reserves. Assured reserves with higher production costs, inferred reserves and undiscovered resources in accordance with NEA and IAEA are thus listed as BGR-resources. This takes into account the aspect of the BGR-definition of reserves of the economic extractability. An adaptation of the BGR-definition of reserves to a higher cost category of NEA and IAEA in the past high-price phase was not conducted, in particular for reasons of comparability with earlier studies.

2.5 Resource Classification for Geothermal Energy

The amounts of geothermal heat quantities, which have been recorded quantitatively and which are economically producible at the current economic conditions and current technical possibilities are called **geothermal reserves** (Haenel & Staroste, 1988; Kaltschmidt & Wiese, 1997).

Geothermal resources comprise the geothermal reserves and in addition those thermal amounts of energy, which have been proved, but which are currently not economically producible, taking into account the economic conditions and technical facilities.

This definition of resources used for geothermal energy differs from the definition of resources for the non-renewable energy resources (Chapter 2.4.2). Data about geothermal resources also contain the reserves and thus largely correspond to the remaining potential for oil and natural gas and the total resources for coal and uranium. For geothermal energy, the term may refer to occurrences of resources as well as to occurrences of reserves.

For geothermal energy, a number of other terms besides resources is used, such as theoretical potential, generation potential, producible amount of heat, maximum producible amount of energy, which are based on different definitions and which result in very different numbers for the same area. When comparing quantitative data about resources, the individual definition of the term and the parameters they are based on have to be taken into account (Chapter 7.3).

2.6 Data Sources of the BGR-Statistics

The BGR does not produce their own data on reserves of energy resources. Rather, the BGR-resource statistic has been based on an extensive acquisition of the accessible data concerning reserves, resources, production as well as economic and technical trends. The data sources used range from supra-national bodies, such as the IEA or the IAEA, over published statistics of individual companies, reports of official geological services or resource authorities, non-public political papers, reports in the daily press up to publications in international journals on resources or the scientific press. A detailed list of the quotable sources used can be found in the bibliography of the data in the table appendix.

After their acquisition, the data will be evaluated regarding plausibility and adapted to the definition of resources, if required (Chapter 2.4.2). Then, they will be combined in the resource database of the energy resources. Information for further evaluation has been listed below.

2.7 References on Energy Resources – Definitions and Classifications

BGR (Bundesanstalt für Geowissenschaften und Rohstoffe) (2003): Reserven, Ressourcen und Verfügbarkeit von Energierohstoffen 2002, Rohstoffwirtschaftliche Länderstudien, Band XXVIII: 426 p; Hannover.

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Pohl, W. (1992): W. & W. E. Petrascheck´s Lagerstättenlehre. Eine Einführung in die Wissenschaft von den mineralischen Bodenschätzen. – 504 p; Stuttgart (E. Schweitzerbart´sche Verlagsbuchhandlung).

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UN (2003): United Nations Framework Classification (UNFC) applied to Petroleum Resources.- Distr. General: ENERGY/GE.3/2003/1, 17 March 2003, 25 p.

UN-ECE (United Nations Economic Commission for Europe) (2004): United Nations Framework Classification for Energy and Mineral Resources. – (http://www.unece.org/ie/se/reserves.html)

WEC (World Energy Council) (2004): 2004 Survey of Energy Resources. Elsevier Ltd. (CD-ROM)

3 Crude Oil

3.1 From Deposit to Consumer

Oil is a collective term for a liquid, natural mixture of hydrocarbons, whose chemical composition and physical characteristics can vary significantly. Crude oil may have low to high viscosity; it may be straw-colored to black-brown and mostly has a density between 0.78 and 1.0 g/cm^3 (Fig. 2.3). Important physical characteristics for oil are, besides density, viscosities and the pour point.

Crude oil has different geochemical compositions, depending on its origin. It contains liquid, but also dissolved gaseous and solid hydrocarbons, amongst them alkanes, cycloalkanes and aromatics, but rarely alkenes. In addition, oil contains 0.1 % up to 7 % sulfur bonded to molecule types such as thiols, thiophenes and heterocyclic compounds, moreover nitrogen compounds, naphthenic acids as well as high-molecular colloidal substances, in which also traces of metals such as nickel and vanadium can be bonded. Oil can be differentiated into paraffin-based and naphthene-based, depending on whether it consists mainly of alkanes (paraffines) or cycloalkanes (naphthenes). Asphaltenic oil contains more than 60 % asphaltenes. Paraffin-based types of oil mostly have a lower sulfur content. They are more suitable for production of diesel fuels with improved ignitability and lubricating oils with a higher viscosity index. Naphthene-based types of oil have a better performance at low temperatures and yield gasoline with a higher octane number.

Crude oil occurs in the subsurface rocks in different depths from a few meters down to 4000 m, in some cases even deeper. Economic deposits, so-called oil fields, are located in porous or fractured-cavernous reservoir rock, which is sealed at the top by impermeable seals and shows a trap position. Sandstones and carbonates can act as reservoir rocks. Deposits consist either of one or several oil-bearing layers. When the deposit's development begins, the crude oil is usually pressurized, making it flow quasi eruptively towards the earth's surface. In the course of production, the pressure inside the deposit decreases and it becomes necessary to employ borehole pumps or rotary borehole pumps for oil production purposes. Besides these methods of production, processes for increasing the oil recovery out of the deposits, the so-called *Enhanced Oil Recovery* (EOR), are being used (Info box 2).

Crude oil from natural points of emergence was already known in the ancient world and was initially used for medical purposes, in civil engineering but also for warfare. Later, usage as an illuminant was added. For nearly 150 years, oil has been exytracted industrially. The economic production of oil started in the middle of the 19th century nearly simultaneously in Azerbaijan, Poland, Romania, the US but also in Germany. In Germany, the cradle of the petroleum industry is located in Wietze (Chapter 8.1.1). The invention of the combustion engine at the end of the 19th century was the basis for the success of petroleum as most important energy source of the emerging economy. Today, petroleum is of major importance for transportation, heat generation and the chemical industry. In the second half of the 20th century, petroleum was the most important energy source and ensured growth and prosperity. The access to oil occurrences also caused conflicts and wars, however.

Oil is subdivided into conventional and unconventional oil, dependent on whether an economic production using classic production technologies is possible, or whether new and expansive technologies have to be developed and applied (Chapter 2.3.1). As production technologies and energy price levels are subject to constant change, the distinction between unconventional and conventional hydrocarbons in accordance with technical aspects and marketability is not clear. There is no standard of terminology, however, thus unconventional petroleum is included in the reserves of some countries, for nearly all countries it is part of the production data.

Oil is, just like natural gas, a finite natural resource. The consumption of these resources has reached a considerable dimension by now. To form the amount of oil and natural gas consumed annually nature took about one million years. At a percentage of nearly 36 % of the total primary energy supply (without biomass), oil is the most important energy source globally (BP, 2008) and simultaneously a natural resource in petrochemistry. Nearly 10 % of the global oil production is used for petrochemical purposes. The percentage of oil of the total primary energy supply increased from about 30 % in 1950 to nearly 50 % in 1973. In the course of the first oil price crisis, a slight reduction to about 48 % occurred. After the second oil price crisis in 1980, the percentage decreased until 1985 to about 40 %. Ever since, this level has been nearly constant, with a slightly decreasing tendency. Prognoses of the IEA (IEA, 2008a) assume that up to 2030 no serious changes of the relevance of petroleum as energy resource will occur.

3.2 Conventional Oil

3.2.1 EUR of Crude Oil and its Regional Distribution

The subsequent assessment of the Estimated Ultimate Recovery (EUR) of conventional oil primarily takes into account the results of the US Geological Survey's world assessment (USGS, 2000) and their updates. The evaluations of other authors and data of national institutions concerning the resources have been included as well as published results of the petroleum exploration of the past years.

At the end of 2007 BGR estimate the EUR of conventional oil at 400 Gt. Changes in comparison to the short study of 2007 (BGR, 2008) resulted from revisions of the reserves of Venezuela by eliminating the extra heavy oil reserves (Chapter 3.2.2) just like newer evaluations of resources (Chapter 3.2.3). This BGR-value for the total potential of petroleum surpasses the assessment of the 2002 energy study (BGR, 2003) with 359 Gt, but is lower than the last assessment of the USGS, which has assumed 450 Gt including NGL (Chapter 2.3.1) and taking into account an expected growth of reserves ("*reserve growth*"). In general, the current assessment by the BGR follows the trend of the resource assessments of the past years (Fig. 3.1, Tab. A 3-1). Since the end of the 1980s, the published assessments of the total potential vary between 300 and 500 Gt with a mean value of 400 Gt.

Extreme deviations downwards show in particular Campbell (2008) at 255 Gt (1875 Gb), who discounts the reserves of the OPEC countries and who also excludes from his assessments the deep-water areas and the Arctic regions as well as NGL. These reasons explain his extremely low assessment only in part, however. The totals of his published values (No.

61, 68, 75, 80 in Fig. 3.1) are all within the range of the original reserves, which indicates that his evaluations have been somewhat pessimistic.

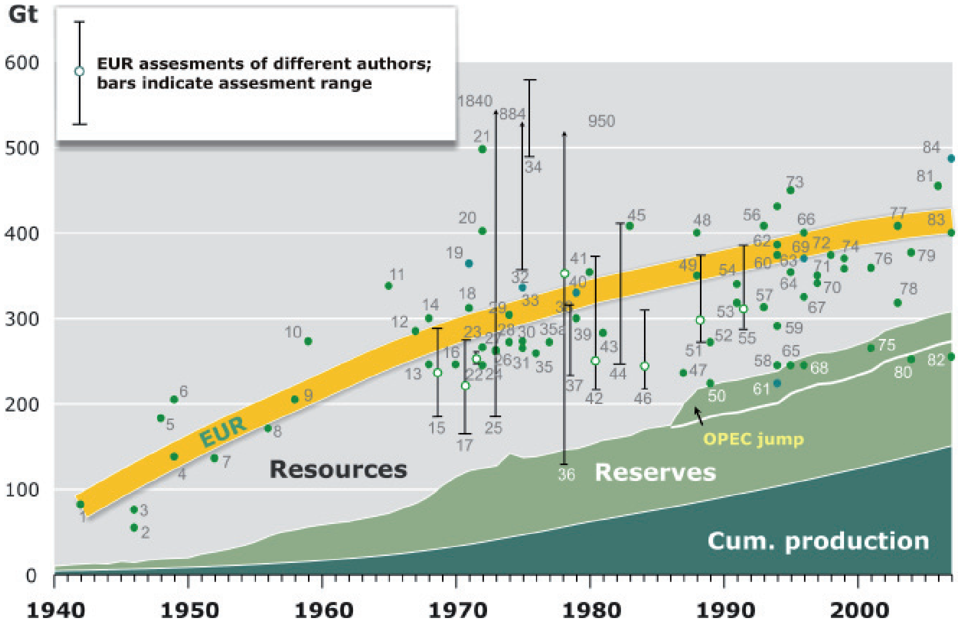


Figure 3.1: Development of the estimates concerning the Estimated Ultimate Recovery (EUR) of conventional oil, the cumulative production and reserves from 1940 to 2007 (sources for numbered references cf. Tab. A 3-1).

The stabilization of the assessments of the EUR of conventional oil, within the depicted limits that can be observed over the course of the past few years, indicates an upper threshold for the globally available conventional petroleum. An increase of the potential seems possible from today's perspective due to improved production technologies, resulting in a higher recovery and thus in an increase of the economically recoverable part of the oil in place of the deposit. In theory, an increase of the recovery factor by 1 % referring to the global petroleum potential would correspond to an amount of about 10 Gt, i.e. app. 2.5 times the annual production of 2007. It has to be noted, however, that this applies primarily to new, as yet not developed fields and only to a limited extent to fields already in production, thus the expected potential is lowered. The future development of the oil price is important, as extensive and costly research and development works will only be conducted and implemented if the price level is sufficiently high.

The EUR, subdivided in cumulative production, reserves and resources, varies strongly depending on the region (Fig. 3.2). The Middle East has the greatest EUR, followed by the CIS and North America. In North America, nearly two thirds of the expected EUR have already been recovered. In the CIS countries, only about one third has been recovered and in the Middle East only about a quarter.

In relation to the economic policy groups, the OPEC at about 210 Gt holds more than 52 % of the EUR, while only one fourth of the oil there has been recovered. The significant increase in comparison to previous statistics is due to the new members Angola and Ecuador. The OECD countries achieve only 79 Gt, of these nearly 63 % have already been produced. In comparison with the BGR-energy study of 2003, great increments have occurred for the Middle East with an additional 12.2 Gt, the CIS with an additional 8.0 Gt, Africa an additional

6.9 Gt, Latin America at plus 5.2 Gt and North America at plus 5.0 Gt as well as to a lower extent for Austral-Asia and Europe with additional 1.9 and 1.2 Gt, respectively.

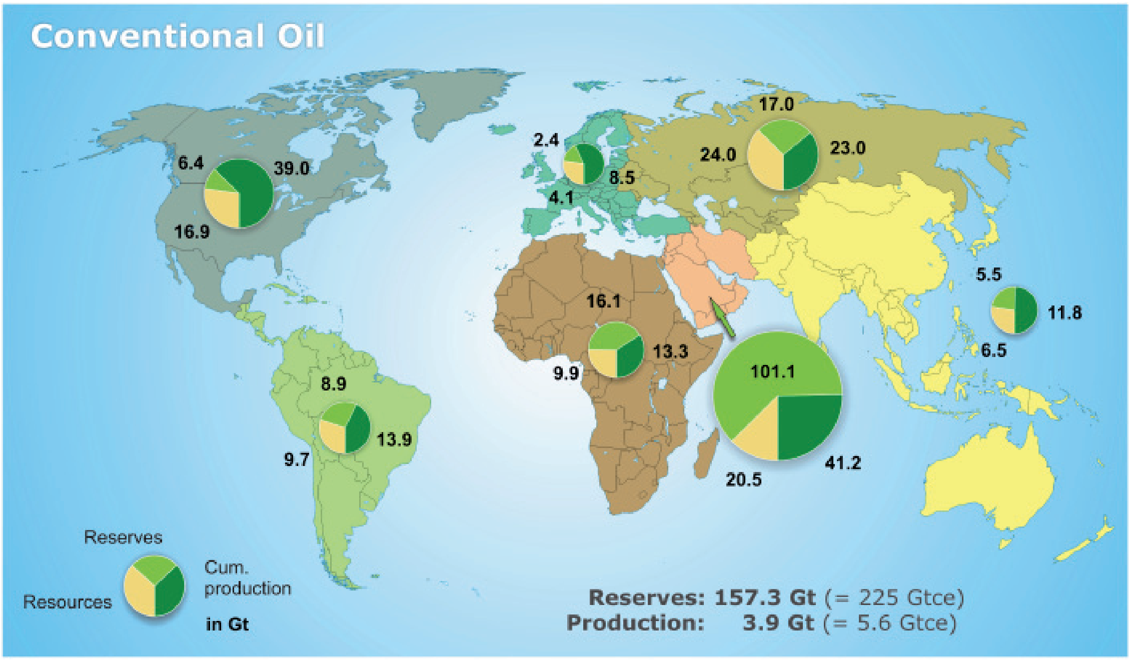


Figure 3.2: Regional distribution of the EUR of conventional crude oil in 2007 (total 400 Gt).

Overlooking the EUR of the most important countries, itemized according to cumulative production, reserves and resources, ten countries remain in focus, which hold over 70 % of the EUR and about 73 % of the remaining potential (Fig. 3.3). Such a high concentration in few countries will have consequences for the future exploration and production. The OPEC countries (indicated by blue characters) are dominating. The US only take rank 7 for remaining potential in spite of having the third-largest total potential. This is caused by its very long production history combined with the globally highest cumulative production. Only a comparatively little recoverable potential remains.

For the OPEC countries of the Persian Gulf region, the ratio of resources to reserves is very small in comparison to the other countries. Thus, even in case of politically motivated exaggeration of the reserves for these countries, the total amount or the remaining potential is still depicted quite realistically. An overview over the total and the remaining potential of the individual countries, regions and economic groups is given in Tables A 3-2 to A 3-4.

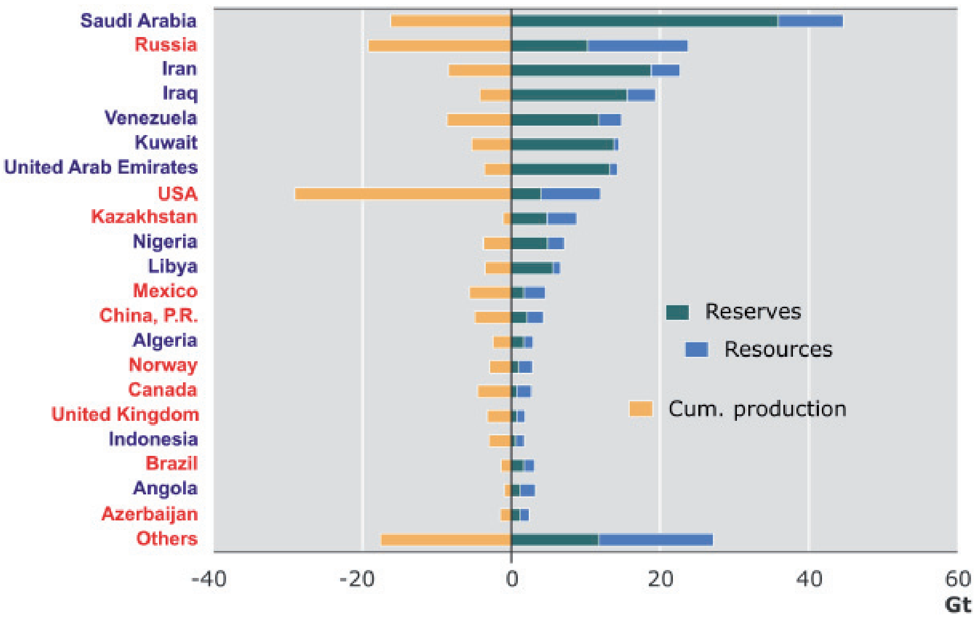


Figure 3.3: EUR of conventional crude oil in 2007: The top twenty countries sorted according to remaining potential (OPEC countries in blue bold-face type).

3.2.2 Crude Oil Reserves

The evaluation of the oil reserves is based on the *Petroleum Resource Management System* (Chapter 2.4.3) jointly prepared by SPE/WPC/AAPG/SPEE. This does not, however, preclude deviations in the reserve information in different sources for the same country. Corresponding tendencies for exaggerating or lowering the actual reserve numbers have been discussed in the 2002 Energy Study (BGR, 2003) in detail. In addition, different approaches by companies and governments play a role, thus an absolute confirmed comparability of the globally existing reserves cannot be achieved. All reserve data have thus to be regarded with caution and with reservations. The objective of the assessment of global reserves cannot be an exact number, but an order of magnitude close to reality.

This evaluation has included the reserves of conventional crude oil, condensate and other liquid components of the natural gas production. It is based on different published sources (cf. list of references of the data in the annex of tables), in addition, data by national authorities have been taken into account and BGR-evaluations have been conducted. In part, departures from other sources result, as can be seen from a comparison of the values relating to individual regions in Table 3.1. The statistics mentioned as a rule only report proven reserves. Probable and possible reserves are considered only rarely, thus in all an undervaluation of the reserves cannot be precluded.

As demonstrated in the comparison of the evaluations of the petroleum reserves by different publications (Tab. 3.1), the Energy Watch Group (EWG, 2008) at 116.3 Gt shows the lowest and OGJ (2007), taking into account the oil sands of Canada, at 181.2 Gt gives the highest value. If the Canadian oil sands are deducted from the reserves, a rather good concurrence of the depicted assessments results, with exception of the evaluation of the EWG. The significantly lower values of the EWG mainly result from lower evaluations of reserves for the Middle East. The reserve figure is only about half of the values stated by other sources. This deviation has been justified by the opinion that the other reported reserves have been exaggerated for political reasons. Thus, the EWG contradicts all other sources, including the source IHS Energy it quotes, which states a value of 92.3 Gt for 2005 for this region.

Table 3.1: Comparison of different evaluations of the reserves of conventional oil in 2007 [Mt].

Region	OGJ	EWG	World Oil	Esso	BP	BGR	OPEC
Europe	1 942	3 469	1 977	1 913	2 218	2 392	2 164
CIS	13 452	20 952	16 784	13 453	17 333	16 969	17 450
Africa	15 622	17 007	15 192	15 366	15 986	16 068	16 268
Middle East	101 808	49 252	98 301	101 610	89 456	101 103	100 893
Austral-Asia	4 673	7 007	4 893	4 628	9 429	5 544	5 208
North America	28 737	11 429	7 921	28 442	14 952	6 367	5 111
Latin America	14 946	7 143	9 600	15 225	13 306	8 870	16 369
WORLD	*181 180*	*116 259*	*154 668*	*180 637*	*162 680*	*157 312*	*163 464*
Oil sands	23 665			23 665	2 857		
World without oil sands	157 515	116 259	154 668	156 972	159 823	157 312	163 464

Sources: OGJ (2007), EWG (2008), EIA (2008a) for World Oil, Esso (2008), BP (2008), OPEC (2008).

In comparison to the previous study (BGR, 2003) and also the last short study (BGR, 2008), the reserves of Venezuela have been reevaluated. Based on newer publications (González Cruz, 2007; Radler, 2008), the extra heavy oil reserves have been removed from the reserves of Venezuela, the current reserves only contain the conventional oil including heavy oil.

Since the last Energy Study (BGR, 2003) with a 2001 dataset, significant regional increases occurred in the Middle East and Africa as well, to a somewhat lesser degree in the CIS and Latin America, whereas in North America, Europe and Austral-Asia decreases have been reported. Looking at individual countries, the increases in Iran, Libya, Nigeria, Kazakhstan, Venezuela, Sudan and Kuwait with increases of more than 500 Mt stick out (Tab. A 3-5). The global reserves of conventional oil have thus risen significantly by about 10.5 Gt from 146.8 Gt in the year 2001 to 157.3 Gt in the year 2007 despite a cumulative oil production of 22.6 Gt during that period.

The historical development of the petroleum reserves and the petroleum production (Fig. 3.4) shows a constant growth of the reserves with a clearly visible step at the end of the 1980s. This increase in reserves was due to the increase in the OPEC-reserves. At 157.3 Gt, the world petroleum reserves at the end of 2007 were slightly lower than the previous year's value of 157.5 Gt. Thus, for the first time in many years, no significant growth of the reserves occurred. Where decreases in reserves are concerned Mexico with a reduction by 2 Gt stands out. This is due to a reevaluation of the reserves at stricter definitions and might possibly be in connection with the planned privatization of the state-owned oil company. The PR of China, Norway, Great Britain, Indonesia, Columbia and the US showed smaller reductions, in the magnitude of 100 to 1000 Mt largely production-related.

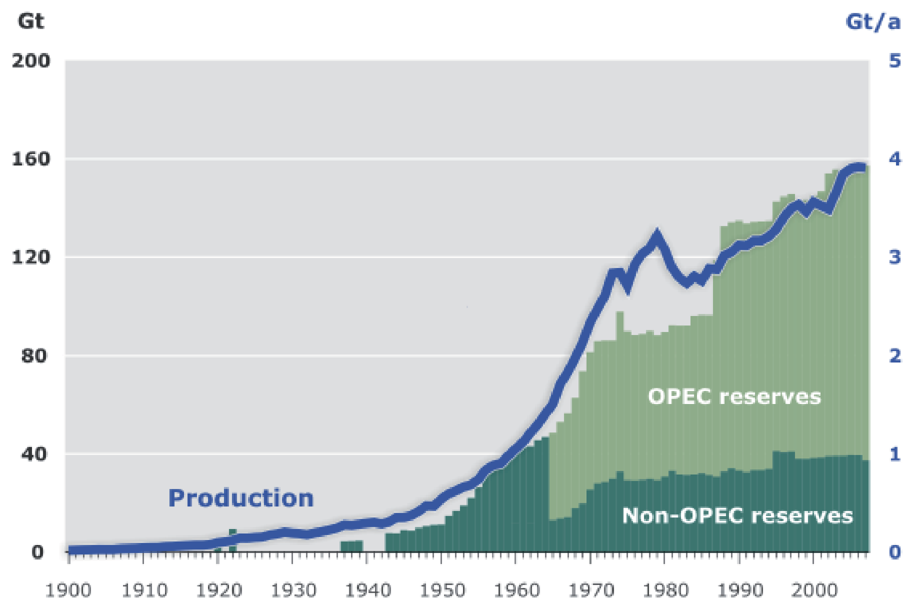


Figure 3.4: Development of the reserves and production of conventional oil from 1900 to 2007.

Comparing the reserves based on countries (Tab. A 3-6, Fig. 3.5), it is noticeable that Saudi Arabia holds a unique position. It alone possesses 22 % of the global petroleum reserves. The six countries with reserves above 10 Gt are, with the exception of Russia, all OPEC members. They have more than two thirds of the global petroleum reserves.

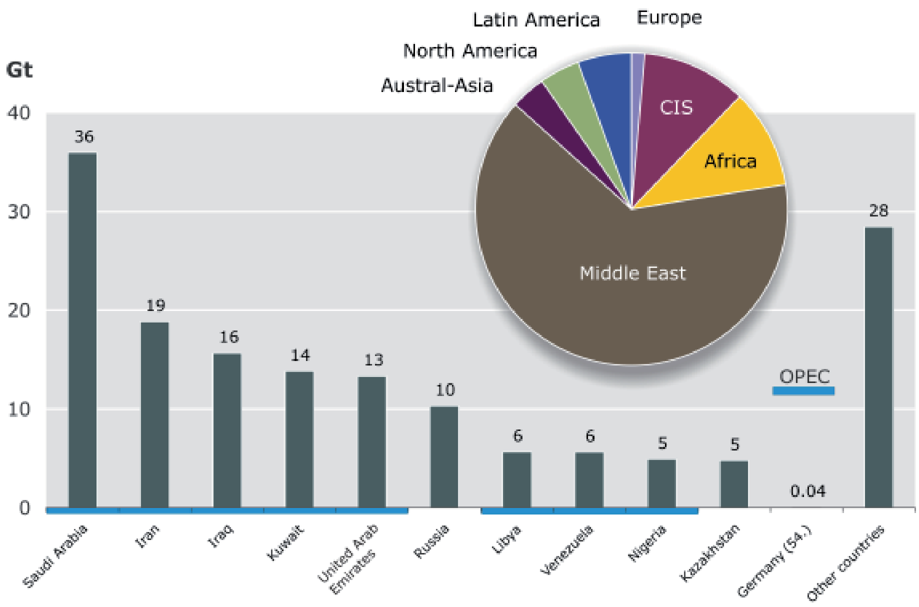


Figure 3.5: Reserves of conventional oil (Total 157.3 Gt) in 2007 of the top ten countries and Germany as well as their distribution by region.

In a regional context, the countries of the Middle East possess 64 % of the global reserves; nearly 11 % can be attributed to the CIS and about 10 % to Africa. In spite of the rich occurrences in the North Sea, Europe possesses only a little more than 2 % of the global reserves (Fig. 3.5). According to economic groups, the distribution of the petroleum reserves is even more irregular. The OPEC possesses slightly more than 76 % of the reserves, of these 63 % are located in the Gulf region, the OECD has only slightly more than 6 %. (Fig. 3.6, Tab. A 3-6). These numbers emphasize the special position of the OPEC for the future petroleum supply. For comparison purposes, the figures also includes the distribution of the natural gas reserves, where the concentration on OPEC is not as pronounced as for petroleum.

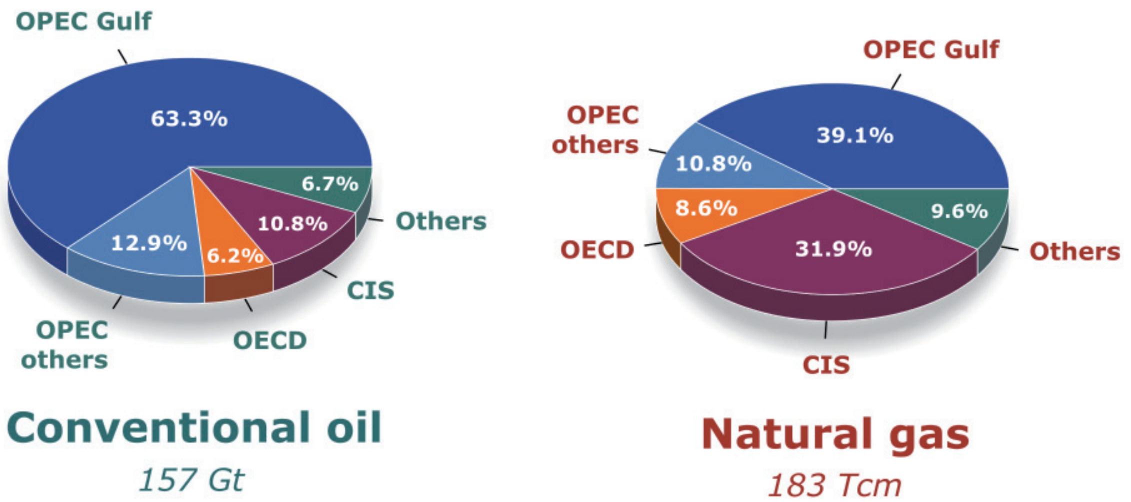


Figure 3.6: Distribution of the reserves of conventional oil and natural gas in 2007 according to economic groupings.

Approximately 41 Gt (26 %) of the petroleum reserves are located in offshore areas (Fig. 3.7). Of these offshore-reserves, 11 Gt are located in deep-water areas in depths deeper than 500 m. The offshore-reserves predominate in Europe and Austral-Asia, the largest are located in the Middle East. Due to increasing exploration in offshore-areas, in particular in the Gulf of Mexico, in the Atlantic Ocean off the coast of Brazil and at the west coast of Africa as well as in the Caspian Sea, a further increase of the offshore-reserves and their proportion of the total reserves is to be expected in future.

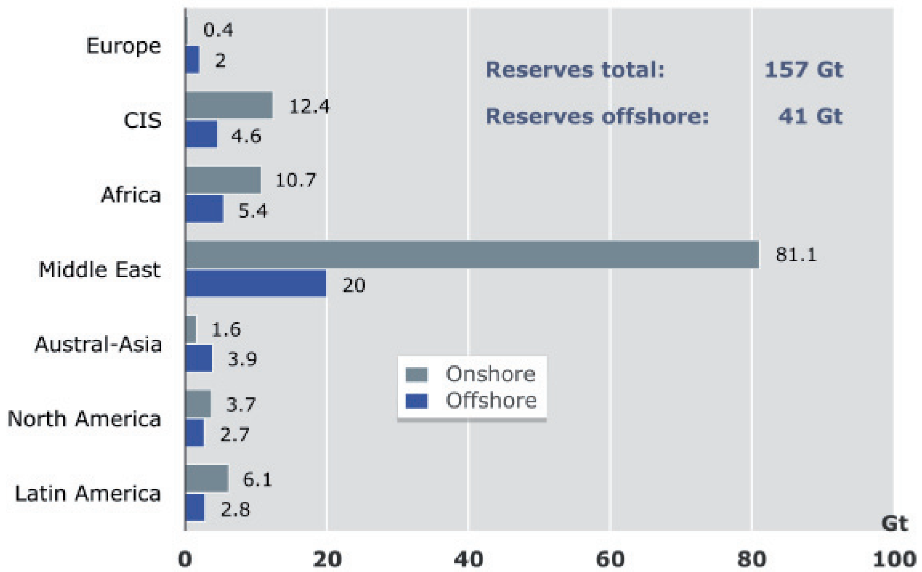


Figure 3.7: Distribution of the reserves of conventional oil in 2007, onshore and offshore, by region.

The oil reserves are owned by private (IOC) and state oil companies (NOC) (Info box 1). Referring to the individual oil companies, a significant predominance of the state companies prevails for the petroleum reserves (Tab. A 3-7). The only private oil company amongst the top ten holders of reserves is the Russian company Lukoil. The first eight ranks are occupied by national oil companies (NOC) from OPEC countries, five of these from the Middle East. The six largest companies with reserves >10 Gt possess 67 % of the global petroleum reserves, about 100 Gt. There are only five private companies amongst the top twenties.

There are indications of a possible future oil reserves increase. On the one hand, the currently ongoing exploration in frontier areas such as the Caspian Sea, in deep water areas in the Gulf of Mexico, off the Brazilian coast, off the west coast of Africa, in Southeast Asia as well as in Arctic regions of Russia and North America might add reserves. In addition, in known fields an increase of reserves (field growth) can take place due to improved production technologies and thus a higher recovery of the initial oil as well as through improved knowledge of the geological structure and of the behavior of the deposits. Technological innovations in the exploration, drilling and production technology play an important role. Thus, 3D and 4D-Seismics contribute to an improved prediction of the structural and internal construction of prospects and fields and thus reduce the risk of exploration and field development. In drilling technology, horizontal drilling opens up the possibility of developing hitherto not accessible prospects or those accessible only with great difficulties, and to increase flow rates. The use of mobile units in production technology, so-called Floating Production, Storage and Offloading (FPSO) units, and subsea installations moves the exploitation of offshore deposits to greater and greater depths. Today, the record for offshore production is in a water depth of 2740 m in the Cheyenne gas field in the Gulf of Mexico.

Due to these technological innovations and further efforts for cost reduction, fields become economically useable, which had been considered marginal or uneconomical years ago. These developments have contributed to a continued increase of the reserves over the past years in spite of increased output and stagnant total potential.

Klett et al. (2005) have conducted an analysis of the conversion of the resources shown by the USGS (2000) into reserves and of the reserve growth. Accordingly, increases in reserves of 69 Gb have been realized for oil in the period between 1996 and 2003. Increases from the reevaluation of fields under production added up to 171 Gb. Thus, in a period encompassing 27 % of the period covered by the study of 2000 (25 years), 11 % of the resources have been converted and 28 % of the forecast "reserve growth" has been realized. The amount of oil of 206.7 Gb (28.1 Gt) produced during that time has largely been replaced by the reevaluation of known fields. Stark & Chew (2005) indicate an increase in reserves of 603 Gb for the period from 1995 to 2003, of which 138 Gb or 23 % are due to recent discoveries. These numbers probably also contain increases of unconventional oil.

3.2.3 Crude Oil Resources

Data on the oil resources are associated with greater degrees of uncertainty than reserve data. In comparison to the reserves, which are reported annually, assessments of resources are conducted irregularly and at longer intervals. The last global assessment was conducted by the USGS in 2000 (USGS, 2000) referring to the end of 1995 and with a projection of 25 years. The mean values for the global resources of conventional oil have been specified at 124.4 Gt for oil and NGL, of these app. 27 Gt NGL. In determining the values for this study (Tab. A 3-8), the previous values of the BGR, the new results of regional USGS-Studies (USGS, 2006, 2008) as well as new results of subsalt exploration off Brazil (Smith, 2008) have been taken into account. As a result, a value for the global petroleum resources of 91.5 Gt has been indicated. This value surpasses the assessment of 2001 (84.3 Gt). The higher evaluation is due to the inclusion of hitherto unconsidered basins in the Arctic and a higher rating of the resources in Brazil. The global amount of resources thus corresponds to little more than half of the oil produced up to now and the reserves. In comparison with the other energy resources, it can be inferred that the production and thus the development of the total potential has progressed furthest for oil.

For the resources, similar to the reserves, a concentration in certain countries has been found. The top ten countries possess nearly two thirds of the resources (Fig. 3.8, Tab. A 3-9). Russia and the US followed by Saudi Arabia and Kazakhstan currently possess the largest crude oil resources. Unlike the reserves, the dominance of the OPEC countries is not reflected in the crude oil resources. Saudi Arabia, Iran, Iraq and Venezuela are the only OPEC countries amongst the ten most important resource-owning countries (Fig. 3.8). Taken together they possess about 22 % of the crude oil resources.

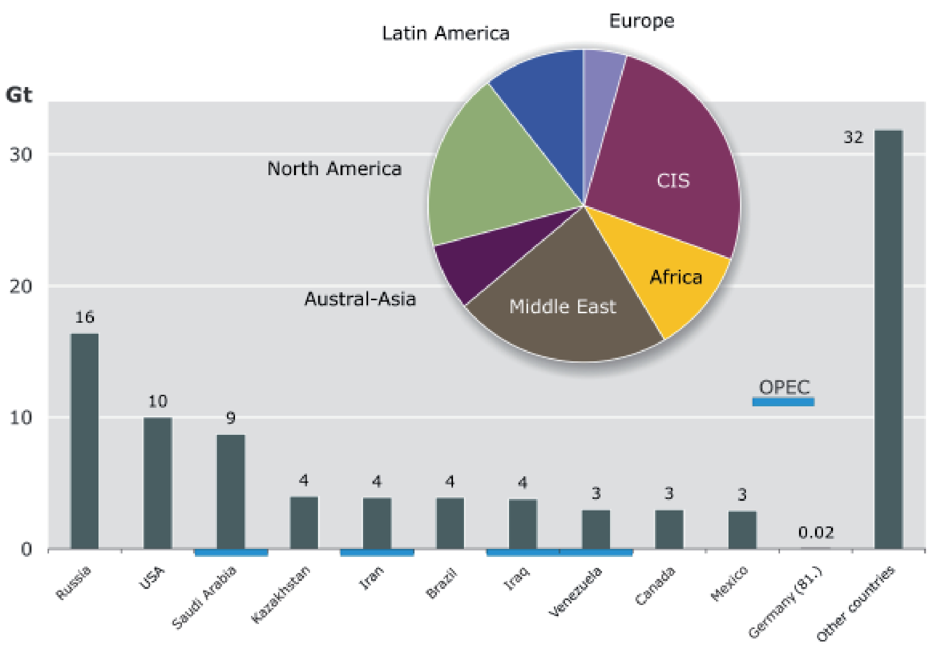
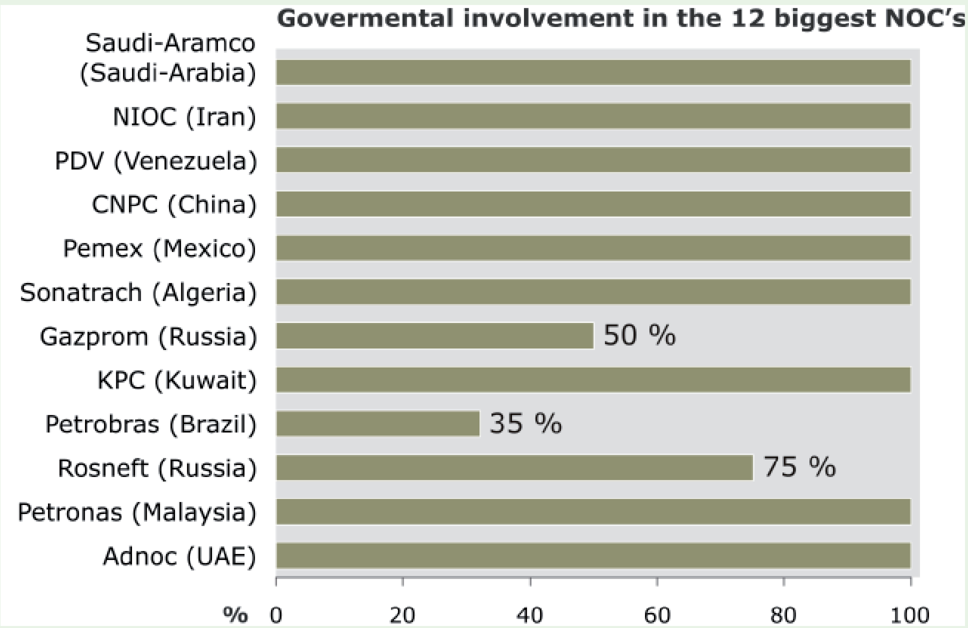


Figure 3.8: Resources of conventional oil (total 91.1 Gt) in 2007 of the top ten countries and Germany as well as their distribution by region.

International vs. National State Oil and Gas Companies

The production of oil is conducted by private international petroleum companies (IOC) as well as national oil companies (NOC). In the 1960s, private oil companies still covered 85 % of the global reserves of petroleum. This ratio has been reversed to this day because of the mass nationalization in the oil-producing countries in the 1970s. The proportion of the global petroleum reserves of the state petroleum companies is more than 80 % by now. Amongst the ten companies with access to the largest petroleum reserves of the world, the Russian Lukoil is the only private company. For the global oil resources, the influence of the private oil companies is even less. There they have access to only 7 % of the resources. For natural gas, state companies currently dominate, too. The ten companies holding the largest reserves of natural gas worldwide are state-owned. For international oil companies it becomes increasingly difficult to gain access to easily and cheaply exyploitable oil and natural gas occurrences.

Half of the 50 largest oil and gas companies are state-owned at more than 50 % up to 100 %. They can pursue different strategies. The activities can be limited to the development and utilization of the domestic petroleum and natural gas potential. Others seek additional shares in petroleum and natural gas consessions abroad, to safeguard their own energy supply. Today, national state oil/gas companies possess in many cases a comparable capital and knowledge about business management and do not have to rely on technology partnerships with private companies. This applies in particular to state petroleum companies from emerging markets, such as Petrobras (Brazil), PetroChina and Gazprom (Russia), which today possess budgets for research and development just like their competitors. The capital expenditure of state petroleum companies was increased by about 24 % in 2008. In the same period, the international oil companies raised their capital spending only by about 16 %.



3.2.4 Crude Oil Production

The statistics on oil production as a rule comprise conventional oil including NGL and in many cases also unconventional oil. A definite differentiation is not possible globally, thus the numbers of this statistic contain the whole spectrum of liquid hydrocarbons. The values by BP (2008) and IEA (2008b) have been preferably used as source data for table A 3-10. Statistics from the OGJ, the EIA, data of national institutions, of Arab Oil & Gas, of Interfax Russia & CIS Oil & Gas Weekly (for the CIS) as well as of numerous other professional journals (cf. bibliography of the data in the annex of tables) have been taken into account as well.

Since the last Energy Study 2003 by BGR, the global oil production has increased only moderately from 3.52 Gt in 2001 to 3.88 Gt in 2007 (Tab. A 3-10). The greatest increases were found in 2003 and 2004, whereas in 2007 the production decreased slightly. The absolute production maximum at 3917 Mt was reached in 2006. At the end of 2007 151 Gt of petroleum had been produced in all since the start of the industrial oil production (Tab. A 3-2). Half of these have been produced within the past 20 years. Thus, the amount produced up to now nearly reaches that of the reserves. If the resources of app. 92 Gt are taken into account, 38 % of the currently expected EUR of conventional oil has already been recovered.

The most important producing regions in 2007 were the Middle East, North America and the CIS (Tab. A 3-11, Fig. 3.9). In comparison to 2001, the CIS, the Middle East and Africa showed production increases of more than 100 Mt. Decreases in the petroleum production concerned in particular Europe at 90 Mt. Referring to individual countries, Russia, Saudi Arabia and Angola reached significant increases (>50 Mt). A greater decrease of more than 40 Mt occurred in Great Britain, Norway and the US. The top ten countries covered nearly 62 % of the oil production (Tab. A 3-11, Fig. 3-9).

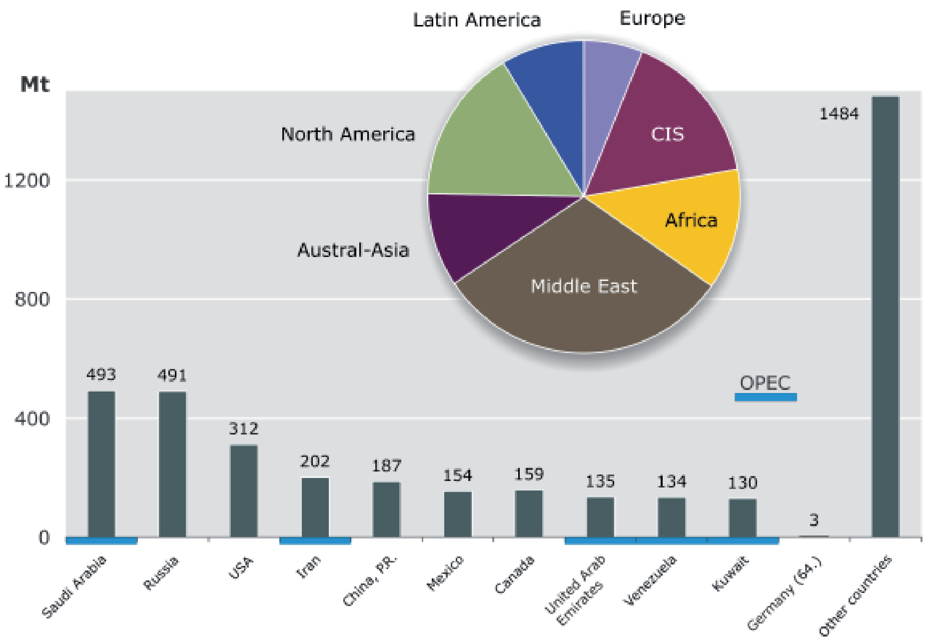


Figure 3.9: Production of conventional oil (Total 3.9 Gt) in 2007 of the top ten countries and Germany as well as their distribution by region.

Changes in comparison to 2001 also occurred in the ranking of the top ten producing countries. Russia replaced the US on rank two and nearly caught up with Saudi Arabia (Fig. 3.9). Norway and Great Britain disappeared from the top ten and were replaced by the United Arab Emirates and Kuwait. The ten largest producing countries encompass five OPEC countries. According to economic groups, the OPEC accounts for 44 % of the world production, of these 28 % of the Gulf States of the OPEC, the OECD accounts for 28 % with only 4 % in the EU. The proportion of the OPEC at the global petroleum production increased from approximately 20 % in the early 1940s to nearly 50 % in the mid 1970s (Fig. 3.10). Due to the oil price crisis, the proportion of the OPEC decreased in the mid 1980s to about 30 %, kept increasing steadily ever since and reached 44 % in 2007. In the long run, the proportion of the OPEC in the petroleum production should keep on increasing. The IEA (2008a) expects for 2030 that 51 % of the petroleum will be produced in the OPEC countries.

The production of petroleum based on regions is more evenly distributed than that of the reserves. The relatively high production rates of the OECD result in a fast extraction of the comparably small reserves, which in turn will result in an increasing dependency on the OPEC. The Gulf States of the OPEC with their huge potential of reserves and production are particularly important. Especially Saudi Arabia is in a position to compensate production failures in other regions at short term as so-called *Swing Producer* or to drastically restrict the petroleum supply. The reserve capacity in times of high demand for petroleum was decreased for Saudi Arabia at about 1 Mb/d between 2006 and 2008. Due to the financial crisis and declining demand for petroleum, the other OPEC countries have some reserve capacities again.

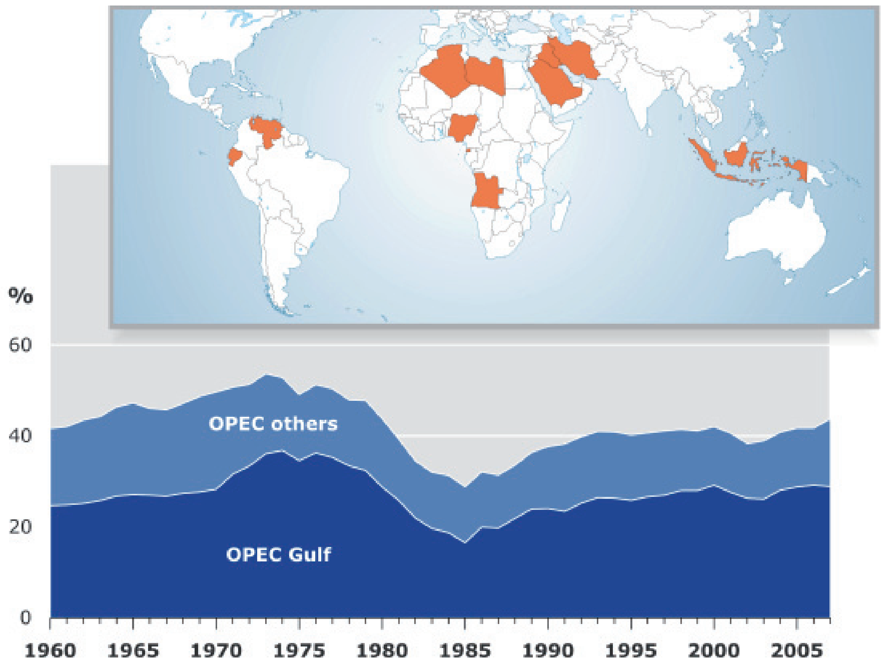


Figure 3.10: Share of the OPEC countries (orange) in the global petroleum production from 1960 to 2007.

The proportion of the production from offshore fields was 37 %, i.e. 1.4 Gt, in 2007. The dominant offshore production areas were the North Sea and the Gulf of Mexico at 210 Mt, each. Other important production regions offshore were the Atlantic Ocean off Brazil, West

Africa (Nigeria, Angola), the Arabic Gulf and South East Asia (China, Vietnam, Malaysia and Indonesia), increasingly also the Caspian Sea. In relation to deep water in depths below 500 m, 157 fields were producing in 2007; this signalizes an increase by 113 fields since 2000. 91 % of these fields are located in the so-called Golden Triangle, encompassing the Gulf of Mexico, Brazil and Western Africa (Petroleum Economist, 2007).

For production as well as for reserves, a preponderance of the state oil companies (Info box 1, Tab. A 3-13) results, but somewhat reduced. This also applies to the Gulf States. In the phalanx of the state oil companies, ExxonMobil and Shell were able to enter the list of the top ten companies and ranked fifth and sixth, respectively. The top ten producing companies generate at 1.65 Gt oil about 42 % of the global production.

According to Guntis (2002) in 2001, EOR was used to produce 108 Mt or about 3.9 % of the global oil production (Info box 2). Newer detailed data for global EOR-production are not available. With rising prices for petroleum, the number of projects increased over the past few years. The most important countries with EOR-projects are the US, Venezuela as well as Indonesia, Canada and China. Pusch (2007) estimates the potential of petroleum based on EOR available for Europe to be 1.4 Gt, of these 1 Gt in the offshore-areas; for the US it reaches 13.6 Gt.

Globally, the oil production of 2007 was performed by approximately 873 000 production wells. Thus, in 2007 in the global average one borehole produced 4447 t of crude oil. In comparison to 2001 this means a decrease by approximately 39 000 production wells and an increase in productivity by 223 t/a per well. Regionally, the performance of the production wells shows significant differences (Tab. A 3-14). The highest production rates occurred for wells in the Middle East with an average of 107.5 kt/a and Africa with 44 kt/a. The region with the lowest production rates is North America with 1.1 kt/a on average. The majority of the production wells is concentrated in a few countries. The US has a special position in this context. In spite of a reduction by more than 40 000, the USA still has approximately 500 000 wells, thus approximately 57 % of all oil wells worldwide, which taken together produce only 8 % of the global oil production. Together with the US, Russia at 11.4 %, China at 8.2 % and Canada with 7.0 % possesses nearly 84 % of the wells. In comparison, the countries of the Middle East with only a little over 1 % of the wells produce nearly 31 % of the global oil.

3.2.5 Costs of Petroleum Extraction

In the *upstream*-area of the petroleum industry, comprising exploration, field development, production and processing, four types of cost can be differentiated (IFP, 2004):

- Exploration costs incurred mainly before the discovery of a hydrocarbon deposit;
- Investment costs for the investigation of the field for decisions concerning the development of the field;
- Development costs with costs for drilling the production wells, construction of the surface installations as well as transport facilities and loading terminals at the fields and
- Operating costs including transportation costs.

The sum of these costs makes up the total costs for a project. The specific costs constitute an important indicator, i.e. the costs for the production of a barrel or a ton of oil. In this context, different terms such as technical costs, production costs and extraction costs occur, for which the cost categories contained are not identifiable. The *supply costs* of oil (in USD/b crude oil) contain the finding and development costs as well as the *production/operating* or *direct lifting costs* including a 15-% discounting, but without taxes.

As an example, the EIA (EIA, 2008b) lists different cost categories for 30 US oil companies operating internationally, who deliver data as so-called FSR (Financial Reporting System) companies for their global operations. *Finding costs* and *lifting costs* are differentiated; the latter contain the direct lifting costs and the production taxes. The sum of both cost categories makes up the *total upstream costs*. The development of the specific *total upstream costs* from the start of the 1980s (Fig. 3.11) shows two tendencies. During the 1980s and 1990s a trend towards lower costs in the wake of the implementation of technological advances has been observed, at the start of the 21st century a significant upswing occurred, which is mainly due to higher finding and development costs. Besides reduced increases in reserves, the costs for energy, materials, equipment and personnel, which rose steeply together with the oil price, are at the root of that. In the course of the current financial crises and decreasing prices for oil and commodities, a fall in the specific costs should become noticeable in future years as well.

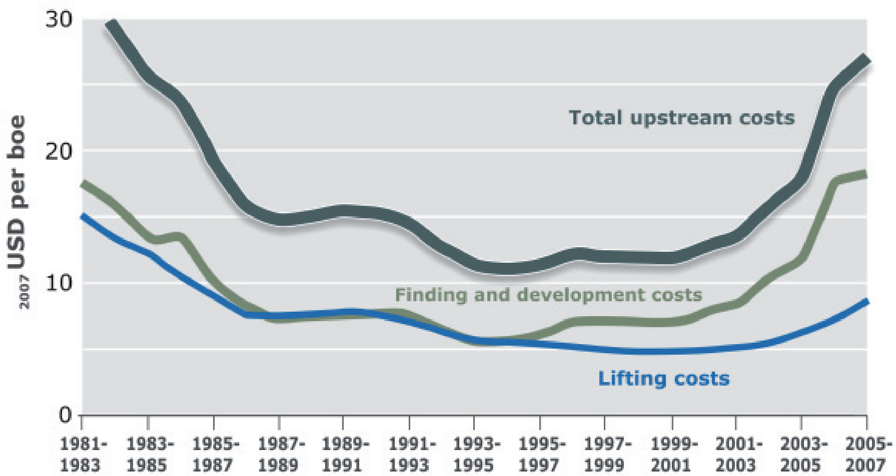


Figure 3.11: Finding and development costs, lifting costs and specific upstream costs for FRS companies, 1981-1983 to 2005-2007 (EIA, 2008b).

There are strong regional differences for specific costs. This concerns in particular the finding and development costs (Tab. 3.2). Here, the Middle East comes off best, even though the most important producing countries (Saudi Arabia, Iran and Iraq) have not been considered because of the dominance of national oil companies (Info box 1). These costs are highest in the offshore areas of the US, due to the high daily rates for drill ships and offshore platforms and the high material intensity of the producing systems. For the producing costs, the differences between the regions are significantly lower (EIA, 2008b).

Data concerning the expected upstream costs for conventional oil by the IEA (2008a) and by Petrobras (2008) envision for conventional oil a variance of less than USD 2/b to USD 100/b (Tab. 3.3). The extraction costs for petroleum from the Middle East, in particular from the states of the OPEC, are the lowest. The extraction of petroleum from the deep sea and in the Arctic using EOR-processes is considerably more expensive than the average of the other regions. As here in particular options for additional petroleum potential in future are envisioned, it can be derived from the numbers that the price of petroleum will rise.

Table 3.2: Specific finding and development costs as well as upstream costs by region for FSR companies 2004-2006 and 2005-2007 in 2007 USD/boe (EIA, 2008b).

Region	Finding and Development Costs		Upstream Costs	
	2004-2006	2005-2007	2004-2006	2005-2007
US Total	15.95	17.01	23.71	26.48
Onshore	11.54	13.38	19.90	23.45
Offshore	65.49	49.54	71.69	57.20
Outside US total	20.06	20.70	26.91	28.58
Canada	19.89	12.20	27.31	21.12
Europe	23.41	31.58	30.61	40.29
CIS	n.a.	n.a.	n.a.	n.a.
Africa	26.36	38.24	33.01	45.98
Middle East	5.41	4.77	14.70	14.85
Other Eastern Hemisphere	13.03	20.56	19.36	27.52
Other Western Hemisphere	43.87	20.30	49.05	36.14
Worldwide Total	17.65	18.48	24.92	27.10

Table 3.3: Mean total upstream costs of conventional oil according to type and region of the occurrences (IEA, 2008a, Petrobras, 2008).

	IEA (2008) (USD/b)	Petrobras (2008) (USD/b)
Middle East	3 – 14	7 – 19
CIS	n.a.	15 – 35
Deep water	32 – 65	23 – 45
EOR	30 – 82	25 – 63
Arctic	32 – 100	25 – 50
Other regions	10 – 40	12 – 30

3.2.6 Oil Consumption

The oil consumption (petroleum products) rose in 2007 by app. 460 Mt in comparison to 2001 and reached a historic high at app. 3.9 Gt. The consumption is distributed very unevenly when groups of countries and regions are regarded. While the OECD countries consume a little more than 56 % of the mineral oil at 2.2 Gt, the OPEC states consume only little more than 9 %. The regions showing the highest consumption are Austral-Asia, North America and Europe (Tab. A 3-15, A 3-16). Since 1978, Austral-Asia and North America showed the greatest increases, whereas consumption in Europe stagnated and even slightly decreased in the course of the previous years. When production and consumption of individual regions are compared (Fig. 3.12), a definite dominance of consumption over production results for

North America, Austral-Asia and Europe. For the Middle East, Africa, Latin America and the CIS production surpasses consumption.

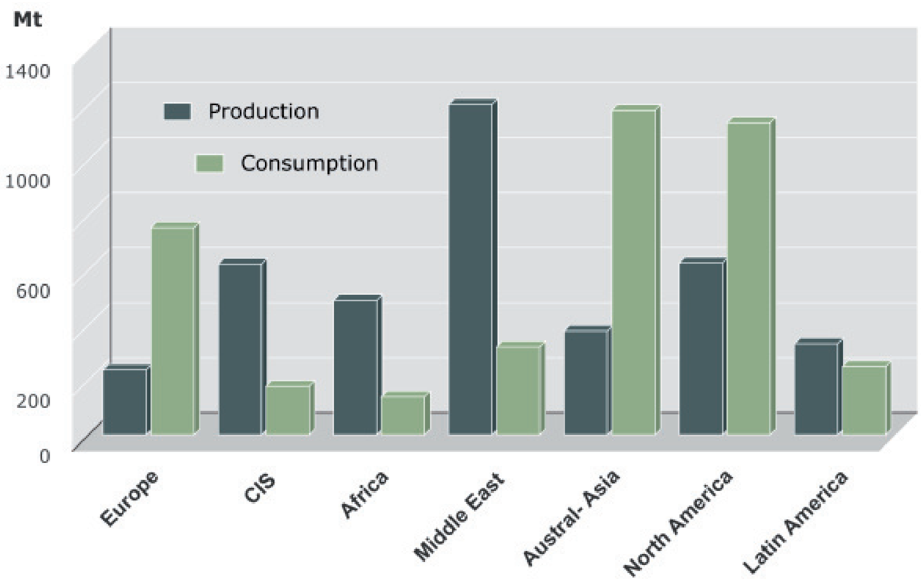


Figure 3.12: Comparison of oil production and consumption in 2007 by region

The top ten countries by oil consumption in 2007 used approximately 58 % of the global consumption. The US are still the largest consumer at 943 Mt, corresponding to nearly a quarter of the global oil consumption (Fig. 3.13, Tab. A 3-16). The subsequent five largest consumer-countries together consume this amount again. Saudi Arabia is the only OPEC country amongst the top ten consumer countries. Germany took eighth place in the consumption, raking in 2007 at about 102 Mt, corresponding to 2.6 % of the global consumption.

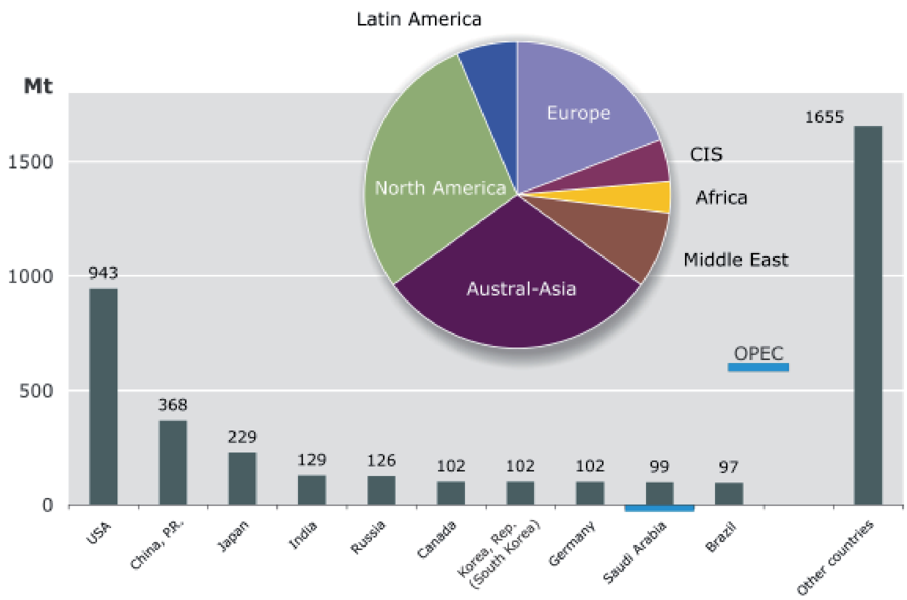


Figure 3.13: Consumption of oil in 2007 (total 3.8 Gt) of the top ten countries as well as distribution by region.

When regarding the per-capita oil consumption (Tab. A 3-17), Singapore has the highest value at 9.9 t/capita. High values of more than 3 t/capita are also shown by countries from the Middle East such as Kuwait, UAE, Qatar and Saudi Arabia but also the US and Canada. In the EU countries, the values vary between 0.5 t/capita in Romania and 5.8 t/capita in Luxemburg. The majority of the countries in the EU show consumptions between 2.0 and 3.0 t/capita and thus significantly above the global average of 0.6 t/capita.

3.2.7 Crude Oil Transport and Trade

Crude oil is traded globally as the main producing regions of petroleum are not identical to the most important consumer regions. Thus, of the oil produced in 2007, approximately two thirds, i.e. 2.2 Gt, have been transported across boundaries and in some cases over long distances, mainly by tanker or pipeline. Smaller amounts have also been transported by rail (Fig. 3.14).

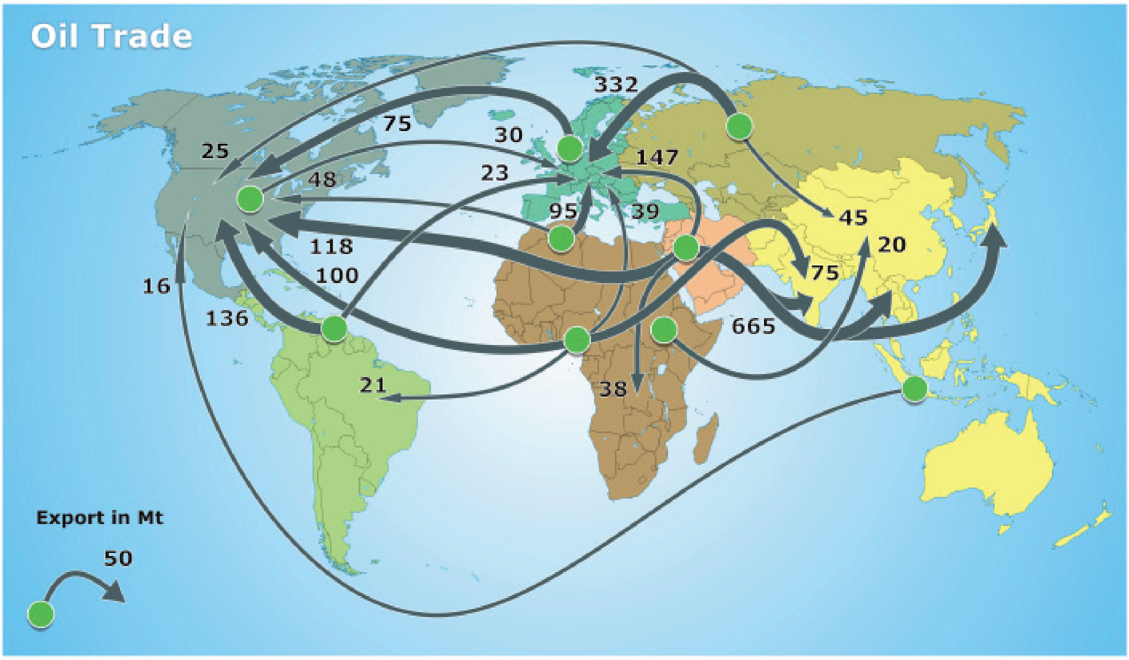


Figure 3.14: Global oil trade movements (crude oil and petroleum products) in 2007 in Mt (according to BP, 2008) without consideration of intraregional trade

When determining the import and export values for the individual countries, the data of the IEA (2008a), of BP (2008) and of the OPEC Annual Statistical Bulletin 2007 as well as national data have been taken into account. The most important export regions in 2007 were the Middle East with 38 % of the exports, Africa with 17 % and the CIS with 16 %. The top six exporting countries with amounts above 100 Mt – Saudi Arabia, Russia, Iran, Nigeria, Venezuela and the United Arab Emirates - covered in 2007 nearly half of the global exports (Tab. A 3-18). The top four importing countries - the US, Japan, PR China and South Korea - received half of all global imports (Tab. A 3-19).

Oil is largely transported through pipelines on the continents. Between the continents, such as from the Middle East to Europe, Asia and America, from Africa to Europe and America as well as from Latin America to North America, oil is transported by tanker or in a combination of tanker and pipeline transport. The transport by tanker predominated in 2007 at a proportion of approximately 75 to 80 %.

Specific transportation costs in relation to the energy content are considerably lower for oil than for natural gas, in particular because of the significantly higher energy density of oil (Fig. 3.15). This is also a reason for the fact that no global trade of natural gas has ever been established (Chapter 4.2.7). For petroleum, transport by tanker is cheaper than transport via pipeline. The trends listed in Figure 3.15 can only be regarded as average values, as the costs of transportation depend on several conditions as the size of the vessel and the capacity of the pipeline. Additional influencing factors are the prices for the raw materials and the general situation of the market. Thus, at times of high prices and limited transportation capacities the freight costs rise significantly.

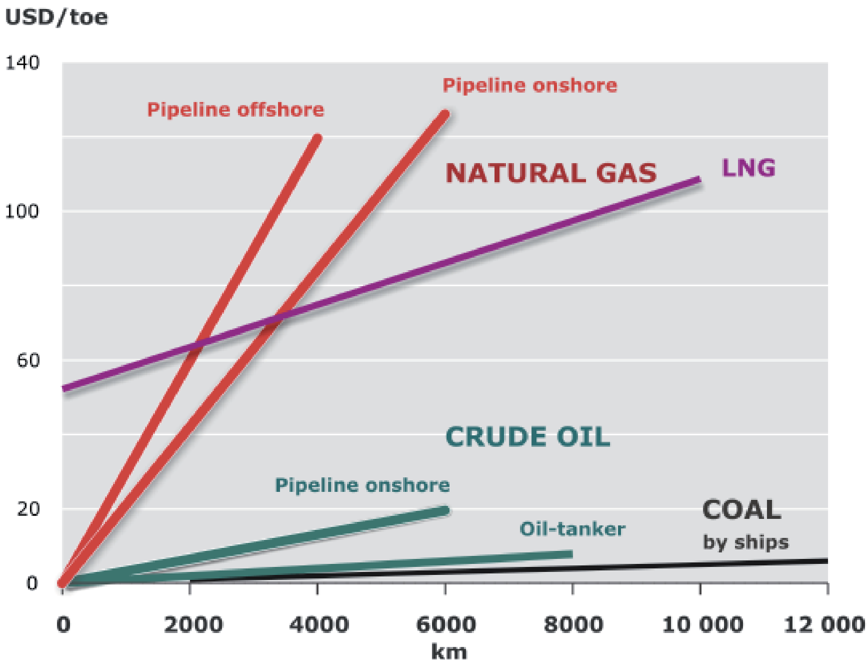


Figure 3.15: Comparison of the transportation costs for oil, natural gas and coal (according to Hatamian, 1998 and VDKI, 1999).

During the past years, a number of large pipeline projects were realized, which are important in particular for supplying Europe. The pipelines Caspian Pipeline Consortium Project (CPC) and Baku-Tbilissi-Ceyhan (BTC) were commissioned, which transport oil from the Caspian region to ports of the Black and the Mediterranean Seas.

3.2.8 Crude Oil Prices

The oil prices constitute today, 150 years after the start of the age of petroleum, a key factor for the world economy. Because life in our modern industrial society is linked to a high degree to the availability and affordability of the required energy, the price for oil as the still most important energy source has a leading function, also for other energy and mineral resources.

The historical development shows that, before the foundation of the OPEC in 1960, the oil price had been largely controlled by the multinational, private oil companies. Its fixed nominal value was USD 2/b to USD 3/b (Tab. A 3-20), which corresponds to – taking inflation into account - USD 10/b to USD 15/b today. During this period, the high profits of the oil companies were faced with comparatively low shares of the profits of the producing countries. This changed drastically when the OPEC actively influenced the petroleum market for the first time in 1973 with a delivery boycott against the USA and the Netherlands. The proportion of the global petroleum production of the OPEC had increased continuously until then and reached more than 50 % of the total production (Fig. 3.10). Such a strong position enabled the OPEC to establish the price for crude oil independently in 1973 and to nationalize the oil companies active in their member states altogether or in part. The nominal oil prices then increased to more than USD 11/b (Fig. 3.16). Even though the prices recovered in the 1980s, the worldwide petroleum market was changed significantly by these events.

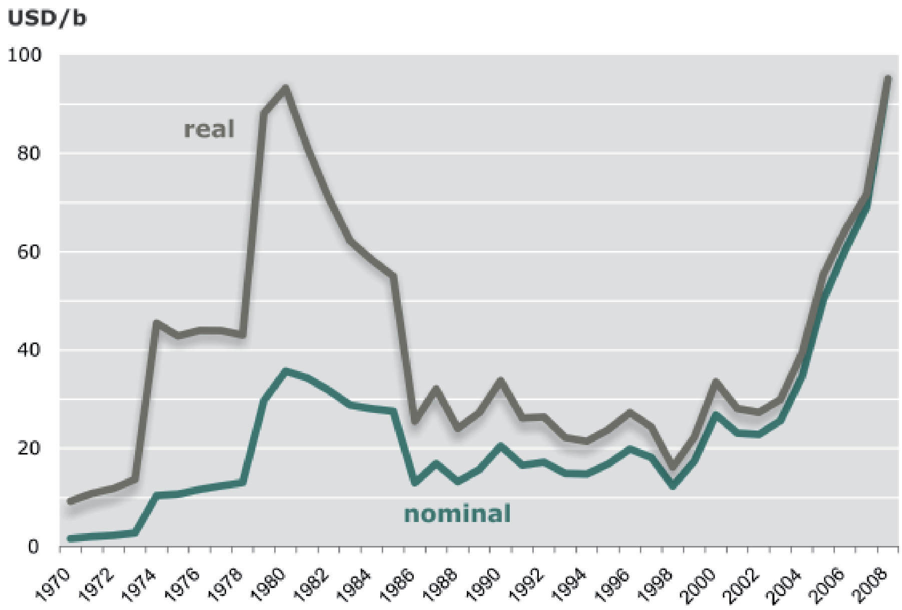


Figure 3.16: Development of the prices for crude oil between 1970 and 2008 real ($_{2008}$USD) and nominally (current rate of the currency) for the oil type Arabian Light in mean annual values.

Triggered by the Iranian revolution in 1979 and the Iran-Iraq war, the second oil price crisis entailed a price increase to more than USD 35/b nominally. These events had been preceded by a further increase in the oil consumption and a disadvantageous global development of the reserves-to-production ratio. The industrial countries reacted on these developments by reducing their energy consumption and developing their own new oil sources. The resulting surplus of petroleum was countered by the OPEC with the establishment of production levels. This artificial shortage was intended to stabilize the price at a higher level. This strategy was undermined by a lack of production discipline within the OPEC and had negative consequences in particular for Saudi Arabia, which had the role of *swing producer*. Saudi Arabia countered this development in 1986 with guaranteed profit agreements with refineries, the so-called *netback pricing* and increased production. The other OPEC countries followed suit and in consequence the oil price decreased from the mid-80s to a level below USD 20/b nominally. Even though the OPEC returned to fixed prices, the oil price remained at about USD 20/b nominally until 1997 without significant fluctuations.

In the wake of a financial crisis in Asia and a significantly reduced oil consumption as well as lacking production discipline of the OPEC countries, in 1998 a considerable decline of oil prices down to below USD 10/b nominally occurred. This very low price induced many petroleum companies to limit their exploration activities significantly. In addition, the economy of the producing countries was severely strained. For the OPEC countries alone, this corresponded to shortfalls in the oil business in 1998 of about USD 50 billion, corresponding approximately to one third of the intended total revenue. As a consequence, the OPEC countries agreed on production restrictions, which were largely adhered too. The aim was to keep to a price range between USD 22/b and USD 28/b. Thus, the oil price skyrocketed to more than USD 30/b nominally at the end of 2000. In the first three quarters of 2001, it was within the price range named, but after September 11th, 2001, it fell beneath USD 18/b nominally. Only massive production cutbacks of the OPEC countries by 1.5 million b/d and of other producing countries (Mexico, Norway, Russia, Angola) were able to stop the price drop at the beginning of 2002.

During the past five years, the petroleum price as a whole increased significantly (Fig. 3.17). An interim downswing from September 2006 to January 2007 showed a lowest daily price for the type Brent of about USD 52/b. Due to the subsequent reduction of production by OPEC, the oil price rose continually up to a price of more than USD 90/b until the end of 2007. This trend lasted until the middle of July 2008 with a record price of more than USD 145/b. Ever since, the oil price has shown a clear downward trend to USD 40/b at the end of 2008. Because of the weak Dollar exchange rate in recent years, the price increases for imports of oil to the Euro area were attenuated (Fig. 3.17).

The **causes for the high and volatile oil prices** of the past years have been the subject of controversy by specialists. Some see an indication of an approaching shortage of reserves, others blame a mixture of different factors, such as the globally increasing demand, the artificial limitation of the supply of oil by the OPEC, lack of capacity reserves, cost inflation of equipment, material and personnel, supply interruptions due to strikes, political instability in producing regions and fear of terrorist attacks, the weak US-Dollar and speculations in the capital markets.

As crude oil is traded globally at relatively uniform prices, which are largely independent of an individual deposit and its supply costs, on the side of the producers three investment risks play an important role. They only take these risks if the expectations of profits are appropriately high. For one, the exploration can remain unsuccessful due to erroneous geological or technical assessments. Secondly, changing political conditions can negatively influence the economy of deposits. Thirdly, it cannot be assessed accurately how prices and demand will develop in the face of unsecured forecasts for renewable and unconventional energy resources as well as future market conditions and political framework over the years. On top of that, as a rule a period of several years up to 20 years passes from the first investments for the exploration of a deposit until the start of production. During this phase, the highest costs accrue. In comparison, the pure production costs are comparatively low. The costs for exploration and development will be much higher in particular in the new frontier areas, the Arctic and on the continental edges as well as for unconventional oil than in the traditional oil provinces, where still *cheap* petroleum can be produced.

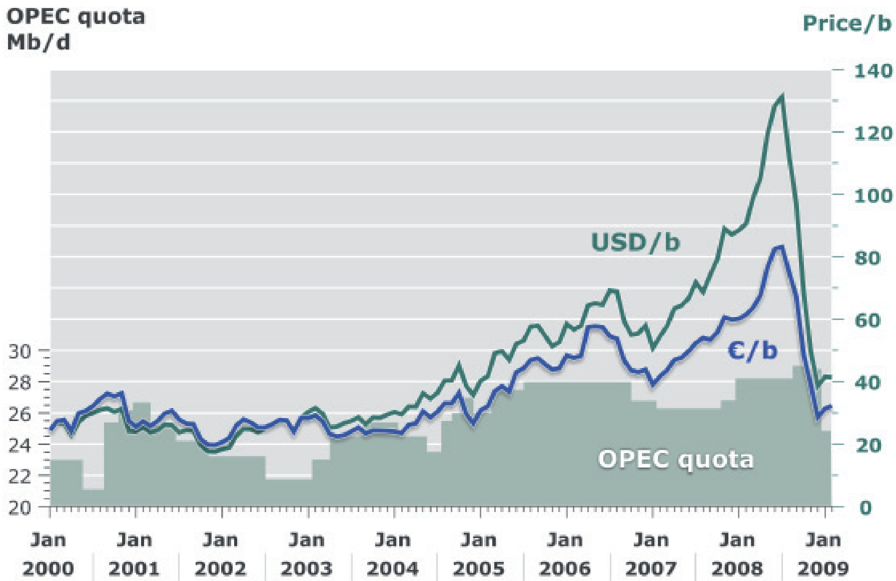


Figure 3.17: Development of the oil prices for OPEC basket in USD and Euro per barrel (monthly mean) as well as the OPEC-10/OPEC-11 (from 9/2008) production quota.

The extraction of petroleum as a finite resource, which can only be produced with high technical expenditure and effort is limited in its speed. Deposits, on which production has started, show as a rule a characteristic course of production, which is largely independent of demand. It is mainly dependent on the geological conditions and the installed production systems. There is very little possibility of reacting to increased demand in individual deposits and if any, the reaction is very slow. Correspondingly a decreased demand means a surplus-production or the necessity of throttling production.

Just like the supply, the demand can only react very sluggishly to shortages of the supply in the face of many various dependencies and a lack of alternatives in the energy mix. Small changes of the supply-demand equilibrium can thus result in quick and severe price fluctuations. An important instrument for influencing such situations is a sufficient reserve capacity for the production of oil. The reserve capacity has been defined as additionally produced amount, which can be supplied within 30 days for at least 90 days. If this is low, it can be interpreted as indication of a lack of competition or insufficient investment activities in the development and production of oil. For a low reserve capacity, there is also a risk of rising prices and increased volatility due to supply bottlenecks in the case of short-term, unforeseen production downtimes due to storms in producing regions or terrorist activities and for unexpected increases in demand.

Oil price fluctuations are also at the root of the effort to safeguard the bilateral physical oil trade via commodities futures trading. This gives expectations concerning the oil price and the reaction to the expectations the rank of significant market factors. The real physical trade between petroleum producer and buyers is conducted on the basis of bilateral supply contracts. There are great risks for purchasers and vendors of oil due to the severe price fluctuations; in order to reduce these risks, long-term contracts are concluded. For this reason, legally binding obligations are entered into, to buy or sell pre-determined amounts of oil of a certain quality at a certain point in time and for an exactly negotiated price (*futures*). This trade in *futures* is conducted at commodity futures exchanges such as the *New York Mercantile Exchange* (NYMEX) and is subject to supervision by regulatory authorities such as the *Commodity futures Trading Commission* (CFTC). For *futures,* every sales contract always corresponds to an identical supply contract. During their terms, the contracts can be dissolved, if two corresponding purchasing and sales agreements can be found. At the time of this equalization, the amount of money one contract party has to pay to the other is calculated. Such a procedure of premature equalization is the rule. In practice, there is usually no physical delivery of oil in such a case. Futures thus serve primarily as protection (*hedging*) against price fluctuations.

Different protagonists are involved in this business, who frequently are not involved in the real oil business at all or only indirectly. Besides the *hedgers* for the protection of the oil transactions, there are speculators, who bank on revenue due to assuming risks. Their involvement infuses a greater liquidity into the market. This group of speculators has been blamed in conjunction with the high oil prices of the past years in public of being the true profiteers and thus the driving force of an oil price bubble, as they might profit from price fluctuations. In principle, it is quite possible that the complete process of trading *futures* influences the oil price (Fattouh, 2007). If the definition of a bubble (*asset bubble*) as a situation, in which the asset value surpasses the fundamental value of the traded good oil, is used, a bubble cannot be used when speaking of the oil price. The individual contract price is based on the spot price and thus corresponds to the fundamental value of the oil. Extensive analyses about the role the speculators have played have been prepared for instance by an expert commission by invitation of the US stock exchange supervision authority *Commodity Futures Trading Commission* (CFTC) (Interagency Task Force on Commodity Markets, 2008) and (Büyüksahin et. al., 2008).

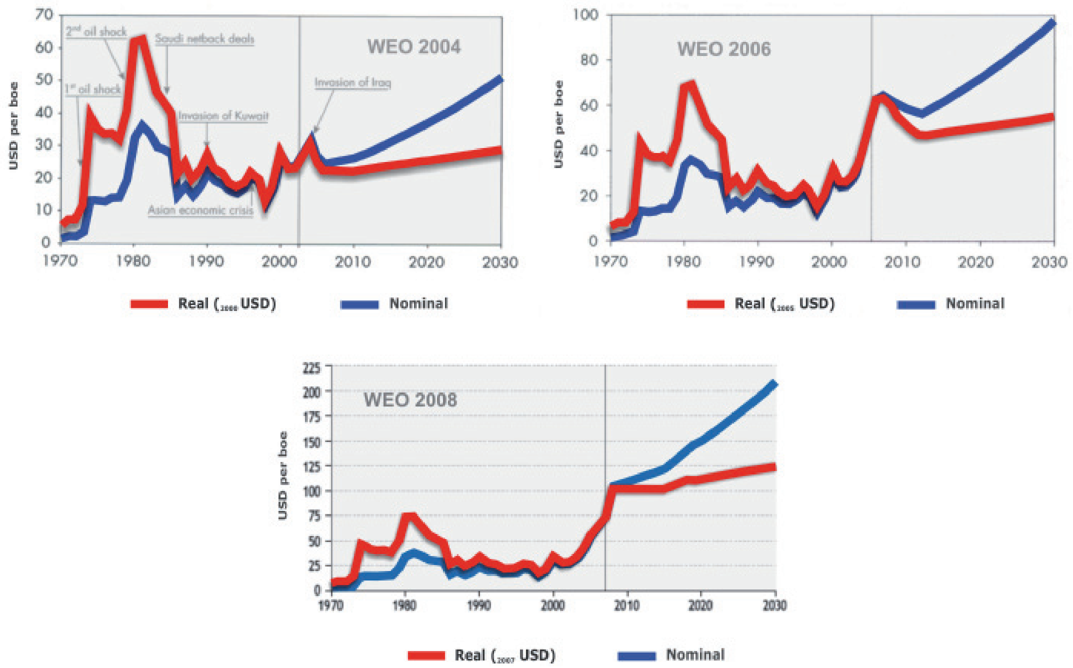


Figure 3.18: Comparison of different oil price forecasts of the IEA (IEA, 2004, 2006, 2008a)

The problem of preparing a forecast of the petroleum price including the numerous incalculable parameters can be gleaned from many published oil price scenarios. Thus, for instance, the IEA repeatedly published price scenarios in their World Energy Outlook (WEO) during the past years, which differ fundamentally from each other; no scenario reflected the true development (Fig. 3.18). Whereas the WEO 2004 (IEA, 2004) had assumed a real oil price of USD 29/b for 2030, this value was increased to USD 55/b in the WEO 2006 (IEA, 2006) and is USD 122/b for the current WEO 2008 (IEA, 2008). Even if the differing price bases are taken into account (2000, 2004 and 2007), the deviations are considerable and demonstrate the difficulty of forecasting oil prices. In contrast, Merrill Lynch warns in its Global Outlook Report for 2009 that the oil price in the year 2009 might fall beneath USD 25/b, in case China is also struck by the recession (Financial Times, 4.12.2008). Thus, in future a great fluctuation range and unforeseen deflections of the oil price shall have to be dealt with.

3.3 Unconventional Oil

A uniform definition of the term unconventional oil is currently not accepted. In accordance with Chapter 2.3.1, the pragmatic reason for the differentiation between conventional and unconventional oil is the greater technical effort and expenditure for extracting unconventional oil. Unconventional oil comprise bitumen or crude oil from oil sands, extra-heavy oil and crude oil from oil shale (Chapter 2.3.1). Thus the denomination unconventional refers to geological aspects of the formation and properties of the deposits as well as technical necessities for an ecologically acceptable, economical exploitation.

3.3.1 Oil Sands – High-Viscosity Oil in Sandstone

Oil sands are naturally occurring mixes of bitumen, water, sand and clay. On average, oil sands contain approximately 12 wt. % bitumen, a high-viscosity petroleum. The individual grains of sand are coated by a thin film of water of some µm and this in turn is surrounded by the high-viscosity oil. Oil produced from oil sands is also called natural bitumen or synthetic crude oil (SCO). It is a sticky, high-viscosity form of petroleum, which behaves like cold syrup at room temperature. Up to 50 % or 60 % it consists of substances comparable to conventional oil, 25 % to 35 % are resins and 15 % up to 25 % are asphaltenes. The components of the oil itself vary with the region of occurrence just as do traces of heavy metals, such as iron, molybdenum, nickel or vanadium. On average, the percentage of carbon is little more than 80 %, that of hydrogen is around 10 %, sulfur ranges from 3 % to 5 %, dissolved oxygen is 0.9 % and nitrogen ranges from 0.36 % to 0.7 %. Bitumen has a density of more than 1 g/cm³ (≤10° API) and a viscosity of more than 10 000 mPa·s. In the reservoir, bitumen is not capable of flowing.

In general, heavy oils and all transitions up to bitumen are the results of secondarily altered, previously conventional petroleum occurrences. Reservoir rock is generally highly porous and permeable fluviatile sandstone of deltaic or very near-shore sedimentary environments. In the case of the gigantic Canadian oil sand occurrences, the oil migrated from the deeper source rocks of the western Canadian sedimentary basin over a lateral distance of up to 360 km into the more shallow sandstones of the Aptian and Albian (upper Lower Cretaceous). Here, organic mudstones of the Devonian or Carboniferous are considered petroleum source rocks. In the course of its migration the petroleum was biodegraded by microorganisms in the rock: The light hydrocarbon molecules were degraded in the course of the microbial activity, the heavy, complex molecule chains were left behind and today make up the bitumen rich in sulfur in the deposits.

Oil sand occurrences are known in more than 20 countries (Fig. 3.19), in nearly 600 individual occurrences (WEC, 2007). The total potential of petroleum in oil sands all over the world is extraordinary large and has been assessed at about 462 Gt in-place. Of these, Canada and the CIS together possess 98 %. The best-known and most important oil sand occurrences are located in Canada. The Energy Resources Conservation Board (ERCB) of Canada estimates that approximately 27.5 Gt of crude oil in oil sands in the state Alberta have to be regarded as reserves. This corresponds to about 17 % of the reserves of conventional petroleum. The reserves and resources shown in table A 3-21 of the countries with the greatest oil sand occurrences should largely be regarded as assessments, as the data basis for many countries is still rather inadequate.

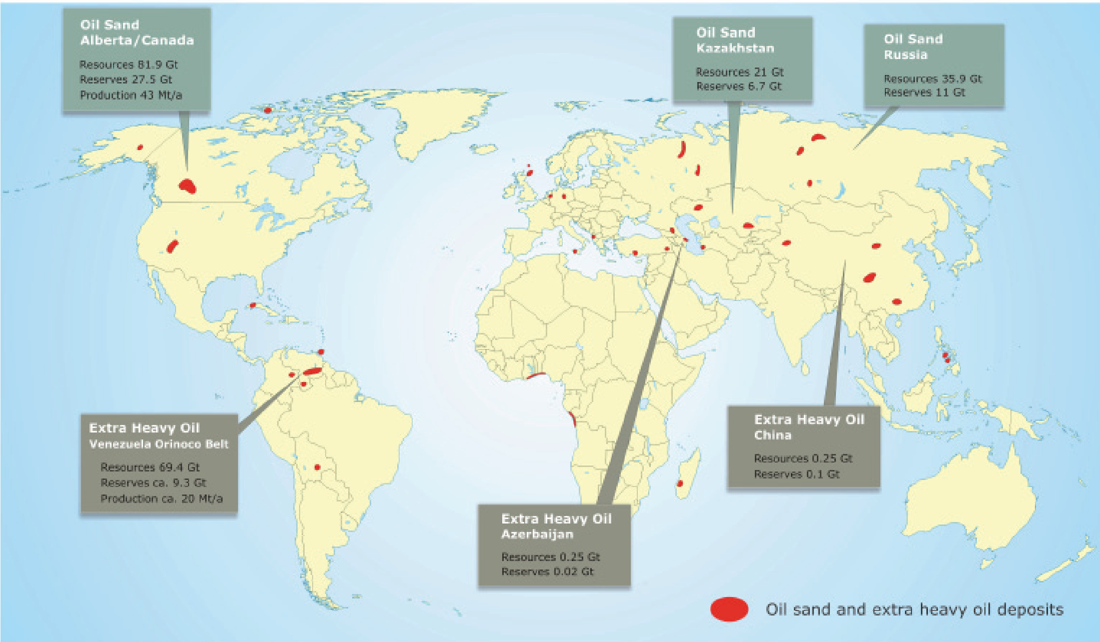


Figure 3.19: Distribution of the known worldwide occurrences of oil sand and extra heavy oils with information on reserves, resources and production.

Even if the oil sand occurrences are distributed over many countries (Fig. 3.19), the greatest part of the resources is concentrated in Canada, Russia and Kazakhstan. Of these, the Canadian occurrences have been investigated most thoroughly. Thus, the data on the amount of resources are still unreliable, last but not least because the distinction between heavy oil, extra-heavy oil and oil sands is not clear. Thus, of the estimated 200 Gt of unconventional oil in the CIS about half are oil sands. A major portion of these occurrences is bound to carbonatic reservoir rocks, whose treatment is technically even more difficult than for oil sands. The largest occurrences in Russia are supposed to be in the Tunguska Basin on the East Siberian Shelf, in the Timan-Pechora Basin and in the Volga-Ural Basin. In principle, it can be assumed that the reserves and resource data for oil sands in Russia are underestimated.

Even though for Kazakhstan large bitumen occurrences in the North Caspian Basin are known, their possible exploitation will not be started in the foreseeable future because of the still abundant conventional hydrocarbons. The oil sand occurrences in the US are distributed over several states, with the largest in Utah and Alaska, further smaller occurrences in California, Alabama, Kentucky and Texas. Large-scale mining is not intended here either, as either the geological setting is too complicated, the oil sands are located too deeply or are too thin. The bitumen occurrences in the Dahomey-Basin in southwestern Nigeria will only be considered, when the reserve situation of the conventional oil of the country decreases. In Indonesia, bitumen occurrences on the island Buton are known, but up to now they have only been mined for manufacturing road asphalt. For nearly 200 years, asphalt from an asphalt lake on Trinidad has been mined, which is also used as tarmac. The annual production here is 10 000 to 15 000 t.

Considerably smaller oil sand occurrences are known in Angola, Gabon, the Republic of Congo and the DR Congo. They are bonded to cretaceous sandstones. In Europe, marginal occurrences in Germany (cf. Chapter 8.1.5), France, the Netherlands, Poland, Romania, Spain, Switzerland and Hungary are known. The most interesting occurrences from an economic point of view of combined heavy oil/extra-heavy oil/asphalt in Europe occur in Sicily/ Italy. Here, heavy and extra-heavy oil have been produced since the 1950s.

The greatest and best-known oil sand occurrences are the **oil sands of Canada** in the northern part of the Province Alberta. They cover a surface of more than 140 000 km^2, which is mainly located in the three regions Athabasca, Peace River and Cold Lake. Currently, Canada is the only producer of importance of bitumen from oil sands. Already in 1967, then still with public subsidies, the bitumen production from oil sands was started. Only approximately 16 Gt, corresponding to 6 % of the *in-place* oil sand volume will presumably be available for surface mining. The remaining amounts are located too deeply and can only be produced using drill holes and in-situ processes. Canada quantifies its *in-place* volume of bitumen currently at 272 Gt, of which 27.5 Gt are listed as reserves (ERCB, 2008). Taking into account the proportion accessible for surface mining and the in-situ areas as well as the different degrees of oil recovery, oil sand resources of 81.9 Gt remain. Between 2000 and 2007, the crude oil production from oil sands in Canada has nearly doubled from 39 to 77 Mt per year. For 2007, this corresponds to not quite 2 % of the global production of petroleum. Until 2007, 940 Mt of natural bitumen were cumulatively produced in Canada.

Oil sands are produced by surface mining (ex-situ) as well as using the so-called in-situ-process. Both processes are aimed at extracting the petroleum or bitumen, respectively, and they are technically and energetically complex.

Oil sand mining via surface mining (ex-situ) is only possible for shallow deposits, if the oil sand layers are located at the surface or beneath a thin overburden. After the overburden has been removed, the oil sand layers, which are up to several meters thick, are mined using excavators. At a capacity of nearly 40 t per scoop, modern backhoes are more flexible and thus more economic than the bucket-wheel excavators used previously. Here, the largest trucks in the world are used with a capacity of up to 400 tons. The extracted oil sand is dumped in a stone crusher and hot water is added. This so-called slurry is transported to the treatment system via pipeline. During this hydro transport, the separation of bitumen and sand already starts. This process is continued in the separating container of the extraction system. During the subsequent flotation process, small air bubbles attach themselves to the released bitumen, it buoys and forms a foam layer in the upper part of the mixture, which can be siphoned off easily. By adding leaches as solvents, water and dissolved salts are separated from the oil. Sand and water accumulate in the lower part of the container. For recultivation purposes, the sand is returned via pipeline to the exhausted areas of the open pits. Water still containing sand, clay particles and residual oil is pumped into a settling tank. Still rising oil is skimmed, whereas the residual oil will be degraded by bacteria in the settling sand. The water treated this way can be re-used in the separation process. The recovery factor in the surface mining technique exceeds 90 %.

The production of petroleum from Canadian oil sands in open-pit mining operation is largely dominated by the three company syndicates Albian Sands Energy Inc., Syncrude Canada Ltd. and Suncor Energy. Additional companies have joined in the past few years. The total area allocated to surface mining here has increased from 470 km^2 in 2001 to 1320 km^2 in 2007. Simultaneously, the production of bitumen from surface mining has nearly doubled to almost 46 Mt (Fig. 3.20).

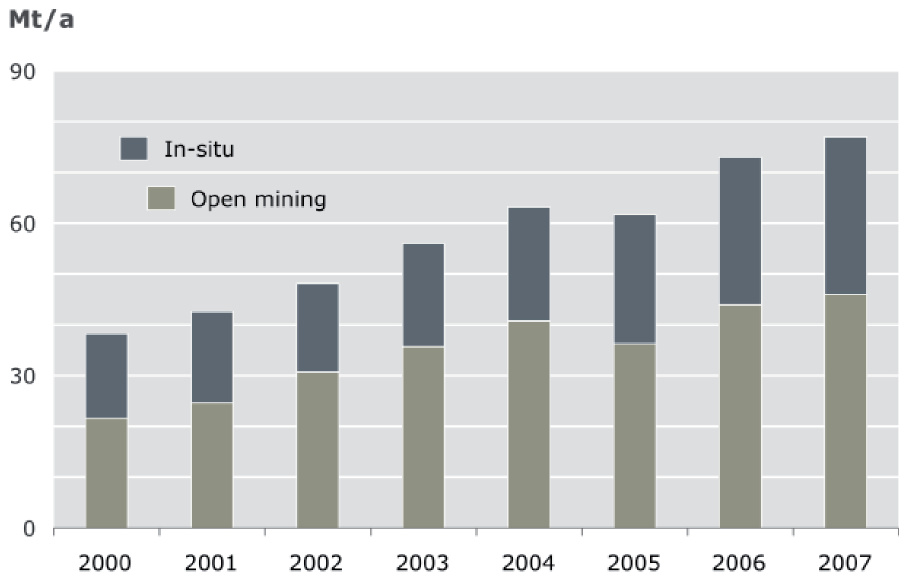


Figure 3.20: Proportions of surface mining - and in-situ processes of the oil production from oil sands in Alberta from 2000 to 2007.

The **production of petroleum from oil sands via the in-situ technique** is conducted for an overburden of more than 40 metres. In contrast to surface mining, the rock remains on site for this method. Hot water vapor is pressed through drill holes into the oil sand layer; it reduces the viscosity of the bitumen and renders the oil capable of flowing. Two different processes are in use:

For the *Cyclic Steam Simulation* (CSS) water vapor is injected at high pressure into a vertical bore hole. The heat reduces the viscosity of the bitumen and the capacity for migration is supported by the steam. The pressure produces micro-cracks in the rock, which additionally improve the influx of bitumen to the borehole. After an inclusion period of several weeks, the production phase is started through the same borehole. If the production rate decreases, a new injection phase is started. The disadvantage of this method is the limited radius of the oil removal. To attain a sufficient degree of oil removal, a close borehole pattern is required.

For the *Steam-Assisted Gravity Drainage process* (SAGD) two horizontal boreholes are drilled in vertical distances from 5 m to 10 m in the oil sand layer. Hot water vapor is injected into the upper borehole and the liquefying bitumen can be extracted through the borehole below.

Other in-situ methods, such as the injection of solvents into the reservoir rock, electrical and electromagnetic processes, the use of microwaves or the combustion while supplying oxygen have been tested repeatedly. All these measures are aimed at increasing the flowability of the highly viscous bitumen and at attaining a greater oil output. The SAGD-production seems to be the most economical method. For this purpose, about 2.5 m³ to 3 m³ water, of which 80 % to 90 % can be re-used via recycling processes, are needed for producing 1 m³ bitumen. For the in-situ extraction, the recovery factor varies from 25 % to 75 %, depending on the geological conditions and the in-situ technology used.

Many companies operate on more than 63 000 km² of concession area awarded for the in-situ production of bitumen. Production could be increased from 18 Mt bitumen in 2001 to about 31 Mt in 2007 (Fig. 3.20).

For the future, a further expansion of the oil sand production in the open-pit mining operation as well as for the in-situ-production is intended. The ERCB 2008 estimated for 2017 a total production of 187 Mt of bitumen. Of these, 102 Mt are to derive from open-pit mining operations and 85 Mt from in-situ degradation. For this development, investments of at least USD 93 billion will have to be raised.

The processing of petroleum from oil sands in traditional refineries is uneconomical or technically impossible due to the high percentage of long-chain hydrocarbon molecules and the inherent high C/H-ratio. Thus, bitumen has to be processed in special treatment plants or converted into light oil beforehand. The bitumen from separation facilities is transported to the treatment system, the upgrader, using pipelines. To maintain the necessary flowability in the pipeline, the density and viscosity of the bitumen is reduced by diluting it using light oil or condensate from other sources. For this purpose, the addition of 17 % to 32 % diluting agent is necessary depending on the initial quality of the bitumen. 2007, in Canada 20 300 m³/day high-value light oil were required per day for the treatment of bitumen. The domestic production of such light oil in Canada was only slightly above that value at approximately 23 500 m³/day, with decreasing tendency. In order to satisfy the rising demand, light oil is to be increasingly imported from the US.

In the upgrader, the natural bitumen is then converted into SCO, which corresponds to commercially available light oil. To this end, the long molecule chains of the bitumen are split into short chains. This is either done in a coking process by removing carbon or by *hydro cracking*, i.e. the addition of hydrogen at high pressure. In a second step, *hydro treating*, the resulting products naphtha, kerosene and gas oil are chemically stabilized and impurities, such as sulfur are removed. About 1.5 Mt of elementary sulfur resulted in 2007 in Canada from the oil sand production alone, which has been used in the chemical fertilizer industry or to manufacture gypsum.

The whole process of the oil sand extraction and treatment uses a lot of power and water. For generating steam for the in-situ-liquefaction and for upgrading to hydrocarbons of higher value, large amounts of natural gas are used. In 2007, the consumption of natural gas for the oil sand production in Canada was 9.9 billion m³ and will rise to more than 26 billion m³/a until 2017 (ERCB, 2008). In addition, large amounts of gas are emitted. In comparison to the light oil production, the oil production from oil sand releases approximately three times as much CO_2 per m³ crude oil (Flint, 2005). Due to the use of improved technology, it was possible to reduce the specific CO_2-emissions over the past years in spite of increased bitumen production. The total emissions could, however, increase in accordance with the intended increase from currently about 50 Mt CO_2 to up to 140 Mt CO_2 until 2020. Current analyses suggest that the internalization of external costs, for instance by CO_2-sequestration, do not jeopardize the competitiveness of the oil sand extraction, if the oil price is sufficiently high (Meyer-Renschhausen, 2007). While the sulfur-dioxide emissions were significantly reduced by the installation of exhaust desulfurization plants in the 1990s, they have increased ever since together with nitrogen oxides in the course of the growth of the oil sand production.

Surface water or groundwater is needed in open-pit mining operations for hydro transport, the extraction of the bitumen and for the generation of steam in the refining plants. In the in-situ operation, hot water or steam is used primarily for injecting it into the deposits. As meanwhile large parts of the water are recycled, the net demand in open-pit mining operations is 2.2 to 4.4 m³ water per m³ bitumen, for in-situ operations it is 0.2 to 0.3 m³ water per m³ bitumen.

In particular, surface mining of oil sand causes a considerable consumption of land. Even if the companies are obligated to conduct reclamation measures, the large-scale interferences in nature will remain visible for a long time. In the long run, however, it is to be expected that the in-situ production will cause greater disturbance of the environment (Meyer-Renschhausen, 2007). Ultimately only about 20 % of the oil sands can be extracted using open-pit mining operations. The major proportion of the oil sands would be produced using in-situ production, for which the land requirement consists of a close-meshed network of infrastructure systems, such as drill holes, access roads, pump stations and pipeline routes. In comparison with surface mining lower costs for recultivation measures occur. This advantage of the in-situ process is offset from a scientific point of view by the higher degree of oil removal in surface mining.

In particular, the increasing oil price of the past years has stimulated a few current development projects besides the production of petroleum from oil sands in the Canadian Province Alberta. For a number of years, in the neighboring province Saskatchewan, reinforced exploration of oil sands is conducted increasingly. The projects planned and the associated optimistic increases in production in Canada until 2020 and beyond, however, will have to be corrected considerably downwards because of the decline in oil prices since the middle of 2008. A number of companies have already delayed their projects or canceled them completely. In parallel, the Canadian oil sand industry has to deal with numerous different problems, such as the constantly high costs for personnel and material, reduced revenue because of lower oil prices, the credit crisis and growing resistance in the population. The Canadian Association of Petroleum Producers (CAPP) (Hyun, 2008 and CAPP, 2008) revised its production forecast for 2015, specifying a probable annual production of only 138 Mt per year, instead of 163 Mt as still forecast last year because of these developments. Other countries such as Russia or the US have not progressed beyond the stage of pilot projects.

Because of the high prices for energy in 2008, the Italian company ENI has assured exploration rights for oil sands in the Congo Republic, up to now neither the working commitments nor the current activities are known.

3.3.2 Extra-Heavy Oil

Extra-heavy oil with a density of ≥ 1.0 g/cm³ is similar to the bitumen of the oil sands, but its viscosity is less than 10 000 mPa·s. Thus, extra heavy oil in the reservoir is more capable of flowing than the bitumen of the oil sands. The sulfur content is on average around 5 %, nickel and vanadium contents are 130 ppm or up to more than 700 ppm. Deposits of extra-heavy oil are regionally widespread and are known in at least 18 countries in the world in more than 160 fields (Fig. 3.19). The total potential of the extra-heavy oil in-place is, in accordance with WEC (2007), about 246 Gt, of which approximately 47.9 Gt are listed as resources and 6.6 Gt as reserves (Tab. A 3-22). About 0.58 Gt of extra-heavy oil have been produced up to now. In both cases, Venezuela is the leader at about 97 % each, for the resources as well as for the reserves. Venezuela contributes 35 % of the global production, followed by Great Britain at 28 % and Azerbaijan at 21 %.

The increase of the crude oil prices since 2000 has triggered increased investments in the area of extra-heavy oil and resulted in a considerable increase in production. Even though the high-viscosity oil is more difficult to produce, to transport and to process than conventional oil, the production level has risen from approximately 20 Mt in 2001 to 93 Mt in 2005. This corresponds to a proportion of about 2 % of the global petroleum production. One problem with the assessment of extra-heavy oil is the difficulty of delineating it from other heavy oil. The information concerning extra-heavy oil in table A 3-22 can also contain proportions of heavy oil of unknown amounts.

In Israel's Dead Sea area, in Iran, Iraq, Egypt, Mexico and Poland relatively small and economically insignificant occurrences of extra-heavy oil exist. The occurrences in Italy, however, in particular those in the Caltanissetta Basin of Sicily, are the most important occurrences in Europe besides those in the British North Sea. The deposits of extra-heavy oil in China located in the Bohai Basin, the Huabei Basin and the Tarim Basin take second place with reserves of approximately 119 Mt. The occurrence in Azerbaijan with reserves of 20 Mt, already discovered in 1904, ranks third.

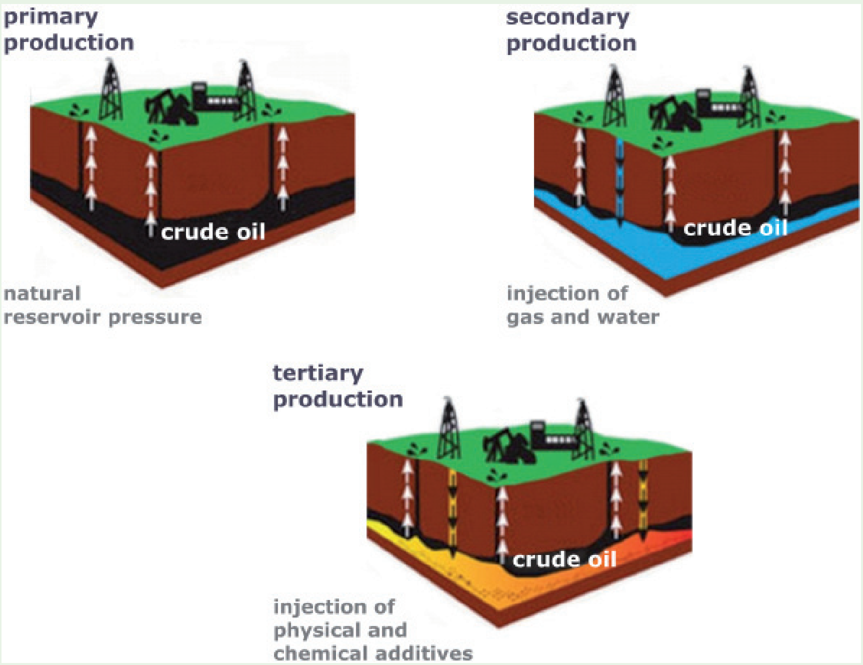
The worldwide largest occurrences of extra-heavy oil are located in the so-called Orinoco Belt in Venezuela with 46.8 Gt of petroleum resources and 6.4 Gt remaining reserves (Fig. 3.21). In 2005, the annual production of conditioned extra-heavy oil was approximately 33 Mt and thus 20 % of the total oil production of Venezuela, the third largest crude oil exporter in the world. The Orinoco Belt constitutes the southern edge of the East Venezuela Basin or Maturin Basin and extends at a width of 50 km to 100 km and about 700 km in east-west direction (Fig. 3.21). The deposits are largely related to Miocene sandstones in depths of 500 m to 1000 m, which rest on Cretaceous, Paleozoic and Precambrian crystalline of the Guyana Shield. Towards the north, where the basin is deeper, the extra-heavy oil successively turn into light oil. The petroleum mainly dates back to the Cretaceous and Oligocene up to Miocene source rocks. The oil has migrated between 100 km and 150 km from the petroleum source until it reached toady's reservoirs. During migration, the originally lighter petroleum was biodegraded to heavy and extra-heavy oil (Chapter 3.3.1).

EOR – How much Petroleum in a Reservoir can be Actually Produced?

In the global average, from a petroleum reservoir only approximately 35 % of the petroleum contained therein is being produced. This so-called recovery factor (RF) differs considerably, depending on the region. The average RF in Venezuela is currently only about 23 % and thus reaches the standard of US deposits of the year 1979. The US, in contrast, have increased to this day the recovery factor to 39 % on average. Deposits in the North Sea region currently rank leading in the world at approximately 46 %. The oil field Statfjord in the North Sea has attained the globally highest recovery factor at 66 %.

During production, part of the petroleum reaches the surface through the production well due to the natural pressure within the deposit. This process is called primary production. If additional measures are taken, these are called either secondary or tertiary production techniques (Enhanced Oil Recovery, EOR). The most important secondary processes in particular is the injection of formation or sea water and/or gas directly beneath or into the deposit, to maintain formation pressure.

Tertiary production techniques render the petroleum remaining in the deposit more capable of flowing by physical, chemical or biological measures and thus making it producible. Standard processes are thermal measures such as the injection of water vapor or of hot water and in-situ-combustion, gas injections, microbiological changes of the composition of the petroleum in the reservoir and chemical additives, such as polymers and tensides. Amongst the EOR-processes, currently the thermal methods dominate, they account for 69 % of the petroleum produced using EOR-methods. Processes using gas injection follow at a proportion of approximately 30 %. Which tertiary process is used depends mainly on the composition of the petroleum and the conditions of the deposits. A combination of different methods is also quite standard. As EOR-processes are expensive, their application is only profitable, if the additional production costs can be compensated by a higher production rate, higher RF or a correspondingly high petroleum price. Globally between 3 % and 4 % of the whole petroleum production are realized by tertiary production processes.



The production of extra-heavy oil is generally conducted using the same in-situ production processes as for the oil sand production. The injection of water vapor in vertical wells, but also the SAGD-process (Chapter 3.3.1) have become established because of the relatively good recovery rates. For the production of extra-heavy oil, new processes, which are even more efficient, are permanently looked for. For example, the so-called cold production is being tested, where horizontal wells are used to open a large section of the oil reservoir. It is attempted to extract sand and oil simultaneously from the deposit by adding solvents. Pilot tests using this method yielded production rates of 130 to 400 t/day with recovery factors of up to 20 %.

Currently, four major projects are active in the Orinoco Belt (Tab. 3.4). The treatment of the extra-heavy oil to produce SCO is only conducted right before it is exported, as Venezuela has a limited availability of light oil for diluting the heavy oil. For this reason, the processing plants are located at the north-east coast of Venezuela (Fig. 3.21). The conversion efficiency from extra-heavy oil to synthetic oil varies from 87 % to 95 %.

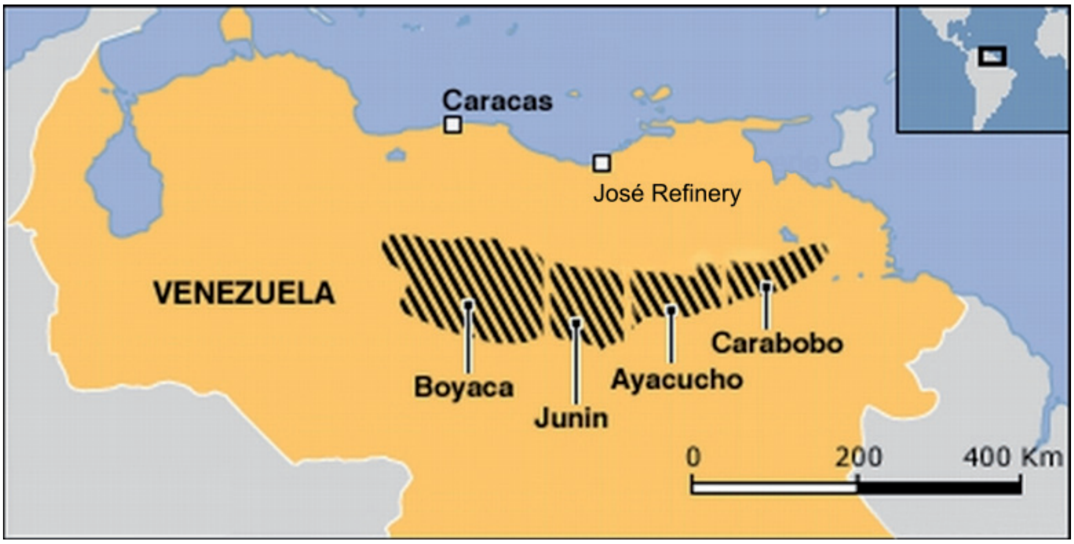


Figure 3.21: Major projects in the Orinoco Belt (hatched), source: PDVSA.

In the Orinoco Belt, approximately 42 Mt of extra-heavy oil have been produced in 2005 and processed to 34 Mt synthetic crude oil and 5 Mt Orimulsion®. In order to adhere to the specified production levels of the OPEC, the production of extra-heavy oil has been reduced by about 17 500 t/day (6.3 Mt/a) since the beginning of 2007. Orimulsion® is a special product of the Venezuelan petroleum industry protected by trademark, made from about 70 % extra-heavy oil, 30 % water and 1 % chemical additives. It has a low viscosity, is easy to transport and can be burned in power plants. Main customer countries for Orimulsion® were up to now Japan, Italy, Denmark and Canada. In order to ensure the Orimulsion® supply of two power plants in China, the Chinese National Petroleum Company (CNPC) formed a Joint Venture with the PDVSA. An investment of USD 330 million was used to push the Sinovensa project in 2006. At the end of 2006, PDVSA stopped the production of Orimulsion® as the direct marketing of the extra-heavy oil as SCO was more profitable. Venezuela considers Orimulsion® as a reserve for the future, thus the patent rights for manufacturing the fuel have not been sold.

Table 3.4: Extra-heavy oil projects in the Orinoco Belt, Venezuela (US DOE, 2006).

Project name	Junin (Petrozuata)	Boyaca (Sincor)	Ayacucho (Hamaca)	Carabobo (Cerro Negro)
Region	Zuata	Zuata	Hamaca	Cerro Negro
Company	ConocoPhillips, PDVSA	Total, StatoilHydro, PDVSA	ConocoPhillips, ChevronTexaco, PDVSA	Exxon Mobil, BP, PDVSA
Commissioning	1998	2000	2001	1999
Commissioning treatment plant	2001	2002	2004	2001
Production of extra-heavy oil (Mt/a)	7	11.6	11.6	7
Density of extra-heavy oil (°API)	9.3	8.0 - 8.5	8.7	8.5
SCO-production (Mt/a)	6	10.5	11	6.1
Densitiy of SCO (°API)	19 - 25	32	26	16
Sulfur (Wt. %)	2.5	0.2	1.2	3.3

3.3.3 Oil Shale – Petroleum still to be Generated

Oil shale is actually an immature petroleum source rock with a high proportion of organic material, which has not yet passed the geological conditions to turn into petroleum under natural conditions. The origin of oil shale can be a widely varied spectrum of depositional areas, consisting of ponds, lakes and swamps with fresh and salt water as well as the flat marine environment in the subtidal shelf area. Lithologically, oil shale originates frequently from calcareous mudstone and can have geological ages ranging from Cambrian to Tertiary. The organic material in oil shale, so-called kerogen, consists mainly of carbon, hydrogen and oxygen with small amounts of sulfur and nitrogen. Thermal treatment of the oil shale allows to extract shale oil. This oil derived from oil shale differs from natural petroleum by its higher percentage oxygen compounds.

The **extraction of oil shale** can be done by surface mining for shallow overburden from 30 m to 40 m. For this purpose a minimum thickness of the oil shale layer of 3 m and an overburden-oil shale ratio of less than 5:1 is advisable. In areas with thicker overburden, such as the deposits in Estonia, the oil shale is produced using underground mining. The rock containing oil shale is blasted and crushed in a stone crusher (Vaher, 1998). The material can then be processed differently. Either it will be burned directly for power generation purposes, like in Estonia, or by coking or carbonization higher-order hydrocarbons can be extracted, for instance in carbonization reactors, so-called retorts, with downstream distillation plants (e. g. Lurgi-Ruhrgas Process). For the in-situ method, oil shale is pyrolysed in the deposit without extracting it. Oxygen is added through drill holes to the ignited oil shale and the resulting gases are processed further. In particular deep oil shale occurrences, such as the *Devonian Black Shales* in the East of the US can only be exploited using the in-situ process. In the US there are currently experiments being run concerning the in-situ pyrolysis based on heating the rock electrically.

In order to extract crude oil from oil shale, the process of oil generation, which takes several millions of years under natural conditions and requires an increase of the temperature conditions, has to be accelerated by an artificial process. To this end, the oil shale is heated to 300°C up to 500 °C for pyrolysis purposes and subsequently cooled down to below 50 °C. The kerogen is converted to a gas mixture, out of which the so-called shale oil condenses during cooling. For an efficient use of oil shale, a minimum content of about 4 % oil is required. This corresponds to a gross calorific value of approximately 3300 kJ/kg in relation to the waterless oil shale. The oil content of oil shale is defined on the laboratory scale in accordance with the standardized pyrolysis process by Fischer–Schrader (Fischer Assay), which supplies reliable data about the technological quality.

Besides the use as energy fuel, shale oil is also used as raw material for the manufacture of different products of the chemical industry. Other by-products are coke, pitch, asphalt, ammonia, sulfur and in some cases metals such as gold, vanadium and uranium.

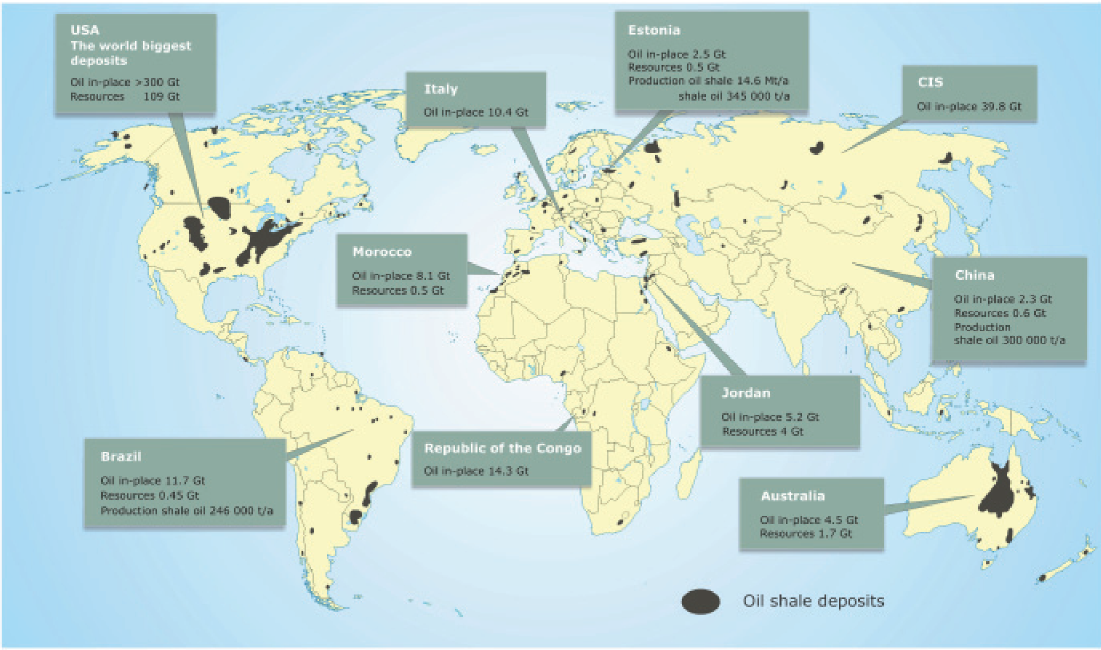


Figure 3.22: Regional distribution of the oil shale occurrences worlwide with data concerning reserves, resources and production.

The **global total potential of oil shale oil** in-place is currently estimated to be 413 Gt of shale oil. Oil shale occurrences are known in nearly 40 countries of the world (Fig. 3.22). The majority of the amounts of shale oil in-place are possessed by the US at 73 %, followed by Russia at nearly 10 % as well as the Congo Republic, Brazil and Italy at together 9 % (Fig. 3.23). The largest oil shale deposits are located in the US, Russia, Australia, Brazil, Israel, Jordan, Morocco and Thailand. Currently, many important parameters for the assessment of the contained crude oil potential are missing for many oil shale occurrences, thus global data concerning extractible amounts of shale oil are very uncertain.

As the oil production from oil shale is currently not economical, the theoretically extractable amounts of oil in the hitherto known oil shale occurrences are shown as extractable resources. Countries with the largest known extractable resources are besides the US, Australia, Brazil, China, Estonia, Israel, Jordan, Morocco and Thailand (Tab. A 3-22). In spite of the large amounts of oil shale in-place in the CIS-countries, data concerning the producible amounts of oil are not known. In the US alone, more than 100 000 Mt of shale oil might be distillable. Even though these data are also very uncertain, the globally extractable resources of oil shale oil of about 120 000 Mt are regarded as conservative estimate, as for many countries there are no data available up to now (Altun, 2006).

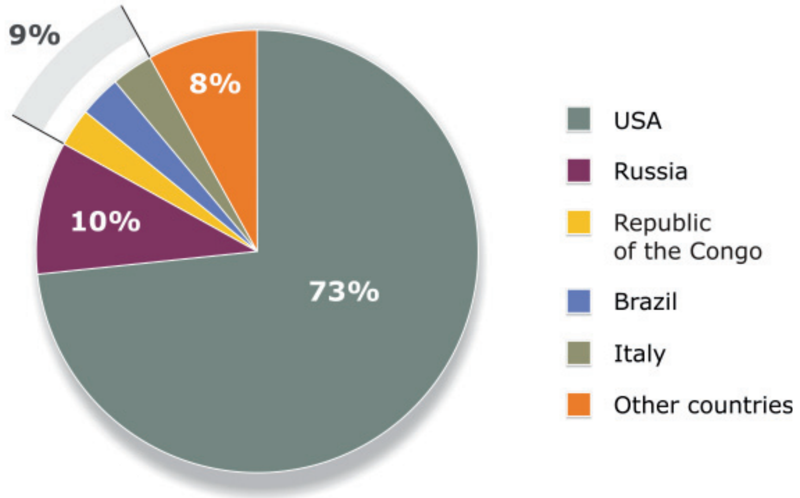


Figure 3.23: In-place shale oil resources (total 413 Gt) according to countries (%).

Amongst the unconventional types of petroleum, oil shale is the energy resource with the highest energy demand for turning it into a *liquid* energy fuel. A cost and energy-efficient production method of exploiting oil shale oil is not in sight for the near future. Up to now, the easy availability and the cheap price of conventional petroleum prevented the expansion of the oil shale industry. With increasing world market prices for petroleum, however, for a few geologically and logistically well-placed oil shale occurrences an economic production might become reality in the not too distant future. But even countries with few occurrences of conventional petroleum and natural gas, which have considerable oil shale deposits, are interested in producing oil from oil shale, to decrease their energy imports in the long run. In all, this development in the past years resulted in re-assessments of oil shale resources, the development of improved conditioning technologies and new pilot projects. Only few deposits have been used to produce oil shale. These are located in Estonia, China, Brazil, Germany and Israel. Only in the three first-mentioned countries, oil has been extracted from oil shale in the past years. In all, in 2005 approximately 684 000 t of crude oil were manufactured worldwide, of which Estonia with 345 000 t has produced slightly more than half, followed by China with 180 000 t and Brazil with 159 000 t.

Concerning the development of the last years in selected countries, the following is summarized:

Estonia's energy-infrastructure has been geared at the use of oil shale for a long time. More than 90 % of the electrical power generated in Estonia is based on oil shale and render the country a net exporter of electrical power. The production of oil shale alone was 14.6 Mt in total in 2005. Until 2007, it was increased to 16.3 Mt, about 75 % of the oil shale is burned directly without further processing for generating energy, the remainder is used for manufacturing shale oil. It is disadvantageous that this form of energy generation can contribute significantly to the pollution of the air and water.

In **Russia** the Leningradslanets Oil Shale Mining Company produced approximately 1.12 Mt oil shale per year until 2005. The shale was transported to the Baltic Power Station in Estonia and the power thus generated was fed into the power supply system of Russia. Production was stopped in 2005 for cost reasons.

In **China** the Fushun Oil Shale Retorting plant of the Fushun Mining Group Company operated approximately 120 retorts with a capacity of 100 t oil shale per day/retort in 2005 and produced 180 000 t shale oil in the same period. The production in China was expanded to 240 000 t of shale oil in 2006 and to 300 000 t in 2007.

Brazil was able to expand the production of shale oil to 246 000 t in 2007. The largest part of the oil shale of Brazil is part of the Permian Iratí formation, which occurs in the provinces São Paulo, Paraná, Santa Catarina, Rio Grande do Sul, Mato Grosso do Sul and Goiás.

In **Jordan** Petrobras has been testing the economic feasibility of producing oil from the oil shale of the Attarat-Umm-Ghudran occurrence in cooperation with the Energy Ministry of Jordan since 2007. The Royal Dutch Shell Oil Company is very interested in the exploration and exploitation of the oil shale in Jordan and was meanwhile awarded large acreage for feasibility studies using the in-situ technique.

Efforts in **Australia** to install an oil shale pilot plant with a capacity of 400 000 t/a in the Whitsunday region, north-east Australia near the McFarlane oil shale field, have been stopped by the government. Intended production has been interrupted until the middle of 2010, until it can be ensured that the production and processing of the oil shale does not have harmful effects on the environment, in particular on the Great Barrier Reef, which is only 15 km away to the offshore. The Australian government will then check the extent to which it will invest in the extraction of shale oil in future.

The Stuart-Oil-Shale project in Gladstone, Australia, produced approximately 220 000 t shale oil between 2000 and 2004. The pilot project was used to test the output of shale oil using the so-called Alberta–Taciuk Process retorting technology (ATP). In the middle of 2004, the plant was shut down because of economic reasons and due to strong emissions of greenhouse gases and possible toxic substances.

In the **US** a number of testing facilities for improving the production and treatment technology of the production of oil from oil shale have been set up. They have an output of shale oil between 30 000 and 80 000 t/a. In 2007, Shell postulated an economic output using its new in-situ technology from a crude oil price of USD 25/b to USD 30/b with a degree of oil removal of approximately 70 %. According to the U.S. Department of Energy (U.S. DOE, 2004), the US might be able to produce approximately 120 Mt of shale oil annually as from 2020 and 175 Mt of shale oil annually as from 2030.

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4 Natural Gas

4.1 From Natural Gas Deposit to Consumption

Natural gas is a mix of different gases occurring in the earth's crust. Besides methane as main component of natural gas, further components such as ethane and propane as well as not flammable gases like nitrogen, carbon dioxide, hydrogen sulfide and helium can be contained. To a large extent, natural gas is accumulated in natural subsurface deposits. These deposits can be developed by drilling and the natural gas can be extracted. From gas fields, gas will be transported to the end consumer over land via a pipeline system or it is transported by sea using special tankers.

Natural gas can be generated jointly with oil as so-called associated gas or separately from coal. The formation of methane by microbes in the rock is also an important process. Just like oil, natural gas migrates in the earth crust and can thus reach trap structures of porous rock, which are covered by impermeable layers. In most sedimentary basins of the world there are, besides such dry natural gas deposits, also associated natural gas deposits, where oil and natural gas occur together.

Depending on the percentage of hydrogen sulfide (H_2S), sour gas (more than 1 vol.-% H_2S), lean gas (less than 1 vol.-% H_2S) and sweet gas (no H_2S and less that 2 vol.-% carbon dioxide) are differentiated. So-called "wet" natural gas, also called rich gas, occurs in many deposits together with oil. As it contains proportions of larger hydrocarbon molecules than methane, during cool-down liquid hydrocarbon mixtures condense, resulting in so-called liquefied gas, condensate or natural gasoline. Natural gas is called "dry", if it can be cooled down without the precipitation of so-called condensate.

The natural gas produced from the deposit is processed right away at the location of the natural gas field. Sweet gas accounts for most of the global gas production. Formation water and in some cases also higher hydrocarbons are separated at the location. The sulfur content of sour gas is removed in a special cleaning process, the so-called gas washing process. Some types of raw gas also require the separation of carbon dioxide and nitrogen.

As a rule, natural gas is transported on the continents via pipelines with diameters up to 1.4 m. To achieve a higher efficiency of the piping, the natural gas is transported at a pressure of up to 84 bar. This way, the gas volume is reduced. To counteract a decrease in pressure along a long pipeline, a compression of the natural gas is required at intervals between 100 and 400 km. The transport distances for natural gas can be considerable in some instances. During its journey from western Siberia to Western Europe, the natural gas covers approximately 6000 km in pipelines.

Natural gas can also be transported in liquefied form. So-called Liquefied Natural Gas (LNG) consists largely of methane and ethane and is liquefied for transportation purposes by cooling-down to -164 °C at atmospheric pressure. This reduces the original volume of the natural gas to one six-hundredth. To the so-called LNG-chain belong systems for the precipitation of higher hydrocarbons as well as for air-cooling and liquefaction of the gas. As liquefied natural gas is transported using special LNG-tankers at atmospheric pressure, in the further course of the LNG-chain loading and landing terminals are required. At the end of the LNG-chain, there are systems for evaporating of the liquefied natural gas to feed it into a pipeline system. As the production, treatment and long-distance transport have to take place largely continuously, consumption, however, varies with the seasons due to varying heating requirements, natural gas is stored temporarily in underground storage facilities during the summer and removed in winter when needed.

Natural gas seeps have been known for millennia; burning natural gas was used as "eternal flame" for cultic purposes. The earliest economic use was described in China in the 3rd century AD. A more intensive economic use only started at the beginning of the last century in North America. In the 1930s, Poland, Romania and the southwest of the Soviet Union joined in, but consumption in these countries remained low in comparison to the US until the 1950s. After the installation of the long-distance pipelines and LNG-chains in the 1960s and 1970s, the consumption of natural gas rose significantly, in particular in Western Europe. Until the 1970s, natural gas was in many countries a by-product of the oil exploration. The transportation costs of natural gas exceeding those of petroleum many times and the rich global supply of other fossil energy resources initially rendered a systematic exploration of natural gas economically advisable only in areas, which are located close to the consumer, which are already connected to markets or which do not possess other energy resources of their own. Over the last decades, environmental and energy efficiency aspects also became increasingly important for exploration decisions in favor of natural gas.

Natural gas is mainly used as high-energy fuel for household, businesses, power plants and industry. To a lesser extent, natural gas is also used as basic material in the chemical industry as well as in combustion engines. At the end of 2008, in Germany about 80 000 natural-gas vehicles were on the road. Due to its chemical composition, natural gas has the lowest proportion of carbon in comparison to other fossil energy carriers in relation to the energy content. Thus, the combustion of natural gas in modern plants releases 20 to 30 % less carbon dioxide (CO_2) than oil and even 40 to 50 % less than coal for the same energy gain.

4.2 Conventional Natural Gas

4.2.1 Total EUR of Natural Gas and its Regional Distribution

Various assessments of the past ten years specify the EUR for natural gas between 300 and 600 trillion m³ (Tcm). Unlike for oil, these assessments seem to keep increasing continuously (Fig. 4.1). Since 2001, only few re-assessments of the EUR (Tab. A 4-1) have been conducted, all of which are above 400 Tcm. The differences between these evaluations result mainly from differences in the evaluation of natural gas resources.

The total global potential of conventional natural gas determined by the BGR is approximately 509 Tcm. This corresponds to approximately 460 Gtoe and thus exceeds the total potential of conventional oil by 13 %. Based on the current studies of the USGS (USGS, 2006, 2008) concerning the natural gas resources in the Arctic, the assessments by the BGR have been raised significantly in comparison to previous studies.

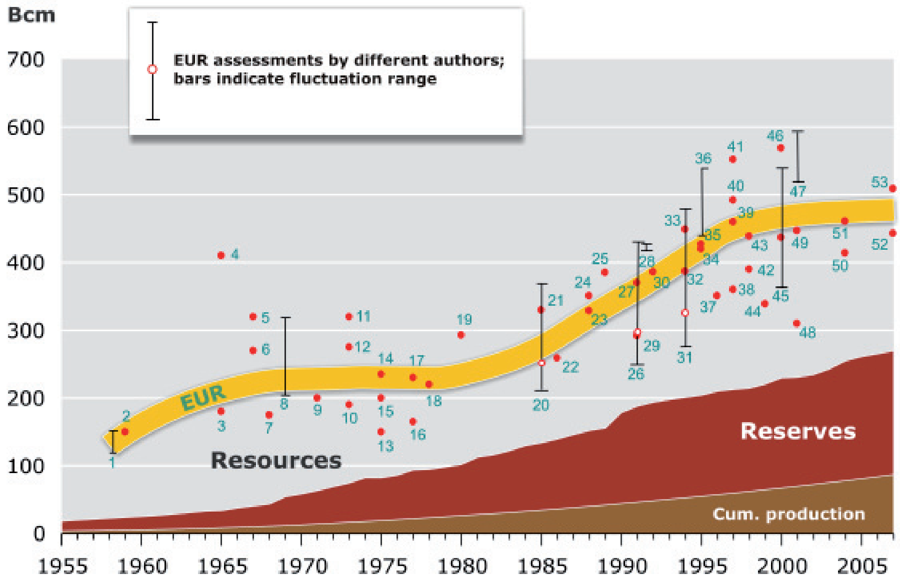

Figure 4.1: Development of the estimates of the Estimated Ultimate Recovery (EUR) of conventional natural gas, the cumulative production and reserves from 1955 to 2007 (sources for numbered references cf. Tab. A 4-1).

At the end of 2007, the cumulative global commercial production of conventional natural gas was nearly 87 Tcm. The reserves amounted to approximately 183 Tcm and the resources to approximately 239 Tcm, i.e. up to now, slightly more than 32 % of the proved reserves and slightly more than 17 % of the total global EUR of conventional natural gas to be expected according to our estimates, have already been consumed. Flared natural gas has not been taken into account.

In the regional view, the CIS (in particular Russia) possesses the most important potential of natural gas worldwide, followed by the Middle East (Fig. 4.2). Even though North America has a large total potential, the remaining potential there is probably lower, as in the US, up to today, already approximately half of the total natural gas has been produced. The proportion of Europe's global potential of natural gas is at not quite 5 % rather low. If the natural gas markets are considered, however, the European market in particular because of the Russian supply, has more than 47 % of the total global potential available. If the Middle East is included as potential supply region for Europe, even an accessible proportion of more than 77 % of the total global potential of conventional natural gas results. Thus, the European market for natural gas in general has a better supply at its disposal than other markets.

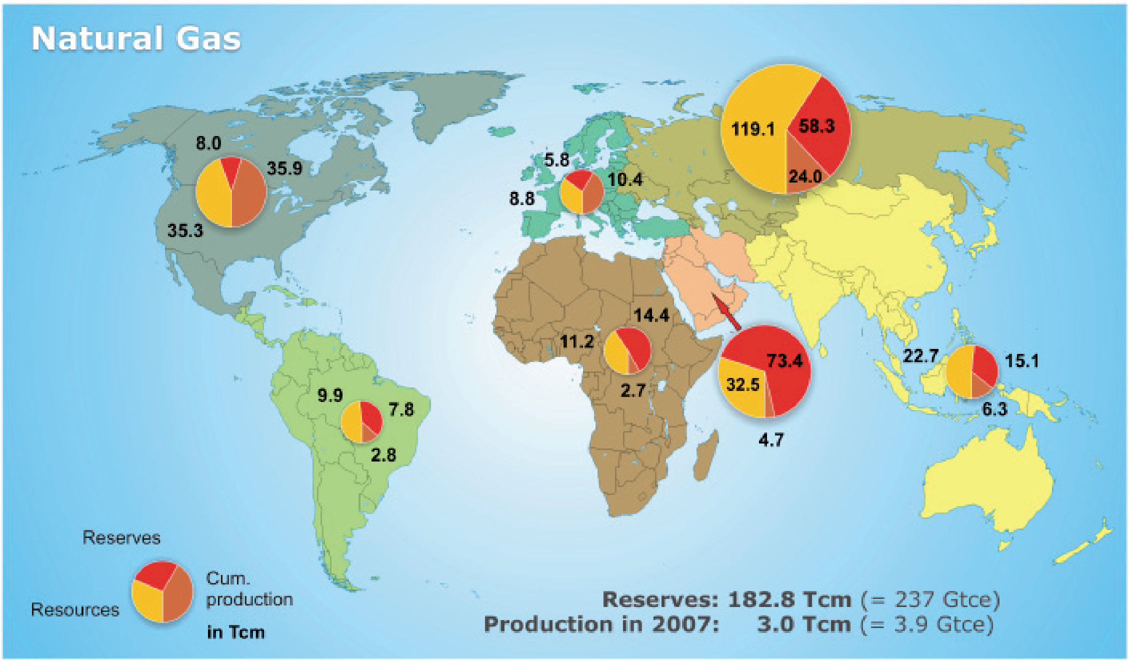

Figure 4.2: EUR of conventional natural gas in 2007 (total 509 Tcm): regional distribution.

Tables A 4-2 to A 4-4 in the appendix contain data concerning the EUR of the countries, regions and economic groups. An overview over the total potential of the most important countries lists the three leading countries Russia, Iran and Qatar at a proportion of together more than 52 % (Fig. 4.3). The top ten countries thus possess more than 73 % of the EUR. In comparison to the BGR-Energy Study 2003 (data status year-end 2001), the EUR of natural gas has increased significantly. This is particularly true for the CIS (29.8 Tcm), North America (13.1 Tcm), the Middle East (6.2 Tcm), for Austral-Asia (4.8 Tcm) and Africa (3.6 Tcm).

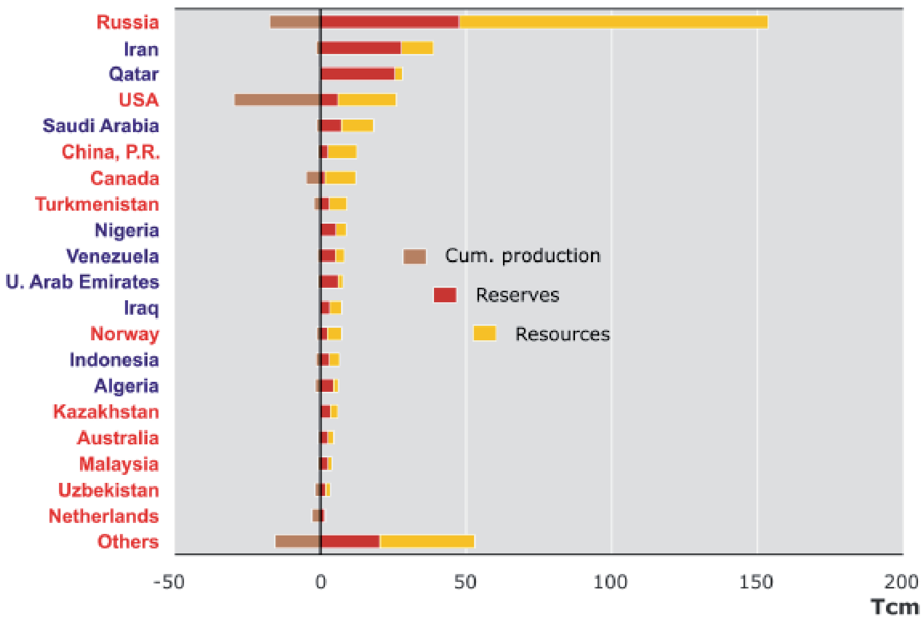

Figure 4.3: EUR of conventional natural gas in 2007: The top twenty countries sorted according to remaining potential (OPEC countries in blue bold-face type).

The remaining global potential is around 422 Tcm. Thus, in relation to the energy content it surpasses the remaining energy potential of conventional oil by slightly more than 50 %. According to countries, a similar concentration as for the EUR results for the remaining potential (Tab. A 4-5). The seven leading countries account for more than two thirds of the globally remaining potential. These countries will play a decisive role in the future supply of natural gas.

4.2.2 Natural Gas Reserves

According to Ivanhoe and Leckie (1993), approximately 26 600 natural gas fields are known globally. Especially large natural gas fields, the giants with reserves of more than 80 Bcm (billion m³) and super giants with reserves of more than 800 Bcm are of particular importance for ensuring the supply of natural gas. Only little more than 100 fields fall into the category giant and super giants. There, about 75 % of the known global reserves are concentrated. Unlike petroleum, the currently published assessments of the global reserves of natural gas vary little, between 170.1 and 183.2 Tcm (Tab. 4.1).

Table 4.1: Reserves of conventional natural gas in 2007: Comparison of different evaluations in Tcm. (OGJ, 2007, EIA, 2008 for World Oil and Cedigaz, BP, 2008, OPEC, 2008).

Region	OGJ	World Oil	Cedigaz	BP	BGR	OPEC
Europe	4 872	4 976	6 100	6 136	5 792	6 232
CIS	57 059	60 510	53 809	53 274	58 303	58 112
Africa	13 866	14 181	14 581	13 370	14 437	14 542
Middle East	72 191	72 361	73 209	67 127	73 374	73 559
Austral-Asia	11 764	14 101	15 218	14 462	15 096	15 166
North America	8 018	8 124	8 003	7 976	7 995	8 018
Latin America	7 414	6 858	7 720	7 727	7 834	7 542
WORLD	*175 185*	*181 111*	*178 640*	*170 070*	*182 830*	*183 171*

The development of the natural gas reserves and the natural gas production since 1900 shows a continuous increase, with the reserves having grown faster in comparison (Figure 4.4). Table A 4-6 contains a general review concerning the development of the reserve situation since 1980. The natural gas reserves of the world rose from 160.8 Tcm by the end of 2001 to 182.8 Tcm by the end of 2007 according to our evaluations, i.e. by approximately 22 Tcm with a cumulative production of natural gas during that period of about 16.9 Tcm in all (Tab. A 4-6). Thus, in 2007 the highest level of reserves was achieved.

Since the BGR-Energy Study 2003, regionally significant increases in reserves occurred in the Middle East and to a lesser extent in Africa and Latin America. In contrast, in Austral-Asia, Europe and North America slight decreases of reserves were noted. Increases of reserves of more than 2 Tcm were found in Qatar due to the upward revision of the North Field reserves and in Iran. In addition, increases of more than 500 Bcm were recorded by Azerbaijan, Egypt, Algeria, Nigeria, Bolivia, Mexico, Indonesia, Russia and China. Due to the large South Yolatan discovery, the Turkmen natural gas reserves will increase significantly in the near future. The decrease in reserves of individual states was less than 1 Tcm.

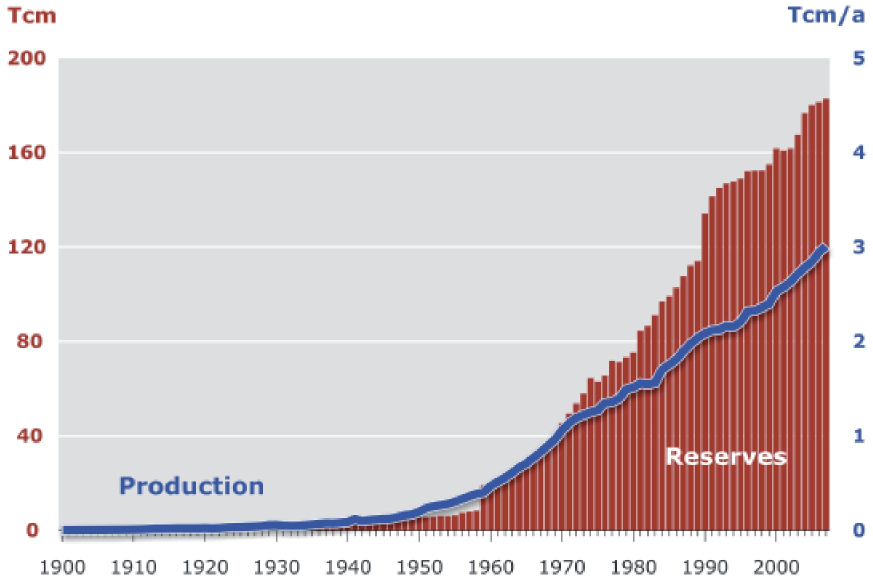

Figure 4.4: Development of the reserves and production of conventional natural gas from 1900 to 2007.

The natural gas reserves are distributed, just like the petroleum reserves, very differently by individual countries and regions (Tab. A 4-7). The Middle East and the CIS possess nearly three-fourths of the global natural gas reserves. Historically, North America is also part of regions with large reserves. Due to the long production history with production at a high level for approximately 100 years more than half of the original reserves have already been recovered here. When comparing the individual reserve countries (Tab. A 4-7), it is obvious that the three top countries have a unique position. Russia possesses slightly more than 26 % of the global natural gas reserves and holds, together with Iran and Qatar, more than 55 % of the global reserves. The eight countries with reserves of more than 5 Tcm possess more than two thirds of the global reserves. Seven OPEC countries number among the ten countries with the largest reserves (Fig. 4.5).

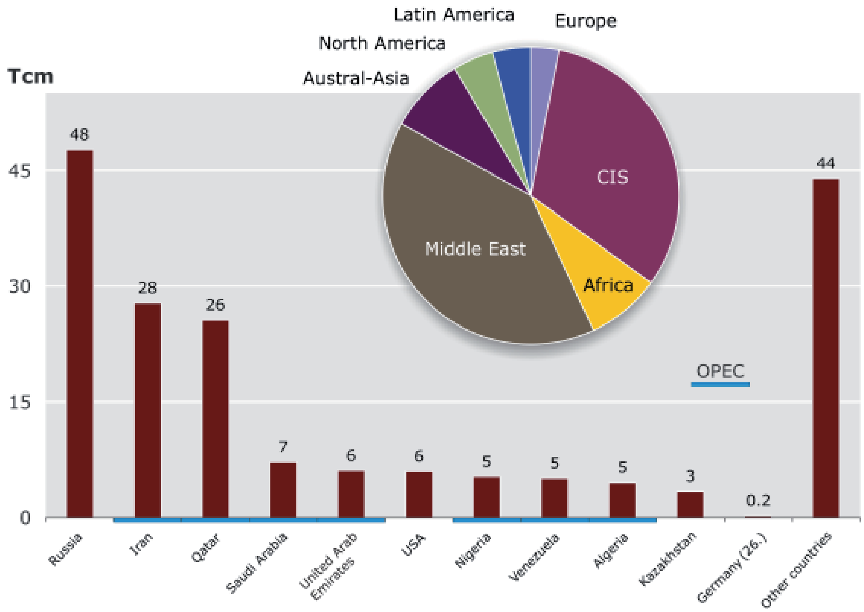

Figure 4.5: Reserves of conventional natural gas (total 183 Tcm) of the top ten countries and Germany as well as their distribution by regions in 2007.

The offshore area at approximately 65 Tcm provides approximately one third of the global natural gas reserves. Figure 4.6 provides an overview over the regional distribution of the offshore reserves. In Europe and Austral-Asia, offshore reserves dominate over the natural gas reserves onshore. The Middle East possesses the largest offshore reserves; the largest natural gas field of the world, South Pars/North Field (Iran/Qatar) in the Persian Gulf, takes up about 38 Tcm.

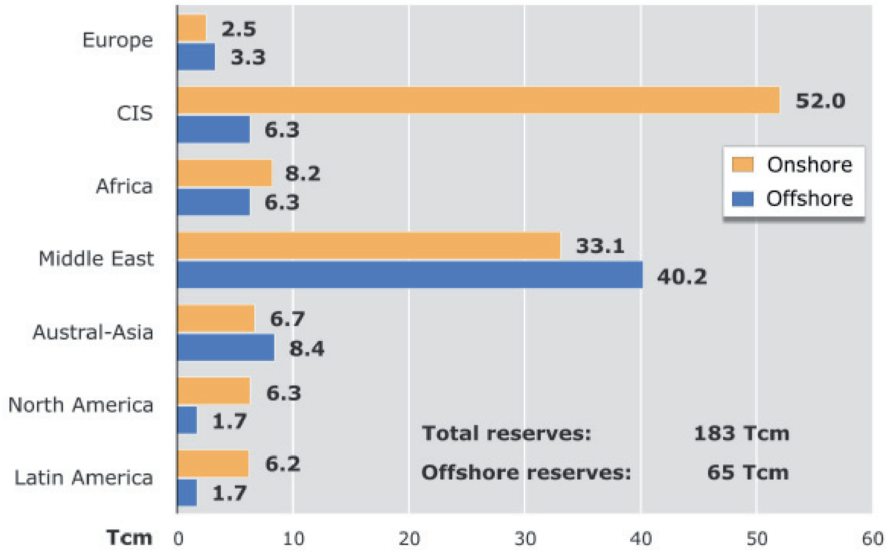

Figure 4.6: Reserves of conventional natural gas in 2007: Regional distribution onshore and offshore.

The natural gas reserves of the most important countries are - similar to petroleum - at more than 72 % predominantly owned by state companies (Tab. A 4-8). BP has, as the first private company, rank 18, directly followed by Shell and the Russian Itera. However, currently several OPEC countries are opening their natural gas markets increasingly also for private companies. Private companies are involved in the development of the South Pars Field in Iran; Saudi Arabia has also awarded natural gas concessions to private companies. In contrast, for instance in Bolivia, nationalizations have been conducted.

4.2.3 Natural Gas Resources

In comparison to reserve information with annual reporting duties, assessments concerning natural gas resources are conducted at irregular and in larger intervals. The last global assessment has been conducted by the USGS in 2000 (USGS, 2000). It referred to the state at the end of 1995 and contained a forecast for 25 years. As a mean average, the global resources of conventional natural gas have been assumed at about 147 Tcm with a range of 76 to 251 Tcm without taking into account the increases in reserves from the producing fields (reserve growth). For this global reserve growth, the USGS indicates a mean value of 104 Tcm.

Since 2000, the USGS has been conducting new evaluations of Afghanistan and the Arctic (USGS, 2006, 2008), with positive evaluation of the Arctic. The results of these studies have been considered in this assessment, i.e. the resources of conventional natural gas reach slightly more than 239 Tcm and thus exceed the value of 2001 by about 22 Tcm (Tab.

A 4-9). For the Middle East, the resources have been reduced; part of the resources has been transferred into reserves by the upward revision of the North Field reserves. The globally reported natural gas resources correspond to approximately three times the amount of the cumulative natural gas production and exceed the known natural gas reserves by about 31 %. These numbers indicate the good situation of resources for natural gas, which is quite advantageous in comparison to petroleum.

In a regional comparison, the CIS possesses nearly 50 % of the global resources of natural gas, followed by North America at nearly 15 %. The Middle East possesses approximately 13 % and Austral-Asia nearly 10 % (Tab. A 4-10). The ranking of the resource countries shows, similar to the reserves, a strong concentration on a few countries (Tab. A 4-10, Fig. 4.7). Russia has a predominant position at 44 % of the natural gas resources. The top three countries account for more than 57 %, the top eleven countries account for nearly 80 % of the resources. Five OPEC countries number among the top eleven countries (Fig. 4.7).

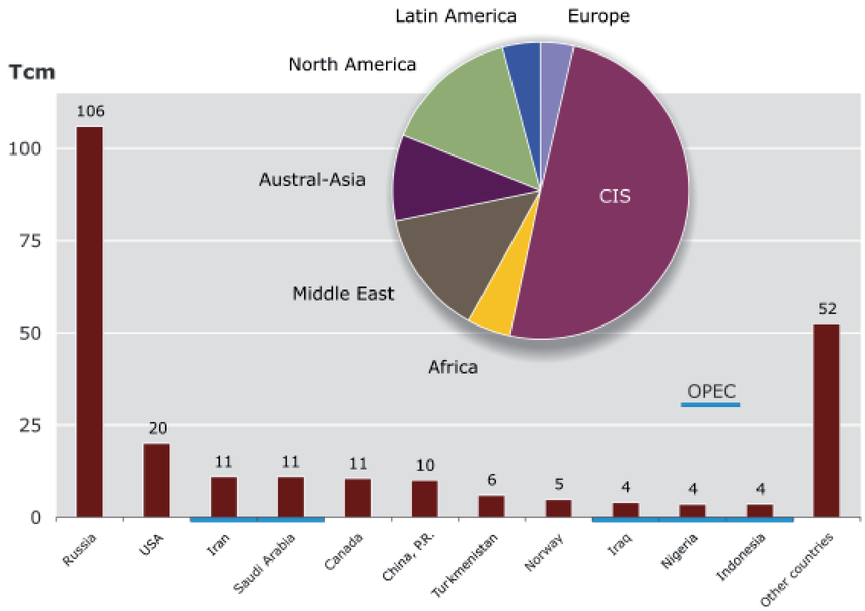

Figure 4.7: Resources of conventional natural gas (total 239 Tcm) of the top ten countries and Germany as well as their distribution by region in 2007.

The analysis of the transfer of the resources to reserves and of the reserve growth reported by the USGS (2000) showed that for natural gas in the period from 1996 to 2003 added reserves from new discoveries of approximately 13 Tcm have been realized (Klett et al., 2005). Increases from the reevaluation of fields under production added up to 48 Tcm. Thus, 10 % of the resources have been transferred and 51 % of the reserve growth forecasted by the USGS were realized. During that period, nearly 20 Tcm of natural gas have been produced. This amount has been largely replaced by new discoveries; the reevaluation of known fields supplied an additional significant growth.

4.2.4 Natural Gas Production

The production numbers of natural gas contain both conventional and unconventional natural gas (Chapter 2.3). Unconventional natural gas has a very low proportion of the total production except for the US. In the US, in 2006 unconventional natural gas contributed 43 % of the total production (Chapter 4.3.1). The data concerning production pertain as a rule to raw gas, i.e. natural gas of the quality occurring in the fields. In some cases, these amounts have been converted to a uniform energy content (e.g. clean gas in Germany), which may result in differences between different statistics.

The global natural gas production has increased steadily over the past years (Fig. 4.4) and reached its historical maximum at 3012 Bcm in 2007. At 0.5 Tcm this means an increase by approximately 19 % in comparison to 2001. Main production areas were the CIS and North America, a quarter each of the global production. Austral-Asia, the Middle East and Europe trail behind at a tenth each of the global production. The cumulative global production of natural gas up to the end of 2007 reached nearly 87 Tcm or slightly more than 32 % of the total reserves discovered up to now. Half of that has been produced in the course of the past 17 years. Some countries increased their production considerably in 2007 in comparison to 2001. Russia at 60 Bcm as well as the PR China, Norway and Iran at more than 45 Bcm each, as well as Trinidad & Tobago, Malaysia, Nigeria, Qatar, Saudi Arabia and Mexico at more than 25 Bcm attained high increases. In future years, significant increases in particular in Qatar, in Turkmenistan and, depending on the politic development, in Iran with the development of the largest natural gas field in the world, South Pars/North Field, are to be expected. Decreases in production were suffered in particular by Great Britain due to increasing depletion of the fields in the North Sea (Tab. A 4-11). Amongst the top ten countries (Tab. A 4-12, Fig. 4.8) Russia and the US were dominant. The top four countries account for nearly half the global production of natural gas, the top ten countries accounted for nearly two thirds. There are only four OPEC countries amongst the top ten (Fig. 4.8). During the last decade, there were no changes in the order of the top three countries (Tab. A 4-13).

In statistics concerning natural gas production, only the marketed proportion of the total natural gas production (gross production) is customarily recorded, but not the flared or discharged proportion of associated gas (Info box 3) or the service consumption of the production companies. The amounts of natural gas, which have been re-injected in petroleum deposits to increase the petroleum recovery, are not contained, either. The amounts of natural gas that have been flared or re-injected between 1960 and 2007 worldwide have been compared in Figure 4.9 to the global production of crude oil. The amounts of flared associated gas have barely increased during the last 25 years, even though petroleum production has increased. Natural gas in particular has increasingly been used since the middle of the 1970s to increase the recovery rate of oil fields.

The production of natural gas from offshore fields has increased by nearly 20 % to about 836 Bcm, from 2001 to 2007; a proportion of 27.7 % of the global production. Of this, one quarter each originates from the North Sea and Austral-Asia and approximately 15 % from the Gulf of Mexico as well as from the Middle East. This trend of an increasing offshore-production in comparison to the onshore production is recognizable for natural gas as well as for oil. In future, in particular the importance of the Middle East and Africa will increase.

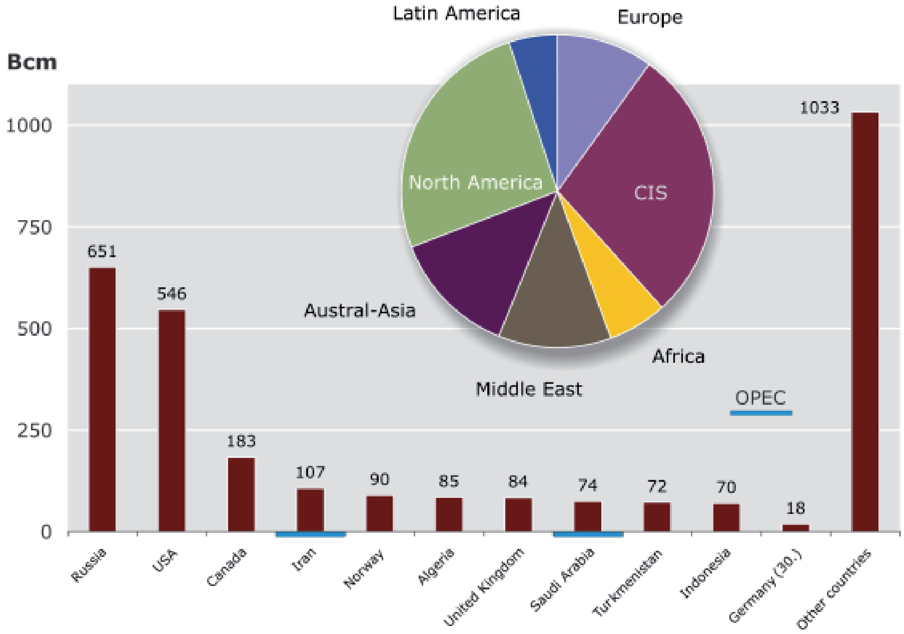

Figure 4.8: Production of natural gas (totall 3 Tcm) of the ten most important countries and Germany as well as their distribution according to region for 2007.

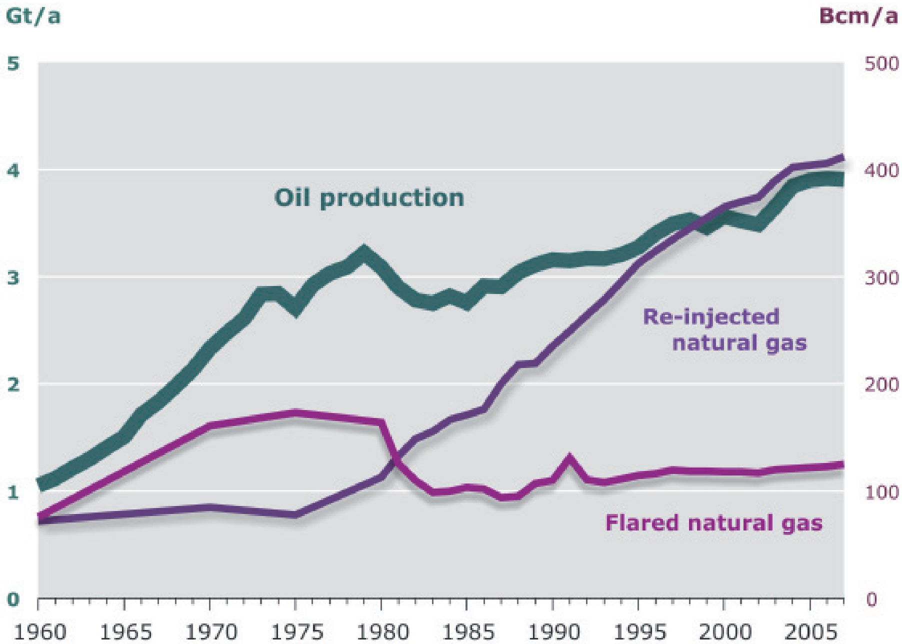

Figure 4.9: Development of the amounts of natural gas globally flared and re-injected and the world production of petroleum.

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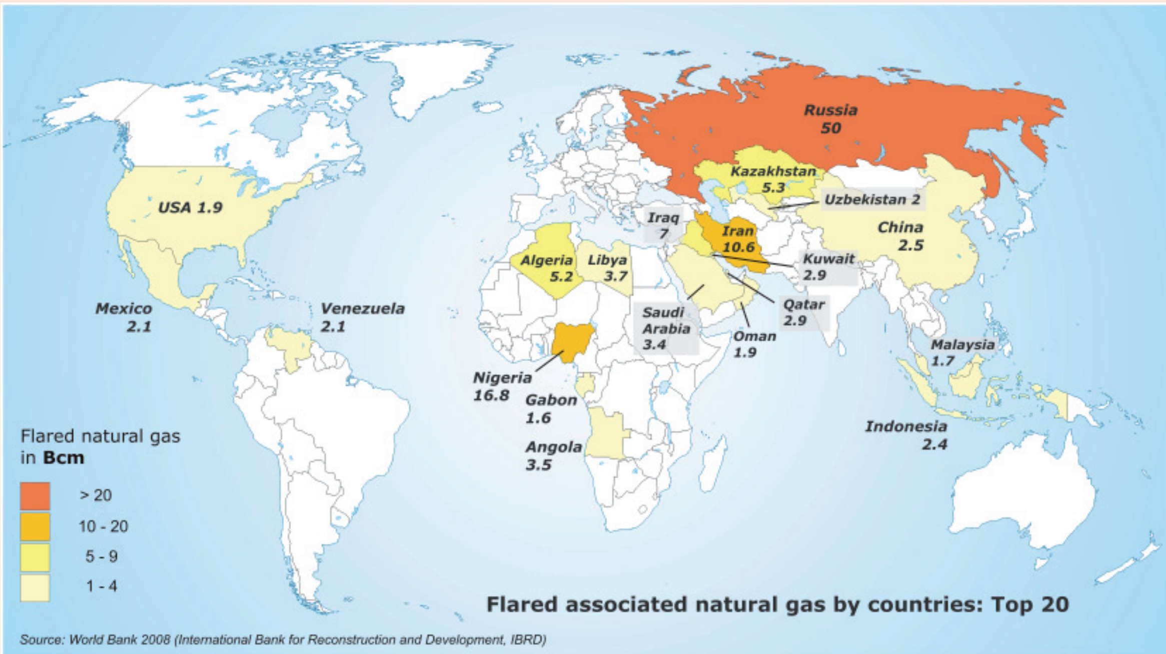
Associated Gas – Unused Potential

Associated gas is a by-product of the petroleum production. Until today, this gas is frequently flared or released into the atmosphere unburnt. It could be re-injected into the deposit for maintaining pressure, for manufacturing fuel like liquefied gas or used locally for generating electricity. The main reason for flaring or venting the gas is the lack of economic incentive for using or processing the gas.

After the effect of the gas flaring and of gas venting and the carbon dioxide and methane emissions was disregarded for a long time, today the possible influence of these emissions on the climate as well as the energy potential lost has been discussed increasingly. According to the World Bank, about 147 Bcm of associated gas were flared in 2007. This amount corresponds to approximately 30 % of the natural gas consumption of the European Union and would have had an economic value of nearly USD 40 billion based on the US-market value. In addition, the useless burning of this natural gas generates annually about 400 million t CO_2. At approximately 50 Bcm, Russia alone contributes about one third of the globally flared associated gas. The OPEC also plays a significant role in causing these emissions. There is little reliable data about the amount of unburned natural gas that is vented, as the measurements are technically difficult. The U.S. Environmental Protection Agency estimates the amount of vented natural gas including some diffuse emissions at currently approximately 100 Bcm annually.

Curtailing the current established practice seems only possible by introducing corresponding guidelines and economic incentives. Algeria for instance plans to impose taxes on flaring gas in order to achieve a reversal of this procedure.



Flared associated natural gas by countries: Top 20

Source: World Bank 2008 (International Bank for Reconstruction and Development, IBRD)

The production of natural gas is largely controlled by national companies (Tab. A 4-14). There are also three private companies amongst the most important ten gas-producing companies. The top ten natural gas companies together produce about 41 % of the global production, of these Gazprom at a percentage of 18 % has a dominant position. In future, the newly founded Gas Exporting Countries Forum (GECF) might play a similar role to that of the OPEC for petroleum (Info box 4).

4.2.5 Consumption of Natural Gas

The global consumption of natural gas reached a historic maximum in 2007 at slightly more than 3 Tcm and increased by approximately 520 Bcm since 2001 (Tab. A 4-15). The US, followed by Russia, Iran, Japan, Germany, Canada and Great Britain used most of the natural gas (Tab. A 4-16). Whereas the OECD countries at more than 1.5 Tcm consumed slightly more than 50 % of the natural gas produced globally, the OPEC accounted for only 12 %. The consumption of natural gas was largely concentrated in three regions: North America, the CIS and Europe. When comparing the consumption and the production of natural gas (Fig. 4.10), differences result. They are less significant, however, than those for petroleum (Chapter 3.2.6). Europe shows significant differences between the production and the consumption of natural gas. The consumption in Europe has to be covered by massive imports of natural gas. The situation for countries of the CIS is just the opposite. These are the main suppliers of the European countries.

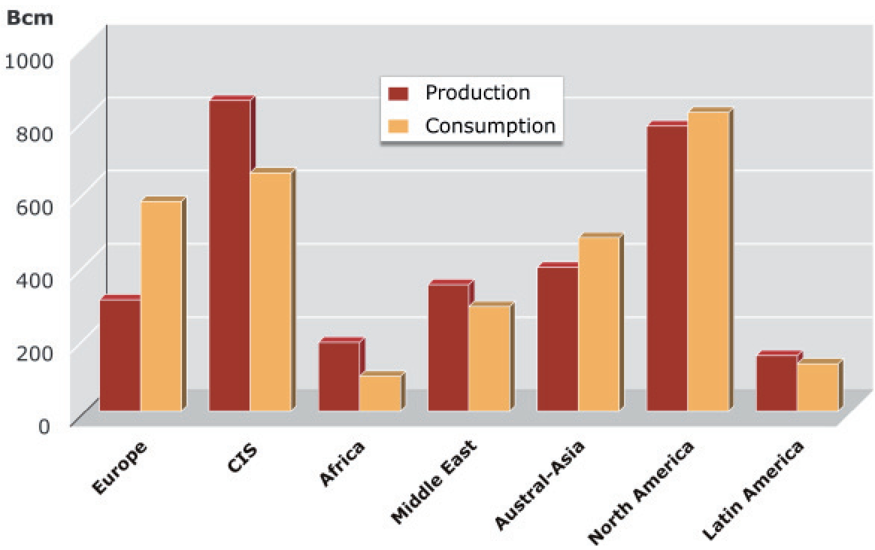


Figure 4.10: Production and consumption of natural gas 2007: Regional distribution.

Since 2001, the consumption of natural gas has increased in all regions, particularly in Africa, Austral-Asia and the Middle East (Tab. A 4-15). Out of the top ten consumers of natural gas in the world, the US alone used more than one fourth of the total global natural gas (Tab. A 4-16; Fig. 4.11). Russian consumption of more than 400 Bcm is also high. In this country the share of natural gas in the total primary energy supply is more than 50 %. Most other natural gas consumers have a significantly lower share. On a global scale, Germany is the fifth largest natural gas consumer and in 2007 it used almost 4 % of the total volume in the world. Among the top ten gas consuming countries is only one OPEC country, Iran (Fig. 4.11).

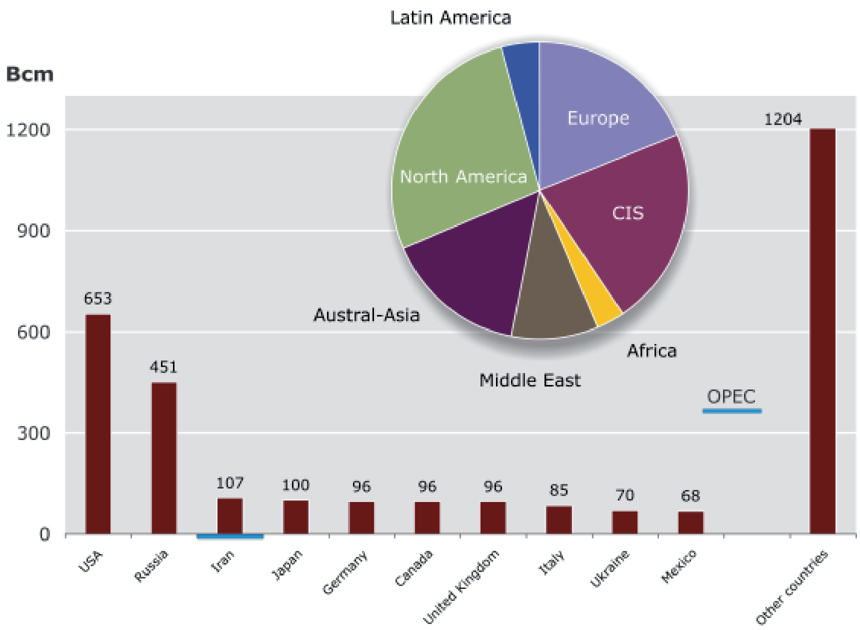


Figure 4.11: Consumption of natural gas (total 3 Tcm) of the top ten countries and Germany as well as their distribution by region in 2007.

4.2.6 Transport of Natural Gas

Regions producing and consuming natural gas do not always overlap, thus natural gas has partly to be transported over long distances. Transport of natural gas takes place either in the gaseous state via pipelines or in the liquefied state as LNG in special tankers. Due to the lower energy content of natural gas per volume, the costs for transportation are approximately one order of magnitude higher than for petroleum and coal. Thus, natural gas has a considerable competitive disadvantage, in particular for deposits located far away from the consumers as far as costs are concerned. The use thus depends on the special requirements of the consumer country, its economic policy basic requirements and increasingly also on environmental demands.

When transporting natural gas via pipeline, the transportation costs depend to a large degree on the capacity of the pipeline (Fig. 4.12). For instance, transportation costs decrease by approximately half for an increase of the capacity from 5 to 20 Bcm per year. Offshore transport through pipelines is approximately 50 % more expensive than onshore. Steinmann (1999) estimates for an average transport distance of approximately 4700 km transportation costs of € 56.25 per 1000 m³. His calculations are based on a pipeline diameter of 1400 mm and an operating pressure of 84 bar at transportation capacities of 26 Bcm per year. The capital expenditure requirements for such a pipeline are thus about € 7.7 billion.

Leaks in the pipelines, in the distribution networks or at the end consumer decrease the economically usable volume of natural gas. The losses in the industrialized western nations have been estimated to range up to 1 % of the volume of natural gas produced.

Beside transport via pipeline, the transport in form of liquefied natural gas becomes increasingly important. It is not, as frequently misunderstood, an alternative to natural gas, but a transport option besides the traditional transport of natural gas via pipeline. Further potential transport options of natural gas as listed by the IEA (2005) are transportation as compressed natural gas (CNG), as Micro-LNG and in form of technically generated gas hydrate. To what extent these additional options will prevail, remains to be seen.

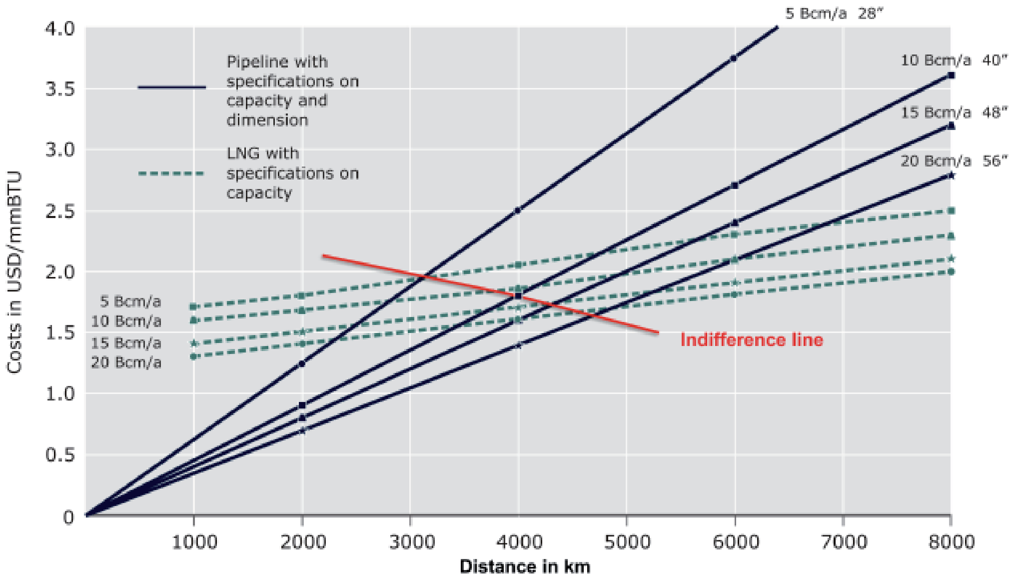


Figure 4.12: Transportation costs for natural gas via pipeline and as LNG as a function of the capacity (according to Schwimmbeck, 2008).

For LNG-transportation, the liquefaction of natural gas requires already considerable amounts of energy. For this reason, the specific transportation costs for short distances are significantly higher than for transportation via pipeline (Fig. 4.12). Transportation of LNG only becomes economically favorable in comparison to pipeline transportation for distances of more than approximately 3000 km. Transport as LNG has the advantage of greater flexibility, as it is not bound to a rigid piping system with fixed starting and end points as for pipeline transport. If no direction clauses have been contractually stipulated, LNG-tankers can operate between any loading facility and landing terminal. This also provides the possibility of establishing a larger spot market for natural gas. On the other hand, the LNG-trade is tied to the oceans, which results in two large markets in the Atlantic and Pacific area. For delivering the LNG market, fields close to the coast or offshore-fields are preferable. Darley (2004) has specified the erection costs for a complete LNG-chain at USD 3 to 10 billion. The specific energy consumption within the LNG-chain is approximately 15 % for instance for the transport from Qatar to the east coast of the US in relation to the total amount transported.

In 1964, liquefied natural gas was delivered for the first time from Algeria to Great Britain. The LNG trade has skyrocketed since. Based on the existing trends, a strong increase of the LNG trade is expected in the medium term. It is assumed that the liquefaction capacities will be doubled in the course of the next five years. A similar development is also to be expected for the expansion of the landing terminals. The IEA (2006a) expects investments of nearly USD 100 billion for this period. Capital expenditure for new LNG-tankers has been specified at USD 32 billion, for regasification plants at USD 31 billion. For the year 2030 the IEA (2004a) estimates an LNG-proportion of the trade in natural gas of more than 50 %.

A trend of the past years is the construction of larger units referring to liquefaction plants and tankers. This way the LNG-trade was expanded and the costs were reduced. In addition, there are technical developments in particular in the offshore-area, which may positively influence an expansion of the LNG-trade (Cox 2006). The following are to be mentioned:

- FPSO (*Floating Production, Storage and Offloading Units*) for LNG (FLNG) for greater water depths, which are used offshore for production, liquefaction, storage and loading,
- LNG-platforms for water depths of 20 to 50 m, where natural gas is taken over from producing platforms and liquefied,
- FSRU (*Floating Storage and Regasification Units*), which restores the liquefied natural gas on board to the gas phase and
- GBS (*Gravity Based Structures*) for storage and regasification in water depths less than 30 m.

These developments are accompanied by the emergence of new suppliers on the LNG market, such as Russia, Iran, Norway, Angola, Cote d'Ivoire (Ivory Coast), Yemen and Peru. Pakistan, Chile, Brazil, Jamaica, but also European countries such as Croatia, Poland and Germany as well as Israel might become new LNG customers. The largest increases in demand for LNG are to be expected in India and China, but also in Great Britain and in the US. For covering its increasing demand for energy, the US will have to depend increasingly on LNG, as the domestic production of natural gas and imports from Canada will either stagnate or possibly even regress. Thus, in the long run the proportion of LNG in the supply of natural gas of the European and North American markets for natural gas will increase. In principle however it can be assumed that the supply of pipeline gas from Russia, Norway, and North Africa and possibly from Iran will remain dominant for Europe. LNG will however have its share in the diversification of the supply of natural gas.

4.2.7 Trade of Natural Gas and Regional Markets

The still existing dominance of pipeline transportation has limited the distances between place of production and consumption of natural gas. For this reason, there is no global market for natural gas as for oil and coal; but only regionally limited markets exist (Fig. 4.13). Within these markets, producers and consumers are linked by long-term supply contracts, to safeguard the high capital expenditure for setting up the infrastructure. There are four regional markets for natural gas in the world: the North American and the South American market, where natural gas is generally traded only pipeline-bound, the Asian market, which is nearly completely a purely LNG market and where the liquefied natural gas has to be transported long distances by tanker as well as the mixed European market (Abb. 4.13). The countries of the Middle East and the Central Asian countries of the CIS hold a special position, as they can supply the European as well as the Asian market. The eastern parts of Russia with the regions to the east of the Yenissey River are assigned to the Asian market. The countries belonging to the individual markets have been listed in the glossary.

In 2007, slightly more than 30 % (approximately 920 Bcm) of the global production of natural gas were traded cross-border (not considering transit trade) (Fig. 4.14), of these approximately one quarter as liquefied natural gas (LNG). The six most important exporting countries Russia, Canada, Norway, Algeria, the Netherlands and Turkmenistan accounted

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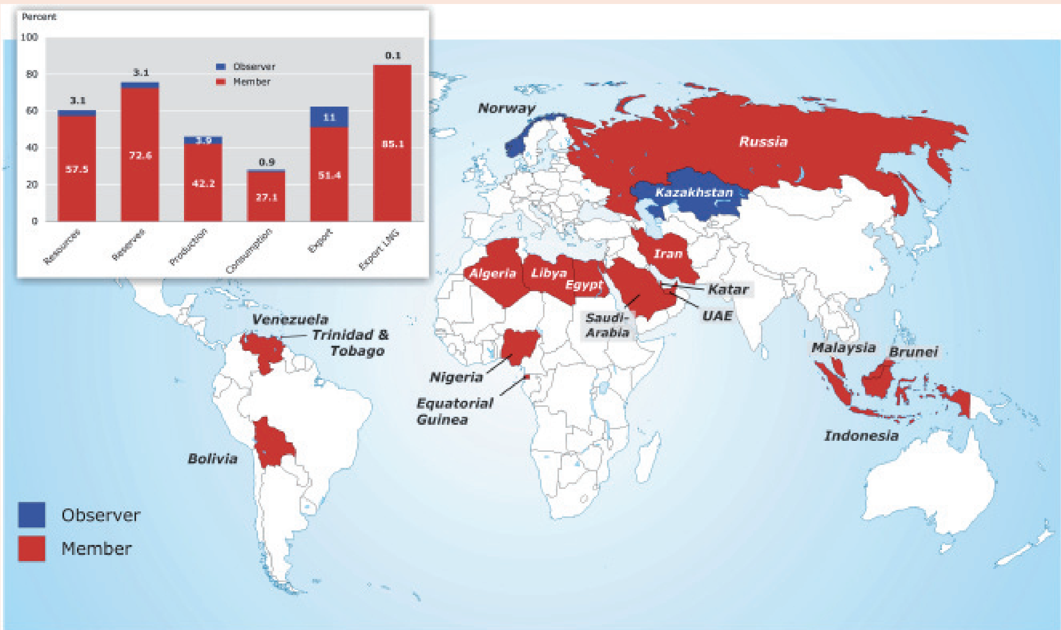
Will There Be a Natural Gas Cartel Analog to OPEC?

The Gas Exporting Countries Forum (GECF) was officially founded on December 23rd, 2008 in Moscow, when the articles of association and an agreement were signed. Currently there are 15 member states: Egypt, Equatorial Guinea, Algeria, Bolivia, Brunei, Indonesia, Iran, Qatar, Libya, Malaysia, Nigeria, Russia, Trinidad & Tobago, the United Arab Emirates and Venezuela. Norway and Kazakhstan have observer status. The organization is based in Doha, Qatar. It is the declared goal of the GECF to strengthen the cooperation between the member states. The core of the organization is the triple alliance (Troika) Russia, Iran and Qatar, who together possess 55 % of the global reserves of natural gas. This triple alliance develops, amongst others, the agenda for the GECF.

The Gas Exporting Countries Forum founded in May 2001 in Teheran was the predecessor of the new GECF, then a loose amalgamation of producers and exporters of natural gas without articles of association, whose economic and strategic-political interests diverged strongly. Even today, important producing countries such as Australia, Canada, the Netherlands or Norway are not members of the GECF. Venezuela and Equatorial Guinea as non-exporters are members, however. The member states of the GECF today possess together nearly 73 % of the global reserves of natural gas and slightly more than 57 % of the global resources of natural gas and jointly cover 42 % of the global production as well as slightly more than 51 % (in relation to LNG even 85 %) of the global exports of natural gas.

Many people view the GECF as an equivalent of the Organization of Petroleum Exporting Countries (OPEC) for the gas sector. This is based on fears that collusion will contribute to manipulations of the gas price and a monopoly could be created that way. The manner in which natural gas is traded constitutes a significant difference to OPEC, however. For natural gas there is no global market as for petroleum and long-term contracts of 25 years and more bind producers and consumers. The gas price has been linked to the oil price. These conditions do not render a price fixing in the style of the OPEC currently possible.



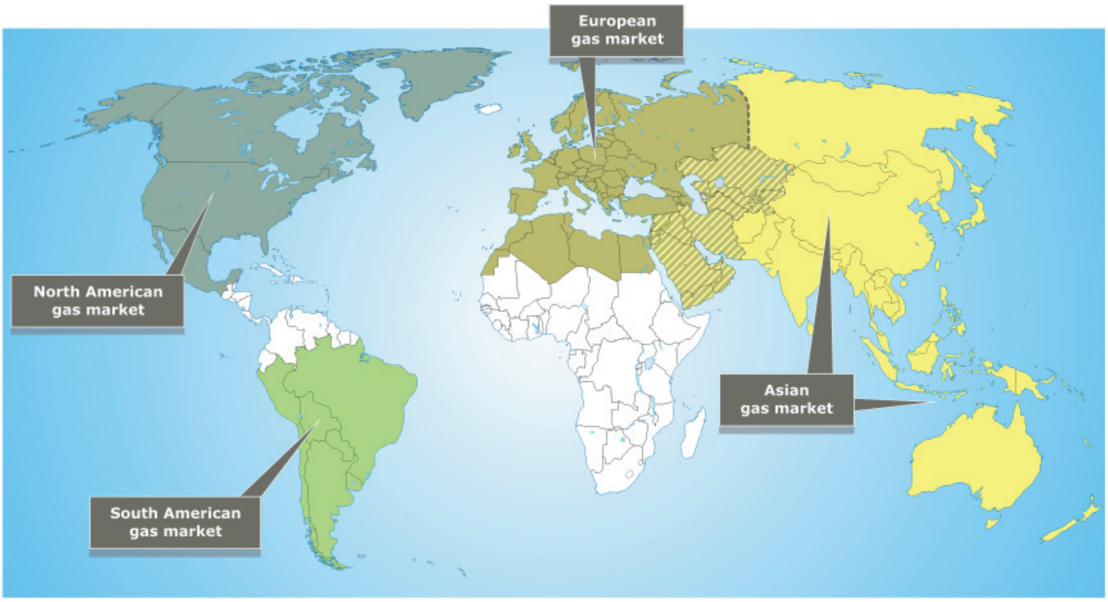


Figure 4.13: The four regional markets for natural gas in the world. Dashed: Transition area between European and Asian market.

for slightly more than 61 % of the global natural gas exports in 2007 (Tab. A 4-17), with a volume of more than 50 Bcm each. The ten top exporting countries possessed an export volume of natural gas of nearly 75 % of the total exports. This shows that in the natural gas market only few suppliers can deliver large amounts of natural gas.

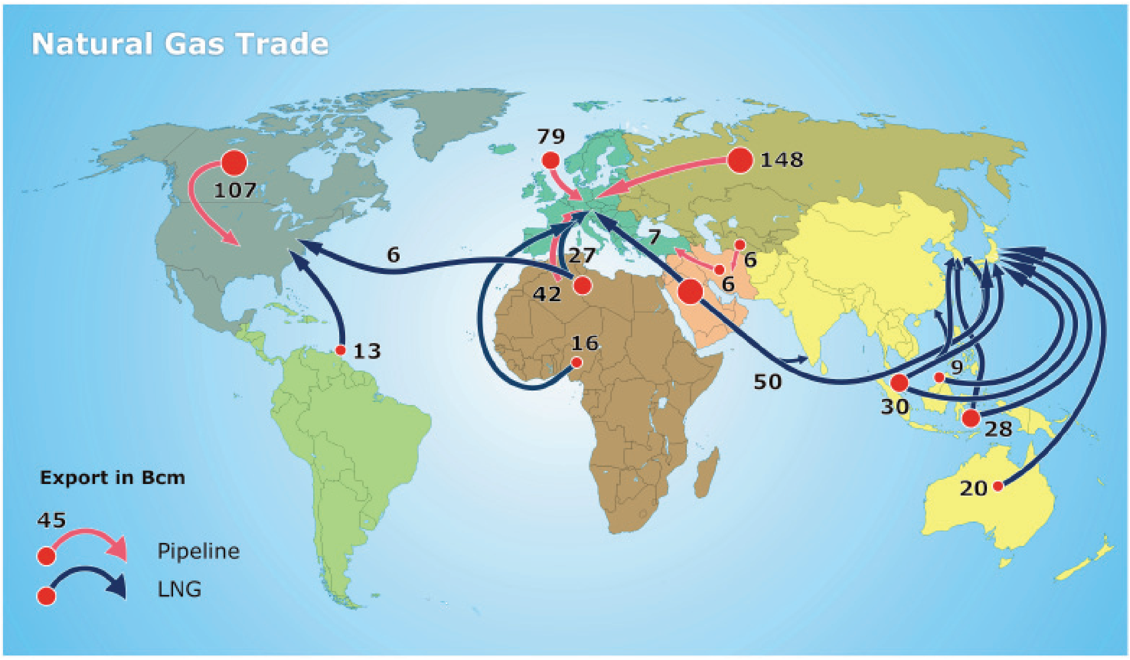


Figure 4.14: Global trade in natural gas in 2007 in Bcm (data according to BP, 2008).

Altogether 15 countries were involved in the LNG trade in 2007. The largest LNG exporter was Qatar, followed by Malaysia and Indonesia (Tab A 4-18). Nearly 40 % of the exports originated in Austral-Asia, but were traded in their regional market (Fig. 4.14). Africa follows at 27 %, just ahead of the Middle East at 26 %. OPEC has, at a 53 % proportion of the LNG export, a leading position similar to the export of petroleum (56 %). With the increase of the global LNG trade, a spot market for natural gas developed little by little. Its proportion of the total LNG market is still small and most of the contracts are still long-termed. In the following years, the proportion of the trade volume through spot markets should increase up to 20 %. This might result in a certain decoupling of the natural gas price from the oil price, which would then probably result in the spot market prices for natural gas being just as volatile as currently the prices for petroleum. Thus, there might also be an increased flexibility of the contracts for LNG deliveries, increasingly deviating from the current practice of the destination fixing and enabling the liberalization requested by the EU.

The US, Japan, Germany, Italy and the Ukraine were in 2007 the top five importing countries with natural gas volumes of more than 50 Bcm, corresponding to 46.9 % of the global import volume (Tab. A 4-19). The top ten importing countries for natural gas received approximately two thirds of the traded volumes. In 2007, 17 countries imported LNG. Japan dominates in this respect with a proportion of slightly more than 39 % (Tab. A 4-21). From a regional point of view, the Asian market for natural gas is dominant as a nearly purely LNG-market, as it takes up 65 % of the LNG imports. Europe follows with an LNG proportion of nearly 24 %. In the regional Asian market for natural gas, the proportion of LNG of the natural gas trade will decline in future in spite of an absolute rise of consumption. This development results from the inclusion of deliveries via pipeline from Russia and Turkmenistan to China and possibly to other East Asian countries. Deliveries via pipeline from Indonesia, Malaysia and Myanmar to Singapore and Thailand as well as from Iran to Pakistan and India are also conceivable.

4.2.8 European Natural Gas Market

The European gas market ranges eastwards to Kazakhstan as well as to the Russian western Siberia, in the south down to northern Africa. The Middle East has not been included (Fig. 4.13). The annual consumption of natural gas in the European market has risen to 1300 Bcm over the past years. The demand for natural gas in this market is met at approximately 70 % by the production from Russia, Norway, Algeria and Great Britain, while Russia alone satisfies approximately half of the demand. Approximately 550 Bcm, corresponding to slightly more than 42 %, were cross-border traded in the European market for natural gas in 2007. The transportation was conducted largely pipeline-bound; only approximately 53 Bcm were imported as LNG, mainly from Algeria and Nigeria.

The reserves base of Europe (Tab. A 4-7) is comparatively small at about 7420 Bcm. Norway, the Netherlands and Great Britain together account for more than three quarters of these reserves (Bittkow & Rempel, 2008, 2009). The dominant position of Russia concerning the reserves (47.7 Tcm) is obvious. The largest part of these is stored in west-Siberian deposits. In addition to the immense reserves, in Russia gigantic additional resources of about 106 Tcm are expected. The potential of eastern Siberia and of the Russian Far East as well as the adjacent shelf area cannot be considered in the foreseeable future for the supply of the European market due to the long distances. The reserves for supplying the European gas market are based on the great potential of the Caspian region (Turkmenistan, Kazakhstan, Azerbaijan and Uzbekistan), on the natural gas potential of the North Sea as well as of North Africa besides the massive Russian natural gas potential. Taking into consideration the significant natural gas potential of the Middle East as an additional source for deliveries to the European market by sea using LNG transportation or via pipeline from Iran, this market is in a comfortable supply situation potentially.

The European gas market possesses a very extensive pipeline network, which connects the great production regions in West Siberia, in the Volga-Ural region, in the North Sea and in North Africa to the main consumer regions in Western Europe and the western part of the CIS (Fig. 4.15). The pipeline network for natural gas of Western and Central Europe comprises approximately 50 000 km, to which a distribution network of more than 1.5 million km can be added. The Russian natural gas pipeline system, which is mainly operated by Gazprom, has a length of nearly 155 000 km with a capacity of 600 Bcm/a. The major part of these pipelines has been in operation for more than ten years, in part even longer than 30 years. In the coming years, extensive reconstruction of the system, in particular the compressor stations will be required.

For safeguarding the increasing demand for natural gas, new fields have to be developed and new pipelines have to be built. Such measures require extensive financial support, which can only be provided by international capital markets or governments. As these funds are tied up for a long time, a long-term and sustainable price perspective for natural gas is required. Currently and in the coming years, a number of large pipeline projects for safeguarding the increasing import demand of Europe are in the planning and construction stages, respectively (Fig. 4.15). Relating to deliveries from Russia, they are the Nord Stream Pipeline through the Baltic Sea and die South Stream Pipeline through the Black Sea and across the Balkan. For deliveries from Central Asia and Iran, the projects Nabucco and the

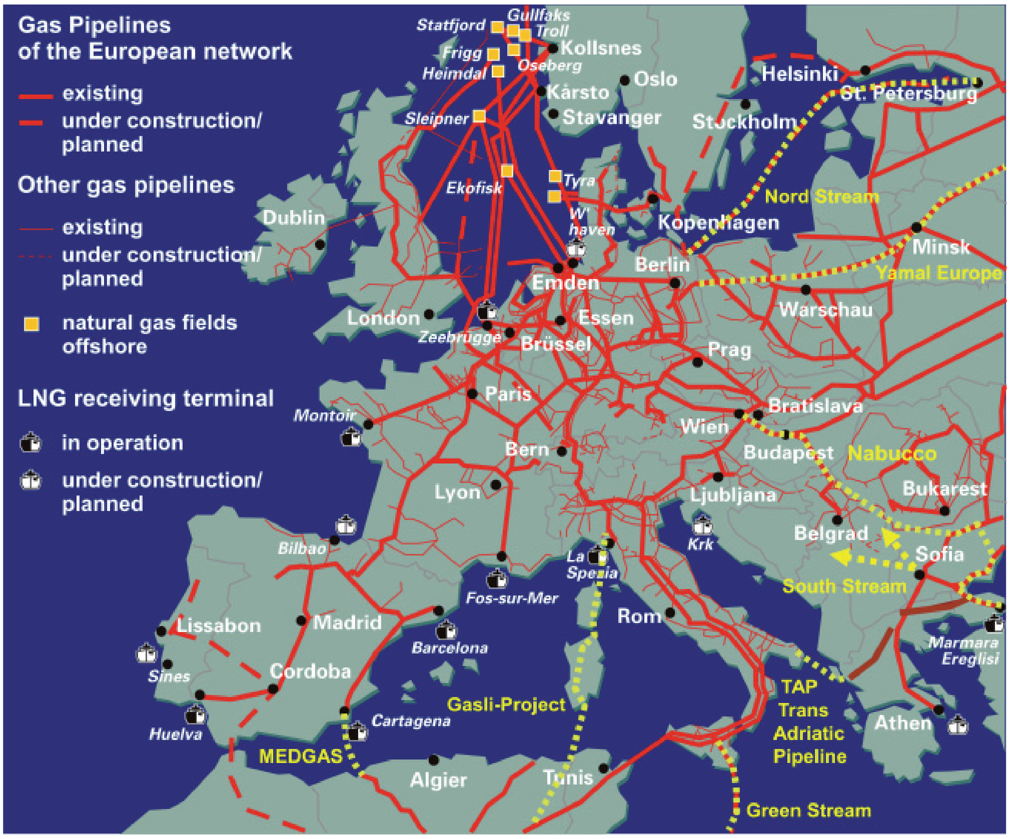


Figure 4.15: European natural gas network and pipeline projects (From Ruhrgas, 1999, updated).

Trans-Adria-Pipeline are important. Deliveries from Northern Africa are to be enabled via the Medgas and Gasli projects (Algeria) as well as via the Green Stream Pipeline (Libya). Turkey could play a key role in the trade with natural gas and the supply of Southern Europe because of its planned link to several areas of supply (Russia via the Balkan and the Black Sea, Iran, Turkmenistan, Egypt).

More than 50 % of the LNG landed in Europe in 2007, or 27.1 Bcm, originated from Algeria, Egypt and Libya. In the European market, only eight countries participate in the trade of LNG. All other European countries are supplied exclusively by pipelines. The Atlantic states Spain, Portugal and France show a high LNG-proportion of their natural gas supply of more than 30 %. The LNG-proportion in the Mediterranean states Greece and Turkey as well as in Belgium is approximately 20 %. In Italy and Great Britain, the proportion of LNG is below 3 %. The general trend for Europe indicates an increase of the LNG-proportion of imported natural gas. An expansion and new construction of landing capacities for LNG is proposed for the Atlantic and Mediterranean area as well as in the North Sea and the Baltic Sea. In the Norwegian town of Hammerfest in September 2007, a liquefaction plant with loading terminal went on stream. It is supplied with natural gas from the Snøhvit field in the Barents Sea. There is no LNG terminal in Germany.

The energy package of the EU commission published in January 2007 and national regulations are aimed at the creation of a true EU single market for energy, the development of liquid commercial markets and the simplification of the access to the pipeline network. The complete liberalization of the EU single market for natural gas applies since July 1st, 2007, also to the European end consumers. New legal requirements for the power and the gas markets apply in Germany since the amendment of the Energy Industry Act (Energiewirtschaftsgesetz, EnWG) as well as the corresponding statutory ordinances since July 2005, which transpose the so-called EU Energy Directives passed in mid 2003 for the power and natural gas single markets into national law. In Germany, this resulted in the termination of the negotiated network access on the basis of the voluntary association agreements. It is the objective of the new Energy Industry Act to provide a safe, cheap, consumer-friendly, efficient and ecologically sustainable supply of power and natural gas. An improvement of the transparency of the market and a better cost efficiency of the network areas are aimed at. Important new components of the German Energy Law are, amongst others, the establishment of a regulation authority (Bundesnetzagentur – Federal Network Agency), the legal and organizational demerger of the power supply companies, the regulation of network access via an entry-exit-model for the gas sector and the regulation of the network connection. Since July 2007, natural gas is also traded at the European Energy Exchange (EEX) in Leipzig in the spot market as well as in the futures market.

4.2.9 Natural Gas Prices

The price for natural gas consists of several components. Extraction, processing and transportation costs contribute the lion's share. The extraction costs of natural gas contain analog to oil (Chapter 3.2.5) the exploration, development and production costs for a natural gas field. They are influenced, amongst others, by the type and depth of the reservoir horizons, the composition of the natural gas and also the climatic conditions on site. There are no concrete data about the extraction costs in the references. According to the assessment of the BGR, these are between USD 0.40 and USD 2.50 per MMBtu for the most important gas providers. Due to the use of modern technologies in exploration, drilling and production these extraction costs have been reduced significantly towards the end of the 1990s. They have, however, risen significantly, in particular since 2003, due to higher costs for energy, equipment, material and personnel.

In addition to the extraction costs, there are costs for processing the natural gas, the official producing taxes, duties and the profits of the company. Costs for the processing of the natural gas depend on the composition of the gas. Lean gases consisting mainly of methane require only drying. Greater expenditure results for rich gases, which contain higher homologues of methane and gas condensate, as their separation from natural gas is required before it can be transported. These products are also marketed as liquefied petroleum gas (LPG) in addition to natural gas and thus contribute to a reduction of the costs. For the production of sour gas, the production equipment has to be corrosion resistant and thus requires additional expenditure for increased technical input. In addition, hydrogen sulfide and possibly carbon dioxide have to be removed from the natural gas. In the course of this process, sulfur is generated, which can be sold as marketable product, but currently profitable marketing is difficult, as the world market for sulfur is saturated. From the cost categories described above the prices for natural gas at the border of the individual producing country can be derived.

As natural gas is not traded on a uniform world market with only slightly regionally differing prices, unique price structures have developed in the regional markets (Tab. A 4-20). Until 2006, a harmonization of the prices of different markets in the course of time was observed (Fig. 4.16). Since 2006, this trend seems regressive, however; the prices of the regional markets diverge once again. The prices for natural gas follow the price for petroleum with a delay of approximately half a year. Accordingly, the prices for natural gas in the second half of the 1980s decreased, fell slightly in 1999, in order to increase again ever since 2000 (Fig. 4.16).

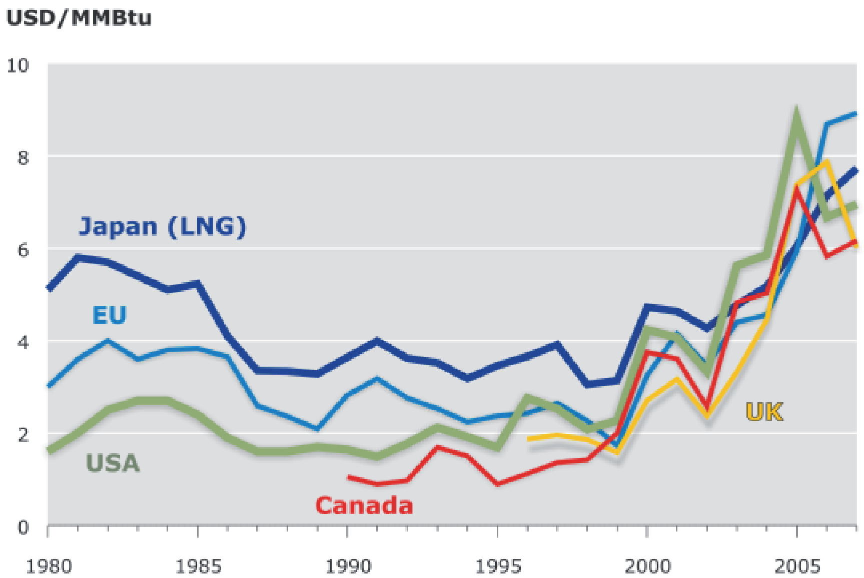


Figure 4.16: Development of the prices for natural gas from 1980 to 2007 (1 MMBtu – Million British Thermal Units – corresponds to approximately 28 m³ natural gas or approximately 0.023 toe).

Worldwide, the major part of the traded natural gas is bought and sold on the basis of medium to long-term contracts, whereas at spot markets only smaller surplus and additional amounts are traded. In addition, the development of the prices in the spot markets is very much affected by the seasonal variations of demand. In particular during the winter months, there are frequently price peaks due to high demand and only limited supply. The spot prices are also indirectly influenced by the development of the oil prices. The comparison of the price development of the spot markets with the gas prices agreed on in long-term delivery contracts linked to oil shows that the development of the oil-linked gas prices is significantly more reliable and less volatile.

The producers of natural gas have repeatedly tried, especially in times of low oil prices, to decouple the natural gas price and the oil price. Because of the considerably decreased oil prices since the fall of 2008, there have already been first requests for decoupling oil and natural gas prices. In doing so, in particular the high capital commitment for natural gas projects has been brought forward as an argument, which can in extreme cases result in projects necessary for a smooth supply not being undertaken in times of low prices. To which extent a decoupling can happen is questionable, as natural gas is in direct competition with other fuels and can be replaced by them. The influence of the GECF on the future pricing remains to be seen (Info box 4).

4.3 Unconventional Natural Gas

Until the mid 1980s, unconventional natural gas was widely regarded as a negligible factor in the natural gas sector. From an emerging resource a decade ago, and a mostly overlooked resource two decades ago, unconventional gas has now developed into a core business of many large independent producers and of a growing number of major oil and gas companies (Kuuskraa, 2007a). According to the classification in Chapter 2.3.2, unconventional natural gas is separated into natural gas from dense rocks (tight gas and shale gas), coalbed methane, natural gas from aquifers and gas hydrates.

4.3.1 Tight and Shale Gas

These types of natural gas are occurring in rocks with very low permaeability as compared to classical reservoirs. They comprise occurrences in sandstone or carbonate reservoirs (tight gas) as well as gas enrichments in mudstone (shale gas). The delimitation from conventional gas deposits is based on the permeability of the rock (Fig. 4.17). Internationally, an aver-

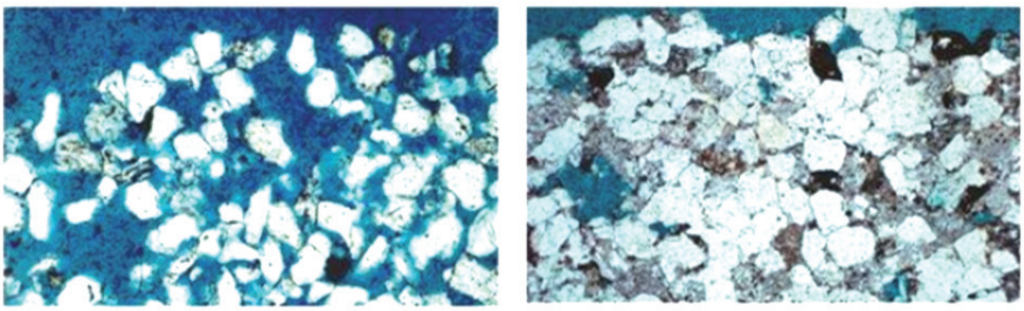


Figure 4.17: Comparison of a sandstone (grain size about 0.5 mm) with high porosity and permeability as conventional natural gas reservoir rock (left photo) to a low permeable sandstone as tight reservoir (right photo). For both specimens the pore spaces have been dyed blue (photos: Naik).

age permeability below 0.1 milliDarcy (mD), in Germany below 0.6 mD, is used to classify natural gas occurrences as tight or shale gas. The source of the hydrocarbons, whether they are of microbial or thermal origin, is not important for this type of differentiation.

Natural gas in tight reservoirs typically occur in the central areas of deep (> 4500 m) sedimentary basins as so-called deep gas or basin-centered gas. Shale gas can occur in shallower depths as long as temperature is sufficiently high to generate hydrocarbons from the organic matter in the mudstones. The generated gas never dismigrated from the shales, hence these rocks are both source and reservoir rock. Every now and then shallow gases (Info box 5) in low-permeable rocks are classified as shale gas deposits. Typical characteristics of natural gas in tight and/or shale reservoirs are their large regional (i.e. basin wide) extension in usually overpressured reservoir rocks and the very large amount of resources. However, amount and quality of these types of hydrocarbon accumulations are very variable, thus production is currently limited to those areas with the most advantageous reservoir properties, so-called sweet spots.

The production of hydrocarbons from tight and shale gas reservoirs is technically very difficult. The low porosity, reduced permeability and the high water saturation in the reservoir result in a complex multiphase flow. Additionally the in-situ stress conditions greatly influence the producibility. Due to the low permeability the influx of the gases into the borehole is impeded and the production rates are low. An increase of the permeability is thus an essential measure for increasing production rates or to enable an economic production at all. The technical development of new production strategies is thus of particular importance for occurrences of natural gas in tight reservoirs. State funded research programs in the US targeting unconventional gas accumulations, in accordance with the Energy Policy Act 2005 (Reeves et al., 2007a), have already resulted in significantly higher production rates from tight reservoirs. Amongst the most important measures to increase production rates are the generation of artificial hydraulic fracs to enhance permeability (Abb. 4.18) and the optimization of the production wells, i.e. development and implementation of horizontal and multilateral drilling.

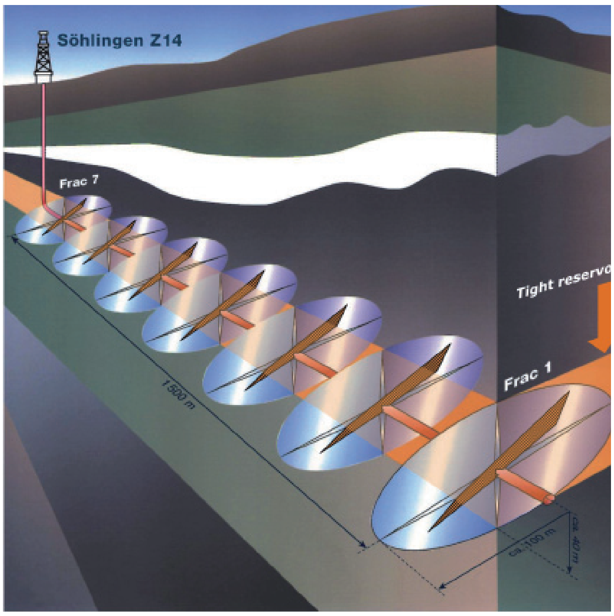


Figure 4.18: Development of a gas in a tight reservoir using artificial fracture systems, so-called fracs (changed in accordance with Mobil Erdgas-Erdöl GmbH).

Development of gas fields and production of natural gas from tight deposits requires significantly more capital and technical development than for conventional deposits (Moritis, 2008). Only sufficiently high production rates render the exceptional capital expenditure economical (Kuuskraa et al., 2007). Currently each successfull well targeting natural gas from tight sandstone reservoirs makes approximately 28.8 million m³ reserves accessible for production.

Unconventional gas in tight deposits have been proven worldwide, important accumulations exist in North America, South and Central America (Mexico, Venezuela, Argentine), Africa (Egypt, Nigeria), Saudi Arabia, Australia, Europe (Germany, France, Netherlands, Great Britain), the CIS, China and India (Wylie et al., 2007; Holditch et al. 2007). Due to lack of sufficient geological information as well as great technical and economic challenges natural gas from tight reservoirs is produced only in a few countries. Unconventional deposits are explored and produced systematically mainly in the US. The dynamic development as well as the great uncertainties in terms of these natural gas resources has be demonstrated in the US.

In the US, the annual production of natural gas from unconventional deposits increased from 140 Bcm in 1996 to 244 Bcm in 2006. This is a share of 43 % on the total US natural gas production (Kuuskraa, 2007a). The production from tight sandstones contributed most to these added production; it increased from 102 Bcm in 1996 to 161 Bcm in 2006. About 13 000 wells were drilled per year. The production of gas from tight mudstone (e.g. shallow and shale gas) is at a lower level, but has more than tripled during the same period from 8.5 Bcm to 31 Bcm (Kuuskraa, 2007a). A further increase of the annual production from unconventional gas reservoirs to 250 Bcm per year until 2015 and 288 Bcm until 2030 has been forecasted (EIA, 2007) for the US. These numbers are considered conservative, as previous forecasts concerning the production of gas from unconventional gas fields have been too low in the past (Reeves et al., 2007b). The proportion of the US gas production from unconventional deposits will thus rise in all likelihood from 60 to 70 % of the total production until 2020 (Moritis, 2008).

The assessment of recoverable reserves from tight reservoirs contains large uncertainties due to the particular characteristics of these occurrences, which can be demonstrated at the deep gas deposit Williams Fork, Mesaverde, USA (Kuuskraa, 2007b). Even small differences in the assumptions the analyses were based on, e.g. distance between boreholes, success rate and total potential of the gas field, resulted in large differences regarding the amount of recoverable gas, which varied by more than one order of magnitude. For instance the US Geological Survey (2003, in Kuuskraa, 2007b) estimated the reserves to be 87.8 Bcm, whereas the consulting company *Advanced Resources International* (Airlington, USA) estimated 1203 Bcm economically recoverable reserves. Similar uncertainties apply to shale gas. Improvements in hydrocarbon exploration and production technology such as horizontal drilling, production stimulation and tighter drill networks resulted in an increase of the estimated extractable reserves of the Barnett Shales in Texas, USA, from 85 Bcm in 1996 to 736 up to 1388 Bcm in 2006 (Kuuskraa, 2007b).

The proven reserves of shale gas in the US have been assessed to be about 99 Bcm in 1998 and are estimated to be 425 Bcm today. Comparably, the proven tight gas reserves have also been re-evaluated from 1036 Bcm to 2265 Bcm (Snow, 2008).

The CIS, North America and Central Asia/China certainly have the largest potential for unconventional gas resources, but except for the US there are few authoritative assessments of resources. Thus, for instance, the resources in Canada are estimated to about 10 000 Bcm gas in-place by Reeves et al. (2007b) whereas Russum (2005) predicts up to 41 000 Bcm. Even Germany has a comparatively high potential of resources (chapter 8.2.5). According to Holditch & Chandelle (2008) the global natural gas in-place resources in dense deposits are approximately 666 Tcm. The currently largely uninvestigated shale gas accumulations account for approximately two thirds of the estimated amounts (Table 4.2).

Table 4.2: Distribution of worldwide shale gas and tight sand gas in-place resources in Tcm (Holditch & Chianelli, 2008; Kawata & Fujita, 2001; Rogner, 1997).

Region /Reservoir rock	Shale Gas	Tight-Sand Gas
North America	108.8	39
Latin America	60.0	37
Western Europe	14.4	10
Central & Eastern Europe	1.1	2
Former Soviet Union	17.8	26
Middle East and North Africa	72.2	23
Sub-Saharan Africa	7.8	22
Central Asia & China	99.9	10
Pacific (OECD)	65.5	20
Other Asia Pacific	8.9	16
Southern Asia	0	6
WORLD	*456*	*210*

Even though natural gas, in all likelihood, occurs in dense formations of all sedimentary basins, the actual resources still have to be proven by exploration. Furthermore the actual recoverability depends to a high degree on the future technological development and the economic conditions. The increasing importance of the unconventional tight gas and shale gas accumulations, in particular in countries with limited gas reserves, is reflected in a recent European research initiative. A consortium of European research institutions, universities and the industry proposes a multi-year project for a detailed investigation of the occurrence of shale gas in Europe (Leblond, 2008). Because of the very limited knowledge concerning the incidence of recoverable natural gas from tight lithologies, the regional distribution depicted in Figure 4.19 reflects to a high degree the state of the hydrocarbon exploration.

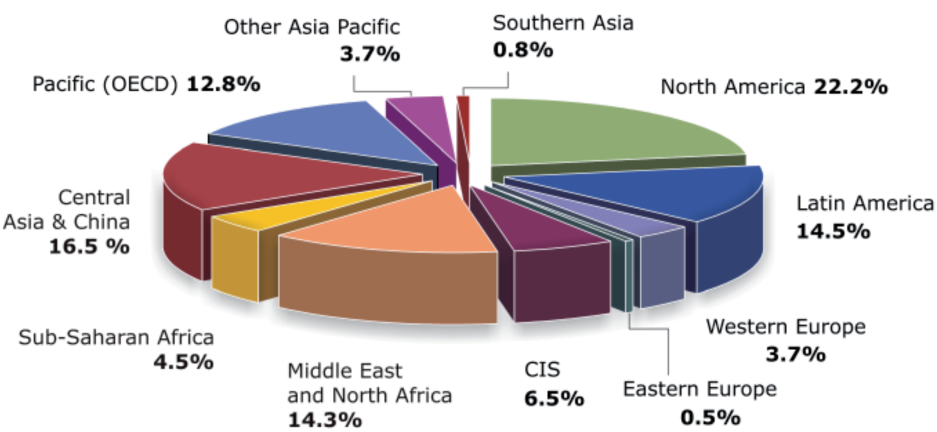


Figure 4.19: Regional distribution of tight sand and shale gas resources.

4.3.2 Coalbed Natural Gas

Coalbed natural gas is a superordinate term for all natural gas mixtures, which occur in conjunction with coal. This mainly refers to coalbed methane (CBM) and coalmine methane (CMM) (Tab. 4.3). CBM is the gas released from virgin coalseams, for example, by drilling. The CBM escaping due to mining from the mine immediately or later is called coalmine methane. CMM can be further subdivided in methane, which is removed from operating underground coal mines via degassing systems and mine ventilation, and in methane, which can leak from the coalseams in closed mines even after many years. Generally, the three types of gas, CBM, CMM from active mines and CMM from abandoned mines, differ in the chemical composition (Tab. 4.3).

Table 4.3: Structure of coalbed natural gas and average contents of different components of the different types of coalbed natural gas.

	Coalbed Methane (CBM)	**Coalmine Methane (CMM)**	
	(Methane from virgin coal-seams)	(Methane from active mines)	(Methane from abandoned mines)
		[Vol.-%]	
CH_4	90 – 95	25 – 60	60 – 80
CO_2	2 – 4	1 – 6	8 – 15
CO	0	0.1 – 0.4	0
O_2	0	7 – 17	0
N_2	1 - 8	4 – 40	5 - 32
C_{2+}		traces	

For centuries, coalbed natural gas has been known and feared in underground coal mines as safety risk and thus as a productivity limiting factor due to its explosive nature in connection with oxygen. Still several hundred miners annually die due to coalmine methane explosions, so-called firedamps; in particular the PR China and the Ukraine head the statistics of the firedamp victims. As counter-measures, the mines are supplied with fresh air (aerated) and coal seams are degassed in advance (pre-mine drainage) via drillholes.

In the past decades, the coalbed natural gas from the degassing system has been increasingly used for energy purposes. After 1908, CMM from active mines was used in the Saarland for generating steam. In 1948, in the Hirschbach mine the first degassing system was put into operation. In 1935, in Japan the first power plant was supplied with 700 000 m^3/a of CBM. In the US, coalbed natural gas has been used for energy purposes since 1975. Today the US account for nearly four fifth of the global CBM production.

Coalbed natural gas can be generally expected in all coal deposits where the coal has reached or surpassed the maturity of the bituminous coal of 0.7 % vitrinite reflectance (Chapter 2.3.3). From this phase onwards, large amounts of methane are being generated in the coal due to thermal processes. The subsidence history of the deposit and the current geological situation have to permit the storage of methane. The highest methane contents are to be expected in fat coal to semi-anthracite (Fig. 2.4), whereas the high coalification of the anthracite may have negative effects on the gas content. Lignite deposits are not suitable for CBM production, or only in rare cases, due to the low maturity of the coal.

In principle, all countries, in which there are deposits of hard coal, possess coalbed natural gas. As production technologies progress all over the world and as energy prices fluctuate strongly, coalbed natural gas can also become regionally economical, even if currently still in conjunction with tax incentives. In some countries, coalbed natural gas is considered part of the gas reserves and included in the production of conventional natural gas. This inhibits a clear demarcation of conventional and unconventional gas.

Information concerning **coalbed methane resources** exist currently only in reference to 23 countries and thus only to about one quarter of all countries possessing hard coal. The global resources of CBM in these countries amount to at least 135.5 Tcm and at most to 372.5 Tcm. The large range reflects the still great uncertainties and different approaches in the assessment of CBM. In some cases, only extractible amounts of CBM have been considered, in other cases the in-situ gas content has been used as the basis of the assessment. In addition, the included depth horizons in the resource assessments differ.

The data concerning global **reserves of coalbed methane** of 1.7 up to 2.6 Tcm are based on information from only eight countries. Thus, remaining **potential of coalbed methane** from 137.2 to 375.1 Tcm result. The small proportion of the reserves of only about 1 % referring to the total resources is based on the fact that many deposits have been insufficiently investigated concerning their gas content. In addition, detailed data frequently refer only to actual mining districts. From the investigated virgin coal seams, only a fragment of the in-situ gas content can be extracted and even the coalmine methane released by coal mines largely leak into the atmosphere without having been used.

For a rough check of the global remaining in-place potential of coalbed natural gas (particularly CBM), the total resources of hard coal specified in this study of 16.4 trillion tonnes with differing typical gas contents of the coal of 3.5 and 15 m^3/t were multiplied. The global remaining potential of CBM derived via this calculation are 49.2 Tcm for a gas content of 3 m^3/t, in-place 82 Tcm for 5 m^3/t and 246.1 Tcm for 15 m^3/t. Only for a given gas content of 15 m^3/t of hard coal, the calculated remaining potential of CBM are within the range resulting from summing up the individual specifications of the countries concerning remaining potential of CBM. This leads to the conclusion that the CBM reservoir data of many countries are based on assessments of the in-situ gas contents. In some hard coal basins, in-situ gas contents of more than 20 m^3/t can actually occur. Resource calculations are, however, frequently based on only 10 to 20 % of the in-situ gas being producible.

The CIS has the greatest CBM resources of 53,8 to 157 Tcm, of which Russia and the Ukraine have a great share. For North America, at 23 to 133 Tcm, only marginally fewer resources are reported, which are nearly exclusively located in Canada and the US (Fig. 4.20). In Austral-Asia, with the third largest CBM resources (52 to 68 Tcm), the PR China and Australia have to be stated. At 7 to 13 Tcm, Europe possesses comparatively small CBM resources, which are located in particular in Germany, Poland, Turkey and Great Britain. Whereas for Africa only for South Africa at 0.1 to 0.9 Tcm of CBM resources are reported, the Middle East has no known resources.

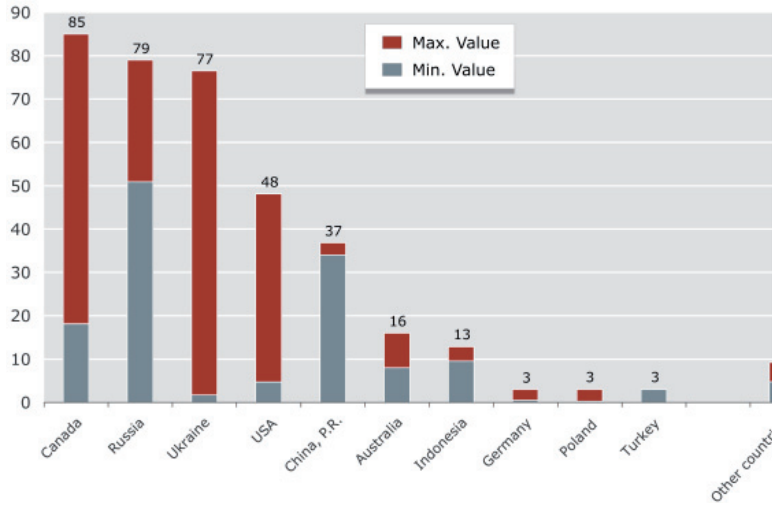


Figure 4.20: CBM resources in 2007: Minimum and maximum values for the top ten countries.

According to current knowledge, CBM reserves are attributed at about 74 %, corresponding to 1.6 Tcm, to North America, followed by Austral-Asia at about 0.4 Tcm and Europe at 0.4 Tcm. Amongst the countries with the greatest CBM reserves number Canada with 0.5 to 1.4 Tcm, the USA with 0.6 Tcm, Australia with 0.3 Tcm as well as the PR China and Poland with 0.1 Tcm each (Fig. 4.21).

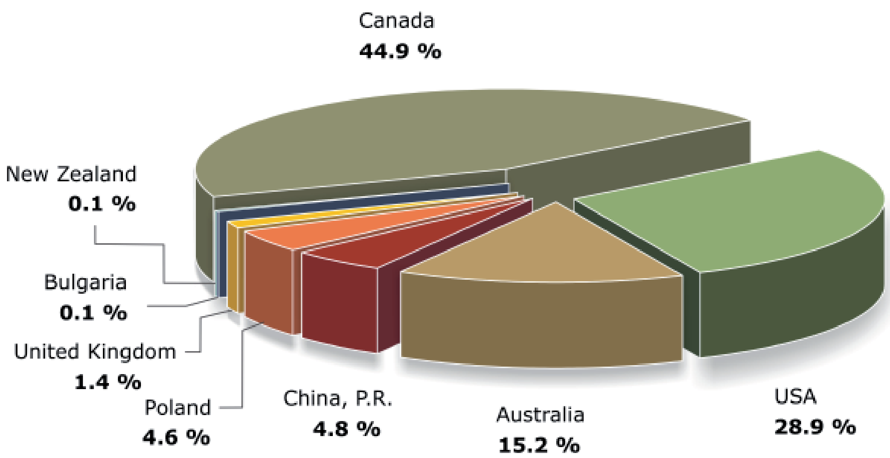


Figure 4.21: CBM reserves by countries in 2007. The percentages refer to CBM reserves of 2.15 Tcm. This value results from the inclusion of the mean value of the Canadian CBM reserves of 963 Tcm.

Drillholes can be driven in the virgin coal seams for development and **production of coalbed methane** (Fig. 4.22). In these drillholes, the individual target horizons are hydraulically stimulated through fracturing using highly pressurized drilling liquid. The cracks developing in the target horizons considerably improve the influx rates of the CBM. After drying of the produced CBM it is either routed directly into a gas engine for combustion or fed into a gas pipeline. The USA have the globally highest CBM-production, where up to now more than 60 000 CBM-wells have been drilled (IEA, 2009).

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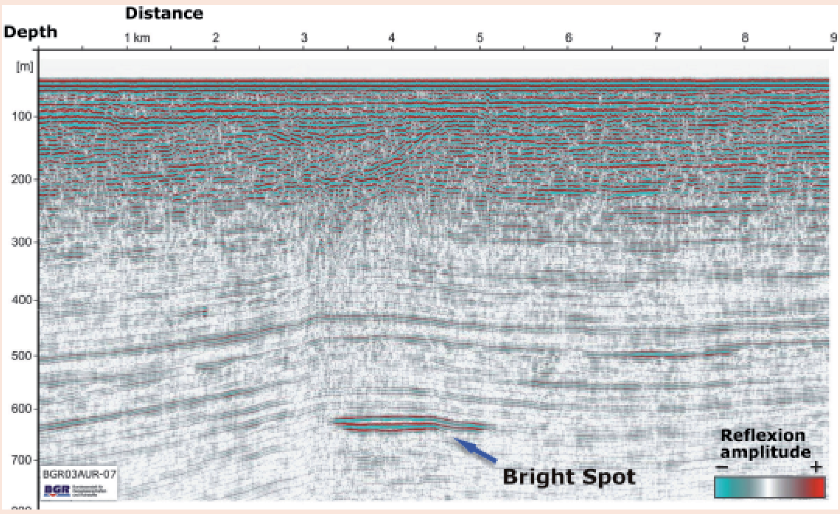
Shallow Gas - Hazard or Potential Resource?

The term *Shallow Gas* denotes natural gas occurrences in a depth of down to approximately 1000 m. Methane is usually the main component; its origin may be microbial as well as thermogenic (Chapter 2.1). Shallow gas occurs worldwide, onshore as well as offshore. The potential of its use is limited, in particular because many of these occurrences occur only in young, slightly compacted rocks. Together with the natural gas and formation water also significant amounts of fine-grained sediment are produced. Up to now, the distribution of shallow gas was of interest, less because of its commercial value but mainly because of its hazard factor for deep-sea projects, construction projects and drilling projects. In addition, shallow gas can be used as an indicator when prospecting deeper deposits.

Occurrences of shallow gas are known in particular from seismic survey investigations (seismic reflection) of the underground in course of the petroleum and natural gas exploration. Seismic reflection data can provide direct indication about hydrocarbon enrichment in two ways: 1) If the gas is distributed randomly in the sediment, because it rises chimney-like from deeper layers, for instance, this results in characteristic, diffuse seismic images of the subsurface. 2) If the gas collects under a seal, the upper or lower contact surface of the occurrence has anomalous reflection properties. These anomalies are frequently exactly defined laterally and form an acoustically noticeable area, called bright spot. Such findings can have causes other than natural gas occurrences and high gas contents do not necessarily show in seismic data. Bright spots thus do not constitute clear evidence of gaseous components of the pore fill. Their further evaluation requires drillhole measurements, chemical analyses of drill samples or the in-depth investigation of the reflection behavior. Still, the detection and classification of bright spots is an important method for the improved evaluation of the incidence of natural gas in a region, in particular for shallow occurrences.

In Germany, shallow gas occurrences are known from the North Sea. These are currently being investigated by the BGR using seismic reflection and geochemical methods. The seismic profile depicted by the BGR from the area of the German North Sea shows an identified bright spot, which presumably constitutes an enrichment of shallow natural gas.



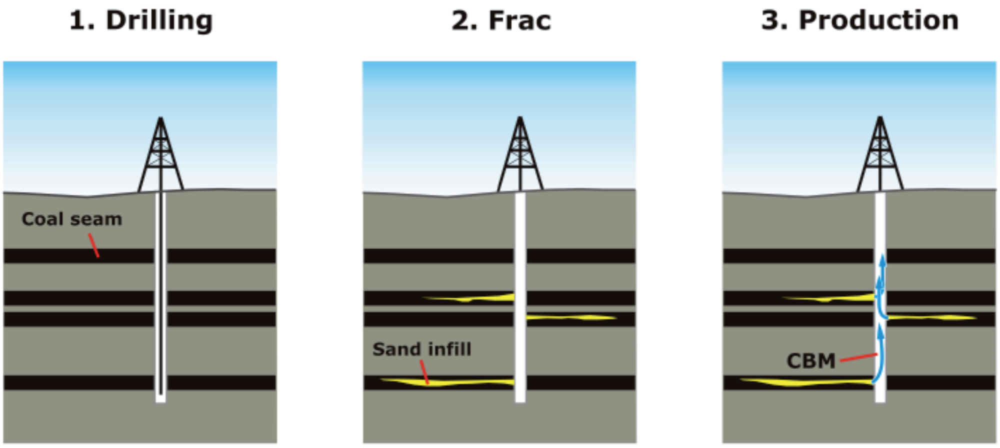


Figure 4.22: Production steps for CBM production.

The development of coalmine methane (CMM) from abandoned coal mines is different from CBM. As CMM from abandoned coal mines is only slightly pressurized, it is extracted through a drillhole or an existing shaft. Countries with many abandoned hard coal mines, such as Germany and Great Britain, are predestined for CMM production.

The CMM production from active mines is frequently done primarily for safety reasons for the prevention of firedamp. The pre-mine drainage of the coal seams and the corresponding mining areas is conducted in most cases through underground drillholes. These largely horizontal drillholes are either drilled directly in the coal seams or in horizons located either immediately above or below.

The total global coalbed natural gas production amounted to 63.3 Bcm in 2007. This already corresponds to a proportion of 2.1 % of the global natural gas production. This way, the global coalbed natural gas production was increased by about 50 % in comparison to 2001 at 42.3 Bcm (BGR, 2003) and nearly tripled as compared to 1997 at then 23 Bcm (Bibler et al., 1998). This trend demonstrates the rapid development of the production of coalbed natural gas (primarily CBM) in the past years, in particular in some industrial countries. The production of large amounts of coalbed natural gas takes place in countries where in particular CBM is produced. Currently these are the USA, Canada, Australia and the PR China, which together produced 96.3 % of the global coalbed natural gas production in 2007. The USA dominate the global coalbed gas production with a production proportion of 78.5 % (Fig. 4.23), followed by Canada at 11.6 %, Australia at 3.9 % and the PR China at 2.2 %. All other countries, such as the Ukraine, Germany, Great Britain, Poland, Russia, the Czech Republic and Kazakhstan, possess with an annual production of less than 1 Bcm of coalbed natural gas a production share of less than 1 % (Fig. 4.23).

In future, the CBM production will increase significantly, primarily in the PR China, Canada and Australia. In the US, where about half of the production originates in the San-Juan Basin, the relative growth between 2002 and 2007 was about 9 % at an already high production level (EIA, 2009). The Canadian CBM production, showing significant increases only since 2002 (ERCB, 2008), is in comparison to its neighbor, the US, still in its infancy (EPA, 2009). More than 90 % of Canadian CBM production originate in the Province Alberta, where in 2007 altogether 9339 CBM wells were being operated. The Energy Resources Conservation Board (ERCB) estimated that the CBM production in Alberta will approximately triple by 2017 in comparison to 2007 (ERCB, 2008). The Chinese CBM production will also expand

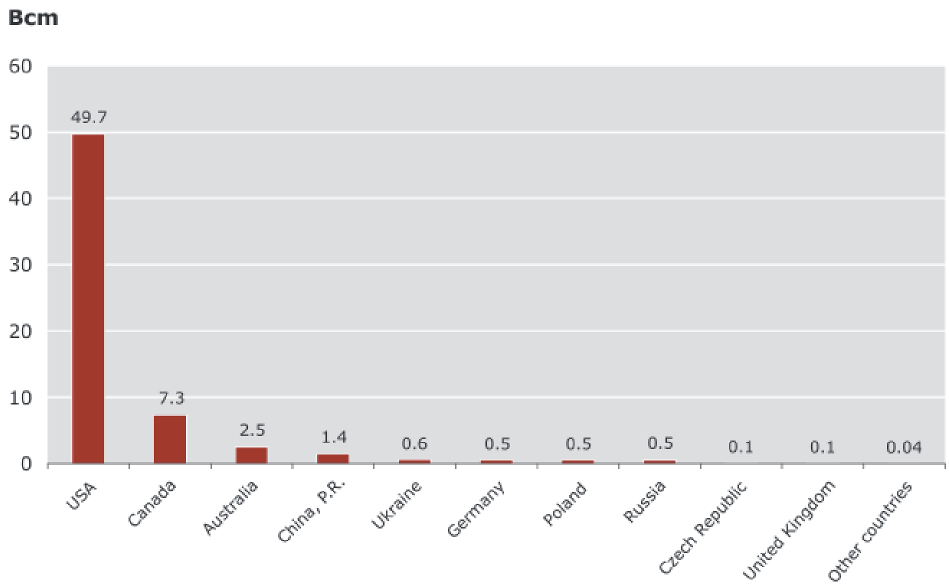


Figure 4.23: CBM production (total 63.3 Bcm) in 2007: top ten countries.

considerably in the coming years. In 1995, the China United CBM Corporation was founded for this particular purpose. Thus, the plans for the Chinese CBM extraction envisage a production of 10 Bcm for the year 2010, which is to be expanded to 40 Bcm by 2020. For transporting CBM, the construction of dedicated pipelines and CBM liquefaction plants are being planned (Qiu, 2009).

In Australia, the CBM production quadrupled between 2002 and 2007 and by now has a proportion of 7 % of the Australian natural gas production. 95 % of the Australian CBM production originates in the state Queensland. The remaining 5 % are produced in the state New South Wales. In view of eight further current CBM projects and five planned liquefaction plants in Queensland, it can be assumed that the Australian CBM production will increase further (ABARE, 2009). With exception of the Ukraine, the exploration and the use of CBM has only a secondary priority in the countries of the CIS, as there are large conventional deposits of conventional natural gas. In Germany, CMM is used for power/combined heat and power generation in regionally important small power plants (Chapter 8.2.5).

4.3.3 Natural Gas in Aquifers – Renaissance with Geothermal Energy?

Gas dissolved in ground water is called natural gas in aquifers or aquifer gas. Nearly all porous rocks underneath the groundwater level contain small amounts of methane gas (Marsden, 1993). Due to the limited solubility of methane in water, concentrations in the ground water are generally low. The solubility of methane as the main component of natural gas increases with increasing depth and thus with rising pressure, i.e. considerable amounts of dissolved gas can occur in deeper groundwater horizons. At normal pressure of the ground water (hydrostatic pressure), the solubility of methane can increase to more than 5 m^3/m^3 (Fig. 4.24). In areas with high pressure (maximum lithostatic pressure), more than 10 m^3/m^3 can be dissolved. From zones of high tectonic tensions even gas contents of up to 90 m^3/m^3 are known.

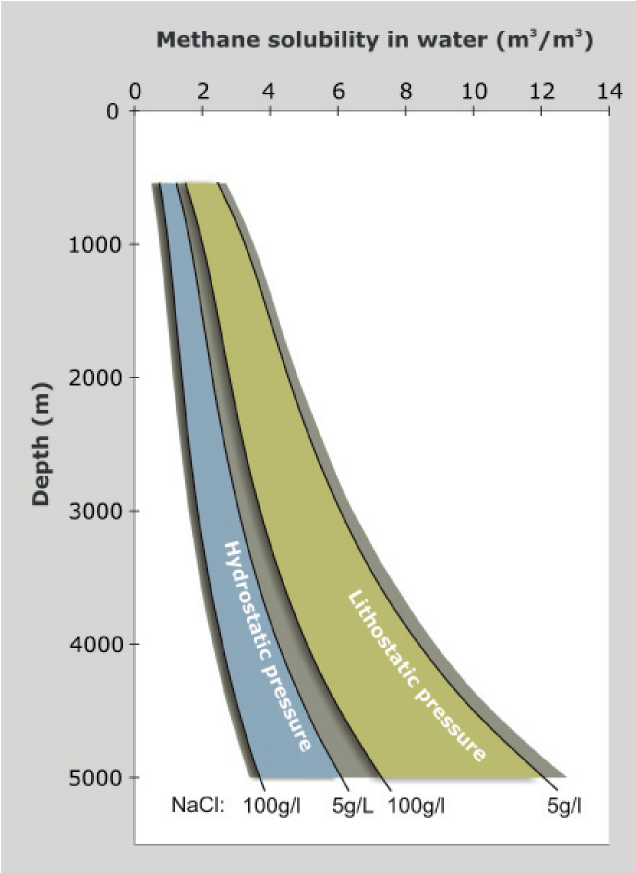


Figure 4.24: Solubility of methane in ground water as a function of the depth calculated in accordance with Battino (1984) and Haas (1978).

In comparison with other unconventional gas resources, aquifer gas is currently of very low economic interest. The hydrocarbon industry presently does not explore on aquifer gas. To be able to use even a part of the potential, currently processes are being discussed, that have been developed years ago, but were not pursued because of the low-cost and readily available conventional natural gas. Gas occurrences in hot, highly overpressured aquifers are considered economically producible. However, it is only the combination of different energy systems which may allow the start of an economic usage of natural gas from aquifers.

In contrast to the gas production of all conventional and unconventional natural gas deposits, the ground water has to be extracted as well, to be able to extract the natural gas dissolved in the water. The expenditure required for this purpose is generally disproportionate to the attainable energy gain from the natural gas. Even in areas with existing infrastructure and for globally high gas prices, this approach will remain uneconomical. Only when the hydraulic and the geothermal energy of the ground water can be used sufficiently besides the chemical energy of the natural gas, an economic use in a hybrid power plant can be imagined (Fig. 4.25). Suitable prerequisites are present in geothermal aquifers at high pressure, so-called geopressured-geothermal aquifers. In exceptional cases, also other substances dissolved in the ground water such as iodine can render the economical use of natural gas.

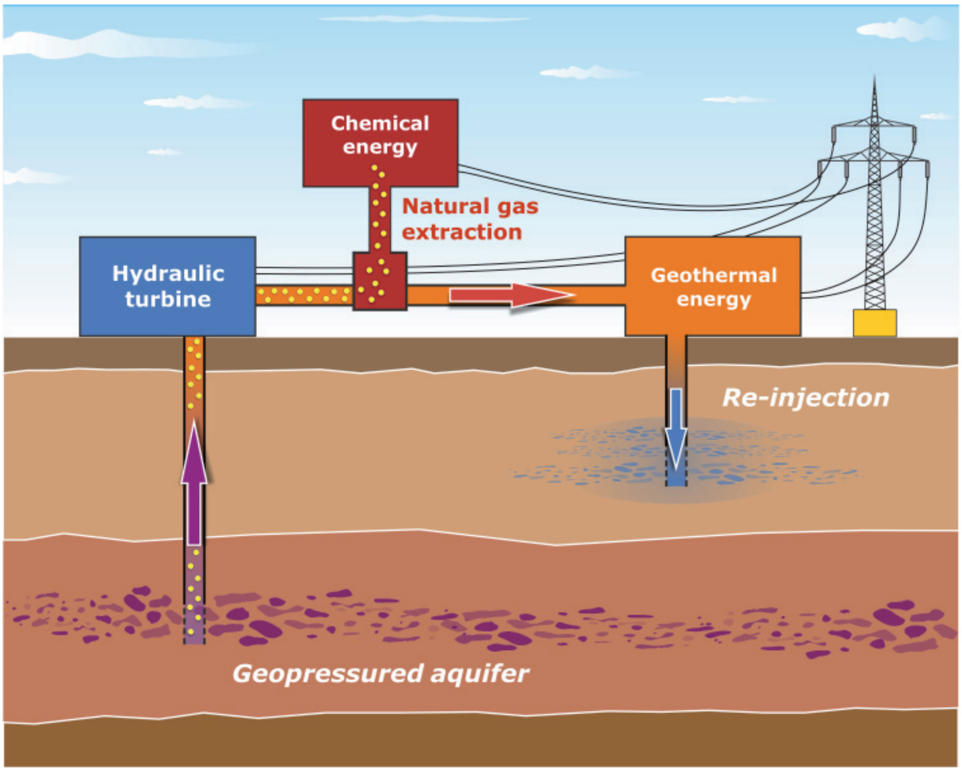


Figure 4.25: Schematic chart of a hybrid power plant for the use of three energies extractible from geopressured-geothermal aquifers: hydraulic energy, geothermal energy and chemical energy (Aquifer Gas).

Hot ground water occurrences, which are highly overpressured in comparison to their depth, are called geopressured-geothermal aquifers. Typically, such occurrences can be found in the earth's crust in depths between 3000 and 7000 m (Dickson & Fanelli, 2004). Due to the high pressure, the water behaves artesian and flows to the earth's surface solely because of the pressure difference.

Up to approximately 60 areas with prospective geopressured-geothermal aquifers are known in the world. Their total gas content has been estimated to be 2500 Tcm (Perrodon et al., 1998). The potential of the region at the northern Gulf of Mexico has been investigated exceptionally well. There the subsurface conditions are known very well because of the thousands of existing wells and the intensive geophysical exploration of conventional deposits. As early as in the 1970s, the amount of gas contained in aquifers there had been estimated to be 650 to 1700 Tcm (Papadopulos et al., 1975; Wallace et al., 1979). According to current estimates, this potential would remain to be uneconomical without the simultaneous usage of the geothermal energy, which is twice as large (Massachusetts Institute of Technology, 2006).

The development of technologies for the exploitation of the geopressured-geothermal aquifers was promoted in the frame of research programs of the U.S. Department of Energy between 1979 and 1990. After extensive long-term studies, a 1 MW hybrid test power plant at the well Pleasant Bayou (Texas) was put in operation in 1989. Half its energy was derived from hot water and the other half from dissolved natural gas (Campbell and Hatter, 1991). Even though the power plant was operated less than a year and it was impossible to use the hydraulic energy of the water, the technical feasibility was successfully proved

(ARCORE, 2007). Because of the comparatively low prices for petroleum and natural gas at that time the project remained uneconomical, however.

Conventional methods for the production of hydrocarbons from petroleum and natural gas wells are aimed at producing as little water as possible using suitable regulation as it is an unwanted by-product. If the water content is too high, this usually signifies the end of production. In contrast, for *geopressured-geothermal aquifers* maximal flow rates of water are required to attain profitability. Additional factors, such as the total volume of the occurrence and the amounts of gas contained, porosity and permeability or the depth influence profitability in the same way as for conventional occurrences of natural gas. The salinity of the water is of special importance, as for increasing salt contents the solubility of the methane decreases. This and further parameters were modeled in a study based on an example of selected occurrences in the northern Gulf of Mexico in view of an economic exploitation of geopressured-geothermal aquifers (Griggs, 2005). According to this study, several locations had already been identified at the time of the publication of the study, which could be considered promising deposits, provided power and gas prices are suitable. Sufficiently high gas contents are decisive for the economic success, as their potential of added value cannot be balanced by a greater geothermal potential (Griggs, 2005).

In particular, the US occurrences in the region of the Gulf of Mexico could be the most promising places for starting the commercial production of aquifer gas. Other countries, such as Russia, do not pursue strategies for producing aquifer gas. In Italy, the production of natural gas from shallow aquifers was stopped in 1962 (Bonham, 1979) because of massive land subsidences. In Japan, there has been a successful production of aquifer gas for many years. The annual production of 500 million m^3 is only economical as by-product of the iodine extraction from the produced brine. In Germany, the exploitation of the energy potential of *geopressured-geothermal aquifers* has been tested exemplarily in the summer of 1982 at the thermal water deposit in Bad Endorf. The calculated power for an estimated operating period of five years was nearly 1 MW, with natural gas and thermal water contributing half each (von Hantelmann et al., 1983). Until today, this thermal water deposit has been exclusively used for balneological purposes.

The gas volumes dissolved globally in the ground water are immense and exceed the known conventional natural gas occurrences several times over. The total amount of aquifer gas dissolved in the ground water of the Earth has been estimated as the enormous amount of 10 000 000 Tcm (Kortsenshtejn, 1979) and would take up approximately twice the volume of the Earth's atmosphere at normal pressure. Similar to the natural gas contained in gas hydrate, only a very small amount will be technically producible and an even smaller proportion will be economically extractible. Still aquifer gas has a potential that should not be underestimated, in particular if improved technologies facilitate the extraction of the dissolved natural gas.

Future innovations for developing the use of aquifer gas are to be expected from the petroleum and natural gas industries as well as from the geothermal sector. The motivation of the hydrocarbon industry is mainly aimed at using their already existing infrastructure for producing oleaginous and gaseous thermal waters beyond the end of the conventional production. From the perspective of the geothermal energy, the additional usage of the methane constitutes a possibly decisive economic incentive. In case of a continuing increase of the prices for conventional natural gas, the use of aquifer gas as a component in a hybrid energy system might be experiencing a comeback.

4.3.4 Gas Hydrate – the "Frozen Natural Gas"

Natural gas hydrate is natural gas bonded in ice and was first discovered at the end of the 1960s. Water and gas can form a crystalline substance similar to ice at high pressures and low temperatures, which is called gas hydrate. The water molecules form a cage-like crystal structure (Clathrate), which might incorporate gas molecules, such as methane, but as minor components also other hydrocarbons (ethane, propane, butane) as well as carbon dioxide and hydrogen sulfide. Due to this special structure, one cubic meter of gas hydrate can contain 164 cubic meters of methane. As natural gas hydrate contains mainly methane, it is also called methane hydrate.

By now, occurrences of gas hydrates are known all over the world, they are, however, generally hard to reach due to their special bonding conditions at low temperatures and high pressure. The stability field of gas hydrate according to pressure and temperature conditions can be reached in marine sediments in deep water or in permafrost areas of the Arctic (continental gas hydrate) (Fig. 4.26). Marine occurrences of gas hydrate are limited to conditions defined by water depths deeper than approximately 400 m and low water temperatures at the sea bottom (Fig. 4.26). Because of the natural increase in temperature with increasing sediment depth, the gas hydrate stability zone can only exist in depths of down to approximately 1000 m under the seabed. Continental gas hydrate is bound to the incidence of permafrost and can occur in depths between approximately 200 m and 2000 m due to the low temperatures (Fig. 4.26).

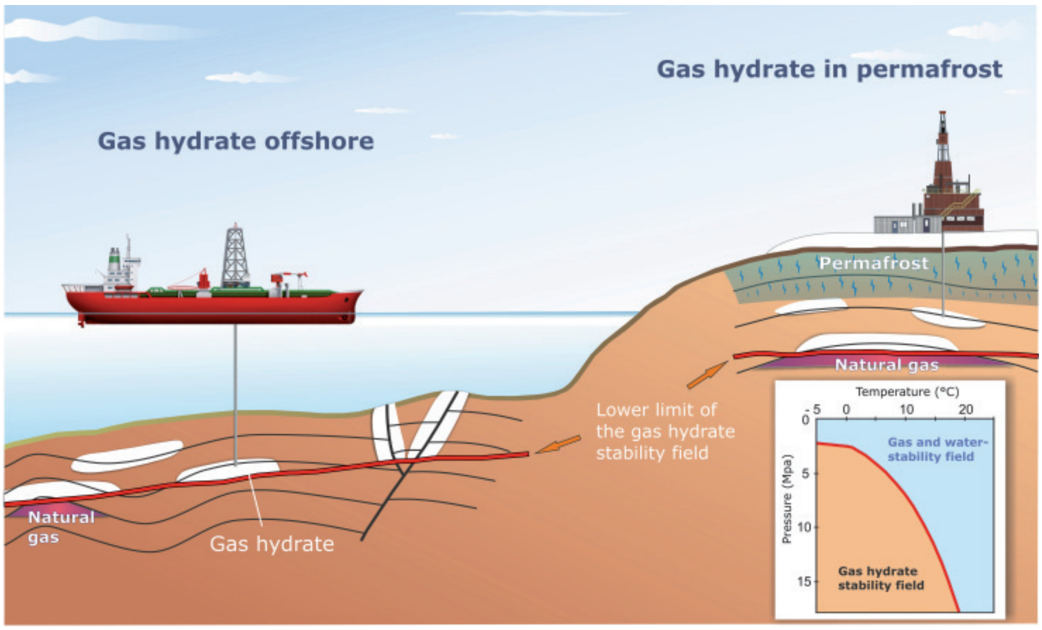


Figure 4.26: Occurrences of gas hydrate: offshore (on the left) and in permafrost areas (on the right). Small diagram: gas hydrate is stable at low temperatures and high pressure.

The formation of gas hydrate depends on four basic factors: high pressure, low temperatures, sufficient availability of methane and the existence of water. If only one of these requirements is not fulfilled, gas hydrate cannot form. Whereas water is usually present in sufficient amounts, the supply of methane is frequently a limiting factor.

In contrast to conventional deposits of natural gas with an area of free natural gas called gas cap, gas hydrate occurrences are not well defined; the gas hydrate is distributed erratically. In principle, an assessment of a reservoir is thus more difficult and entails data on possibly producible amounts of natural gas from gas hydrate being rather uncertain.

Important criteria for the classification of a deposit are, besides the total potential, in particular the reservoir properties, such as the distribution of the gas hydrate, the permeability of the reservoir rock and whether the gas hydrate is underlain by free natural gas.

The total amount of gas bound in gas hydrate is immense in spite of great uncertainties of the assessments and exceeds the conventional amounts of natural gas many times over. Up to today, gas hydrate has been reported from approximately 100 locations based on geophysical, geochemical or geological indicators and tested at 20 locations (Fig. 4.27). In spite of the continuously improving basis of information on the incidence of gas hydrate occurrences, the data on the amounts of natural gas stored as gas hydrate vary considerably. Current estimates range between 1000 and 120 000 Tcm of natural gas in gas hydrate. In the marine area, occurrences are assumed that surpass those in permafrost areas by two orders of magnitude (Council of Canadian Academies, 2008). In comparison to conventional natural gas, thus approximately 2 to 10 times the amount of natural gas is bound in gas hydrate (Fig. 4.28).

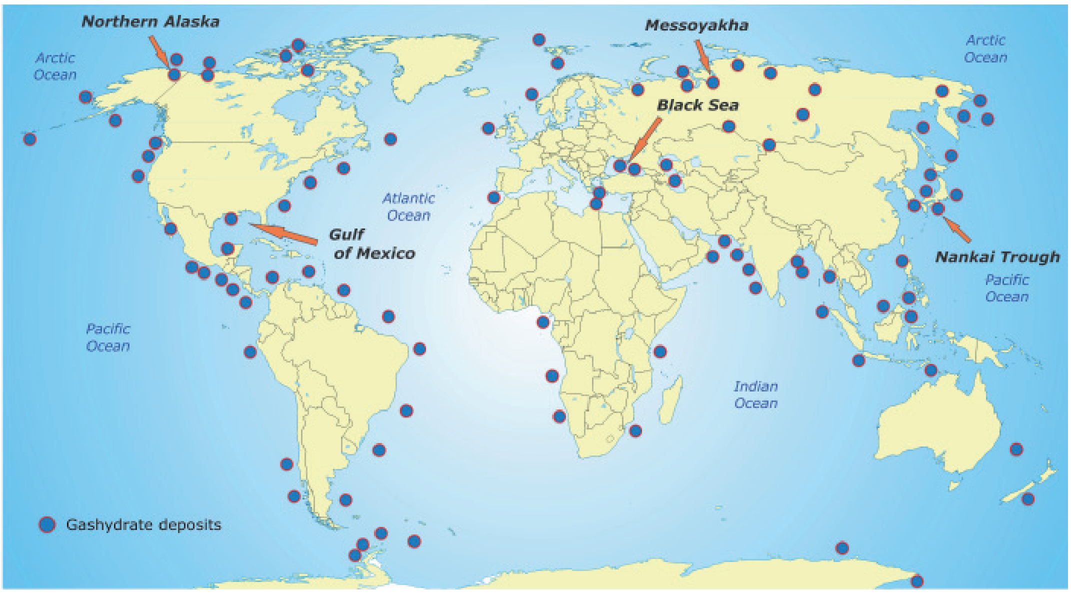


Figure 4.27: Proof of gas hydrate globally naming occurrences mentioned in the text.

The estimated total amounts are unimportant for an assessment of the technically and economically producible amounts of gas from occurrences of natural gas. The identification and classification of occurrences that are really suitable for industrial use are important for the start of production (Fig. 4.28). The chances are best for easily accessible occurrences close to existing infrastructure such as in Northern Alaska. Also occurrences located in rock with a high permeability (Max et al., 2006) are of particular economic interest. In contrast to the rough assessment of the existing amounts in principle, the USGS published an assessment of the technically extractible volumes of natural gas in gas hydrate for a defined territory in a current study. Accordingly, for Northern Alaska an amount of natural gas of more than 2.4 Tcm has been assumed, which might be produced using today's methods (Collett et al., 2008). Once commercial production has started, it can be assumed that, similar to other previously unconventional occurrences of natural gas, such as CBM, the potential will increase. It will, however, be impossible to develop a large part of the gas hydrate, in particular in marine sediments, in the long run and maybe for all times.

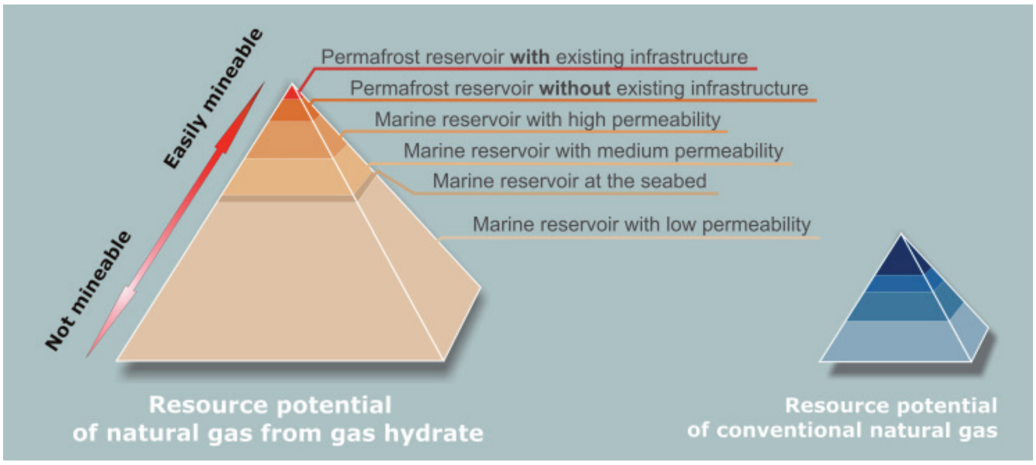


Figure 4.28: Resource pyramid: total natural gas potential in gas hydrate and conventional natural gas (modified in accordance to Boswell & Collett, 2006).

If potential production options are discussed in connection with gas hydrate, all approaches seeming realistic are based on a scenario where the gas hydrate is 'melted' within the rock. The natural gas mobilized that way can be conventionally produced using production wells employing technologies already being used. Mining processes or open-cast pits seem unrealistic, as the expected benefit would not justify expenditure and environmental risk, and in addition the released natural gas from gas hydrate can only be collected at a great loss.

For occurrences, which are developed through wells, the technical challenge consists of establishing a continuous mobilization of the natural gas. In the course of international research and test programs in the North American Arctic, this process based on pressure drop and/or increase in temperature in the rock has been successfully tested. The chemical inhibitors used for a long time in transporting natural gas through pipelines can contribute to the reduction of the freezing point quasi in accordance with the de-icing principle for mobilizing the natural gas out of gas hydrate. As another possibility not yet tried in practice, the injection of carbon dioxide (CO_2) is being discussed, to replace the methane in the gas hydrate already in the rock by CO_2-gas hydrate (Moridis & Collet, 2003).

The conditions for the production of natural gas from gas hydrate are particularly attractive, if free gas exists underneath the occurrence of gas hydrate (Moridis & Collet, 2004). In all likelihood, deposits of this type can be produced using technology already known from the conventional production of natural gas. The necessary pressure reduction would be attained relatively easily by the production of the free natural gas. Gas from the destabilization of gas hydrate would subsequently enter the reservoir of the free gas field, so that depending on the composition of the reservoir rock, the reservoir pressure might be regulated by gas extraction from the deposit. This process was probably already applied for the production of natural gas from gas hydrate in the Siberian Messoyakha Field. In the 1970s, conventional natural gas was produced there without knowledge of the existence of gas hydrate in the area of the field, and the pressure in the deposit decreased accordingly. During a pause in production an unexpected increase of the pressure was observed, which was subsequently linked to the destabilization of gas hydrate.

For a specific production of natural gas from gas hydrate, the selection and selective adaptation of the production technology has to take place beyond the difficult determination of extent and capacity of the field. In comparison to a deposit of conventional natural gas, higher expenditure is necessary for the development of gas hydrate deposits. A breakthrough at the gas hydrate production will thus in all likelihood happen where the risks of a failed attempt can be minimized. The joint project "Mount Elbert" (Northern Alaska) between the U.S. Department of Energy, BP Exploration and the U.S. Geological Survey seems to be exemplary. Based on an already existing infrastructure of the oil and gas industry, on research programs that have been ongoing for years with state support and on geologically particularly suitable gas hydrate occurrences, currently preparations for the first long-term production test are under way.

The commercial production of natural gas from gas hydrate has not started yet. Countries with few occurrences of conventional energy resources or with occurrences approaching exhaustion are currently intensifying their efforts to attain a use of gas hydrate soon (Fig. 4.29). Based on positions and activities of countries and international programs selected as examples, the current state can be determined:

In the US, the Department of Energy evaluated the national gas hydrate occurrences, in particular in the permafrost regions of Alaska (Fig. 4.27) and in the Gulf of Mexico as largest hydrocarbon resource of the country. According to US estimates, the future gas consumption of the country could be supplied in full from these occurrences of gas hydrate. Even conservative estimates of a use of only one percent of the gas hydrate resources result in a doubling of the useable occurrences of natural gas in the US. For researching these occurrences, which seem promising from a geological point of view, the US government issued an *Interagency Roadmap for Methane Hydrate Research and Development* (Department of Energy, 2006). In their approach, the U.S. government places emphasis on international and industrial research cooperation and considers itself to be the global leader in gas hydrate research (Collett, 2004; Sloan & Koh, 2008).

Japan is pursuing a very determined course in the utilization of gas hydrate. In the past five years, the subsidies for gas hydrate research granted involving the Japanese government were higher than those of all other nations. The Japanese motivation for an intensive involvement in gas hydrate research can be derived being largely dependent on importing fossil energy resources. In the course of Japan's *Methane Hydrate Exploitation Program*, technical developments for the exploration and extraction of marine gas hydrate occurrences in the Nankai subduction zone off the Japanese Pacific coast are to be promoted until 2016. The development of the Japanese gas hydrate occurrences would cover the national demand for natural gas for a period of approximately one hundred years (Research Consortium for Methane Hydrate Resources in Japan, 2001; Takahashi and Tsuji, 2005).

Besides other industrial nations with highly developed research infrastructure, such as South Korea, there are quite a number of emerging nations and developing countries, which support this kind of research aimed at exploration (Fig. 4.29). Among these also China and India target their efforts in particular at marine gas hydrate occurrences in their own exclusive economic zones as a potential domestic source of energy.

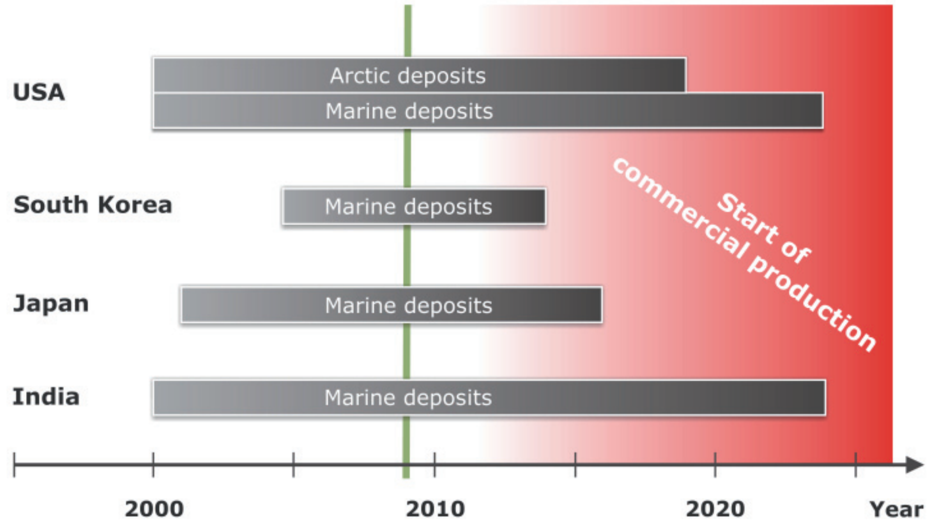


Figure 4.29: Terms of important national programs aimed at an economic extraction of natural gas from gas hydrate.

The situation is different for countries possessing sufficient natural resources. Russia, for instance, recognized the energy supply potential of gas hydrate in the permafrost areas of Siberia early on. The first offshore gas hydrate occurrences were proved by Russian scientists in the Black Sea in 1972. As Russia possesses large conventional occurrences of natural gas, there are currently, in spite of existing know-how and experience in the area of gas hydrate research, no nationally coordinated research programs aimed at their utilization. Still, even there, plans exist to develop the potential of gas hydrate, which is regarded as being immense, in the medium term. This idea is based on the continuous use of the infrastructure already existing for the production of gas, in particular in Siberia, once the conventional gas deposits have been exhausted.

Germany does not possess own gas hydrate occurrences, but belongs to the leading nations where offshore engineering and gas hydrate research are concerned. Thus, Germany has the potential of participating in the development of an economically sensible and ecologically justifiable recovery (Info box 6) of gas hydrate (Andruleit et al., 2008).

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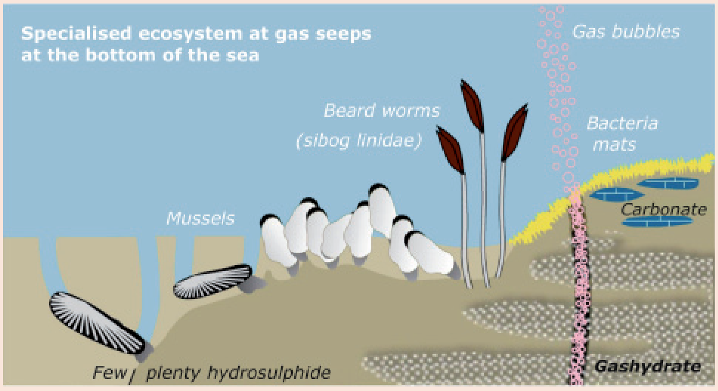
Possible Environmental Effects on the Use of Gas Hydrate

Gas hydrate is a natural component of the global carbon cycle. Besides the energy potential, the influence of the use of gas hydrate on the environment and the climate are being discussed in public most of all. Gas hydrate, as metastable occurrence of methane, can store large amounts of this natural gas for a long time in the sediment and return it to the environment. The extraction of natural gas from gas hydrate affects this cycle and thus the environment.

From exploration via production up to transportation, every phase of the process of the conventional production of natural gas potentially affects the environment. This concerns the construction and operation of infrastructure devices (production systems, etc.), the disposal of refuse material as well as accidental escaping of natural gas (blow out) in the course of accidents. These potential effects on the environment are known and can be minimized by applying suitable environmental management and safety standards. When using gas hydrate the same effects as for conventional natural gas can be assumed. In addition two further hazards are being discussed: The influence on the special living environment in the surroundings of marine gas hydrate occurrences and the destabilization of the seabed.

Rocks bearing gas hydrate are being used by specifically adapted microorganisms as living environment at which they meet their metabolic needs by ingesting methane from gas hydrate. The extraction of natural gas from gas hydrate would influence this area of the so-called deep biosphere, but the effects would remain limited to a locally limited to a small area. The special biocenoses, which are known in connection with escaping methane and gas hydrate occurrences at the seabed, are significantly more susceptible than the microorganisms. A continuous supply of methane constitutes the prerequisite for the development of a special ecological system, independent of sunlight and photosynthesis. The metabolism of a consortium of protozoae provides the basis for chemoautotroph macro organisms like shells and beard worms (siboglinidae). The submarine removal of gas hydrate near the surface would have the most considerable effects on this living environment. This production technology is currently not being seriously considered for ecological and economic reasons.

A disturbance of the stability of the sea floor in the vicinity of production plants could result in subsidences and submarine land slides. On the one hand gas hydrate in marine deposits strengthens the loose rock and thus contributes to stabilization. On the other hand gas hydrate hampers processes of compaction and cementation that would proceed otherwise, because it takes up room in the pore space. Thus marine sediments can be stabilized nearly exclusively by gas hydrate. If the gas hydrate is broken down by technical measures for producing natural gas, the stability of the rock can be reduced to such an extent that submarine landslides can be triggered and natural gas can accidentally escape at the seabed. Such a mechanism is also known as a natural process, initiated by variations in the sea level during ice ages, and is being discussed as a cause for known, widespread sliding events in later history of the earth. In comparison the hazard potential of slides due to the technical destabilization and the release of methane would remain limited to the limited location of the production area (Archer, 2006).



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5 Coal

5.1 Fossil Plant Residue with High Energy Potential

5.1.1 Coal Formation

Coals are solid, combustible, fossil sediments originated predominantly of dead organic material, which were subject to diagenetic changes after they were deposited and covered; these changes caused an enrichment of carbon (Pohl, 1992). Thus, coals are fossil residues of dead biomass. This organic material was deposited in swamps, in which organic material accumulated over time and peatbogs were created. Thick peatbogs developed, if a sufficient plant growth was possible in the swamp, if dead organic material was covered with water as protection against oxidation, if only small amounts of mineral sediment were introduced and a constant water level in the swamp prevented flooding and desiccation. The latter would either have resulted in a cessation of the growth of plants or the organic degradation and oxidation processes of the peat. Important coal basins with productive coal bearing formations and coal seam thicknesses of several meters to several tens of meters develop from peatbogs in slowly subsiding areas. This in part wide-ranging subsidence is frequently of tectonic origin, in some cases also caused by salt leaching and salt migration in the substratum, respectively. In the process the annual subsidence rates must approximately keep up with the growth of the swamp and thus with that of the organic material. The vertical growth of the swamp ranges approximately between 0.5 mm/a in cooler regions and up to 4 mm/a in tropical regions. The longer a peatbog can grow relatively undisturbed, the thicker the coal seams become in the end. Generally, approximately 6 m peat result in lignite (soft brown coal) seams of a thickness of about 3 m and hard coal seams of a thickness of approximately 1 m (Pohl, 1992). The reduction in thickness from peat via lignite to hard coal is caused by the diagenetic processes, which follow upon the end of the growth of the peatbog, and which mainly occur after the peatbogs have been covered by sediment layers. The increasing pressure of the covering rocks increasingly squeezes the water out of the peat and the temperature increases with increasing depth of burial. A multitude of biochemical and geochemical processes then convert the formerly soft peat into solid coal. With increasing coalification the dead organic material is transformed in accordance with the coalification series via peat, the different types of brown coal to hard coal (incl. anthracite). Also the vitrinite reflectance and the energy content of the coal increase, in addition to the carbon content. In return, the percentage of volatile matters and the bed moisture decrease (Fig. 2.4).

The formation of the largest occurrences and thus resources of hard coal mainly took place in the geological periods Carboniferous, Permian and Jurassic. Lignite originates primarily in the Tertiary. Coal occurrences consist of layered coal seams occurring mainly in extensive, continuous provinces. In comparison to their vertical thickness (seam thickness) they have considerable lateral dimensions. Laterally, coal seams can extend along hundreds of kilometers, whereas the seam thicknesses vary between a few centimeters and several tens of meters. In general, coal seams occur in interbedded strata with other sediments. Depending on the conditions of their formation, coal basins with several hundred coal seams layered one above the other can develop. Correspondingly, coal can be found in different depths. It can range from the ground level down to a depth of several thousand meters. The coal deposits investigated world-wide for which resource calculations and assessments have been conducted are located in depths down to 2000 m. Economically recoverable deposits are rarely located at depths below 600 m.

Most of today's coal production originates in coal basins, which have been assigned either to the platform type or to the geosynclinal type. Coal basins of the platform type were formed on so-called shields, which subsided slowly and over a very long time. For this type, relatively few, but very deep and undisturbed seams in shallow location with long horizontal dimensions are characteristic. The coal deposits and coal basins of South Africa and India with the Gondwana coal from the Upper Carboniferous to the Permian, the huge Siberian Tunguska Basin (Pohl, 1992) as well as the majority of the coal deposits in the north of China on the North China Platform (Sinic Shield) are typical representatives of this type (Fig. 5.1).

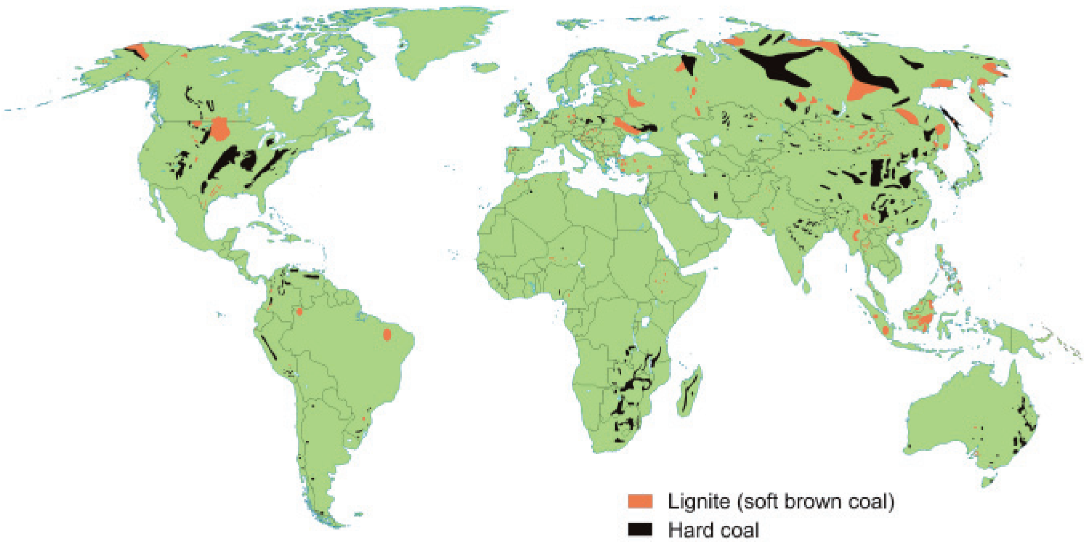

Figure 5.1: Geographic location of the most important coal deposits/basins of the world.

Coal seams of the geosynclinal type developed in quickly subsiding troughs in the foreland. Inclined to steeply dipping, folded coal seams in frequently thousands of meters thick stratigraphic sequences are characteristic. These coal basins usually contain a high number of irregularly formed as well as thin coal seams. Well-known representatives of this geosynclinal type are the German Ruhr Basin as well as coal deposits in the Appalachian Mountains in the US.

5.1.2 Composition and Characteristics of Coal

Coal consists of macerals, the organic pendant of minerals, and impurities, which are also called partings or dirt bands. The impurities usually consist of clay, shale or sandstone and form non-combustible and thus undesired components of coal (Pohl, 1992). Coals are thus heterogeneous mixtures of different organic substances and inorganic materials, in particular water and mineral admixtures. The carbon content, measured at the water and ash-free substance, is between 60 and 70 % for lignite. In hard coal, it can reach up to 97 % for anthracite. At higher levels of carbon, graphite is present, which may be used for instance as lubricant. Depending on the depositional environment, coal can contain higher contents of sulfur and chlorides. Increased sulfur contents generate correspondingly higher sulfur dioxide emissions during combustion. For this reason, commercially available coal rarely contains more than 1 % sulfur. Chlorides can result in harmful scaling and corrosion in the boilers during combustion, thus low chloride contents are required as well.

Whereas lignite is soft, sliceable with a knife and as a rule has a brownish color, hard coal is rigid and of black-brown to anthracite color and has a density between 1.2 and 1.45 g/cm^3. Today, peat has only a very limited, regional importance as a fuel. Peat is increasingly used in gardening and landscaping. Therefore, peat in its use as energy resource will not be dealt with.

5.1.3 Which Type of Coal for which Use?

Depending on the intended use, coal is subdivided into energetic and coking coal. Energetic coal comprises lignite and the majority of the hard coal types (Fig. 5.2). Power generation out of lignite is usually conducted at the place of production because of the high water content and the relatively low energy content and the associated high cost of transportation.

Subdivisions and classifications	**Increasing coal rank** →			
Internationally conventional classification	lignite	hard coal		
Germany and countries to the east	brown coal	hard coal	anthracite	
English speaking area	lignite	sub-bituminous coal	bituminous coal	anthracite
International Classification of in-Seam Coals (UN-ECE 1998)	lignite	sub-bituminous coal	bituminous coal	anthracite
commercial classification according to intended use		steam coal		steam coal
		coking coal	anthracite	
		PCI-coal		PCI -coal

Figure 5.2: Comparison of standard subdivisions and classifications of coal in accordance with the coalification (cf. also Fig. 2.4).

Energetically useable hard coal, which is called steam or thermal coal, is more common for transportation to the consumer due to its higher energy content. The dominant quality parameter for steam coal is a high calorific value. Besides low sulfur and chlorine contents, a low energy demand for crushing the coal, the so-called grindability, is advantageous, as in power plants mainly finely ground coal is used. The coal used for Pulverized Coal Injection (PCI-coal) is usually low-volatile steam coal, which is increasingly gaining importance as reduction agent for the pig iron production (IEA, 2006). There are significantly higher quality requirements for coking coal than for steam coal. The high-quality hard coking coal used in coke plants has to be low in ash as well as low in sulfur and, above all, needs corresponding coking properties, such as the caking power.

5.1.4 Coal as Global Power Source

Currently, coal is the second most important energy resource of the world after petroleum in view of the consumption. Due to its widespread and plentiful occurrences in comparison to other energy resources it is regarded as an important element of supply security in the energy sector. The remaining potential of coal, i.e. the total resources of reserves and resources, has been estimated by the BGR to be about 21 trillion Gt at the end of 2007. 16 404 Gt or about 79 % of these are hard coal and the remaining amount of 4345 Gt is lignite. Lignite and hard coal together have the greatest potential of all non-renewable energy resources at a percentage of about 55 %, corresponding to 722 Gtce, of the reserves and about 76 %, i.e. 14 866 Gtce of the resources. This is sufficient to meet the foreseeable demand for many decades.

In 2007, coal with a proportion of about 30 % (hard coal 28 %, lignite 2 %) of the global total primary energy supply took the runner-up position behind petroleum with a proportion of approximately 36 %. Today, coal is primarily used for power generation in power plants in the base and medium load range. For the global power generation (gross), coal was the most important energy resource at a percentage of 40 % (7620 TWh) in 2006 (IEA, 2008a). From a global point of view, this mainly refers to hard coal. Of the approximately 5.5 Gt of hard coal globally produced in 2007, approximately 4.77 Gt were steam coal and only 0.77 Gt were coking coal, indispensable for today's steel production (IEA, 2008b). 0.98 Gt of lignite were produced, which is also nearly exclusively used in power plants, but which has a lower energy content in comparison to hard coal.

Modern power plant technologies today reach efficiencies of up to 45 % and thus contribute to the reduction of CO_2-emissions. The future development of coal´s share in the generation of primary energy in many industrial countries will also depend on the extent to which CO_2 capture and storage, CCS, can be developed, introduced and implemented, and on the corresponding costs (Info box 7). In emerging countries, the consumption of coal might increase short-term and mid-term, relatively independently of the CCS-development. New and more efficient technologies in the area of the surface and subsurface gasification and the liquefaction of coal (Info box 8) as well as the intensification of the energetic use of coalbed methane open new possibilities of use for the primary energy source coal.

5.2 Hard Coal

5.2.1 Total Resources of Hard Coal and Regional Distribution

The total resources of hard coal as of 2007 have been assessed at 16 404 Gt and can be divided into 4.4 %, corresponding 729.5 Gt reserves and 95.6 %, i.e. about 15 675 Gt resources. Regionally, hard coal is rather evenly distributed on the continents in comparison to petroleum and natural gas (Fig. 5.3). The globally highest total resources of hard coal are located in North America, about 6870 Gt (41.9 %), followed by the regions Austral-Asia at 34.9 % and the CIS at 18.3 %. The vast majority of the remaining approximately 664 Gt is located in Europe (Fig. 5.4).

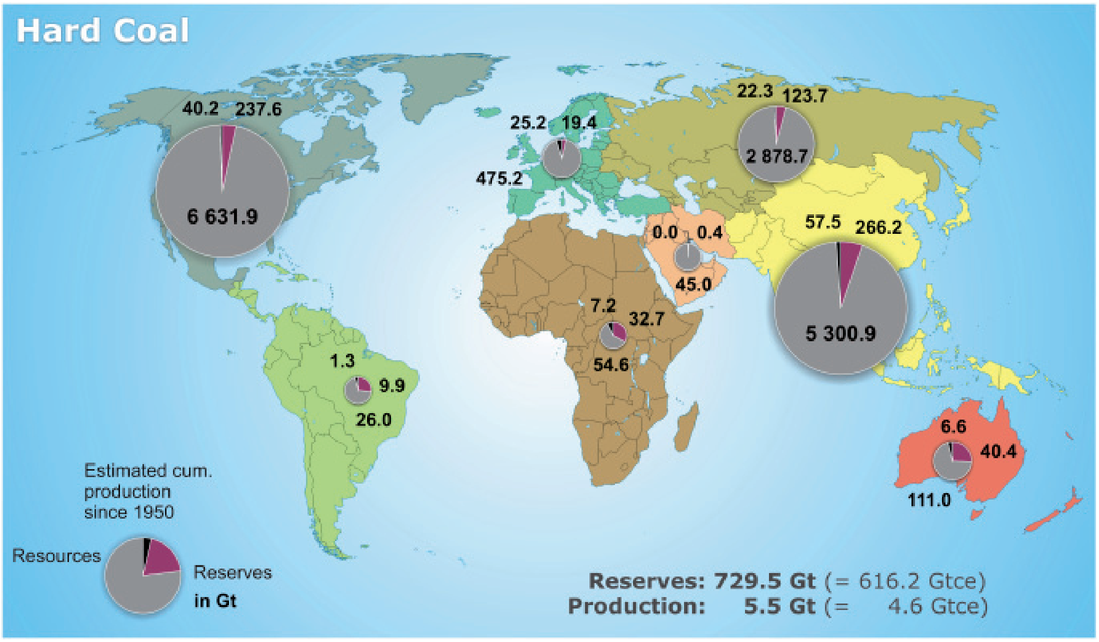

Figure 5.3: Regional distribution of the reserves, resources and the estimated cumulative production since 1950 of hard coal at the end of 2007.

According to countries, the most important total resources are located in the US, about 6720 Gt (41 %), followed by the PR China at 31.6 % and Russia at 16.7 % (Fig. 5.4). These three countries thus together possess more than 89 % of the currently known total resources of hard coal. All other countries have percentages in the single-digit percentage range. In comparison to the individual production of the countries, these comparatively low total resources still represent very large amounts. Germany ranks tenth for the total resources of hard coal at about 83 Gt.

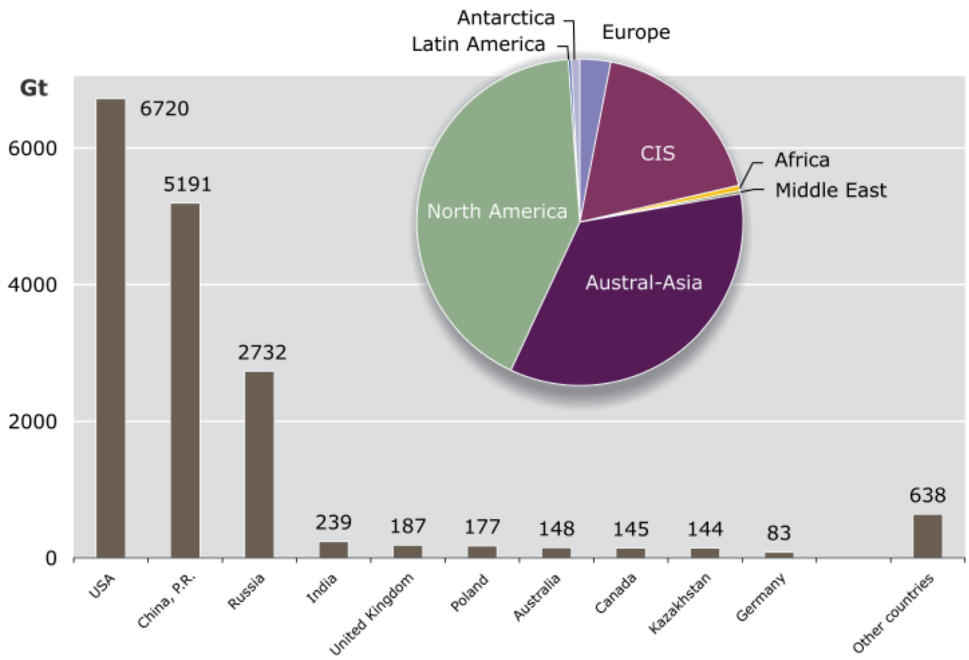

Figure 5.4: Total resources of hard coal (total 16 404 Gt) in 2007 of the top ten countries as well as their distribution by region.

5.2.2 Hard Coal Reserves

According to regions, most of the reserves of hard coal (91.6 %) are concentrated in Austral-Asia, North America and the CIS. 306.6 Gt of the reserves, 42 % are located in Austral-Asia, mainly the PR China, India and Australia with together about 297 Gt, approximately 96.7 %, (Fig. 5.5). North America possesses the second largest reserves of hard coal of 237.6 Gt (32.6 %). There, the US alone possess 97.6 % of the reserves. The CIS follows with 17 % (123.7 Gt) at rank three. There, the largest reserves of 69.9 Gt are located in Russia, in the Ukraine at 32 Gt and in Kazakhstan at 18.9 Gt. The regions Africa (32.7 Gt), Europe (19.4 Gt) and Latin America (app. 9 Gt) possess smaller, but still significant reserves of hard coal. In the Middle East there are only few hard coal reserves (0.4 Gt).

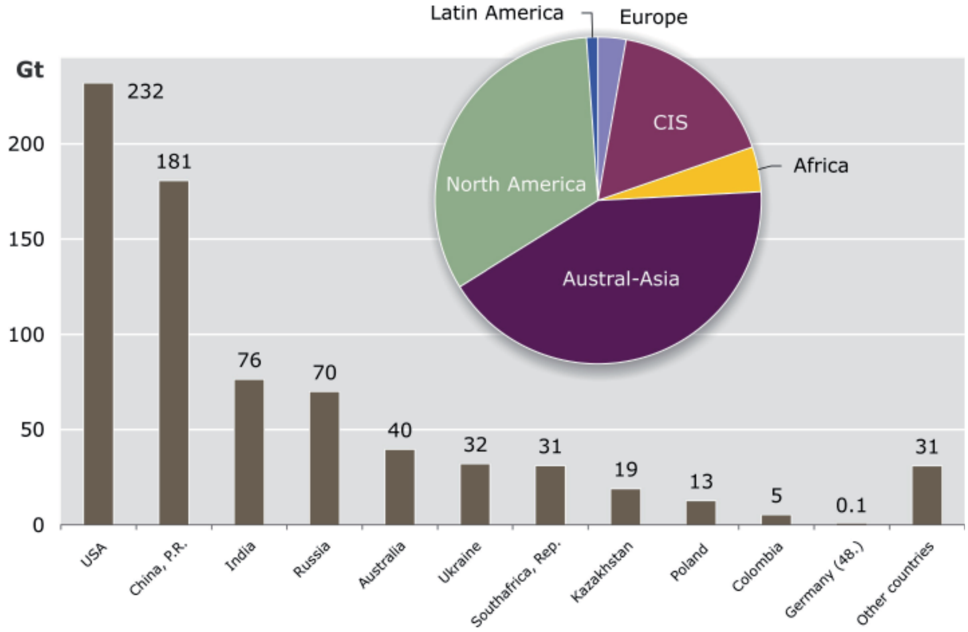

Figure 5.5: Reserves of hard coal (total 729.5 Gt) in 2007 of the top ten countries and Germany as well as their distribution by region.

5.2.3 Hard Coal Resources

Just as for hard coal reserves, the largest part, 95.2 %, of the global resources of hard coal are concentrated in the regions North America, Austral-Asia and the CIS (Fig. 5.6). At roughly 6632 Gt (42.3 %) North America dominates the resources, which are, however, mainly located in the still largely undeveloped areas of Alaska. The resources of hard coal in Austral-Asia amount to 5412 Gt (34.5 %). The resources of hard coal in Asia amount to 5301 Gt or 33.8 % of the global resources. In Oceania, the hard coal exporting country Australia accounts for the comparatively relatively small amount of about 109 Gt. The main part of the Asian resources of hard coal, 5010 Gt, is located in the PR China (Fig. 5.6).

The CIS-region also possesses considerable resources of hard coal, 2879 Gt (18.4 %). More than 80 % of these are located in the largely undeveloped areas of Siberia. There are also considerable resources located in Europe, about 475 Gt (3 %). The other regions only contain very small amounts of 1 % at most.

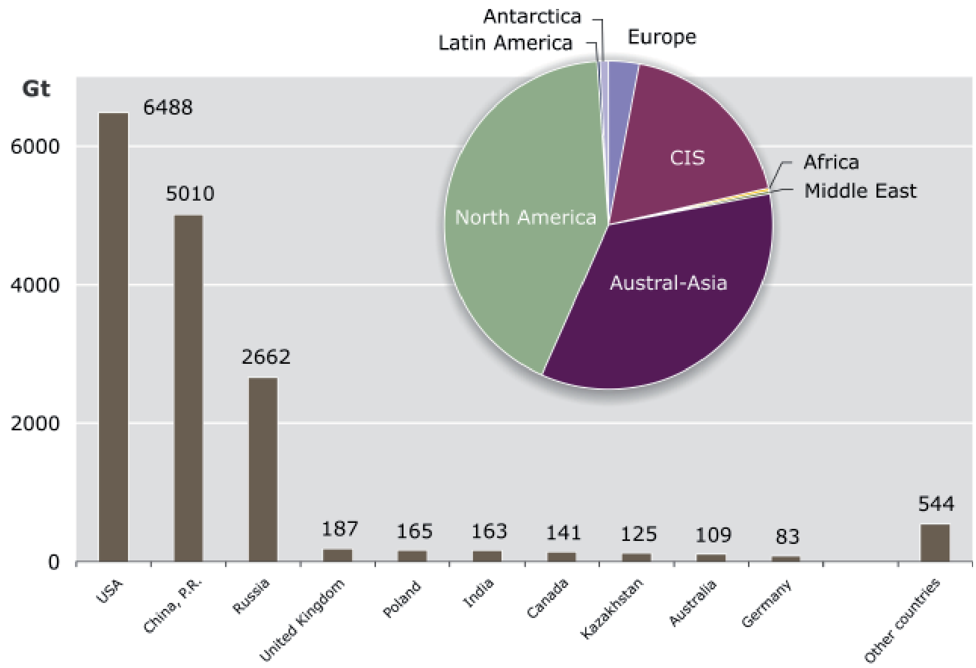

Figure 5.6: Resources of hard coal (total 15 675 Gt) in 2007 of the top ten countries as well as their distribution by region.

The comparatively low amounts of reserves and resources of hard coal in the regions Latin America and Africa can only be explained to a certain extent by the individual geological formation conditions for coal in these regions. For these regions – with the exception of South Africa – the historically grown degree of utilization of coal has to be considered. Because of the relatively low-volume use of coal, in comparison to Europe and North America, which has only started to increase in the past decades, up to now there had been little need for coal exploration. For the future, increased reserves and resources of coal can be expected in these regions due to the increased exploration efforts of the past years.

5.2.4 Hard Coal Production

Hard coal is produced via surface mining and underground mining. The surface mining is the more favourable alternative, because the use of large equipment (Fig. 5.7) and less personnel yields a significantly higher production rate. The most important criterion for an economic extraction in surface mining is the ratio of overburden that must be moved to extract one ton of coal, the so called strip ratio (in m^3/t). For coal seams in shallow depths to about 200 m and favorable strip ratios the production of hard coal in surface mines preponderates.

More than half of the globally produced hard coal is produced from underground coal mines. This is primarily due to the high share of the Chinese hard coal production from underground coal mines, which ranges at about 95 % (Schmidt, 2007). The extraction methods predominant in underground mining are the so-called longwall mining and the room and pillar mining. Underground hard coal production is mainly executed in depths up to 500 m. In particular in coal mining districts, in which hard coal has been extracted for more than 100 years on a large scale, significantly deeper average extraction depths can be reached. These comprise first of all the European coal basins such as the Polish Upper Silesian Coal Basin with an average extraction depth of about 800 m, the Ukrainian/Russian Donets Basin with approximately 720 m and the German Ruhr Basin at 1145 m. Progressive mechanization in underground mining resulted in a significant increase of productivity in the past decades. Simultaneously, the utilization of deposits decreased, as the mining of thin coal seams has become increasingly uneconomical. In particular the use of increasingly larger and heavier extraction machinery in longwall mining, such as shearers and plows, requires as thick as possible, little disturbed and horizontally bedded coal seams.

The numbers given about the hard coal production deal as a rule with the production of saleable hard coal. In contrast to raw coal (Fig. 5.7), the saleable product has frequently been treated in order to correspond to the quality requirements of the individual consumer. The specification only used in Germany of tons of useable production (Tonnen verwertbare Förderung/t v. F.) allows the comparison of the production from different German hard coal mines independently of the coal qualities produced. These production amounts standardized for purposes of comparison are on average 10 % lower than the actually saleable output (BGR, 2005). This has been taken into account for the comparison of the German amounts with the production of other countries.

Figure 5.7: Production of hard coal (raw coal) using truck and shovel in the surface mine Baganuur/Mongolia.

In 2007, the global production of hard coal amounted to approximately 5523 Mt. Nearly two thirds of this production or 3581 Gt were generated in Austral-Asia, followed by North America at 18.8 % and the CIS at 7.4 %. The other four regions Africa, Europe, Latin America and the Middle East together contributed less than 10 % of the produced hard coal (Fig. 5.8, Tab. 5.1). The three top producers of hard coal in 2007 were the PR China with a proportion of 44.9 % (2479 Mt), the USA with 17.5 % (968 Mt) and India with 8.2 % (about 452 Mt). Thus, more than 70 % of the global hard coal production originated from only three countries (Fig. 5.8). The by far predominant part of the production of these three countries is consumed in the country itself (Section 5.2.5). The following ranks are taken up by the four currently most important hard coal exporting countries Australia, the Republic of South Africa, Russia and Indonesia (Section 5.2.8). The most important European hard coal producing country in 2007 was Poland at about 88 Mt (globally at the ninth position), amounting to more than half of the EU-27-hard coal production of 159.1 Mt. Other important hard coal producing countries in Europe were Germany at 24.2 Mt, Great Britain at 16.8 Mt and the Czech Republic at 13.1 Mt.

An overview of the production and simultaneously the consumption of hard coal, the coke production and the coal trade, differentiated according to the two main purposes, steam coal and coking coal, is only possible if statistics of other institutions are included. These are primarily the International Energy Agency (IEA), the Statistik der Kohlenwirtschaft (SdK) and the German Coal Importers Association (VDKI). Due to differences in data acquisition and processing, differences between the BGR-data and the data of the other institutions may occur. As a rule, these differences are only marginal, at most in the single-digit percentage range. They are primarily based on the use of different sources as well as assessments and result from the difficulty of the different assignment of steam coal and coking coal based on different national coal classifications (Section 2.3.3).

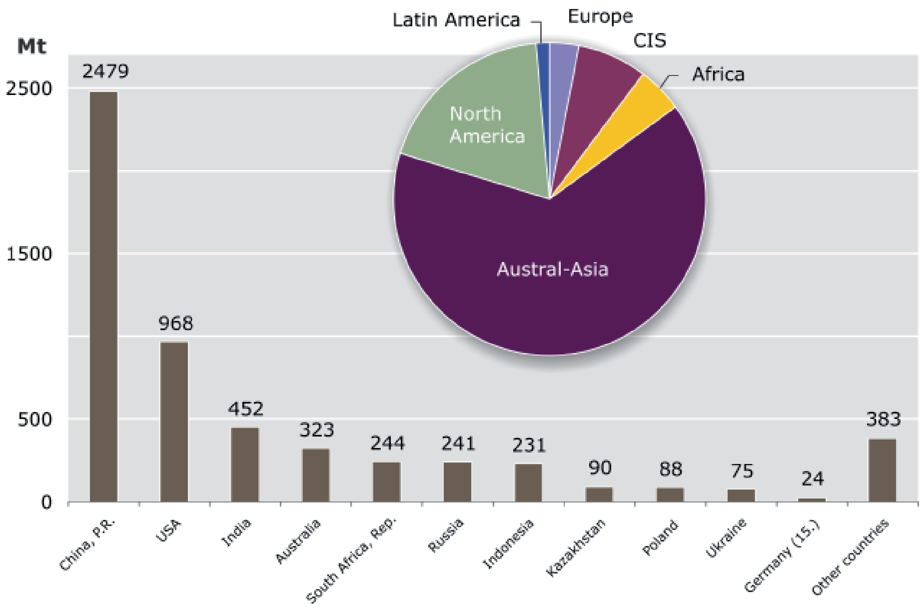

Figure 5.8: Hard coal production (total 5523 Mt) in 2007 of the top ten countries and Germany as well as their distribution by region.

According to IEA data, about 86 % of the global hard coal production of 5.54 Gt in 2007 consisted of steam coal and and only about 14 % of coking coal (IEA, 2008b). High-quality hard coking coal traded on the world market is only produced in relatively few countries, primarily in Australia, Canada and the US. However, the by far greatest coking coal producer with a production of 356 Mt (46 %) in 2007 was the PR China. For several years, Australia has been the second greatest coking coal producer and produced approximately 142 Mt in 2007. The share of coking coal of the Australian hard coal production is disproportionately high in comparison to all other important hard coal producing countries and was nearly 44 % in 2007. The currently third most important coking coal producer is Russia with a production of about 62 Mt in 2007. From these three countries together derived nearly three quarters (72.8 %) of the worldwide coking coal production.

Whereas the PR China and Russia consumed most of the coking coal domestically because of the high domestic demand, Australia currently exports more than 90 %. Coking coal accounted for about 13.8 Mt, corresponding to 57 % of Germany's total hard coal production of 24.2 Mt in 2007 (IEA, 2008b). Only 18 % (4 Mt v.F.) of the German hard coal production were consumed by the steel industry, whereas the majority was consumed in power plants and secondarily in the heat market (RAG AG, 2008). The reasons are probably insufficient coking coal qualities as well as long-term supply contracts with power plants.

The **production of hard coal** has doubled during the last 30 years to 5.5 Gt (Tab. 5.1). In particular since the start of the new millennium, the annual growth rate of the global hard coal production has ranged between five and nine percent. These growth rates considerably exceed the otherwise customary ten-year trend of 2.6 % (IEA, 2006). The development of the hard coal production during the observation period can be subdivided into three phases: 1.) gradual increase of the production up to the collapse of the Eastern Block 1990, 2.) lateral movements in the 1990s and 3.) rapid increase of production after the end of the

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CO_2 from Burning Coal, CCS in Germany?

A major challenge is using coal, as one of the most important fossil energy carriers in the world, while minimizing carbon dioxide emissions. The precipitation and subsequent storage of the carbon dioxide (CO_2) generated during combustion might provide a significant contribution. From a technical point of view, it may become possible to prevent 20 to 40 % of the global CO_2 emissions by 2050 using CO_2-precipitation and storage (Carbon Capture and Storage, CCS). CCS is not only possible for coal power plants, but also for other CO_2-emitting industries such as the steel or chemical industries.

The CO_2-precipitation in coal power plants takes place either before, during or after the coal is burnt. No explicit preferences for a certain process can be derived from the available cost analyses. The deterioration of the efficiency of the power plants due to CCS has to be considered. For transportation and storage purposes, CO_2 can be liquefied and transported through pipelines or in tankers to the storage location. Possible storage locations are exhausted deposits of petroleum and natural gas, salt-water bearing layers and possibly coal seams.

In Germany, primarily former natural gas fields and deep salt-water bearing layers can be used for CO_2-storage. Storage locations are located in particular in the North German area approximately to the north of an imaginary line between Berlin and Hannover up into the North Sea and the Baltic Sea. The Molasse Basin north of the Alps only has a low potential in comparatively small structures and also the Saar-Nahe depression and the Thuringian Basin are suitable to only a limited extent for geological reasons. In the Upper Rhine Graben the increased earthquake hazard limits the possibilities for CCS.

Currently the groundwork is laid for energy and climate change policy to implement the CCS-technology in Germany and in other countries. Up to now, CO_2-precipitation and storage are still in the research and development phase. For a final evaluation of the industrial applicability, pilot projects have to be conducted on an industrial scale.

Asian crisis since 2000. The quadruplication of the production in Austral-Asia in the course of the past 30 years is particularly striking (Tab. 5.1), in particular due to the increase in production in the PR China, in India, Australia (Tab. 5.2) and in Indonesia. Together, these four countries produced about 97 % (3.5 Gt) of the Austral-Asian output in 2007. After 1999, the hard coal production in this region alone doubled due the soaring energy demand.

In contrast to the global trend, the European hard coal production declined during the past thirty years. Whereas at the end of the 1970s nearly one fifth of the global hard coal production originated in Europe, in 2007 only 3 % of the global production remained (Tab. 5.1). This corresponds to a reduction of the European production by two thirds to about 166 Mt. The production of hard coal in the CIS dropped dramatically in the wake of the political-economic upheaval in the 1990s due to the dwindling demand. In the meantime, the hard coal demand and in consequence also the production in the CIS have increased again, which can mainly be attributed to the increased hard coal exports from this region. Current production is still significantly below the level of the 1980s (Tab. 5.1).

Table 5.1: Development of hard coal production according to regions from 1978 to 2007 (WEC, 1980; BGR, 1989, 2003).

Region	**Hard coal production in Mt** (Region´s share of the global annual production)				**Change 1978/2007** (%)
Year	**1978**	**1987**	**1999**	**2007**	
Europe	491.8 (18.4 %)	589.5 (16.6 %)	277.5 (7.8 %)	165.8 (3.0 %)	- 66
CIS	572.0 (21.4 %)	594.5 (16.7 %)	256.0 (7.2 %)	407.2 (7.4 %)	- 29
Africa	96.7 (3.6 %)	182.6 (5.1 %)	231.1 (6.5 %)	249.3 (4.5 %)	+ 158
Middle East	1.0 (0.0 %)	1.3 (0.0 %)	0.9 (0.0 %)	2.0 (0.0 %)	+ 100
Austral-Asia	895.2 (33.5 %)	1339.8 (37.7 %)	1763.2 (49.8 %)	3581.1 (64.8 %)	+ 300
Asia only	821.5 (30.8 %)	1188.7 (33.5 %)	1535.2 (43.3 %)	3253.5 (58.9)	+ 296
North America	604.0 (22.6 %)	820.4 (23.1 %)	964.5 (27.2 %)	1037.8 (18.8 %)	+ 72
Latin America	9.6 (0.4 %)	24.7 (0.7 %)	50.0 (1.4 %)	79.6 (1.4 %)	+ 733
WORLD	*2670.2 (100 %)*	*3552.8 (100 %)*	*3543.2 (100 %)*	*5522.7 (100 %)*	*+ 107*

From 1980 to 2007, the steam coal production increased from 2.270 Gt to 4.773 Gt (+ 110 %). This was significantly higher than the increase of coking coal production from 0.531 Gt to 0.769 Gt (+ 45 %) according to IEA (2008b). Thus, about 86 % of the global hard coal production in 2007 were steam coal and only about 14 % were coking coal (Fig. 5.9). The enormous expansion of the steam coal production can mainly be attributed to the soaring global demand for energy, primarily for power generation. For instance, the global consumption of electricity increased by about 130 % to 15 655 TWh between 1980 and 2006. In 2006, the OECD-countries accounted for most of it at about 58 %, followed by the PR China and India, which consumed 18 % together (IEA, 2008c).

Even though the pig iron production in furnaces nearly doubled to approximately 946 Mt between 1980 and 2007 (World Steel Association, 2009), the production of coke required for the production of pig iron increased only by little more than half (Section 5.2.6). Thus, the growth of the global coke production has the same order of magnitude as the increase in the production of coking coal, from which coke is produced. The low increase in the coke production in comparison to the pig iron production can be mainly attributed to the reduced use of coke per produced ton of pig iron. Thus, in 1980 in the countries of the EU-15, for the production of 1 t of pig iron about 500 kg of coke (dry) were still required, in 2006 only 349 kg (SdK, 1990; Ameling, 2007). This corresponds to a reduction by about 30 %. Today coke is mainly used as propping agent in modern furnaces. The functions as energy source and reducing agent have increasingly been taken over by PCI-coal (pulverized coal injection) and heavy oil.

Table 5.2: Production development of the top five hard coal producing countries of the year 2007 from 1978 to 2007 (WEC, 1980; BGR, 1989, 2003).

Country	**Hard coal production in Mt** (Region´s share of the global annual production)				**Change 1978/2007** (%)
Year	**1978**	**1987**	**1999**	**2007**	
China, PR	620.9 (23.3 %)	888.5 (25.0 %)	1045.0 (29.5 %)	2479.2 (44.9 %)	+ 299
USA	572.0 (21.4 %)	763.3 (21.5 %)	919.6 (26.0 %)	967.9 (17.5 %)	+ 69
India	101.3 (3.8 %)	178.5 (5.0 %)	292.2 (8.2 %)	451.6 (8.2 %)	+ 346
Australia	71.8 (2.7 %)	149.0 (4.2 %)	225.0 (6.4 %)	323.0 (5.8 %)	+ 350
South Africa, Rep.	90.4 (3.4 %)	176.5 (5.0 %)	222.3 (6.3 %)	243.6 (4.4 %)	+ 169
Total	1456.3 (54.5 %)	2155.8 (60.7 %)	2704.1 (76.3 %)	4465.2 (80.9 %)	
WORLD	*2670.2 (100 %)*	*3552.8 (100 %)*	*3543.2 (100 %)*	*5522.7 (100 %)*	*+ 107*

In spite of the wide regional spread, there are concentration tendencies among the **largest hard coal producing companies**. As the hard coal produced in China, the USA and India is mainly used domestically, 30 % of the steam coal traded by sea and even 47 % of the coking coal traded by sea are concentrated on the so-called Big Four (Wodopia, 2009). These four companies, also called RBXA Group, are Rio Tinto, BHP Billiton, Xstrata/Glencore International and Anglo Coal (Tab. 5.3).

The world market share of the ten largest corporations according to revenue amounted to 62 % for steam coal and to 71 % for coking coal in 2005 (VDI, 2006). Thus, the coal industry at this point in time ranges in the midfield of the extractive industry, whose highest degrees of concentration were reached for iron ore (97 %) and nickel (95 %). Lower concentration tendencies occurred for instance for copper at 54 %, zinc at 42 % and gold at 37 % (VDI, 2006). The degree of concentration in the coal sector will probably increase in the coming years mainly in the Asian area. According to the tenth Chinese five-year plan (2006 to 2010), only 13 really large coal companies were to exist in China, of which five to seven companies were to have a production capacity in the range of 100 Mt/a (Chen, 2006). In relation to the production of 2007, four Chinese coal producers were already amongst the twelve top global producers (Tab. 5.3).

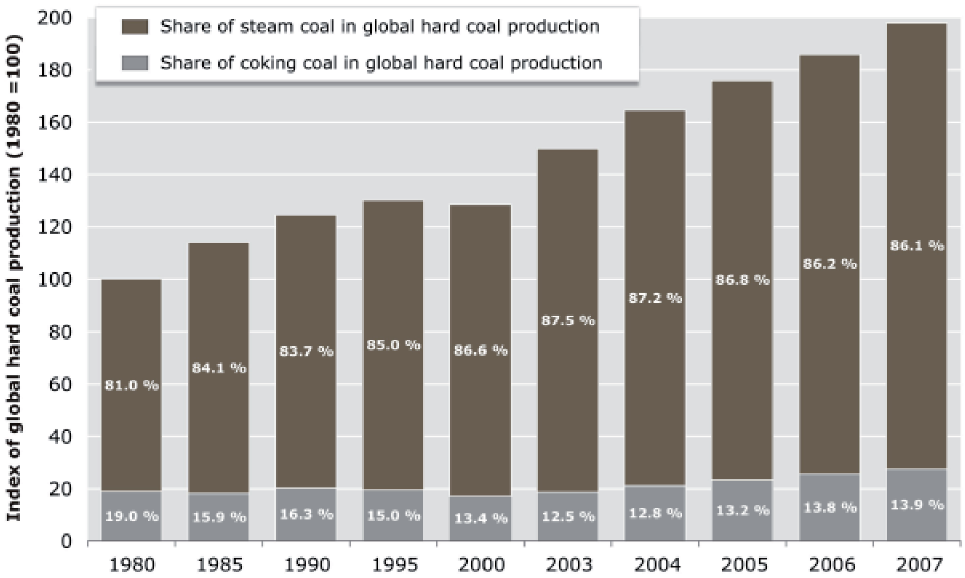

Figure 5.9: Development of the global hard coal production subdivided into coking coal and steam coal from 1980 to 2007 (IEA, 2008b).

Table 5.3: The top twelve hard coal producing companies in the world in 2007 (company information; The Tex Report, 2008; EIA, 2008b).

Company	Production locations	Production 2007 (Mt)	Remarks
Coal India Ltd.	India	379.5	raw coal production
Peabody Energy Group	Australia, USA, Venezuela	193.8	total of 215.7 Mt sold
China Shenhua Energy Company	China	158.0	total of 209.1 Mt sold
Rio Tinto	Australia, USA	155.7	
BHP Billiton	Australia, Colombia, South Africa, USA	122.9	
Arch Coal	USA	115.1	
Anglo Coal	Australia, Canada, Colombia, South Africa, Venezuela	95.6	
SUEK (Siberian Coal Energy Company)	Russia	90.9	
Xstrata/Glencore International	Australia, South Africa	82.8	
Shanxi Coking Coal Group	China	72.4	raw coal production; in total 74.4 Mt sold
China Coal Energy	China	69.3	in total 85.2 Mt sold
Datong Coal Mine Group	China	65.5	raw coal production; in total more than 100 Mt sold

The hard coal **production costs** vary significantly from country to country. They are primarily influenced by the type of production, in surface or underground mines. Important geological parameters are, besides the depth, the bedding conditions as well as the formation (undeformed/disturbed, thin/thick) of the coal seams (Fig. 5.10). In addition, the geographic location and the associated infrastructure as well as climatic conditions of the mining area are important as well.

Figure 5.10: Several meters thick hard coal seams in semisteep stratification in the surface mine Panian on Semirara Island, the greatest surface mine of the Philippines.

The prevailing part of the globally produced hard coal is consumed close to the deposit or in local power plants, respectively (Section 5.2.5). These are usually set to the regional coal qualities; this way, an extensive treatment of the coal can usually be avoided. If the coal is exported, however, frequently a treatment consisting of coal washing, screening and drying becomes necessary to attain the quality parameters required on the world market. Such treatment processes result in correspondingly higher production costs.

Typically those countries, where hard coal is produced mainly from surface mines, have the lowest production costs (Fig. 5.11). Accordingly primarily the countries exporting steam coal, such as Russia and Venezuela, followed by South Africa, Indonesia and Colombia, have the lowest production costs of approximately USD 15 to USD 30/t (Ritschel et al., 2005, 2007). Higher costs result for the production of coking coal in Canada in surface mines and in the US in underground mines. Whereas the costs listed in Figure 5.11 refer primarily to production costs of export mines in the individual countries, the comparatively low production costs in China are caused by the inclusion of the production costs of all mines.

From a technical point of view, there is no difference in mining between coking coal and steam coal. Because of higher quality requirements for coking coal, for instance concerning the ash content and coking characteristics, the number of possible deposits for the production of high-quality coking coal decreases. In addition, a higher beneficiation effort becomes necessary. As high-quality coking coal is produced in comparatively few deposits in the world, the producers can obtain higher prices on the world market. The higher revenue also allows a production at higher costs. The coking coal produced in underground mines in one of the oldest coal districts in the US in the central part of the Appalachian Mountains is considered a graphic example. In spite of large coal reserves, production costs of up to USD 80/t occur there, as the most accessible and thickest coal seams have already largely been exhausted. The production of coal from thin coal seams requires a much higher expenditure, which can only be procured, if the world market prices for coking coal permit it.

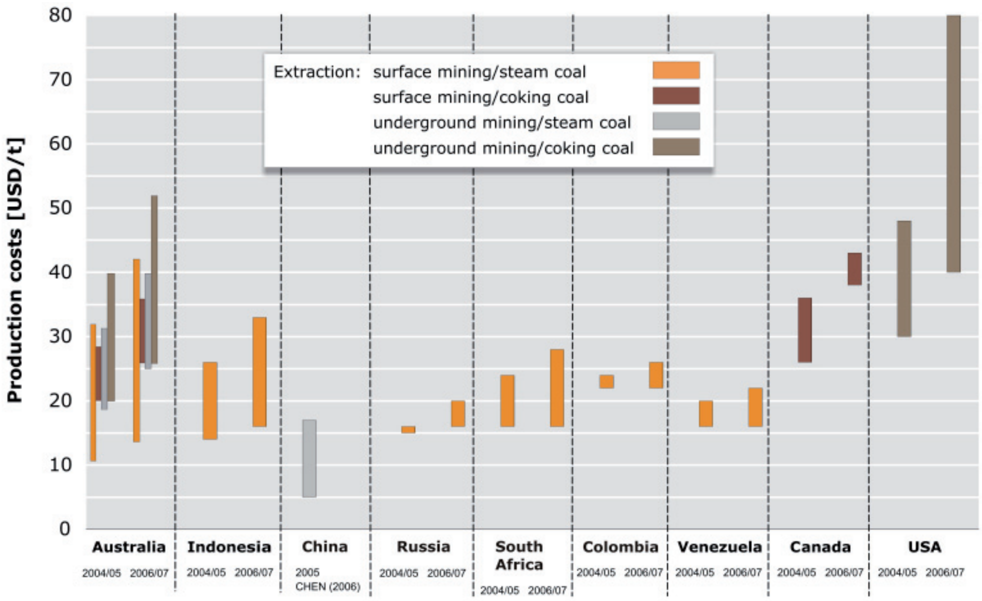

Figure 5.11: Hard coal production costs in selected countries comparing the years 2004/2005 and 2006/2007 (Chen, 2006; Ritschel et al., 2005, 2007).

In Australia, the most important hard coal exporting country, there is a relatively wide range of production costs. In some Australian surface mines, steam coal can be mined at lower production costs than in Russia or Venezuela, i.e. from approximately USD 14/t (2006/2007). In some cases they can be two or three times as high with costs of up to USD 42/t. The coking coal production costs in Australian surface mines at USD 26 up to USD 36/t are lower than in Canada (Fig. 5.11).

The Chinese production costs for hard coal which is nearly exclusively mined underground ranged in 2005 between USD 5 and USD 17/t (Chen, 2006). The very low production costs in the comparison to other countries probably refer to the whole Chinese coal sector and comprise the modern Chinese high-performance coal mines as well as the non-mechanized small mines with low capital expenditure and wages. Today the production costs of high-quality Chinese export coal can be even higher than the USD 17/t specified by Chen (2006), as shown by the example of the China Coal Energy Company (Tab. 5.4).

Table 5.4: Development of the hard coal production costs of selected companies according to annual reports and company presentations.

Country	Company (Producing region)	Remarks	Production costs (USD/t) 2002	2003	2004	2005	2006	2007	2008	Change 2004/2008 (%)
Canada	Elk Valley Coal/Teck Cominco www.teck.com	Surface mining; CC[1]	17.2	20.1	20.0	27.2	35.3	39.1	50.1	+ 150
USA	Arch Coal www.archcoal.com						14.9	16.0	17.9	
USA	Powder River Basin	Surface mining; SC[2]		6.0	6.8	7.9	9.6	10.3	11.3	+ 66
USA	Western Bituminous	underground SC[2] mining;		17.0	17.3	18.1	17.2	21.6	24.0	+ 39
USA	Central Appalachian Mountains	primarily underground mining; SC[2] and CC[1]		34.0	38.4	47.7	50.8	48.9	55.2	+ 44
USA	Consol Energy www.consolenergy.com (Northern and central Appalachian Mountains)	primarily underground mining; SC[2] and CC[1]		28.9	30.4	33.1	35.9	37.1	45.9	+ 49
PR China	China Shenhua Energy Company Ltd. http://en.shenhuachina.com	underground and surface mining; primarily SC[2]			6.4	7.0	8.3	9.9	13.7	+ 114
PR China	China Coal Energy Company Ltd. www.chinacoalenergy.com/eng	underground and surface mining; primarily SC[2]					21.7	22.7	29.4	
Indonesia	PT Bumi Resources www.bumiresources.com	Surface mining; SC[2]; Cash costs only (without amortization, depreciation, overhead etc.)			16.0	23.7	26.1	25.9	33.1	+ 107

[1] CC – coking coal, [2] SC - steam coal

In the global comparison, the German production costs for the underground production of hard coal are significantly higher, mainly because of difficult mining conditions in great depths of 1145 m on average (SdK, 2008b). The German production costs in 2007 were 170 €/tce (VDKI, 2008) or USD 265/tce.

On average, the production costs in the most important hard coal exporting countries (Fig. 5.11) rose by 25 % between 2004/2005 and 2006/2007. This can be mainly attributed to the soaring energy costs during that period. However, it was possible to compensate these cost increases by risen revenues during the regarded period, as the price for coal also increased steadily (Section 5.2.9). The changes in the production costs of selected coal producers for 2008 show that the energy costs increased disproportionately in comparison to the previous years because of the soaring energy prices until the middle of 2008 (Tab. 5.4). The increased costs can also be attributed to increased expenditure for personnel and spare parts as well as increased mining fees.

5.2.5 Hard Coal Consumption

The global hard coal consumption was about 5.52 Gt in 2007. As for the production, Austral-Asia accounted for nearly two thirds of the global consumption at 3.54 Gt (Fig. 5.12), followed by North America at 18.4 % and Europe at 7.4 %. Of the remaining four regions, only the CIS at 5.7 % and Africa at 3.5 % show significant consumption, whereas Latin America and the Middle East at together 0.05 Gt consume a proportion of less than one percent.

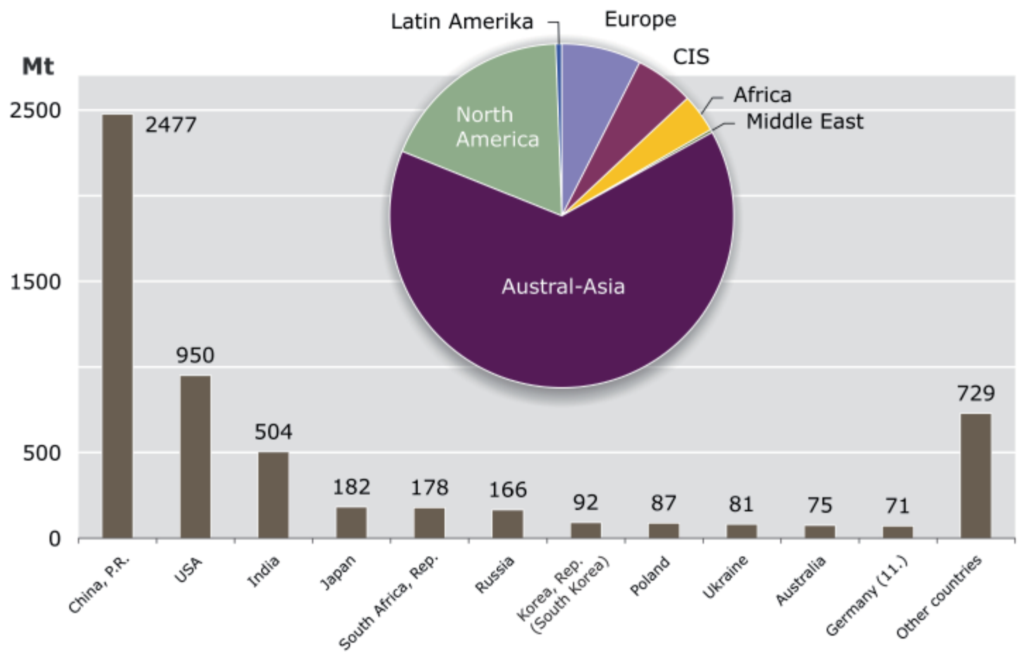

Figure 5.12: Hard coal consumption (total 5520 Mt) in 2007 of the top ten countries and Germany as well as their distribution by region.

As the main part of the globally produced hard coal is intended for individual domestic consumption, the three top producing countries are also the largest consumers. The PR China (Fig. 5.12) holds the leading position at a percentage of 44.9 %, followed by the US at 17.2 % and India at 9.1 %. The fourth-largest consumer at about 182 Mt (3.3 %) is Japan, which has to import nearly all its coal.

With the exception of South Korea at rank 7, which also imports its coal nearly entirely, the ten largest consumer countries (Fig. 5.12) are only those countries with a significant production of hard coal, i.e. South Africa, Russia, Poland, the Ukraine and Australia. Germany, with a hard coal consumption (including coke) of 71.3 Mt ranked eleventh in 2007. The three countries Poland, Germany and Great Britain accounted at about 221 Mt for nearly 59 % of the total hard coal consumption of the EU-27 in 2007.

About 87 % of the global hard coal consumption of 5.52 Gt in 2007 was steam coal and only about 13 % was coking coal (IEA, 2008b). The ranking of the largest consumers of steam coal (Tab. 5.5) differs only slightly from the ranking of the largest hard coal consuming countries (Fig. 5.12). This can be attributed to the high proportion of steam coal of the total hard coal consumption. In contrast, the demand and thus the ranking of the countries consuming coking coal is largely dependent on the pig iron production, which requires coke.

The PR China accounted for about half of the global coking coal consumption in 2007. With considerably less consumtion follow Japan and India, two more Asian countries, which rank second and third (Tab. 5.5). Germany ranked sixth with a consumption of 23 Mt of coking coal, corresponding to 3.2 % of the global consumption, behind Russia and the Ukraine.

The global **hard coal consumption** doubled between 1980 and 2007 according to IEA-data; however, the development was regionally very different (Fig. 5.13, Tab. 5.6). Whereas the hard coal consumption in Austral-Asia, North America and Latin America, the Middle East as well as in Africa increased significantly, the consumption in Europe and the CIS region decreased by nearly one third or about half (IEA, 2008b).

As the development of the hard coal consumption in principle does not differ from the production of hard coal, there will be no separate consideration.

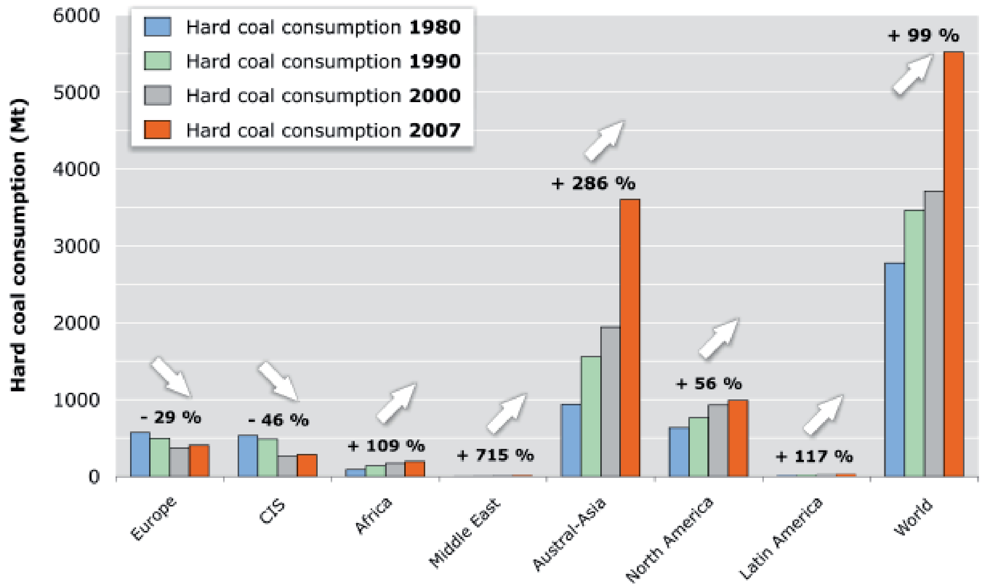

Figure 5.13: Development of the global hard coal consumption from 1980 to 2007 according to regions (IEA, 2008b).

Table 5.5: The top ten hard coal consumer countries differentiated according to steam and coking coal (IEA, 2008b).

Rank	Country	Steam coal consumption (Mt)	Share (%)	Rank	Country	Coking coal consumption (Mt)	Share (%)
1	China, PR	2 183.8	45.5	1	China, PR	359.3	49.7
2	USA	936.4	19.5	2	Japan	54.0	7.5
3	India	456.4	9.5	3	India	48.1	6.6
4	South Africa	176.1	3.7	4	Russia	47.1	6.5
5	Japan	128.3	2.7	5	Ukraine	29.8	4.1
6	Russia	105.4	2.2	6	Germany	23.0	3.2
7	Poland	73.8	1.5	7	South Korea	21.7	3.0
8	South Korea	70.4	1.5	8	USA	20.5	2.8
9	Australia	69.5	1.4	9	Poland	13.7	1.9
10	United Kingdom	62.7	1.3	10	Kazakhstan	10.8	1.5
	Total	4 262.6	88.8		Total	628.0	86.8
	WORLD	*4 798.6*	*100.0*		*WORLD*	*723.5*	*100.0*

Table 5.6: Regional development of the global hard coal consumption for 1980 and 2007 (IEA, 2008b).

Year	Consumption [Mt]	Region´s share of the global consumption in %						
		Europe	CIS	Africa	Middle East	Austral-Asia	North America	Latin America
1980	2777	20.6	19.1	3.3	0.1	33.7	22.8	0.5
2007	5522	7.3	5.2	3.5	0.3	65.3	17.9	0.5

5.2.6 Production and Consumption of Coke

The global coke production amounted to 544.4 Mt in 2007. At a proportion of 59.1 %, the PR China is the by far largest producer (Fig. 5.14), followed by the CIS-countries at 9.9 %, Japan at 7.1 %, India at 3.6 % and the USA at 2.7 %. Germany ranked ninth with a coke production of about 8.4 Mt (SdK, 2008a). Whereas the global coke production in the 1980s and 1990s varied between 330 and 375 Mt/a, it increased rapidly from 2001 onwards. Until 2007 the coke production increased by 197 Mt from 347 Mt to about 544 Mt. This growth is nearly exclusively due to the PR China with an increase of 190 Mt (SdK, 2008a).

Globally, the coke consumption in 2007 has the same order of magnitude as the production, at 544.3 Mt (SdK, 2008a). The largest coke consumer was also the PR China with a proportion of about 56 % (Fig. 5.15), followed by Japan at 9 % and Russia at approximately 5 %. Germany ranked seventh at 13.1 Mt coke (IEA, 2008b). The top ten coke consuming countries accounted for nearly 90 % of the global coke consumption of about 487 Mt.

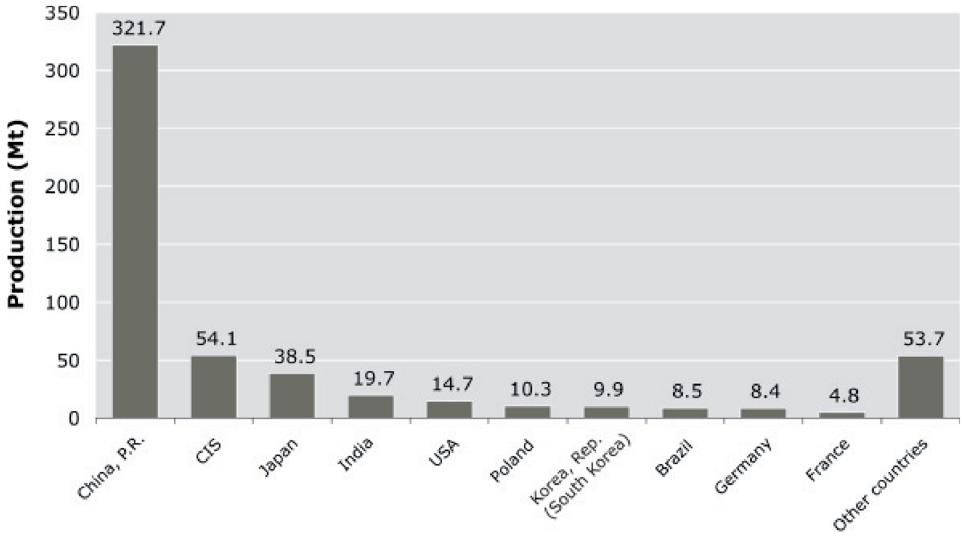

Figure 5.14: Coke production (total 544.4 Mt) in 2007 of the top ten countries (SdK, 2008a).

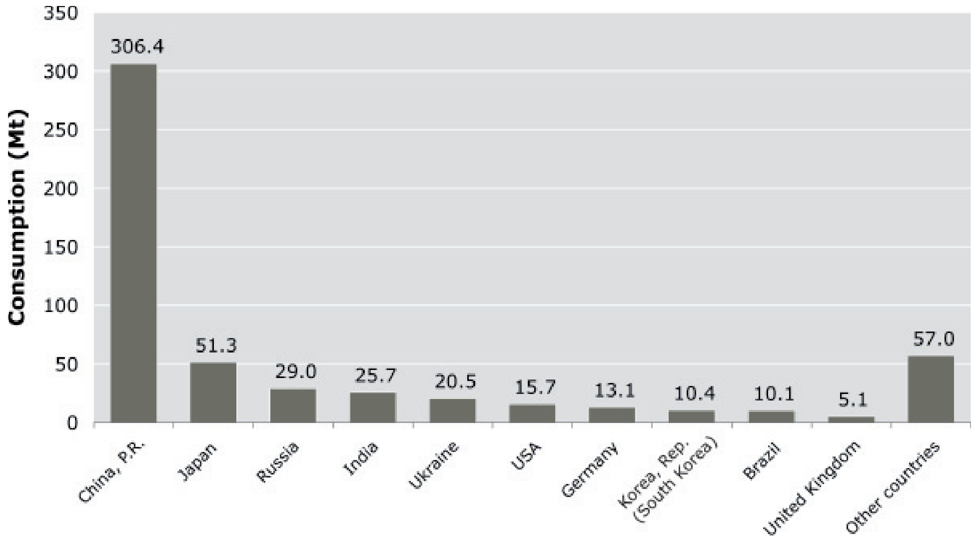

Figure 5.15: Coke consumption (total 544.3 Mt) in 2007 of the top ten countries (IEA, 2008b; Interfax, 2003-2009; SdK, 2008a).

5.2.7 Hard Coal Transportation

Generally, the long-distance transport of coal is conducted by ship and is thus in direct competition to other bulk goods such as ores or grain. Of the about 3 Gt of bulk goods transported by ship in 2007, nearly one quarter each was iron ore and coal. Iron ore at a plus of 76 % and coal at a plus of 50 %, since the year 2000, show the by far greatest growth rates of maritime transport (VDKI, 2008).

On principle, the freight costs depend on the size of the vessel and decrease with increasing tonnage. They are also influenced by seasonal fluctuations, for instance by increased grain exports after harvesting. Whereas the freight costs changed little in the 1990s, they increased significantly in 2003 and quadrupled or even quintupled by 2007 for all coal transportation routes (Fig. 5.16). This additionally increased the acceleration in prices of imported coal in the past years.

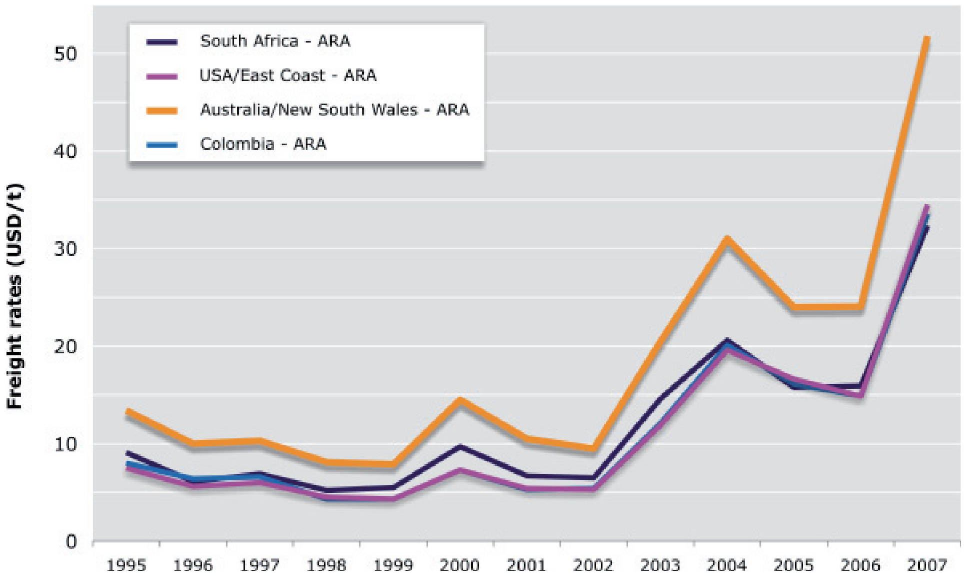

Figure 5.16: Development of the Capesize freight rates from 1995 to 2007 from different coal export countries to the large European ports Amsterdam, Rotterdam and Antwerp (ARA) (VDKI, 2006, 2008).

Investigations by Ritschel et al. (2007) show that the proportion of the sea freight and the port handling of the total costs in relation to the year 2006 amounted to approximately 28 to 37 % (USD 25 to USD 27/t) for coking coal and 36 to 46 % (USD 20 to USD 23/t) for steam coal. As the costs for the port handling with approximately USD 2 to USD 6/t cause a comparatively small share of the costs, the marine freight constitutes the second largest cost pool in most cases, the most important one being the production costs.

The inland transport from the mine to the export harbour is frequently covered by train. The coal export mines of the greatest hard coal exporter Australia are usually less than 200 km away from the ports, the South African export mines about 600 km (Productivity Commission, 1998). At 550 to 600 km, the distance from the Polish mines of the Upper Silesian Basin to the export harbors Gdansk, Gdynia and Swinoujscie is similar (UN-ECE, 1994). The main part of the Polish hard coal exports is transported to the adjoining countries by train. At 4500 km on average, Russian export coals are transported by rail over the greatest distances, as the majority is being produced in western Siberia (Rosinformugol, 2007). Such long transportation distances by land are only possible for subsidized railroad rates and for high coal prices on the world market (Schmidt et al., 2006). Depending on the local conditions, modern coal trains transport up to 10 000 t of coal. For a capacity of 100 t per railroad car, this corresponds to trains with 100 cars. Special trains, called Unit Trains, are primarily used in Canada, the US and Australia.

In 2006, the transport costs from the mine to the export port amounted to 15 to 17 % (USD 7 to USD 11/t) for steam coal and to 19 to 20 % (USD 16 to USD 21/t) for coking coal (Ritschel et al., 2007). In countries with transport distances of more than 600 km this proportion can even be higher. This mainly applies to coking coal, however. In the US this portion of costs for transports from the Appalachian Mountains to the east coast and in Canada from Alberta or Saskatchewan to the west coast is up to 33 %, in Russia, in spite of subsidies, it is above 40 %.

In Europe the better part of the imported coal is landed in ARA-ports. From there they are transported to the end consumers by train or river barges. According to data by the Bundesverband der Deutschen Binnenschiffahrt (BDB) in 2007 about 14.6 % or 36.3 Mt of the total cargo volume of the German inland navigation were solid mineral fuels (BDB, 2008).

5.2.8 World Market for Hard Coal

The beginnings of the international hard coal trade date back to the middle of the 19th century, when the onset of steam navigation resulted in a demand for coal as fuel in all major ports (Ritschel et al., 2005). In 1896, the coal trade volume amounted to approximately 68 Mt and was dominated by England at approximately 70 %. After the Second World War (1946), the global hard coal trade had a volume of about 85 Mt, half of which originated in North America (VDKI, 1996). The global hard coal trade only experienced a lasting upswing after the second oil price crisis in 1979/1980 (Fig. 5.17). Of the globally produced 5.5 Gt of hard coal in 2007, about 914 Mt were traded internationally. This corresponds to a proportion of 16.5 % of the global production. Other institutions specified the global trade at 906 Mt (VDKI, 2008) or 917 Mt (IEA, 2008b). Thus, the deviations of the two institutions listed above are less than 1 % in comparison to the BGR data. These differences are mainly based on the use of different sources. The historic considerations below are mainly based on the data of the VDKI.

The global hard coal trade increased 3.3-fold to 906 Mt between 1978 and 2007 (VDKI, 2008). The increase of the seaborne trade accounted for the main part, today it accounts for the better part of the global hard coal trade. According to information by the VDKI (2008) in 2007, approximately 820 Mt were transported by sea and only 86 Mt by land (intracontinental), mainly via train. At 37 %, the CIS accounted for the major part of the intracontinental trade in 2007, followed by Europe at 22 %, where transport takes place primarily from Poland and the Czech Republic to other EU-countries and North America at 21 %. The significantly increased Chinese coal demand also resulted in high growth rates of the intracontinental trade between the PR China and its neighboring countries North Korea, Mongolia and Vietnam (VDKI, 2008). The share of steam coal and coking coal for transportation both by sea and by land currently has a ratio of approximately 3 to 1.

Whereas in 1978 with a global hard coal trade of 210 Mt the proportion of hard coal transported by sea was 60 %, this proportion increased to about 90 % by the year 2007 (Fig. 5.17). Thus, during this period the maritime trade increased more than five-fold. Until the mid 1980s, mainly coking coal was traded by sea. Since the early 1990s steam coal dominates the global hard coal trade. After the Asian crisis had been overcome at the end of the 1990s, the maritime hard coal trade underwent a significant growth of about 9 %/a on average, this was mainly due to steam coal. Thus, the maritime steam coal trade doubled between 1999 and 2007 and increased from 309 to 618 Mt, whereas the maritime coking coal trade only increased by about 22 % from 166 to 202 Mt. The maritime traded proportion of the global hard coal production has increased nearly continuously from average 10 % in the 1980s until 2007 to about 16 % (miscellaneous annual VDKI reports).

Amongst the **hard coal exporting** regions, Austral-Asia with 538 Mt was the by far most important region in 2007, followed by the CIS with 128 Mt, North America with 83.9 Mt, Latin America with 73 Mt and Africa with 67.8 Mt. Nearly 98 % of the global hard coal ex-

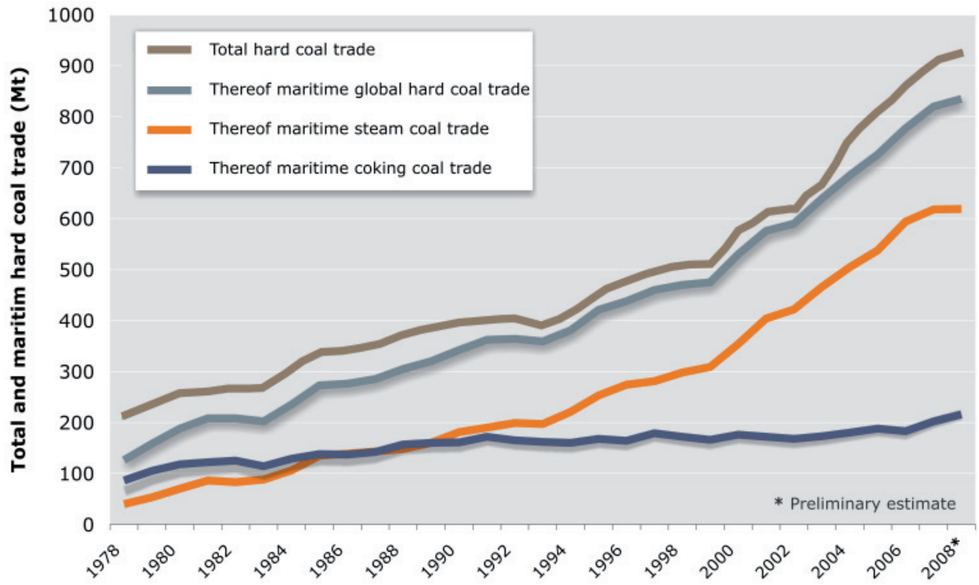

Figure 5.17: Development of the global hard coal trade since 1978 (annual VDKI reports since 1986).

ports of about 914 Mt originated in these five regions (Fig. 5.18, Fig. 5.19). Australia was by far the greatest exporting nation in 2007 with a share of about 27 % of the global hard coal exports (Fig. 5.19). Indonesia and Russia with a proportion of about 21 % and 11 % respectively, ranked second and third. The market share of the top ten hard coal exporting countries amounted to approximately 95 % in 2007.

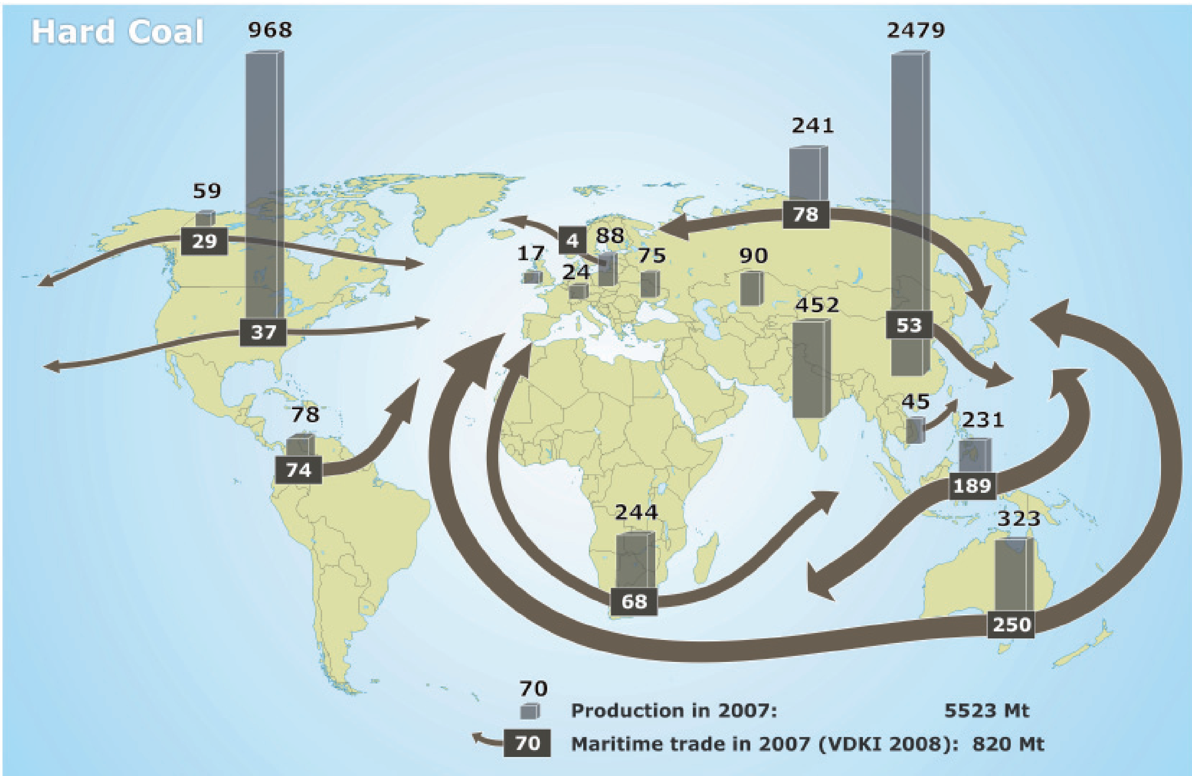

Figure 5.18: The largest hard coal producers and the maritime trade (in total 820 Mt) in 2007 (BGR, 2008; VDKI, 2008).

Coal Liquefaction – An Alternative to Petroleum?

If petroleum prices keep rising in the mid-term and long-tern perspective, coal liquefaction might contribute to producing substitutes for petroleum. Methods for converting coal into liquid hydrocarbons (Coal-to-Liquid, CTL) have been known since the early 20th century. In 1913, the German Friedrich Bergius managed to liquefy coal for the first time (Bergius-Pier process). In 1931, he received the Nobel Prize in chemistry. In 1925, a patent for another method for coal liquefaction via synthesis gas and subsequent catalytic conversion into hydrocarbons and water was applied for by Fischer and Tropsch (Fischer-Tropsch-Synthese). Until 1945, both processes were used in Germany involving a total of 21 liquefaction plants. This way it was possible to meet the German demand for mineral oil during of the 2nd World War by primarily synthetically produced products. In spite of several approaches, large-scale coal liquefaction in Germany was never taken up again. The last German pilot plant for coal liquefaction was dismantled in 2004 and sold to the Chinese coal corporation Shenhua in Shanghai.

Outside Germany, the technology was developed further mainly in South Africa, as the country suffered from a lack of oil due to an embargo. In 1955, the South African Synthetic Oil Limited (SASOL) in Sasolburg started producing synthetic oil from coal. The corporation is still using a modified Fischer-Tropsch process today and currently generates about 150,000 b/d of CTL products out of about 45 Mt coal per year. This is used to supply approximately 40 % of the total South African demand for fuel. Besides South Africa, mainly China has been pushing the subject of coal liquefaction for years mainly as part of its energy policy agenda. Thus, the largest coal company in China (Shenhua) operates projects at eight different locations from experimental plants to large-scale industrial usage. The first large-scale commercial liquefaction plant was commissioned in Ordos in Inner Mongolia at the end of 2008. In China for the year 2020 up to 30 Mt CTL products have been planned, for whose production approximately 120 to 150 Mt coal are necessary per year.

The coking coal trade in 2007 was dominated by only three countries. Australia at 68 % took the undisputed first rank, followed by the US at 13 % and Canada at 12.5 %. 93.5 % of the altogether 202 Mt of maritime coking coal originated in these three countries. Indonesia dominated the maritime steam coal market (Fig. 5.21) at a percentage of 30.6 %, followed by Australia at 17.5 %, Russia at 11.7 %, South Africa at 11.3 % and Colombia at 9.9 %. Thus, the five most important steam coal exporters accounted for about 81 % (618 Mt) of the maritime hard coal trade (VDKI, 2008).

The most important hard coal importing regions in 2007 were Austral-Asia at 500.4 Mt and Europe at 267 Mt. Together they accounted for nearly 84 % of the global hard coal imports of about 915 Mt (Fig. 5.20). The largest hard coal importers were only Asian countries with a volume of together 448.4 Mt, corresponding to 49 %. Behind Japan (20.3 %), South Korea (9.7 %) and Taiwan (7.5 %), two more Asian countries, India (5.9 %) and the PR China (5.6 %), followed for the first time. Only then, European countries with Great Britain (5.5 %) and Germany (5.2 %) appear in the ranking. At 239.8 Mt the European Union (EU-27) accounted for nearly 26 % of the global hard coal imports.

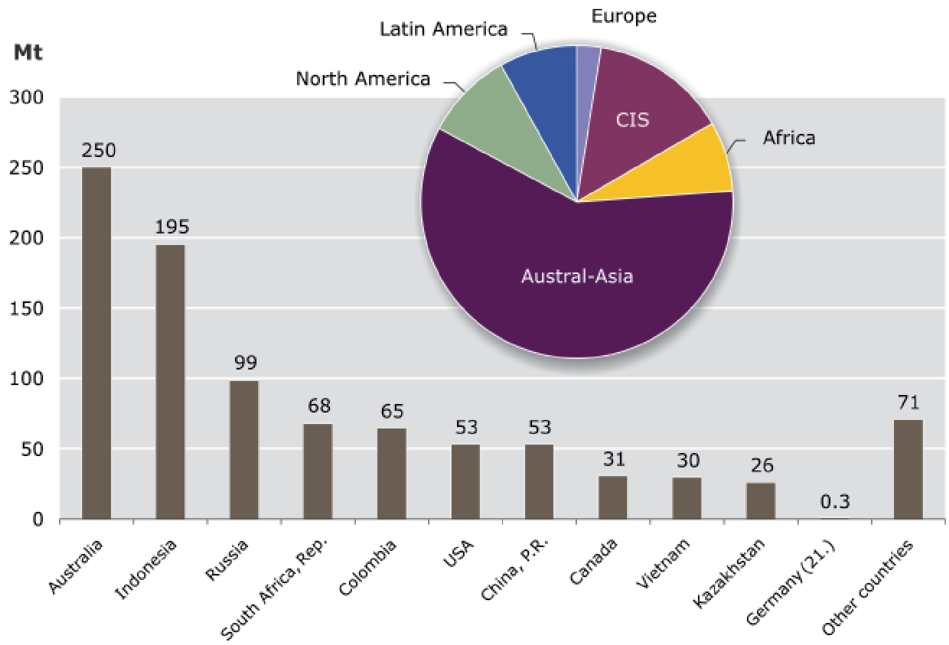

Figure 5.19: Hard coal exports (total 914 Mt) in 2007 of the top ten countries and Germany as well as their distribution by region.

According to IEA information, Austral-Asia accounted for about 57 % of the global coking coal imports of 207 Mt and these were exclusively Asian countries. Japan dominates at a proportion of about 26 %, India and South Korea follow suit at approximately 11 % each. Europe at 61 Mt was the second largest importing region of coking coal. Europe's most important and globally fourth largest importing nation of coking coal in 2007 was Germany at about 9.6 Mt. The ranking of the most important steam coal importing countries differs only slightly from the ranking of the most important hard coal importing countries (Fig. 5.20), as the amount of steam coal in the global hard coal market is approximately three times as high as the amount of coking coal. Only for India there is a change in the ranking. Due to the relatively high coking coal import share of 23.3 Mt in the Indian hard coal imports, it ranks eighth amongst the largest steam coal importing countries (IEA, 2008b).

The world market for steam coal is subdivided into a Pacific and an Atlantic market. Whereas Europe, Africa and North America supply the hard coal demand in the Atlantic market mainly via South Africa, Colombia, Venezuela and Russia, the Pacific importers such as Japan, South Korea and Taiwan are mainly supplied by Indonesia, Australia and the PR China. The main reason for the subdivision into two markets is primarily the portion of freight charge of the import coal costs. Thus, the exchange between the Atlantic and the Pacific market in the year 2007 was only a few million tons (VDKI, 2008). Indonesia and Australia supplied at 26 Mt about 10 % of the steam coal import demand of the Atlantic market. Conversely, South Africa and Colombia together supplied 13 Mt or about 3 % of the imported steam coal in the Pacific market. In contrast there is a uniform global market for coking coal which is not influenced as much by freight cost, as the small number of supplier countries and the globally dispersed consumers generate higher revenues than for steam coal. For this reason, the portion of freight charge of the total costs is lower than for steam coal.

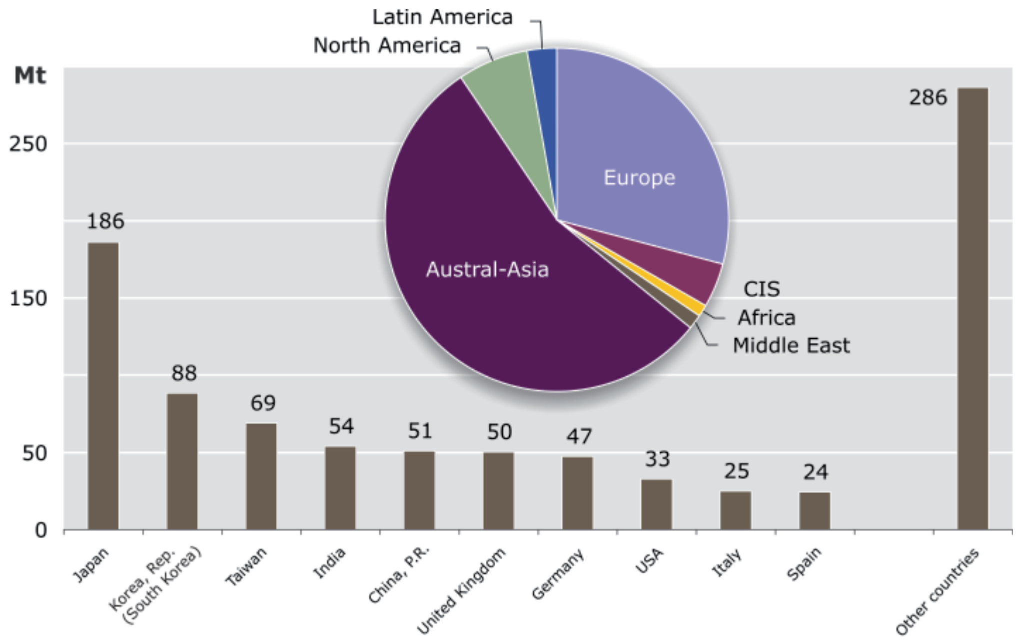

Figure 5.20: Hard coal imports (total 915 Mt) in 2007 of the top ten countries as well as their distribution by region.

In 2007 the maritime steam coal trade amounted to 618 Mt. The Atlantic market accounted for about 229 Mt and the Pacific market for 389 Mt (VDKI, 2008). The most important steam coal suppliers of the Atlantic market in 2007 were Colombia, South Africa and Russia, whereas mainly Indonesia, Australia and the PR China supplied the Pacific market (Fig. 5.21).

The comparatively high sales of Indonesian steam coal in the Atlantic market can be attributed to their high quality at low sulfur contents and relatively low prices. The Australian deliveries in the Atlantic market are only to a lesser degree steam coal and nearly exclusively high-quality coking coal. Russia can serve both markets due to its geographic location, as there are suitable ports in the European area as well as in the Far East. The South African deliveries in the Pacific area were predominantly intended for India, which is increasingly also dependent on imports from the Atlantic market.

With about 5 % only a small part of the global coke production is traded globally (VDKI, 2008). The PR China is by far the greatest coke producer (Section 5.2.6) and also the greatest exporter of coke. Even though the PR China exported at 15.3 Mt only 4.8 % of the domestic output in 2007, still it corresponded to a world market share of approximately 49 %. Thus, the PR China dominates the world market for coke. The second largest coke exporting country in 2007 with a share of approximately 20 % (6.3 Mt) was Poland (PIG, 2009). Amongst the coke importing countries, Germany was second to none world-wide in 2007 at 4.1 Mt (VDKI, 2008). Runners up with coke imports of 2 to 3 Mt were Japan, South Korea and the USA. A continuously increasing demand was also noted for Brazil, which imported about 1.6 Mt coke in 2007 (McCloskey, 2003-2009).

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Coal Fires – Destruction of Resources and Environmental Protection

Coal seams close to the surface can ignite spontaneously, if they are supplied with a sufficient amount of oxygen. Such coal fires are known all over the world in coal deposits. Some underground coal fires are caused by mining, if coal comes into contact with oxygen due to mine ventilation.

Fires in coal seams close to the surface are a global problem. In the process, resources are destroyed on a large scale. In addition, climate-related gases, such as CO_2, methane and different toxic gases are being emitted into the atmosphere. In China such fires have been raging for many years in a belt crossing the north of the country. Hundreds of burning areas are known, in which 10 to 20 Mt of coal burn annually. An amount of coal approximately ten times as large becomes unusable, as in the environment of the fires no mining activities can take place.

Coal fires can only be extinguished at great expenditure, i.e. removing energy by water cooling, separating fuel by digging ditches or creating barriers as well as cutting off the oxygen supply by applying an extensive cover of loam or clay. In the interdisciplinary geo-scientific joint project *Sino-German Coal Fire Research* (BMBF, support code 0330490) the development of innovative technologies for the exploration, fighting and monitoring of coal fire in Northern China is currently being advanced.

Coal fire in the Wuda mining district, Inner Mongolia, PR China

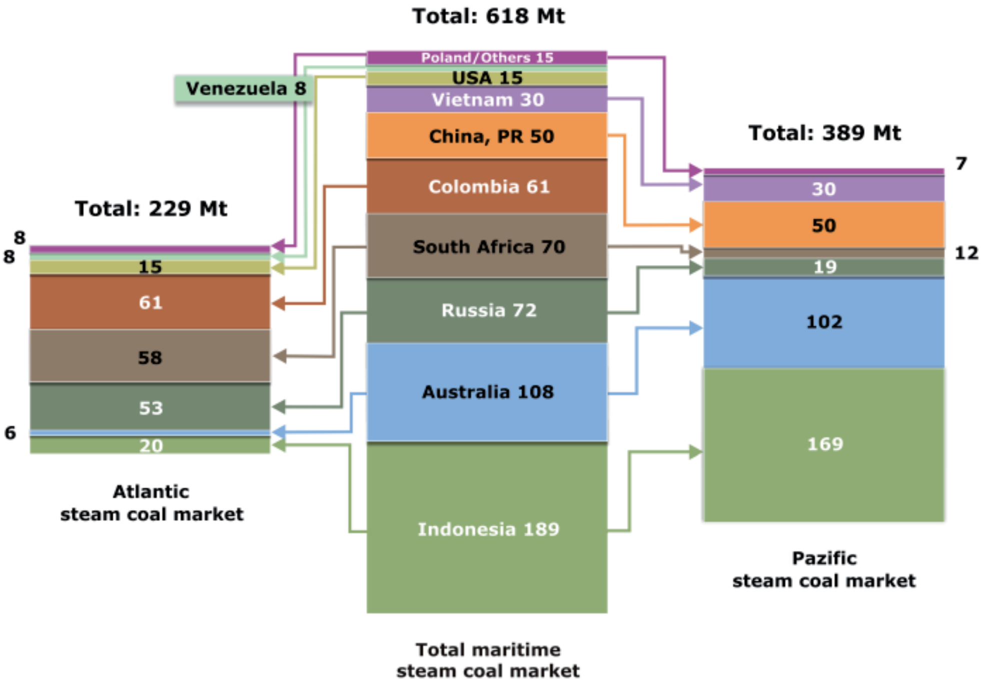

Figure 5.21: Supplier and recipient countries of the maritime steam coal trade in 2007 (VDKI, 2008).

5.2.9 Hard Coal Prices

The average annual import costs for the steam coal imported into the EU, according to the prices in the landing ports, ranged between USD 34.43 and USD 82.81/t cif (cost, insurance and freight) for the past 22 years (Fig. 5.22). The range for coking coal was USD 47.88 to USD 125.86/t cif. These prices constitute average prices in USD of the individual years, which the IEA received from the corresponding public import authorities on the total import volume and contained the total value of the imports. The average prices comprise all coal qualities, without consideration of the final usage or the contract conditions. Whereas the EU import prices between 1986 and 2003 for steam coal largely ranged in a price range from USD 35 to USD 50/t and those for coking coal ranged from USD 50 to USD 65/t, the import prices rose steeply from 2004 onwards. The nominally highest prices for steam coal and coking coal were reached in 2006/2007, after the import prices for steam coal in comparison to the low price marked in 1999 had increased by about 141 % to USD 82.81/t cif in 2007 and the coking coal import prices even increased by about 163 % to USD 125.86/t in the year 2006 in comparison to 2000 (IEA, 2008b). Taking into account the spot market prices in 2008, which had risen to more than USD 200/t for steam coal and coking coal prices of more than USD 300/t, the EU import prices probably increased significantly in 2008 as well.

The coal import prices have been listed in Figure 5.22, they are also listed as real prices in USD, taking inflation into account as of 2007. The import prices for steam coal or coking coal have been deflated using the US Consumer Price Index /All Urban Consumers (CPI-U) from the Bureau of Labor Statistics (Bureau of Labor Statistics, 2009). On closer examination of the real prices for imported steam coal in the course of the past 22 years it turns out that in spite of the immense nominal rise in prices since 2003 the real steam coal import price only reached the inflation adjusted level of the years 1986 to 1990 in 2007.

For coking coal, however, the price rises resulted in an increase of the real prices by 18 and 14 %, respectively, between 2006 and 2007 in comparison to the inflation adjusted maximum price of USD 109.7/t in 1986.

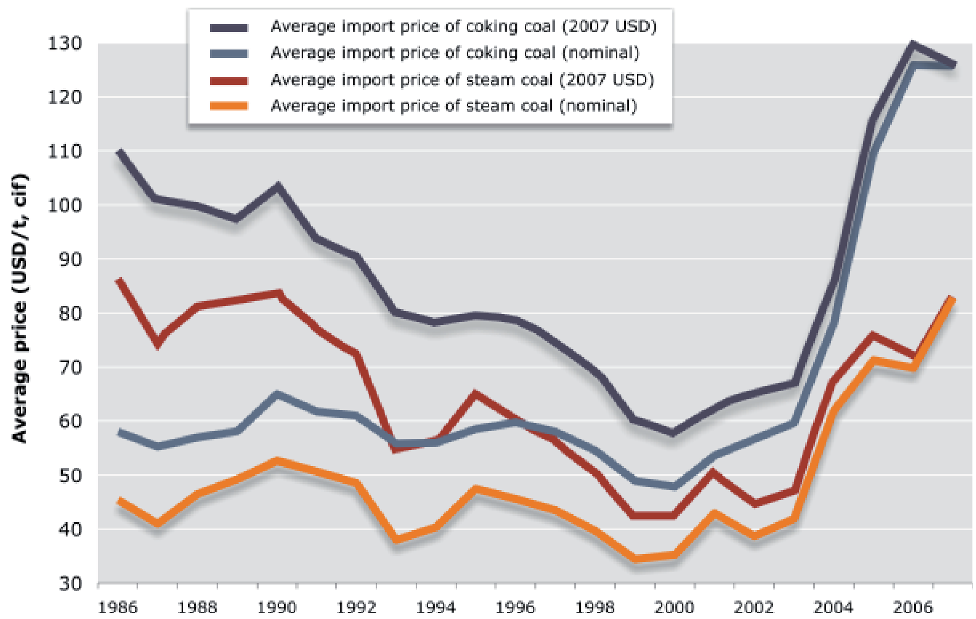

Figure 5.22: Price history for steam coal and coking coal imported into the EU from 1986 to 2007 (IEA, 2007, 2008b).

The **spot market for steam coal and the development of its prices** have changed lastingly in the past years due to the increasing publication of daily, weekly and monthly prices for globally traded hard coal. McCloskey, along with Platts the best known information server in the hard coal market sector, publishes two price indices, the *MCIS NW Europe steam coal marker* for North-Western Europe and the *MCIS Asian steam coal marker* for Asia. Only the European price index will be dealt with, which is based on cif-prices for steam coal delivered to North Western Europe (ARA-ports) with a standard quality for a heating value of 6000 kcal/kg (25.1 MJ/kg) and a sulfur content of 1 % at most. The VDKI regularly publishes the MCIS NW Europe steam coal marker-prices on its internet pages, however referring to a heating value of 7000 kcal/kg (29.3 MJ/kg, which corresponds to the energy content of 1 (hard) coal equivalent per kg), for this reason the price is listed in USD/tce, a customary specification in particular in Germany. In comparison to the EU import prices given annually (Fig. 5.22), the current supply and demand situation becomes much more apparent in the spot market prices specified on a monthly basis.

In the 1990s and until the middle of 2003, the *MCIS NW Europe steam coal marker* price varied approximately in five-year cycles relatively steadily between USD 25/t and USD 45/t cif. Between May 2003 and July 2004, the price increased by about 140 % to USD 78.70/t cif due to growing demand with a simultaneous shortage of freight capacities (Fig. 5.23). In 2005 the prices decreased by approximately 20 % to just USD 50/t cif. Subsequently, caused in particular by the cold winter in Europe and the continuously rising prices for the other fossil fuels, the spot market prices boomed again and in September 2006 they were still about 94 % above the bottom price in May 2003. Starting in early 2007, the spot market price for steam coal then developed in parallel to the oil price. Within the year

2007, which was mainly characterized by a vastly increased demand for imported coal in India and China, the price increased by about 91 % to a nominal price of USD 127/t cif which had been hitherto unheard of. Backed by a severe onset of winter with production and transport losses in China, severe flooding of important Australian export coal mines as well as of a rapidly rising oil price the *MCIS NW Europe steam coal marker* price rose again by 72 % between January 2008 and July 2008 to its highest level to date of USD 219/t cif. Thus, the spot market price for steam coal rose from its lowest level in August 2002 at nearly USD 26/t until July 2008 by nearly seven-and-a-half times. Until April 2009, the spot market price for steam coal decreased by about 70 % to USD 66/t in comparison to July 2008, which is still a quite high nominal price level in comparison to the 1990s and the start of the new century.

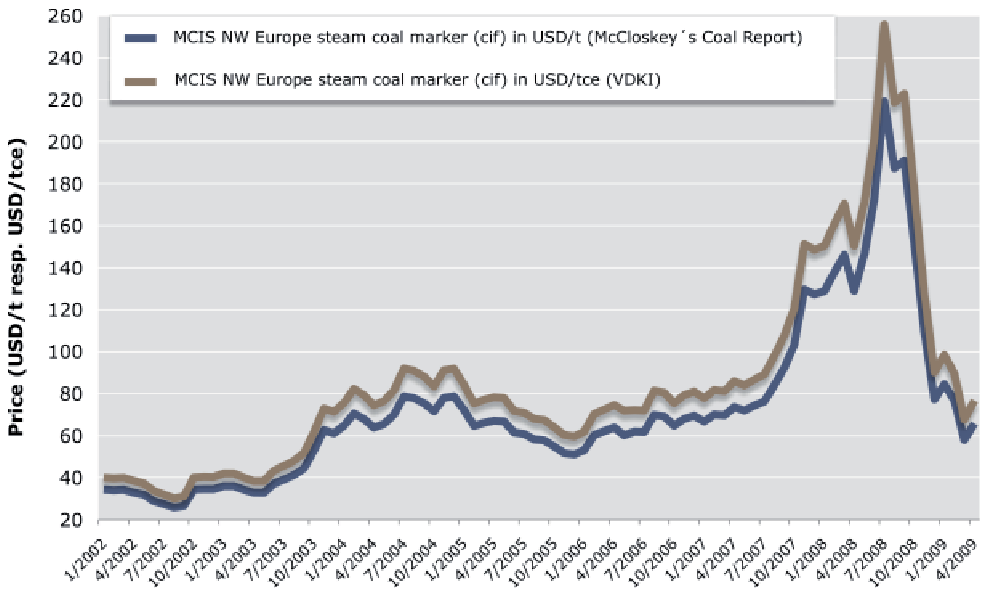

Figure 5.23: Development of the MCIS NW Europe steam coal marker price from January 2002 to April 2009 (McCloskey, 2003 – 2009; VDKI, 2003 - 2009).

5.3 Lignite

5.3.1 Total Resources of Lignite, Regional Distribution

The total global resources of lignite amount to 4345 Gt. Of these, 268.9 Gt, approximately 6.2 %, have been classified as reserves. Thus, the resources with 93.8 % account for the main part of the total lignite resources. In particular, in comparison with petroleum and natural gas, these total resources are relatively evenly distributed worldwide (Fig. 5.24).

The largest global total resources of lignite occur at 33.5 %, or approximately 1454 Gt, in North America, followed by the CIS at 31.8 % and Austral-Asia at 25.9 %. Of the remaining roughly 383 Gt (8.8 %) of the total resources, about 358 Gt are located in Europe (Fig. 5.25). In North America and the CIS the total resources of lignite are nearly exclusively located in the two countries covering large areas, the US at 1401 Gt and Russia at 1371 Gt.

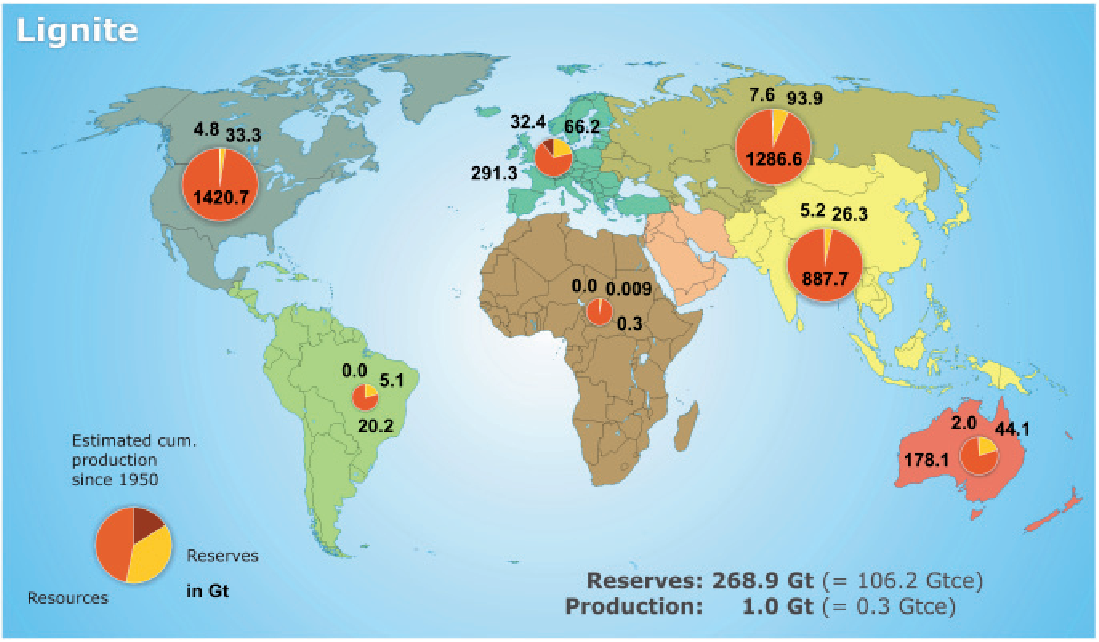

Figure 5.24: Regional distribution of the reserves, resources and the estimated cumulative production of lignite since 1950 at the end of 2007.

In Austral-Asia Australia, Vietnam, Pakistan and Mongolia besides the PR China possess large total resources. In Europe the total lignite resources are mainly located in Poland and Germany, which ranks ninth in the world. In these two countries, nearly 84 % of the European total lignite resources are located.

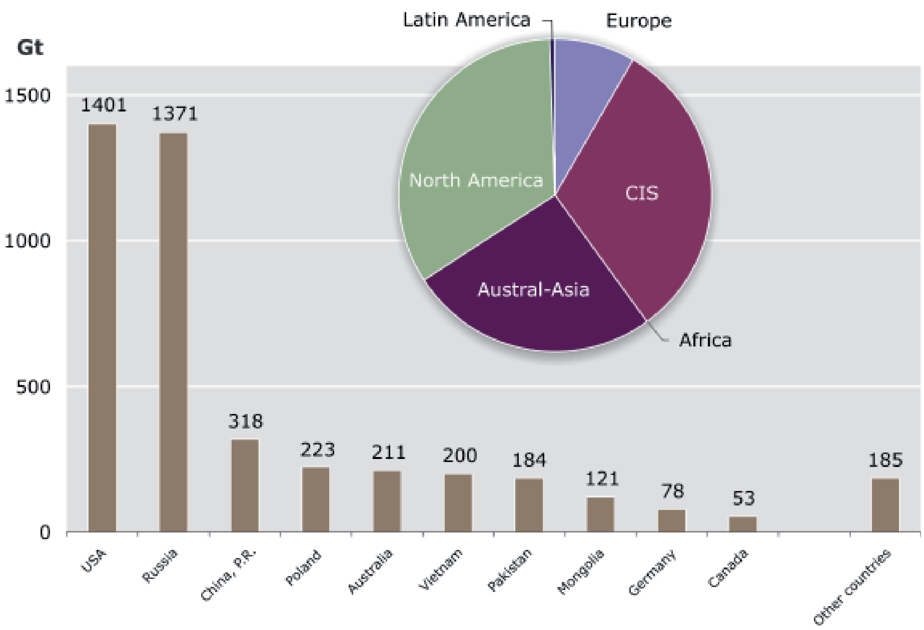

Figure 5.25: Total resources of lignite (total 4345 Gt) in 2007 of the top ten countries as well as their distribution by region.

5.3.2 Lignite Reserves

The three extensive regions CIS, Austral-Asia and North America account for 197.6 Gt or nearly 74 % of the global lignite reserves. Thus, the degree of concentration of these three regions is lower for lignite than for the reserves of hard coal (Section 5.2.2). At 34.9 %, corresponding to 93.9 Gt, the largest lignite reserves (in this case including hard brown coal) are located in the CIS, to which Russia at 91.6 Gt contributes in particular (Fig. 5.26).

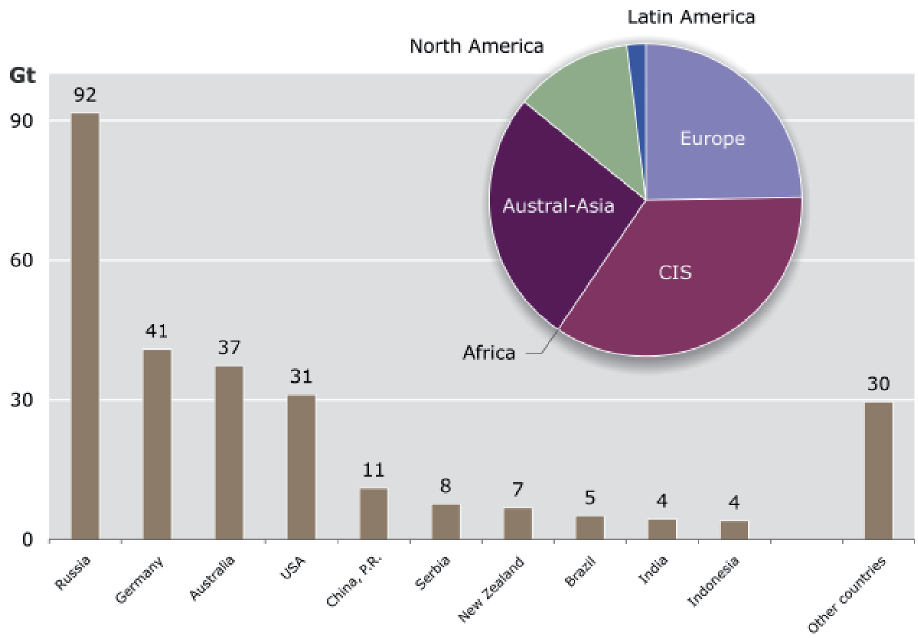

Figure 5.26: Lignite reserves (total 269 Gt) in 2007 of the top ten countries as well as their distribution by region.

Austral-Asia at 26.2 % possesses the second largest lignite reserves, which are mainly located in Australia (37.3 Gt) and the PR China (11 Gt). Europe possesses at 66.2 Gt (24.6 %) the third-largest lignite reserves, with Germany (40.8 Gt) being the second largest owner of reserves in the world. Important amounts of lignite reserves are also located in North America, 33.3 Gt, and there primarily in the US at 31 Gt. The regions Latin America at 5.1 Gt and Africa at 9 Mt have comparatively small lignite reserves (Fig. 5.26). In the Middle East there are no known lignite reserves.

5.3.3 Lignite Resources

In contrast to the situation for the reserves, about 92.4 % of the total resources of lignite, 3764 Gt, are located in the three regions North America, CIS and Austral-Asia (Fig. 5.27).

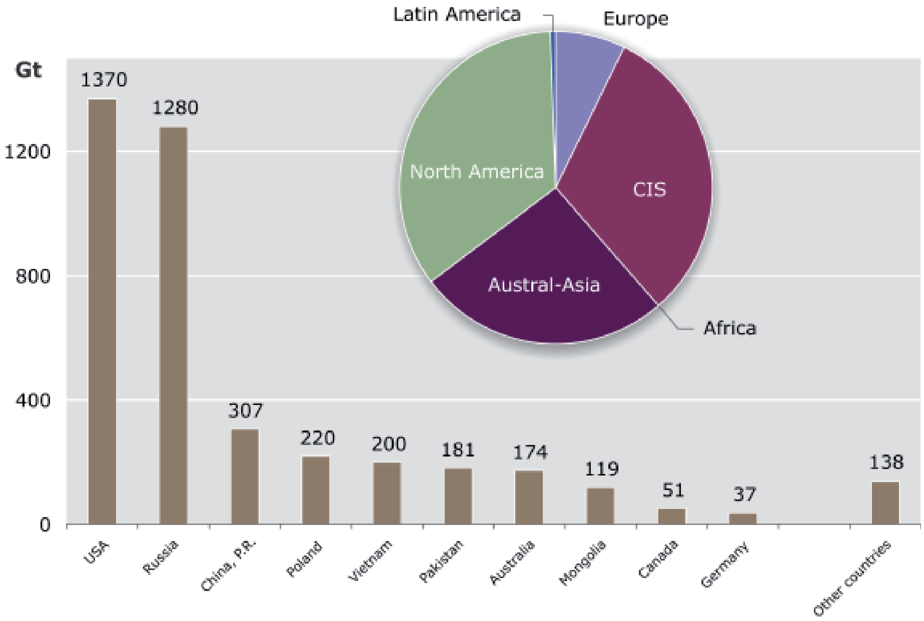

Figure 5.27: Lignite resources (total 4076 Gt) in 2007 of the top ten countries as well as their distribution by region.

Approximately one third each of the global resources of lignite are located in North America (1421 Gt), and the CIS (1287 Gt, including hard brown coal), the most important countries being the US at 1370 Gt as well as Russia at 1280 Gt (including hard brown coal). At about 1057 Gt (26.2 %) Austral-Asia holds rank three, as there are large lignite resources in the PR China (307 Gt), in Vietnam (200 Gt), Pakistan (181 Gt), Australia (173.5 Gt) and Mongolia (119 Gt, including hard brown coal). Europe at 291 Gt also possesses important lignite resources. These are mainly located in Poland and Germany, which takes rank 10 in the world (Fig. 5.27).

5.3.4 Lignite Production

With few local exceptions, lignite is only mined in surface mines. Internationally, production depths below 200 m are rarely surpassed. Germany is an exception; there the employment of large equipment for surface mining makes the production of lignite profitable down to depths of 400 m.

The global lignite production was about 978 Mt in 2007. At 566 Mt, more than half of the global production was generated in Europe, followed by Austral-Asia at 237 Mt (Fig. 5.28). Large amounts of lignite (90 Mt) were produced in North America and the CIS (79 Mt, including hard brown coal). Latin America at 5.8 Mt and the Middle East at 0.6 Mt together possessed on a proportion of 0.7 % of the global lignite production (Fig. 5.28). From Africa no lignite production is known.

The by far most important lignite producing country in 2007 was Germany with a share of 18.4 % of the global production corresponding to 180.4 Mt. Runners up, with a production of at least 70 Mt, were Australia, Russia (including hard brown coal), the USA, Turkey and the PR China (Fig. 5.28). Due to a significant production of lignite in European countries such as Greece, Poland and the Czech Republic, the production in the EU-27 amounted to app. 443 Mt. In 2007 this corresponded to a proportion of the global production of 45.3 %. The high proportion of the EU-27 of the global lignite production also reflects the great importance of lignite for the power supply of the European Union. For some EU-member countries, in particular for Germany, it is the most important domestic energy resource.

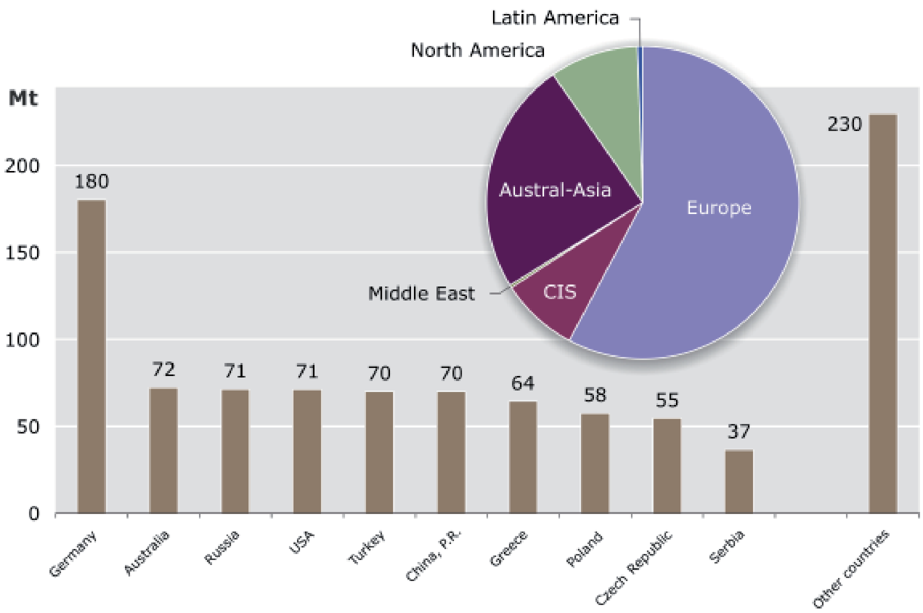

Figure 5.28: Lignite production (total 978 Mt) in 2007 of the top ten countries as well as their distribution by region.

Whereas the global hard coal production doubled in the course of the past 30 years (Section 5.2.4), the global lignite production increased only by about 83 Mt (9 %) to 978 Mt in the period from 1978 to 2007 (Tab. 5.7). The global lignite production rose significantly by 186 Mt (21 %) to about 1081 Mt until 1987. The decrease in the global lignite production in the 1990s by more than 200 Mt to about 856 Mt in 1999 can be attributed to the political and economical changes in the territory of the former GDR, in the east-European countries as well as in the former Soviet Union. In particular the collapse of the Council for Mutual Economic Assistance (COMECON) resulted in a massive reduction of the production of industrial goods, due to the slump in demand for COMECON-industrial goods. Thus, the power demand was reduced as well. In the newly-formed German states the lignite production decreased from 309 Mt in 1987 by about 244 Mt (minus 79 %) to 65 Mt in 1999.

In comparison to 1999, the lignite production in nearly all regions increased in the new Millennium. Only in the CIS, production decreased distinctly during that period (Tab. 5.7).

Table 5.7: Development of lignite production according to regions from 1978 to 2007 (WEC, 1980; BGR, 1989, 2003).

Region	Lignite Production in Mt (Region´s share of the global annual production)			
Year	**1978**	**1987**	**1999**	**2007**
Europe	670.5 (74.9 %)	738.8 (68.4 %)	507.6 (59.3 %)	566.1 (57.9 %)
CIS	152.0 (17.0 %)	164.0 (15.2 %)	90.1 (10.5 %)	79.0 (8.1 %)
Africa	0.0 (0.0 %)	0.0 (0.0 %)	0.0 (0.0 %)	0.0 (0.0 %)
Middle East	0.0 (0.0 %)	0.0 (0.0 %)	0.0 (0.0 %)	0.6 (0.1 %)
Austral-Asia	40.4 (4.5 %)	97.3 (9.0 %)	167.2 (19.5 %)	236.8 (24.2 %)
North America	32.1 (3.6 %)	80.8 (7.5 %)	90.8 (10.6 %)	89.7 (9.2 %)
Latin America	0.0 (0.0 %)	0.0 (0.0 %)	0.0 (0.0 %)	5.8 (0.6 %)
WORLD	*894.9 (100 %)*	*1080.9 (100 %)*	*855.7 (100 %)*	*978.0 (100 %)*

Whereas in 1978 three quarters of the global lignite production still originated in Europe, this proportion decreased continually over the past 30 years and was about 58 % in 2007. Austral-Asia showed the largest increases in lignite production where the production increased six-fold, thus the proportion of this region in the global lignite production increased from less than 5 % in 1978 to about 24 % in 2007 (Tab. 5.7). This can be primarily attributed to the expansion of the production in Indonesia, Thailand, India, the PR China and Australia (Tab. 5.8).

Table 5.8: Development of the production of lignite of the five largest producing countries in 2007 for the years 1978 to 2007 (WEC, 1980; BGR, 1989, 2003).

Country	Lignite Production in Mt (Region´s share of the global annual production)				Change 1978/2007 (%)
Year	**1978**	**1987**	**1999**	**2007**	
Germany (FRG+GDR until 1987)	376.9 (42.1 %)	417.8 (38.7 %)	161.3 (18.8 %)	180.4 (18.4 %)	- 52
Australia	33.0 (3.7 %)	40.5 (3.7 %)	65.0 (7.6 %)	72.3 (7.4 %)	+ 119
Russia (former Soviet Union until 1987)	152.0 (17.0 %)	164.0 (15.2 %)	83.5 (9.8 %)	71.3 (7.3 %)	(- 53)
USA	27.0 (3.0 %)	68.3 (6.3 %)	79.1 (9.2 %)	71.2 (7.3 %)	+ 164
Turkey	14.8 (1.6 %)	40.5 (3.7 %)	64.8 (7.6 %)	70.0 (7.2 %)	+ 374
Total	603.7 (67.5 %)	731.1 (67.6 %)	453.7 (53.0 %)	465.2 (47.6 %)	
WORLD	*894.9 (100 %)*	*1080.9 (100 %)*	*855.7 (100 %)*	*978.0 (100 %)*	*+ 9*

In principle the same geological, geographical and climatic factors are decisive for the amount of the lignite production costs as for the production of hard coal (Section 5.2.4). As the energy content of lignite is two thirds lower than that of hard coal, the revenues from lignite sale are essentially lower than for the sale of hard coal. Thus, an economic lignite production is only possible for lower production costs. Thus, the production is nearly exclusively done in competitive surface mines. In addition, to keep production costs down, there is usually no beneficiation or a lengthy transport of lignite. Instead, lignite is largely converted into power in power plants in the vicinity of the mines.

There are only few countries specifying tangible mining/production costs. An example is the Electricity Generating Authority of Thailand (EGAT). The purchasing prices indicated in their annual business reports for lignite ranged between USD 11 and USD 13/t and Euro 9 and 10/t, respectively, for the past years. EGAT is also owner of the largest Thai lignite surface mine, Mae-Moh, where 88 % of the Thai lignite production in 2007 originated. Thus the purchasing prices specified in the EGAT business reports probably largely correspond to the production costs (Tab. 5.9).

Table 5.9: Development of the lignite purchasing prices (~production costs) in Thailand (EGAT, 2007, 2008).

Production costs/year	2005	2006	2007
in Thai Baht/t	433.6	424.7	437.2
in USD/t	10.8	11.2	13.5
in Euro/t	8.7	8.9	9.9

Thus, the lignite production costs in Thailand range in the same order of magnitude as in Germany, where production costs of approximately Euro 8 to Euro 11/t accrue (BGR, 2003). The Metalworld Research Team (2008) specifies lignite (raw lignite) production costs of USD 14 to USD 16/t, i.e. Euro 10 to Euro 12/t for India in 2007. Considering additional costs, for instance for beneficiation, the Indian lignite production costs amounted to USD 16 to USD 18/t (Euro 11 to Euro 13/t). The largest Bulgarian lignite producer, the company Mini Maritsa Iztok EAD, produced 23.9 Mt of lignite in 2007 from three surface mines, corresponding to 94 % of the Bulgarian lignite production. The production costs amounted to app. USD 11/t, i.e. Euro 8/t (Mini Maritsa Iztok EAD, 2009). The sole Canadian lignite producer, Sherritt International Corporation, specified its costs for surface mining of lignite in Saskatchewan as well as of hard brown coal (sub-bituminous coal) in Alberta at USD 9.2/t, i.e. Euro 6.7/t in 2007 (Sherritt International Corporation, 2008).

The majority of the globally mined lignite from surface mines is produced at production costs between Euro 7/t and Euro 15/t according to the E.ON Kraftwerke GmbH (pers. com. Bayer). For lignite with higher calorific values, which in reality is hard brown coal and which is ranked among the hard coal (Section 2.3.3), an economical production is still possible even at higher production costs. For the few existing lignite underground mines the production costs are probably higher than the range from Euro 7 to Euro 15/t specified for surface mines.

5.3.5 Lignite Consumption

As there is only very little cross-border trade of lignite, the situation for consumption is nearly identical to that of production. The global consumption of lignite amounted to app. 977 Mt in 2007. Europe accounted for more than half of the global consumption of about 565 Mt, followed by Austral-Asia at 237 Mt. Significant amounts of lignite were also consumed in the regions North America at 90 Mt and the CIS at 79 Mt (Fig. 5.29).

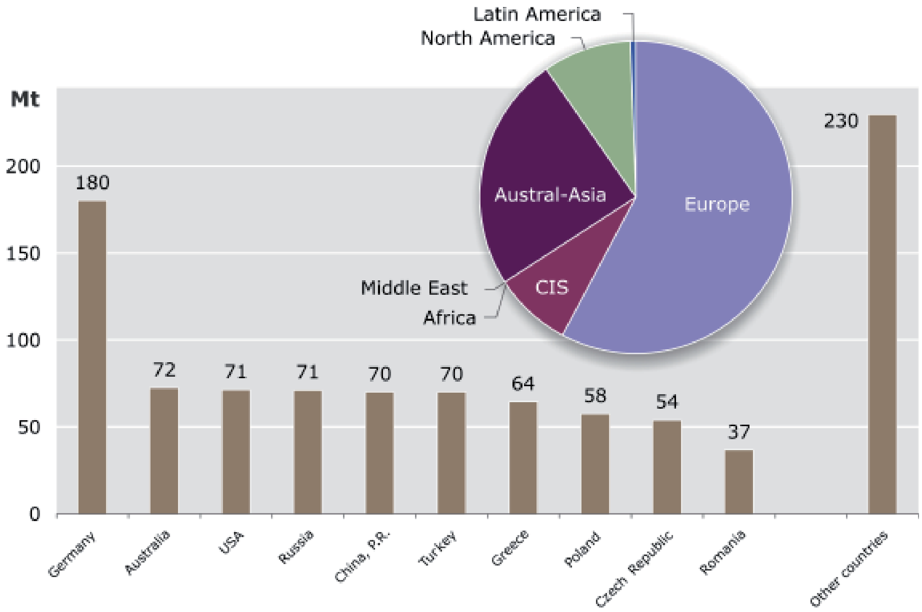

Figure 5.29: Lignite consumption (total 977 Mt) in 2007 of the top ten countries as well as their distribution by region.

In 2007 Germany had the highest lignite consumption of all countries at 18.4 % (180 Mt) (Fig. 5.29). Runners up, with a consumption of at least 70 Mt, were Australia, Russia (including hard brown coal), the USA, Turkey and the PR China (Fig. 5.30). The lignite consumption in the EU-27 amounted to app. 443 Mt. This corresponded to a proportion of the global lignite consumption of 45.3 %.

Between 1980 and 2007, the global lignite consumption decreased slightly by 3.3 % (IEA, 2008b). Whereas the global consumption still increased significantly in the 1980s (Fig. 5.30), it decreased in particular in the 1990s for the reasons already mentioned (Section 5.3.4). The development of the lignite production in the individual regions was in phase with consumption during the whole period reviewed here. Whereas the lignite consumption in Austral-Asia, North and Latin America as well as in the Middle East doubled and tripled, respectively (Fig. 5.30), the consumption in Europe and the CIS area decreased by one fifth and about two fifths, respectively (IEA, 2008b).

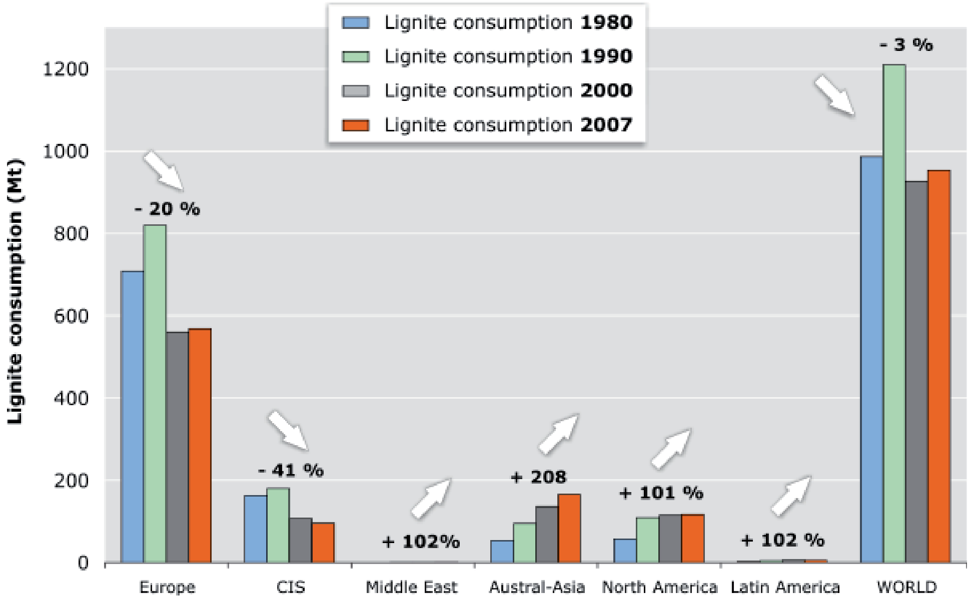

Figure 5.30: Development of the global lignite consumption from 1980 to 2007 according to regions (IEA, 2008b).

5.3.6 Lignite Trade

There is no global market for lignite. Because of its low energy content and high water content, lignite is traded only in exceptional cases. This mainly refers to trade of small amounts of (raw) lignite in the areas close to borders between the Czech Republic, Poland and Germany as well as of lignite products such as briquets, pulverized coal or coke from Germany to Belgium, France or the Netherlands. In 2007, German imports amounted to several tens of thousand tons; the exports amounted to several hundreds of thousand tons, which is way below 1 % of the annual German lignite production (SdK, 2008a). In Germany in the past years nearly 93 % of the annual lignite production was sold to power plants for the general power supply and another 1 % to 2 % for power generation in mine power plants. Only small amounts of lignite are refined. These products made of German lignite consist mainly of briquets as well as of pulverized coal and to a lesser degree of fluidized-bed lignite as well as of lignite coke (SdK, 2008a).

Relatively small amounts of several 100 000 t annually of Russian lignite (hard brown coal) are exported to Japan. This hard brown coal originates from the Russian island of Sachalin (Rosinformugol, 2008). Canada also exported about 100 000 t of lignite from the surface lignite mines close to the border in the south of Saskatchewan into the US in 2007 (Stone, 2008). A small part of the Indonesian coal exports are probably also lignite.

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6 Nuclear Fuel

6.1 Uranium

At the beginning of 2009, 436 nuclear power plants in 30 countries with a total power of 372 GW_e were operating. In 2008 nuclear power plants around the world produced 2 601 TWh power. Nuclear energy thus had a share of about 15 % of the global power generation. Approximately 65 405 t of uranium are required annually for supplying the current power plant pool. All over the world, numerous countries such as the PR China, Finland, Russia, South Korea, Japan and India announced the construction of new power plants. Simultaneously, the amount of uranium being mined increases only slowly.

6.1.1 Uranium Occurrences

Uranium is a natural component of the rocks constituting the earth crust. For an economic recoverability, uranium has to be enriched in the rocks. Uranium deposits can have developed in nearly all geological ages based on very different formation conditions. Their configurations, sizes and contents vary. Currently the following types of deposits are of economic importance:

Unconformity-related deposits contain uranium at 10 000 to more than 200 000 t U. Examples for this type of mine are Key Lake, McArthur River, Cigar Lake in Canada and Ranger, Jabiluka in Australia.

Sandstone deposits are common all around the world and contain between 0.1 and 0.2 % U. Medium-sized to large deposits host several thousand to more than 100 000 t U.

Hydrothermal vein-type deposits are also widely spread. A number of German deposits in the Erzgebirge belonged to this type. The uranium contents vary between 0.5 and more than 1 % totaling up to 10 000 t U for single deposits of this type.

Quartz-pebble conglomerate deposits are typically associated with gold for instance in the Witwatersrand (Rep. South Africa) or Elliot Lake (Canada) with typical concentrations between 0.01 % and 0.1 % U. Typical uranium deposits host up to 100 000 t U.

In **breccia complex deposits** uranium occurs as a by-product of the copper-gold production. In the currently sole deposit of this type, Olympic Dam, Australia, there are uranium reserves of 222 000 t U at average values of 0.06 %.

Intrusive and metasomatite deposits are large-scale but low-grade uranium deposits. Examples for this type are represented by Rössing in Namibia with more than 100 000 t U at an average value of 0.04 % U and Lagoa Real in Brazil with more than 20 000 t U at 0.3 % U.

Uranium can occur in rock and in water at percentages above those of the normal geological background contents, but still insufficient for a formation of economically extractible deposits. Uranium, however, can be associated with other raw materials and be produced as a byproduct. Contents of 2 up to 5 ppm uranium in granite, of 3 ppm in black shales and concentrations of 0.003 ppm in seawater may be suitable for extraction, given very high commodity prices. The technical challenge and the associated costs would be very high, for that reason these occurrences will not be dealt with in this study. The largest non-conventional uranium deposits are associated with phosphorites with 120 ppm U on average. Uranium can, if the economic conditions are favorable, be produced as a byproduct in the course of the processing of phosphates to phosphoric acid. In the US, uranium has been extracted from domestic phosphorites for a number of years, in Belgium from imported phosphorites from Morocco. In Kazakhstan, uranium was produced from fossil bones in marine sediments. Very few such occurrences have, however, been evaluated as resources.

6.1.2 Total Potential of Uranium, Historical Development

In the 1970s a strong growth of the nuclear energy for the future decades was forecast. There were concerns that the conventional uranium supply might not meet the demand. On an international level, efforts to evaluate the global potential of conventional uranium deposits were supported. This action complemented the global collections by the Nuclear Energy Agency (NEA) and International Atomic Energy Agency (IAEA), which have been conducting evaluations of the uranium supplies every two years since 1965. NEA and IAEA recorded the speculative uranium supplies in excess of that and presented the results of the *International Uranium Resources Evaluation Project* (IUREP) in the study *World Uranium potential* for 185 countries in 1978. The development of the uranium supplies since 1965 has been described in detail in the studies *Reserven, Ressourcen und Verfügbarkeit von Energierohstoffen* 1995 and 1998 (BGR, 1995, 1999). An overview of this study is presented here.

From 1965 to 1981, the supplies were recoded by NEA and IAEA in the categories *Reasonably Assured Resources* (RAR) and *Estimated Additional Resources* (EAR) at extraction costs of up to USD 80/kg U. Since 1983, a segmentation into EAR category I and category II (EAR-I, EAR-II) was conducted. EAR-I supplies are mainly those occurring in the vicinity of RAR occurrences, whereas EAR-II are less well explored and number amongst the so-called undiscovered resources. In addition, in all categories supplies with extraction costs up to USD 130/kg U were listed from 1977 onwards. In 1995 the class of the extraction costs up to USD 40/kg U was introduced. From 1991 to 1995 the assignment of the supplies of the CIS and a number of other countries in central and Eastern Europe to categories and cost classes was only possible to a limited degree; since 1995 it was implemented in stages. The integration of the supplies of China and India is not possible due to a lack of data.

The changes of the classification of reserves take into account the changes of the state of knowledge and the economic requirements, in particular the extraction costs. This resulted in changes of the reserves and reserve categories as well as the class of the extraction costs; a direct comparison becomes more difficult. The data for the RAR, recoverable up to USD 80/kg U are most reliable. These have been determined since 1965 and can thus be used as references. Global statements are restricted by the fact that there are no data of the countries of the former Warsaw Pact until the beginning of the 1990s, which only then gradually became available according to the required definitions. The development of the reserves until 1993 thus took into account only the countries of the *World Outside Centrally Planned Economy Areas* (WOCA).

1965 was excluded from the consideration as this was the first year of the determination of reserves, and only a limited number of countries was covered. Between 1967 and 1993, RAR recoverable up to USD 80/kg U of 1.4 Mt U and 1.85 Mt U were conveyed in the WOCA-area. This variation range can be explained from the changes in national data due to changes of reserve categories. 1991 and 1993, these reserves amounted to 1.5 Mt U. Between 1967 and 1993, in the WOCA-area a total of 0.8 Mt U was produced. The produced reserves have thus been more than balanced by new discoveries in the observation period.

For the EAR reserves a greater change occurred in 1983 as a consequence of the distinction into EAR-I and EAR-II. Between 1967 and 1981, EAR varied between 1.48 Mt U (1979) and 1.74 Mt U (1967). In the wake of the distinction into EAR-I and EAR-II in 1983, the EAR-I reserves decreased to 0.79 and to 0.93 Mt U, respectively. The US have not fully implemented this distinction. According to agreement, their reserves have been listed in category EAR-II. In 1994 the IAEA did not conduct a determination of the reserves.

Since 1995 the reserves in the category RAR, recoverable up to USD 80/kg U, have been recorded globally in accordance with uniform definitions. The former centrally planned economies have taken over the classification of reserves of NEA and IAEA in stages. If reserves without deductions for extraction losses (in-situ) had been reported, corresponding corrections were made. Since 1995 the RAR recoverable up to USD 80/kg U varied little, between 2.12 Mt U and 2.34 Mt U. In 2001 2.24 Mt U were recorded globally, whereas the reserves of China and India were not taken into account. The increase of the RAR recoverable up to USD 80/kg U to about 0.6 Mt U between 1995 and 2001 has been mainly attributed to the reserves of the CIS. Between 1995 and 2001, globally approximately 0.25 Mt U were produced. As no reduction of the reserves was noted between 1995 and 2001, the produced amounts have been more than balanced by the transition from lower-level classes (EAR). As a consequence of an increasing number of country statements, the RAR recoverable up to USD 40/kg U have increased from 0.5 Mt U to approximately 1.5 Mt U between 1995 and 2002.

Since 2003 the reserve category EAR-I has been defined as Assumed Reserves, the former *Known Conventional Resources* as *Identified Resources* (Chapter 2.4.3). Due to the lasting market upturn, the RAR recoverable up to USD 40/kg U have been chosen as the reference cost category.

The identified uranium deposits have increased significantly in all cost categories in the period 2001 to 2007 (Tab. 6.1). This can be mainly attributed to successes in the exploration and the expansion of production as a consequence of the significant increase in prices for uranium. The cost category <USD 40/kg U comprised 2.97 Mt U globally in 2007. The increase in RAR recoverable up to USD 40/kg U during the same period by approximately 0.2 Mt U to more than 1.76 Mt U can mainly be attributed to new reserves in Kazakhstan. No reduction of the reserves in spite of ongoing production occurred, i.e. the produced amounts have been more than balanced by transition from the lower-level reserve classes and cost categories.

Table 6.1: Development of the global reserves and resources of uranium in Mt (2001 to 2007).

Category of resources	2001	2003	2005	2007	Changes 2001-2007
Identified (gesamt)					
<USD 130/kg U	3 933	4 588	4 743	5 469	+1 536
<USD 80/kg U	3 107	3 537	3 804	>4 456	+1 349
<USD 40/kg U	>2 086	>2 523	>2 746	2 970	+884
RAR					
<USD 130/kg U	2 853	3 169	3 297	>3 338	+485
<USD 80/kg U	2 242	2 458	2 643	2 598	+356
<USD 40/kg U	>1 534	>1 730	>1 947	>1 766	+232
Assumed					
<USD 130/kg U	1 080	1 419	1 446	>2 130	+1 050
<USD 80/kg U	865	1 079	1 161	>1 858	+993
<USD 40/kg U	>552	>793	>799	1 204	+652

In order to assess the **total potential of uranium,** a task force of NEA and IAEA determined the speculative uranium reserves and in 1980 presented the results of the *International Uranium Resources Evaluation Project* (IUREP) in *World Uranium potential* for 185 countries of the world (IUREP, 1980). Accordingly, the speculative reserves for 1977 in the WOCA countries had been estimated at 6.6 to 14.8 Mt U, for the USSR, the countries in Eastern Europe and the PR China at 3.3 up to 7.3 Mt U. In conjunction with the known reserves of about 4.3 Mt U, the resulting conventional resources total at 9.0 to 22.1 Mt U. The wide range is due to uncertainties in the recoding and evaluation of regions of the earth that are geologically little explored.

In 1976 the BGR gave conservative estimates of the total resources at about 10 Mt U in the study *Das Angebot von Energie-Rohstoffen*, of these approximately 3.5 Mt U were identified reserves (Mixius et al., 1976). Since 1979 the Uranium Group of NEA and IAEA evaluates the conventional global uranium reserves, including the speculative uranium reserves on the base of national data. Accordingly, the current total potential, balancing the conventional reserves and resources at the end of 2007, was 16.0 Mt U. An analysis of the total resources by the BGR resulted in 18.2 Mt U, including high cost resources previously not considered.

The total potential of uranium is regionally distributed quite uniformly (Fig. 6.1). The detailed distribution of the reserves, resources, the production and of the consumption have been depicted below.

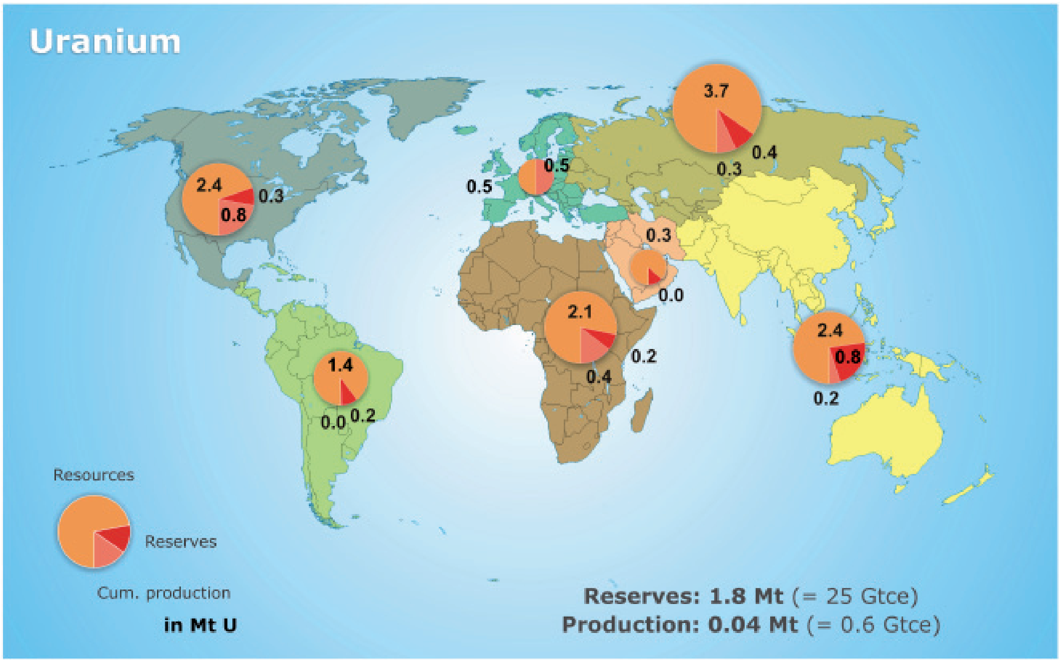

Figure 6.1: Distribution of the total potential of uranium 2007 according to regions.

6.1.3 Uranium Reserves

The mining reserves comprise mainly the recoverable reasonably assured reserves (RAR) up to USD 40/kg U (Chapter 2.4.3). An overview as of January 1st, 2007, was published by NEA/OECD and IAEA (NEA/OECD – IAEA, 2008) (Tab. A 6-2). Accordingly, the reserves of 1766 Mt U recoverable up to USD 40/kg U (Tab. A 6-1) are unevenly distributed among the countries (Fig. 6.2).

Besides geology, differing degrees of exploration as well as economic, infrastructural and political conditions are responsible for the uneven distribution. Australia possesses the highest proportion of uranium reserves at more than 40 %, followed by the CIS at approximately 20 %, North America at approximately 15 % and Africa at 11 % (Fig. 6.2). Europe possesses at 0.1 % only small reserves, as the known deposits have been exhausted. By economy policy regions, the OECD ranks first at more than 55 %. The CIS provides nearly 21 % of the reserves and the developing countries about 15 %. The EU possesses only 0.1 % of the uranium reserves of this cost category.

Besides the reasonably assured reserves (RAR) recoverable up to USD 40/kg U, reserves at these extraction costs are also included in the category inferred reserves (IR). This category frequently plays a more important role for the determination of reserves and plans than reserves with higher extraction costs. In early 2007 the global reserves in this category amounted to 1.2 Mt U (Tab. A 6-3). The Identified Reserves in accordance with NEA and IAEA, the sum of the categories of reasonably assured reserves and inferred reserves (Chapter 2.4.3), recoverable up to USD 40/kg U, globally amounted to 2.97 Mt U at the beginning of 2007.

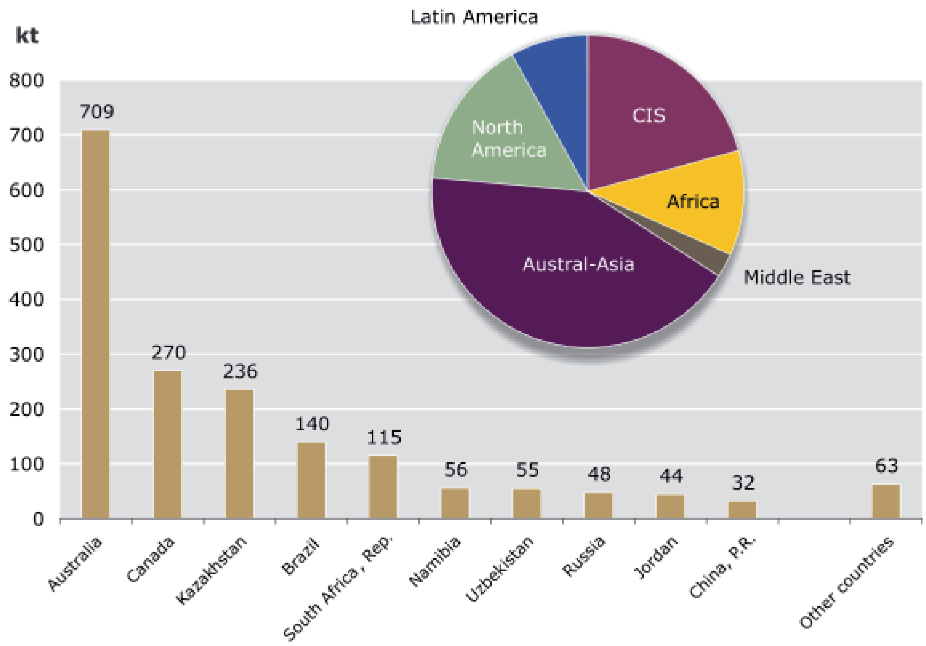

Figure 6.2: Uranium reserves in 2007 (total 1766 Mt U) recoverable up to USD 40/kg U of the top ten countries as well as their distribution by region. The reserve data of the countries with in situ-reserves has been converted to recoverable amounts.

6.1.4 Uranium Resources

The categories exceeding reserves in **conventional uranium occurrences**, in some cases recorded with a high certainty of proof, have been classified as resources. In spite of significantly higher market rates since 2005, the reasonably assured reserves (RAR) have also been included in the cost categories USD 40 to <80/kg U and USD 80 to <130/kg U. As the RAR have been determined with a high degree of certainty, they constitute the reserves for higher prices. From the 1990s until 2004 they were not recoverable at economic conditions due to the low price level and were thus assigned to the subeconomic resources. With increasing prices many of these resources became reserves. As the spot market only represents a small trade volume and uranium is traded mainly based on long-term delivery contracts slightly above the USD 40/kg category, these categories will continue to be classified as resources. The inferred reserves (IR), recoverable at costs between USD 40 and USD 80/kg U as well as between USD 80 and USD 130/kg U will be treated the same way. Their degree of proof is lower than for RAR.

The surveys of uranium reserves by NEA and IAEA (NEA/OECD – IAEA, 2008) also extend to undiscovered resources (Chapter 2.4.3). They are registered in the cost categories recoverable up to USD 80/kg U and recoverable up to USD 130/kg U. In Table A 6-3 only the resources determined up to USD 130/kg U are depicted together. The speculative resources (Tab. A 6-3) have been listed without extraction costs, as due to its speculative nature only the total amount is of interest.

The global distribution of the resources amounting in total to 14.2 Mt U is similar to the distribution of the uranium reserves (Fig. 6.2). At nearly 28 % North America possesses the largest resources of uranium, of these the US, as the country with the largest resources, possess 2.95 Mt U and Canada hosts approximately 1 Mt U (Fig. 6.3). The second most important region consists of the countries of the CIS at a proportion of slightly more than 25 %.

Mainly Russia at 1.49 Mt U, Kazakhstan at 1.38 Mt U and the Ukraine at 0.45 Mt U account for these resources. Important regions are also Australasia with the dominant position of Australia with 0.53 Mt U and Africa, where the Republic of South Africa alone hosts 1.54 Mt U as reserves, with a resource proportion of 17 % (Fig. 6.3). Germany is listed globally on rank 21 of the resource countries, with 81 kt U. The countries important for uranium, Australia and Namibia do not list undiscovered resources, which seems implausible. Thus it can be assumed that the data on the global resources are on the conservative side.

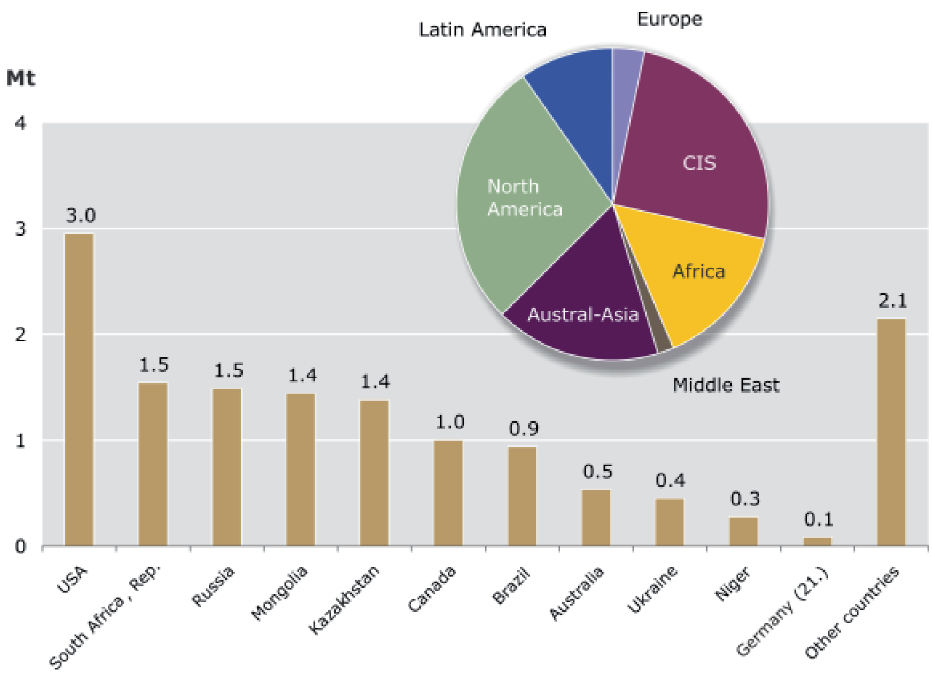

Figure 6.3: Uranium resources (14 243 Mt) in 2007 of the top ten countries and Germany as well as their distribution by region.

The resources recoverable at costs of more than USD 130/kg U are currently no longer recorded in detail. Thus, they were not included in the evaluation of this study in Table A 6-3. The last time they were determined in a study was for 'Reserven, Ressourcen und Verfügbarkeit von Energierohstoffen 1998' (BGR, 1999) on the basis of older documents with about 419 000 t U for the RAR >USD 130/t U and about 497 000 t U for the IR >USD 130/t U. As these investigations date back more than 30 years, there are limitations concerning the scope of these data. The values specified in Table A 6-3 were compiled from the most current sources such as NEA/OECD – IAEA (2008) and World Nuclear Association (WNA, 2008) including proprietary data of the BGR. For the IR for the USA data were used from the WNA, as NEA/OECD – IAEA (2008) does not contain complete data.

In the past decades, the amounts of non-conventional uranium reserves have been assessed very optimistically in some cases. Thus, the possibility of extracting uranium from phosphates (phosphorites) during the production of phosphoric acid resulted in very optimistic assessments. Different studies have specified the uranium contents of marine phosphate deposits worldwide as 15 to 30 Mt U. From available phosphoric acid plants, a theoretical annual production of 5000 to 10 000 t U had been assumed. These assumptions turned out to be unrealistic; in the meantime all plants for producing uranium via the phosphoric acid process have been shut down. In Belgium approximately 690 t U were produced from imported Moroccan phosphates between 1975 and 1999. In Florida in the US a total of 17 150 t U were produced from phosphate rock between 1954 and 1962. A plant in Kazakhstan produced approximately 40 000 t U between 1959 and 1993. Lately some countries have renewed their interest in uranium occurrences in domestic phosphate mines. Since 2007 Jordan has been exploring its deposits with an estimated uranium content of 59 360 t.

All other non-conventional resources have not yet achieved economic importance. In the former GDR between 1947 and 1955 as well as from 1968 to 1989 about 3000 t U were produced from the coals of the Freitaler Revier in Saxony. The US pursued the extraction of uranium from bituminous coal, the produced amounts, however, were low. In Sweden the shale deposit Ranstad yielded approximately 200 t U. The extraction of uranium from granite also aroused temporal interest. Based on the example of the deposit Rössing in Namibia with uranium contents between 200 and 300 ppm U, similar occurrences were explored for in many regions. Even though granite with elevated uranium contents and potential of several Mt U has been taken into account, a true economic potential is currently not perceptible. Likewise do economic reasons currently cast doubt on the uranium extraction from seawater with estimated 4.5 Gt U. In 2006 Japan, however, resumed research on corresponding extraction technologies. Researchers managed to enrich approximately 1.5 g U under natural conditions in the ocean during a period of 30 days. The system used can be designed for an annual production of approximately 1,200 t U at extraction costs of about USD 700/kg U.

6.1.5 Additional Uranium Stocks

Additional sources are represented in uranium which was previously produced for different purposes. The uranium, however, can have different forms. From 1945 until the end of 2007 2.3 Mt U were produced globally, but only about 1.7 Mt U were used for civil purposes. The remaining 0.6 Mt U were kept in readiness for use by the military as well as for stock kept for safeguarding the supply by consumers, producers and public institutions. Neither the uranium used in the reactors nor the uranium for nuclear weapons has been exhausted. According to the World Nuclear Association (WNA, 2008), the nuclear fuel that has not been consumed in the nuclear reactors can be reused, uranium as Reprocessed Uranium, REPU and plutonium as mixed oxide (MOX). The REPU that will be available until 2020 corresponds to 26 500 to 52 000 t U, depending on the demand scenario, the plutonium used as MOX corresponds to approximately 24 000 to 48 000 t U.

The uranium used by the military constitutes a further resource. The US and Russia negotiated the disarmament of highly enriched uranium (HEU) from nuclear weapons. 500 t HEU from Russian nuclear weapons have been and will be disarmed between 1993 and 2013 and depleted in Russia for civil usage (Low Enriched Uranium, LEU). This amount converted to natural uranium corresponds to about 152 000 t U, until June 2007 approximately 93 000 t U had been processed. 8 939 t LEU have been delivered to the USA for usage in commercial reactors. This delivery corresponds to the disarmament of 12 231 nuclear warheads. Of intended 174.3 t of American HEU 151 t are to be made available for research purposes and commercial demand. Until 2006, 94 t HEU had been converted to 1051 t LEU. The amounts theoretically becoming available in the market correspond to approximately 358 000 to 408 000 t U. The annually available amounts depend on contractual agreements as well as on the economic situation. Between 1500 and 3000 t U annually can be made available from

REPU until 2030, from MOX between 1200 and 2400 t U for the same period. In total, that would correspond to approximately 8 % of the currently foreseeable annual demand.

The depleted uranium resulting from enrichment for civil usage (reduced in 3 to 5 % ^{235}U) and military usage (>90 % ^{235}U) also constitutes a potential source. The total amount has been estimated to be 1.2 to 1.35 Mt of depleted uranium (0.3 % ^{235}U or smaller). After re-enrichment to the natural ^{235}U-concentration of 0.7 % these amounts would correspond to 440 000 to 500 000 t U. The depleted uranium is already being used for civil purposes by mixing with HEU to produce LEU or can be re-enriched in case of unused enrichment capacities.

6.1.6 Uranium Production

Between 1945 and 2007 a total of 2.3 Mt U were produced. The global mining production during this period was determined by many factors. Thus until the break up of the Soviet Union and of the Warsaw Pact it was mainly controlled by military requirements. In the Western countries the military requirements resulted in a continuous growth of production up to approximately 33 000 t U in the year 1959. A decreasing military demand and low civil demand resulted in a decrease until the middle of 1960s to about 16 000 t U. Based on the expectation of a high growth of the use of nuclear energy, from 1970 onwards an increase in production began, which reached a maximum at 44 000 t U annually in 1980 and 1981 and significantly exceeded consumption. For supply-strategic considerations governments, consumers and producers established stocks, which exceeded significantly the customary stockpiling of approximately two annual consumptions of the conversion and enrichments plants as well as of the power supply company. In the wake of the decelerated growth of the civil usage of nuclear energy production in the Western countries decreased until 2001 to approximately 27 000 t U annually.

For the former Eastern Block and the PR China only an assessment of the annual development of the production can be made, based on the overall output or assumptions. Accordingly a continuous increase of the production to more than 26 000 t U annually occurred until the middle of 1980s, controlled by the production of nuclear weapons and the demand of the civil usage for the reactor programs the Soviet Union. The political upheaval in the early 1990s changed the area of the uranium production, as the dominant military importance ceased to exist. The integrated state-owned companies had to adapt to free-enterprise conditions, to reception restrictions of some countries for uranium from the GUS. The re-orientation of the supply in the countries of central and Eastern Europe were decisive factors for a reduction of the uranium production. By the mid 1990s the output in the GUS has decreased to approximately 6400 t U, but recovered until 2007 to about 13 200 t U. The uranium production of the previous years, which had been largely required by the military and the civil demand, which had not been up to expectation, have resulted in the existence of stocks. The amounts of uranium available from current production have significantly undershot the demand since the early 1990s.

The production capacities existing in 2007 in deposits with reserves <USD 40/kg U amount to 41 000 t U, i.e. it would be impossible to meet the demand by the mining production alone. The current production capacities, based on reserves available, including the category inferred reserves, up to USD 80/kg U, amount to about 55 000 t U/a.

From 1995 to 2007 Canada took top rank of all producing countries with a total of 141 176 t U. This corresponds to 29.5 % of the global production during this period. Canada's annual output varied with the exception of 1999 between 9500 and more than 12 000 t U and amounted to 9476 t U in 2007 (Fig. 6.4). The decrease in 1999 can be attributed to the discontinuation of production in the pit Key Lake and the start of production in the mines McArthur River and McClean Lake. This change in production sites was finished in 2000, when the former production volume of more than 10 000 t U was reached again. In 2001 in Canada a production maximum was reached at 12 522 t U. Lower grade ore in the deposits McClean Lake and Rabbit Lake have reduced the output to approximately 9500 t U after 2005.

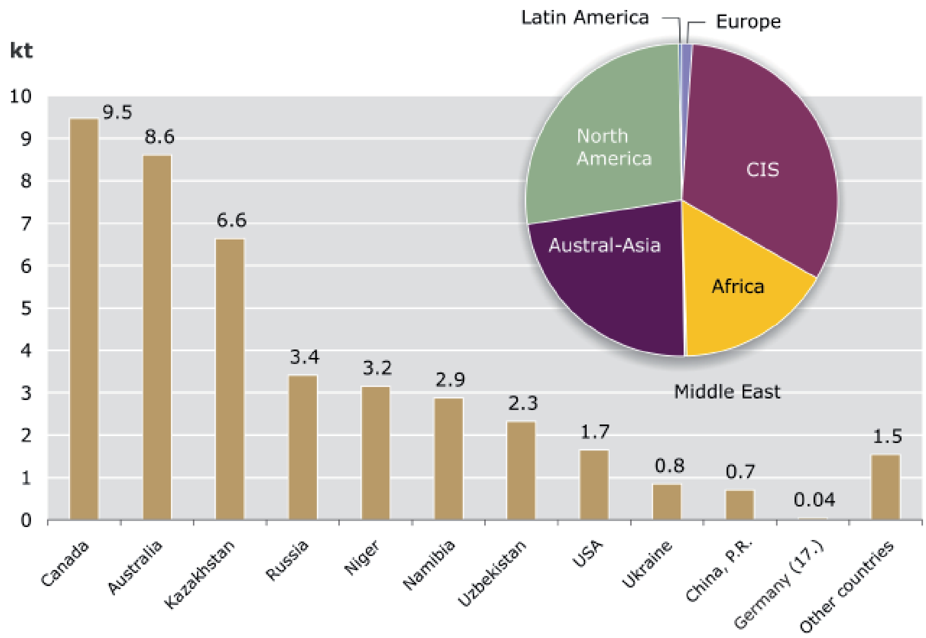

Figure 6.4: Uranium resources (14 243 t U) in 2007 of the top ten countries and Germany as well as their distribution by region.

Australia with a total of 89 440 t U or 18.6 % of the global production is the second largest producer of the years 1995 to 2007 (Fig. 6.4). The annual production rose with interruptions in 1998 and 2002 continually from 3712 t U in 1995 to 8611 t U in 2007, with a maximum of 9512 t U in 2005.

The development of the uranium production in the CIS-countries took very different courses. For Kazakhstan 1998 a significant increase in production to 6637 t U in 2007 occurred. Kazakhstan thus has risen to be the third-largest uranium producer worldwide (Fig. 6.4). The growth is based mainly on the expansion of the previous output as well as on the development of new deposits. Russia moderately increased its output until 2007 to 3413 t U in order to fulfill its delivery commitments for reactors of soviet origin in third countries and its domestic demand. Ukraine, also with a domestic usage of nuclear energy, has kept the output stable at annually approximately 800 t U. The mining production in Uzbekistan shows a slight growth since 1995, due to improved production methods.

Production in the US showed a significant downward trend from 1995 to 2003. Market-related factors, abandonment of operations that were no longer profitable, such as the uranium production from phosphoric acid by-products and low-cost acquisition from Canada's rich ore mines have been decisive factors in this context. Since 2004 the output has increased again due to increased exploration efforts and improved conditions and has reached the production volume of 1998.

Because the deposits have been depleted and operations that were no longer profitable were shut down, the uranium production in Europe has decreased from 2279 t U in 1995 to only 425 t U in 2007. France, Hungary and Romania have ceased commercial production and deliver like Germany remaining quantities from the remediation of old production centers. The sole relevant mining production takes place in the Czech Republic at annually 300 t U and decreasing trend.

From 1997 to 2007 the uranium production was controlled all over the world by take-overs, amalgamations and shut-downs by a few nationally and internationally operating corporations, which controlled between 70 and 80 % of the production during that period. As a consequence only seven companies were responsible for 86 % of the global mining production in 2007 (Tab. 6.2).

The twelve most important uranium deposits provided about 70 % of the global output in 2007 (Tab. 6.3). Dominant by far was the rich ore deposit McArthur River in Canada, where 7199 t U or 17 % of the annual global production were mined. Ranks two and three were taken by the Australian mines Ranger and Olympic Dam at 4589 and 3388 t U, together they provided about 19 % of the global production in 2007.

Corresponding to the multitude of the possible occurrences of uranium (Chapter 6.1.1) the output in 2007 was not dominated by one extraction technology. In principle the four processes open-pit mining, underground mining, in-situ leach mining (ISL) and production as by-product are to be distinguished, which all provided relevant amounts of uranium (Tab. 6.3). Open-pit mining varied in the past 20 years between 28 and 40 % with decreasing tendency. Between 31 and 51 % were mined underground, on average approximately 40 %. The proportion of in-situ leach mining increased from approximately 6 % to 29 % today in the period from 1990 to 2007. By-product extraction, which currently mainly takes place in the deposit Olympic Dam, has an overall proportion of 10 %and shows increasing tendencies.

Table 6.2: Uranium production of the most important mining companies in 2007.

Mining company	Uranium production 2007 (t U)	Proportion (%)
Cameco	7 770	19
Rio Tinto	7 172	17
Areva	6 046	15
KazAtomProm	4 795	12
ARMZ	3 413	8
BHP Billiton	3 388	8
Navoi	2 320	6
Uranium One	784	2
GA/ Heathgate	673	2
Andere	4 919	12
TOTAL	*41 279*	*100*

Table 6.3: The most important uranium deposits in 2007 with the corresponding mining process (ISL = in-situ leach mining) and the ownership structures of the individual corporations.

Mine	Country	Main owner	Type	Production 2007 (t U)	Proportion (%)
McArthur River	Canada	Cameco	underground	7 199	17
Ranger	Australia	ERA (Rio Tinto 68 %)	surface	4 589	11
Olympic Dam	Australia	BHP Billiton	by-product	3 388	8
Kraznokamensk	Russia	ARMZ	underground	3 037	7
Rossing	Namibia	Rio Tinto (69 %)	surface	2 583	6
Arlit	Niger	Areva/Onarem	surface	1 750	4
Rabbit Lake	Canada	Cameco	underground	1 544	4
Akouta	Niger	Areva/Onarem	underground	1 403	3
Akdala	Kazakhstan	Uranium One	ISL	1 000	2
Zafarabad	Uzbekistan	Navoi	ISL	900	2
McClean Lake	Canada	Areva	surface	734	2
Beverley	Australia	Heathgate	ISL	634	1,5
SUMME				*28 760*	*70*

6.1.7 Uranium consumption

Numbers of consumption for uranium are published by different national and official international organizations as well as commercial companies. The numbers published by NEA and IAEA in the regular publications (NEA/OECD – IAEA, 2008) are based on surveys of public institutions and can thus be regarded as reliable. The commercial World Nuclear Association (WNA) publishes consumption numbers, which are based on surveys of companies (WNA, 2008). With the exception of slight deviations, which presumably result from the differences in collecting data described above, no significant differences for the consumption between 1995 and 2007 were found between NEA/OECD and IAEA as well as WNA. For estimates of the future consumption NEA and IAEA considered a High and Low Scenario from 2010 to 2030. For this period the WNA included a Reference Scenario.

Between 1995 and 2007 the demand of natural uranium increased from 61 378 t U according to NEA/OECD - IAEA (2008) and 57 783 t U, respectively, according to WNA (2008) to 69 110 t U (NEA/OECD - IAEA, 2008) and 66 529 t U (WNA, 2008), respectively. This corresponds to a significant increase of nearly 13 % and 15 %, respectively. At the same time the annual production increased from 35 635 to 41 870 t U between 2003 and 2007 in comparison to 2002. As a consequence competitive new projects were tackled and production operations, which had formerly not been economic, remained in production or have even been upgraded. Countries such as Bulgaria, Spain, Hungary, France and Gabon, which had been producing uranium at higher cost for meeting domestic demand, terminated production. Other countries such as Kazakhstan and Malawi have recently entered the group of uranium producers, continue production, such as the Czech Republic and South Africa or plan the resumption of production such as currently Argentine and the DR Congo.

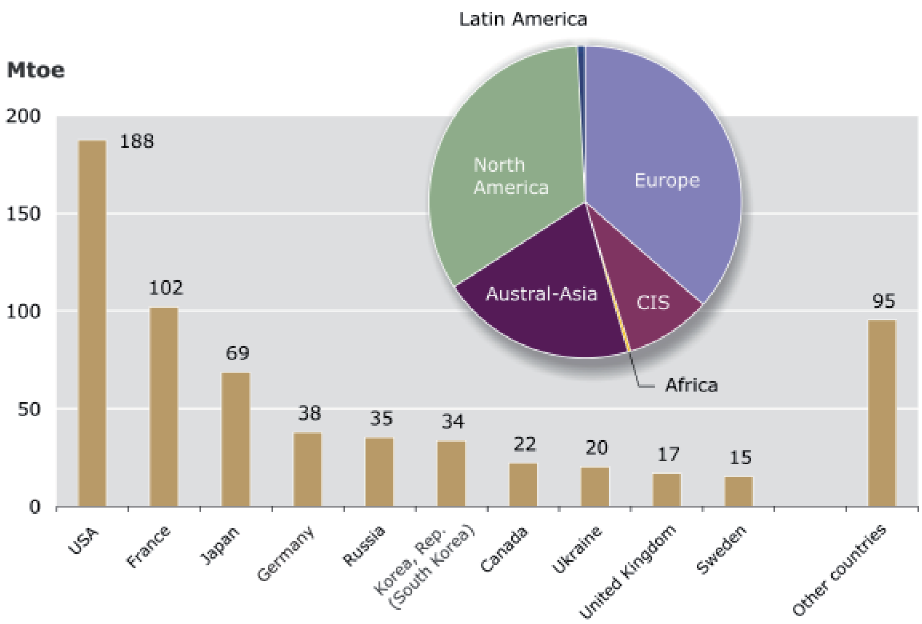

Figure 6.5: Consumption of uranium (636 Mtoe) in 2007 of the top ten countries as well as their distribution by region.

The by far most important consumer countries in 2007 were the US, France and Japan with a joint proportion of 57 %; Germany, Russia and South Korea come close (Fig. 6.5). These six countries jointly covered about three quarters of the global uranium consumption in 2007.

The future consumption of uranium depends on the further development and the implementation of the ambitious plans of national nuclear energy programs. The Low Scenario by NEA/OECD and IAEA assumes, in contrast to previous forecasts a growth to 70 395 t U from 2010 with a further increase until 2030 to about 93 775 t U (NEA/OECD – IAEA, 2008). The global renaissance of nuclear energy in countries with previously decreasing consumption such as the US, Russia or Canada, new users such as the United Arab Emirates, Thailand, Turkey or Vietnam and most of all the intended massive construction of new power plant capacities in the PR China, India, Russia, Japan, South Korea and the US will result in an increased demand. The High Scenario by NEA and IAEA anticipates a significantly increasing demand to 98 600 t U until 2020. Accordingly for 2030 a demand of 121 955 t U is expected (NEA/OECD – IAEA, 2008). In the Reference Scenario of the WNA an increase to 80 500 t U in 2020 is assumed, for 2030 the demand accordingly reaches 110 000 t U (WNA, 2008).

6.1.8 Nuclear Fuel Cycle and Trade

Uranium is traded globally. As it undergoes several treatment stages until it is used in a nuclear reactor, the individual treatment products are frequently transported over long distances. The concentrate packaged in barrels (Yellow Cake) is either stored temporarily at the treatment plant or directly delivered to conversion plants because of purchase contracts with the recipient. There, the concentrate is converted to gaseous uranium hexafluoride (UF_6), before it is enriched in processing plants to the desired ^{235}U-composition. The enriched uranium is then processed in separate fuel elements for its ultimate use. The individual steps are executed depending on availability and the form of contract in different countries.

The conversion is conducted, with the exception of a number of national institutions, in large plants, operated by Cameco in Canada and Great Britain, Areva in France, Conver Dyn in the US, Atomenergoprom in Russia as well as CNNC in China. The European conversion capacities cover approximately 25 % of the global demand. At the suggestion of the IAEA and Russia and in coordination with the American Global Nuclear Energy Partnership (GNEP) there are efforts being undertaken for setting up international centers for the enrichment of uranium. The first of such centers exists in Siberia, Russia. It is called Angarsk IUEC and operated with Kazakh participation. The French Atomic Energy Agency has suggested the new plant Georges Besse II for an international opening under comparable conditions. Another proposal for an international enrichment center is being expected from South Africa.

Urenco (Germany, Netherlands, Great Britain), Areva (France), US Enrichment Corp (USA), Atomenergoprom (Russia), JNFL (Japan) and CNNC (China) operate enrichment plants on a large scale. Fuel elements are produced in 17 countries. The largest plants are located in the US, Russia, Japan and Canada. The annual enrichment capacity in Germany corresponds to a global proportion of nearly 16 %.

The power supply companies as consumers procure their fuel directly from producers or via traders. The delivered quantities, qualities and times are governed by contracts. In Europe these have to be presented to EURATOM for approval purposes. For trading purposes the following groups of countries can be distinguished: Exporting countries with production without domestic demand, such as Australia, Niger, Namibia, Uzbekistan and Kazakhstan; exporting consumer countries, whose production is significantly higher than the domestic demand such as Canada and South Africa; importing countries with domestic production such as the US, Russia, Ukraine, the Czech Republic, Romania and India as well as importing countries with their own nuclear power plants but without domestic production. Among the last category there are many large consumer countries, such as Germany, Great Britain, Sweden, Finland, Belgium, Switzerland, Japan, South Korea, France, Spain and Argentine. Russia takes a special position, in that it produced less uranium than it consumes, but it possesses stock and secondary sources.

The supply of the EU, whose demand in 2007 was 21 280 t U, is only covered to a small proportion by the domestic production of annually approximately 425 t U and by stock. With exception of the last remaining primary production in the Czech Republic and small amounts from the remediation of former production centers in France, Romania and Germany, the EU is nearly completely dependent on imports from third countries. The delivery contracts for consumers in the EU are handled by EURATOM Supply Agency. In the last years annually 20 to 25 % of the demand, i.e. between 3000 and 3500 t U have been supplied by Canada. The deliveries from Russia, Kazakhstan and Uzbekistan reached with 3500 to more than 5000 t U annually more than 30 % of the demand. As a consequence concerns about a one-sided dependency resulted in import restrictions. Russia's uranium deliveries to the EU contain probably also uranium of Kazakh, Uzbek and Ukrainian origin. In 2007 Russia at nearly 25 % of the deliveries, corresponding to 5144 t U, superseded Canada after many years as most important uranium provider of the EU. The Canadian deliveries decreased by 25 % to 3786 t U. Further important provider countries for the EU were Niger at a proportion of 17 %, corresponding to 3531 t U and Australia, which contributed 3209 t U or about 15 %. The imports from South Africa and Namibia have decreased significantly in the past years to 4.8 % now.

6.1.9 Uranium Prices

On principle two price structures can be distinguished: Prices for multiannual contracts and for immediate deliveries (Spot). Most of the uranium is traded based on long-term contracts. The price quotations are usually in USD per pound (lb) U_3O_8.

Reliable data on production costs of uranium are not internationally published. The production costs are determined usually by the individual mining and production methods as a function of the geological deposit parameters. The described changes of the proportions of the different mining methods (Chapter 6.1.6) reflect the efforts of the producer, even in times of high commoditiy prices, to lower production costs. Since 1990 this has been realized by concentrating on underground mining of rich ore deposits and by optimizing the in-situ leach mining. This way the prices for multiannual contracts for deliveries in the EU dropped from USD 17.48/lb U_3O_8 to USD 13.18/lb U_3O_8 until 2001. Then the price for long-term deliveries rose to approximately USD 21.60/lb U_3O_8 until 2007.

For spot deliveries, which account for about 3 % of the trade volume, the price decreased between 1990 and 2001. After a significant market recovery an all-time high occurred in June 2007 at USD 136 00/lb U_3O_8. Until the end of 2008 the prices dropped again as part of the adjustment of the market. They consolidated however in spite of the looming financial crisis above USD 45.00/lb U_3O_8. This market recovery has resulted in an increased economic profitability even of low-grade uranium ore. sales revenue of USD 13 to USD 15/lb U_3O_8 and deducting sales costs and suitable yield of the invested capital pure production costs of significantly less than USD 10/lb U_3O_8 are taken into account. Revenues in the spot market were not considered, as this uranium was mainly from stock. The mean EURATOM spot market price in 2007 was USD 64.21/lb U_3O_8. This corresponds to an increase by 127 % in comparison to 2006.

The rapid economic development in populous emerging markets, a rapidly increasing energy demand in these countries as well as the development of the global climate policy have resulted in many countries in a renaissance in the interest in an expansion of the civil use of nuclear energy. Simultaneously mining production has lagged behind demand for many years; the latter was only met by mining stock and other secondary sources (Chapter 6.1.5). As a consequence since 2003 the uranium prices increased significantly and the market underwent a lasting recovery. This entailed high capital expenditure in exploration, the new development of new uranium mines as well as an expansion of the production from known mines.

6.2 Thorium

6.2.1 Thorium as Nuclear Fuel

Thorium can be used as nuclear fuel for the generation of energy in special reactors. In the 1960s and 1970s different types of reactors for power generation, for generating heat, for coal gasification and for other processes were developed. Thorium was supposed to complement uranium as nuclear fuel in case of a possible shortage. In addition thorium was favored as fuel in countries, which, like India, do not possess sufficient uranium deposits. After the development of thorium-based test and prototype reactors further development was stopped, as the expected increase of the usage of nuclear power did not occur and existing uranium deposits ensured the supply. The German thorium high-temperature reactor THTR Hamm-Uentrop with 300 MW_e was shut down in 1989 after a short operating time.
In South Africa a high-temperature gas-cooled reactor with Thorium as fuel was developed further. South Africa and China have agreed on a future cooperation and the construction of a test reactor until 2015. India has been developing a proprietary type of reactor based on thorium as fuel for some time. The start of production is not anticipated before 2020.

6.2.2 Supply of Thorium

The situation of the reserves and resources for Thorium has not changed by much since the BGR-Energy Study 1998 (BGR, 1998), as a lack of demand has precluded new supply determinations. The global thorium reserves (<USD 80/kg Th) thus amount to 2.57 Mt Th. In addition resources of approximately 1.8 Mt Th have been the forecast.

6.2.3 Production and Consumption of Thorium

There are no reliable numbers on the production of thorium available, as thorium is not mined separately as a resource. Thorium is usually a by-product of the fabrication of monazite for the mining of rare earth elements. Monazite in turn is a by-product of the production of heavy mineral sands on ilmenite, rutile and zircon. On average monazite contains approximately 10 % thorium dioxide (ThO_2). Considerable amounts are available from previous mining of ore containing uranium-thorium on uranium like in Madagascar. During the past years monazite was produced in particular in India, Malaysia and Sri Lanka. The global output of monazite amounted to 6000 to 6350 t per year. Monazite also used to be produced in the US. There production was stopped in 1995. The non-energetic application of thorium and compounds containing thorium in high-temperature ceramics, catalytic converters and welding electrodes decreased due to the radioactivity of thorium.

The current use of thorium in research reactors is restricted to small amounts. The demand can be met from existing stock. In the USA more than 3000 t of thorium compounds are being kept as stock. The stock in other countries is not known, but it is assumed to be considerable in producing countries, such as India and South Africa.

6.3 References on Nuclear Fuel

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7 Geothermal Energy

7.1 Heat from the Earth for Usage as Energy

Energy stored as heat underneath the surface of the solid earth is called geothermal energy. The enthalpy of the earth can be traced back in part to the initial heat when the earth was formed, in part to the decay of radioactive isotopes in the rock of the earth crust. The high temperatures in the earth's interior cause a constant heat flow towards the earth's surface. The total heat flow is theoretically sufficiently high to supply a considerable part of the global energy demand; the heat flux of about 70 mW/m^2 is rather low in the global mean, however. The use of geothermal energy from the deeper basement thus, as a rule, refers to a local extraction of stored geothermal heat. In most cases, the amount of heat removed is much greater than the heat rising from the depth within a reasonable time frame.

An exploited geothermal deposit will regenerate due to the heat flow from the depth, but this process can take more or less time. Depending on the geological situation, a deep reservoir can take centuries to regenerate. In comparison to the other renewable energies this is a long period, in relation to the formation time of fossil energy resources a short period of time, however. The geothermal energy thus numbers amongst the regenerative energy sources, but on the other hand it is also a ‘mineable' resource (BGR, 1999).

For use near the surface down to approximately 20 m depth the heat from the earth's interior is available in addition to the amount of heat provided by solar irradiation. The radiation of the sun exceeds the heat flow from the earth's interior many times over. The near-surface thermal energy is still part of the geothermal energy, because the energy is stored underground and taken from there. The earth's surface acts like a solar-thermal plant, absorbing part of the insolation and conducting the heat downwards. The yearly fluctuation of the temperature penetrates only a few tens of meters into the substratum, climate variations penetrate far deeper, however. For near-surface usage, the cooled area of the underground is comparatively quickly re-heated by insolation.

The most important process of the heat transmission in the earth crust is the conduction of heat. The resulting vertical temperature gradient, the so-called geothermal gradient, amounts to 30 °C/km in the continental mean. Based on the surface temperature, which corresponds to the local mean annual temperature, in Germany approximately 7 to 11 °C, at a depth of about 2000 m thus temperatures of app. 70 °C occur. In a depth of 5000 m these exceed 160 °C as a rule. In areas with rising ground water heat is also transported to the surface by convection. In such areas, as for instance near Landau in the Oberrhein Graben, temperatures of more than 100 °C are measured in depths of 1000 m.

The energy content of a geothermal deposit is determined by the temperature as well as by the heat capacity. For rocks this is in the range from 700 to 1200 J/(K·kg). A rock volume of 1 km^3 and a mass of $2.65 \cdot 10^{12}$ kg at a heat capacity of 850 J/(K·kg) contains a thermal energy of 2.3 PJ/°C. If this volume is cooled down by 10 °C, an energy of 23 PJ and $6.4 \cdot 10^6$ MWh, respectively, is drawn from it. This energy is sufficient to provide an average thermal power of 25 MW over a period of 30 years. The enthalpy of the rock is added to the enthalpy of the fluids in form of water or vapor, which is stored in the pores and fissures of the rock. Its mass-specific energy content, in particular that of vapor, is greater than that of the rock, but its mass fraction in the dense crustal rock is very low, thus rock heat prevails by far.

Crustal rock in general is a poor heat conductor with a heat conductivity between 2 and 4 W/(m·K). As a consequence, the heat of the deeper basement cannot be mined directly via drill holes. For an effective utilisation a carrier medium such as water or vapor is required, which flows through the rock and transports the heat to the drill holes. This in turn implies a sufficient permeability of the rock, which is usually only attained by highly porous sandstone and intensely fissured or karstified rock formations. The low permeability of the rock is thus one of the greatest obstacles for a wide exploitation of geothermal energy. In research projects the improvement of the exploitability by creating artificial flow paths through hydraulically generated fractures in the rock is currently being worked on.

In the following, the use of thermal heat energy is subdivided into direct use for heating purposes as primary geothermal energy and secondary use, i.e. geothermal energy is converted into electrical energy. When the geothermal energy is converted into electric power, the efficiency of the geothermal power generation has to be taken into account. This depends on the temperature and on the conversion technology used. The gross efficiency, which does not include the station supply needed for operating the plant, for instance the pumps, amounts to 9 to 14 % for current systems.

Installations for the direct use of geothermal heat are differentiated according to their temperature levels. The high temperature range can be used to supply district heating systems, industrial companies and companies of the food industry, the low temperature range to supply agricultural companies, for instance for greenhouses or drying plants, as well as pools and fish farms. Another use of geothermal energy in particular for industrial companies is cooling, using absorption refrigeration.

The greatest contingent by far of the globally installed non-electrical power is engaged by heat pump systems (Fig. 7.1). The power of the installed heat pumps has tripled globally since 2000. Pools, direct room heating without heat pumps and greenhouse heaters follow in the incidence of utilisation. The rest taken together amounts to less than 10 % and comprises also very specialized local usage processes (Fig. 7.1).

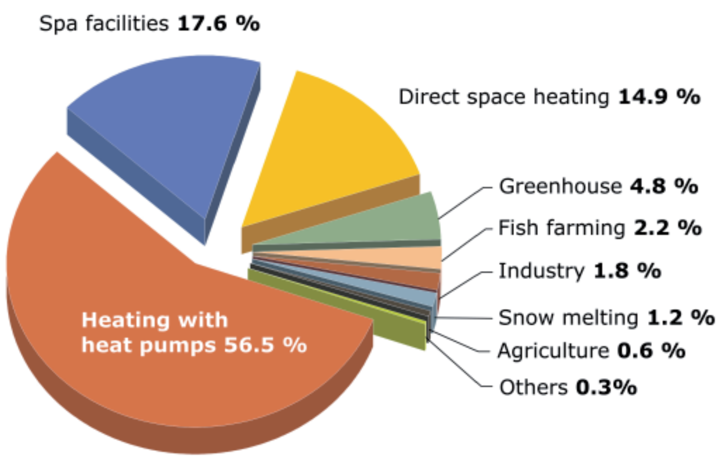

Figure 7.1: Distribution of the globally installed non-electric geothermal energy of 27 825 MWth in total to the different types of use in 2005 (Lund et al., 2005).

7.2 Sources of Geothermal Energy

7.2.1 Near-surface Substratum

The near surface basement is an economic heat source in view of the accessibility and the low development risk. In near-surface layers of the earth the temperatures change with the rhythm of the air temperatures, the temperature fluctuations decrease quickly with increasing depth and are barely detectable (<0.1 K) beneath 15 to 20 m of depth. As the energy flux introduced by insolation in these top meters of the soil is approximately 2000 times greater than the heat flow from the interior of the earth, the thermal use of the shallow substratum is mainly provided by solar energy.

Due to the low temperature, the energy stored in the shallow substratum cannot be used for direct heating. A heating system which uses the heat of the shallow underground mainly consists of the components soil heat exchanger, circulating pump, heat pump, storage tank and low temperature heating system. Soil heat exchangers are usually inserted as vertical geothermal probes in depths of mostly down to about 100 m, in individual cases up to 400 m, executed as horizontal heat exchanger loops or as spiral type heat exchangers. In summer these installations can directly cool buildings by circulating the brine, bypassing the heat pump. In addition, ground water extraction can produce heat from the ground. Typically not only a producing well, but also a re-injection drilling is required, in which the ground water cooled in a heat exchanger is re-injected into the ground.

A great advantage of the named technologies is that, with exception of the groundwater-coupled heat pump, it can in principle be employed anywhere. The savings in primary energy, which can be attained with such, in general electrically powered heat pump systems, are rather small, however. At the low temperature of the shallow substratum, heat pumps generally reach performance coefficients (COPs) between 3.5 and 4. This means that with every unit of electrical power, which is provided for the heat pumps, 3.5 to 4 units of thermal power are reached. For generating the power used for the pumps, efficiencies between 30 and 50 % are reached. If the consumed primary energy is included, this results in COPs between 1 and 2 in total (BGR 1999).

7.2.2 Hydrothermal Occurrences of Low Temperatures

Hydrothermal resources of low temperatures are warm and hot water aquifers with temperatures between 30 and 150 °C. Their occurrence is not connected to geothermal anomalies. They are frequently regionally widespread and can also be used in areas with normal temperature gradients. The permeability of the rock and the hydraulic conductivity (transmissibility) of the aquifer are essential. The lower the temperatures and the deeper the required drill hole, the higher the permeability of the rock and the hydraulic conductivity have to be. In general, production flow rates between 30 m^3/h and 300 m^3/h at temperatures above 60 °C are required for an economic operation of such large district heatings. To warrant these production flow rates with acceptable energy input for the production and injection pumps, a transmissibility of the aquifer between 10 and 100 Dm (Darcymeter) is needed. These values can only be attained in deep, very porous sandstone formations and in extremely fractured or karstified rock areas, such as zones of joints or fault zones. The high hydrostatic pressure in these depths prevents the water from boiling; therefore, even at temperatures far higher than 100 °C there is no vapor in the formation. When assessing the energy contents of such deposits, it has to be taken into account that only part of the total extractible amount of heat is stored in the water, whereas the greater part is in the rock surrounding the fluid.

Usually warm and hot water systems are accessed via well pairs, so-called doublets. In the production well the hot water is extracted, whereas the cooled water is subsequently returned to the ground through the reinjection well. The energy for production and transmission through the parts of the plant that are above ground is supplied by a submersible pump, which is installed in depths from 200 to 600 m, depending on the conditions. Systems with only one well are rare. Here the processed and cooled water is reinjected through the same well using well-isolated pipes or it is treated and discharged into a drinking water system or a discharge system.

In individual cases, electricity is also generated from low temperature resources using Organic Rankine Cycle (ORC)-plants. To this end, the steam turbines are operated using an organic substance with a boiling point lower than that of water. The efficiency is only approximately 10 % (BGR 1999), however. The so-called Kalina-process constitutes an alternative to the ORC-process. Here two-component substances, for example ammonia and water, are used as working media. It provides a higher efficiency and lower power generation costs, in particular for lower temperatures, but technically it is not as advanced as the ORC-process.

7.2.3 Hydrothermal Occurrences of High Temperatures

Hydrothermal resources of high temperatures are hot water or steam occurrences with temperatures of more than 150 °C. They are located mainly in geologically recent tensile zones of the upper earth crust, such as oceanic rift systems, graben systems and at the edges of lithospheric slabs, frequently in connection with volcanoes.

In vapor-dominated deposits, the reservoir pressure is lower than the steam pressure, according to the reservoir temperature. For this reason, there is mainly water vapor in the deposit, whose discharge is prevented or hampered by an impermeable cap rock. Vapor dominated deposits are the highest quality and most easily useable geothermal deposits. The temperatures of the known and frequently already used vapor reservoirs mainly range between 200 and 300 °C. The liquid dominated deposits reach similarly high temperatures. A higher hydrostatic pressure prevents boiling, thus in these deposits the liquid state predominates.

The geothermal energy of the vapor reservoirs is nearly exclusively used for power generation via steam turbines. After the thermal energy of the vapor has been used, the remaining water typically with a temperature of 70 to 80 °C is reinjected into the ground. If this is not done, a pressure drop in the deposit may occur, which can cause the power plant to shut down in the worst case. If the vapor temperatures are below 200 °C, ORC-plants (Chapter 7.2.2) can be used, just as for low temperature reservoirs.

7.2.4 Hot-Dry-Rock Occurrences

Rocks with very low hydraulic permeability and porosity as well as comparatively high temperatures are assigned to the category of the hot dry rocks. For an effective use of these rocks special exploitation methods have to be used, the Hot-Dry-Rock (HDR) technology becomes necessary. For this technology artificially produced fractures between at least two deep boreholes are used to create large-scale heat exchangers. The water is circulating between the wells, thus cooling down the surrounding rocks and attaining heat from the environment of the connecting fractures. The fracture areas between the injection and the extraction wells constitute the underground heat exchanger. The problem of realization consists in generating an adequate fracture area of permeable hydraulic connections between the drilled wells, which permits circulation by production and reinjection of large amounts of hot water.

The HDR-technology was significantly advanced in a European Community initiative in Soultz-sous-Forêts in France after first attempts in the US near Los Alamos. Further projects for testing the technology have been started lately. The experience gained during HDR-projects showed that the assumption the term Hot-Dry-Rock was based on, i.e. of finding dry rock formations in deep depths, is not correct. In the HDR-Project Soultz, natural fault zones contribute significantly to water circulation between the boreholes. For this reason there are additional names for the heat exploitation of nearly impermeable rock formations, such as for instance Hot-Wet-Rock (HWR), Hot-Fractured-Rock (HFR) or Enhanced-Geothermal-Systems (EGS).

7.3 Geothermal Resources

7.3.1 Quantitative Analysis of Geothermal Resources

The definition of the term geothermal resource provided in Section 2.5 does leave the question, for which geological conditions and for which technology the individual value of useable heat has been specified, unanswered. The amount of energy to be specified depends on the depth, in particular on the maximum depth, on the minimum temperature necessary for the individual technical conversion and on the residual temperature after the amount of used heat has been subtracted. In view of these peculiarities of geothermal energy the following parameters can be used for the quantitative analysis of hydrothermal and HDR-resources:

(1) The total amount of heat stored in the underground of an area from the surface down to a certain depth (Haenel & Staroste, 1988; Kaltschmitt & Wiese, 1997).

(2) The ratio of the amount of heat specified in (1), which is stored in potentially water bearing rock formations (Haenel & Staroste, 1988; Kayser, 1999).

(3) The ratio of the amount of heat specified in (2), which is maximum extractible, if no minimum energy per well pair has been specified. The maximum extractible amount of energy is then determined by the assumed exploition technology and the residual temperature of the water after heat extraction. From this the so-called extraction

factor results, which in typical cases amounts to approximately 0.12 to 0.33 for hydrothermal resources. The definition of resources is based on the assumption of a maximum areal density of dublets and does not take any restrictions of the land use into account (Haenel & Staroste, 1988; Kaltschmitt & Wiese, 1997; Kayser, 1999; Jung et al., 2002).

(4) The ratio of amount of heat specified in (3), which is realistically extractible after specification of a minimum energy per well pair and a maximum duration of the energy generation at the site. The fraction mainly results from the relative size of the partial areas, where with high probability sufficiently large hydraulic permeabilities are encountered or can be produced, which are sufficient for reaching the specified minimum power. In addition the present restrictions of the land use (usage for other purposes, possibly vicinity to consumers) are taken into account.

An energy amount assessment according to definition (1) gives little information on the amounts of energy exploitable under realistic conditions for hydrothermal resources. A realistic assessment of resources according to definition (4) can be lower by several orders of magnitude than the amount of heat assessed according to definition (1). A rough assessment of existing amounts of energy according to definition (1) can be conducted without detailed knowledge of geology. Even the restriction to water bearing formations (2) requires extensive knowledge on the geological composition of the substratum, in particular on the lithological composition, the extent, the depth and the temperatures of the relevant layers. The subsequent calculation of a maximum exploitable amount of energy using the extraction factor (3) requires no major additional geological data.

The assessment, in which partial areas and with which probabilities sufficiently high permeabilities are to be expected in the substratum, may cause great difficulty. This applies in particular to layers with spatially very variable hydraulic characteristics, such as Karst rock. Statistically representative statements can only be made based on hydraulic investigations at numerous wells, which are usually only available in sufficient numbers in very few areas. For this reason there are only very few resource data according to definition (4). At a required minimum power, which would permit economic generation of energy under today's conditions, this definition would provide geothermal reserves.

The elaborations above refer to the evaluation of hydrothermal resources. For the evaluation of resources based on HDR technology using technical means, the consideration of the natural rock permeabilities are not relevant, as this method is based on the artificial generation of permeable structures using technical means. For this case, analyses are based on the heat capacity of a total rock volume and a maximum exploitable amount of energy (3) is calculated via a mean extraction factor between 0.02 and 0.07. Such resource data are based on the prerequisite that a successful, large-scale application of HDR-engineering is possible with full coverage. As this method is still in the research and development stage and up to now only few experiences exist, corresponding data are associated with great uncertainties.

For the near-surface heat energy, which is rebuilt in the seasonal cycle due to insolation, it does not make sense to quantify resources in the sense mentioned above. Instead, data on the annually sustainable exploitable amounts of energy are given for the near-surface area. Two different sizes are used:

(5) The amount of heat, which can be gained from the near surface substratum in an area without causing a long-term cool-down. In this case the whole earth's subsurface can be used by ground heat collector (Kaltschmitt & Wiese, 1997).

(6) The reasonable ratio of the amount of exploitable heat specified in (5), which is regarded in consideration of the restrictions of the land use (building density, usage for other purposes, soil/ground structure, groundwater protection areas) and the proximity to the consumer (Kaltschmitt & Wiese, 1997).

7.3.2 Global Usage of the Geothermal Energy

The ratio of the geothermal energy of the global energy supply was low in 2004 at 0.414 %, but still higher than the proportion of solar and wind energy (Fig. 7.2). Whereas in 1975 only ten countries produced electricity geothermally, in 2005 24 countries were doing so, with a total annual power of nearly 57 000 GWh/a. This corresponds to approximately 0.4 % of the annual global power consumption (Bertani, 2008). Since 2000, in 19 countries altogether 290 wells have been drilled for geothermal power generation with an average depth of 1.9 km. In the same period, the installed power plant capacity in Costa Rica, France, Iceland, Indonesia, Italy, Kenya, Mexico, Nicaragua and Russia increased by more than 10 %. Until 2010, in all likelihood countries like Armenia, Canada, Chile, Djibouti, Dominica, Greece, Honduras, Hungary, India, Iran, Korea, Nevis, Rwanda, Salomon-Islands, Slovakia, St. Lucia, Switzerland, Taiwan, Tanzania, Uganda, Vietnam and Yemen, will start operations for geothermal power generation (Gawell & Greenberg, 2007).

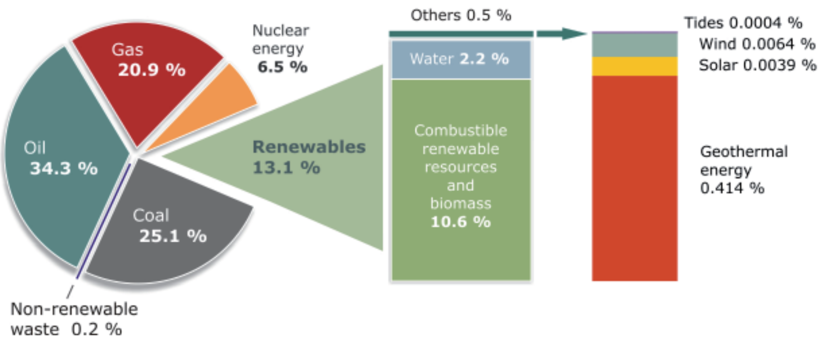

Figure 7.2: Ratio of the geothermal energy in the global power supply 2004 (IEA, 2007).

At an installed power of 2504 MWe for electricity generation and 7817 MWth for the direct use of heat, the US stand out from the other countries as the largest user of geothermal energy world-wide (Fig. 7.3, Tab. A 7-2 & A 7-3). Sweden takes rank 2, because of the significant increase in the direct use of geothermal energy, before China. The geothermal electricity generation in Germany is comparatively low (240 kW_e in 2005), altogether Germany takes rank 15 in the use of geothermal energy (Fig. 7.3).

Globally, the electricity generation from geothermal energy has been increasing significantly every year since the middle of the 1990s (Fig. 7.4). The very much higher increases for the direct use of geothermal energy in many countries are mainly due to the growth of local heating systems using heat pumps. This growth is expected to keep on in future decades (Nitsch, 2001) however the base is rather inaccurate there. In the past years, heating systems using heat pumps were not included in the statistic of individual countries, the use of thermal water in pools was also documented differently in different countries (Lund & Freeston, 2001; Lund et al., 2005).

In individual countries, the low temperature usage is increasingly and to different degrees included in the energy balance. Thus, the real growth is probably somewhat lower than shown here (Fig. 7.4). In 1985, geothermal energy was used directly in 24 countries, in 1995 28 countries, in 2000 48 countries and in 2005 already 59 countries.

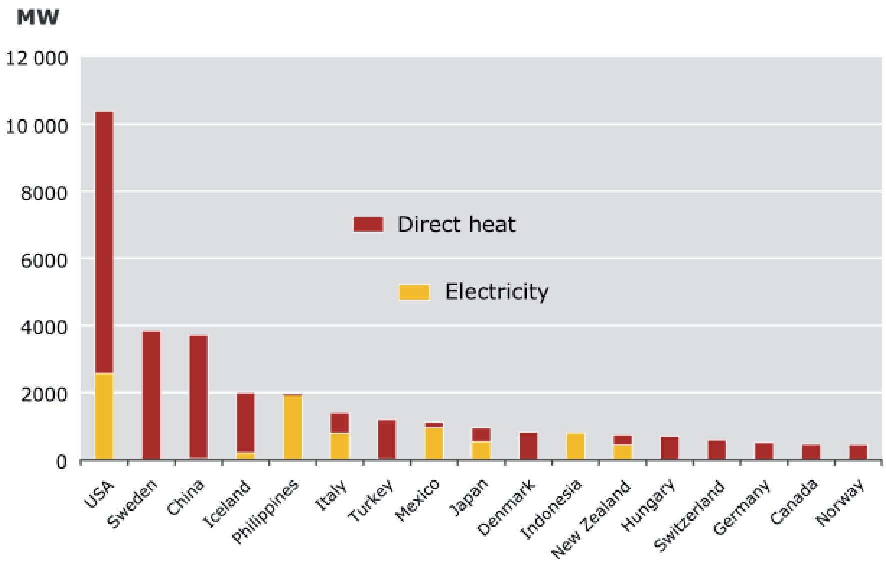

Figure 7.3: Installed power for electricity generation from geothermal energy [MWe] and for direct use of geothermal energy [MWth] for the 17 largest user countries 2005 (Lund et al., 2005; Bertani, 2005).

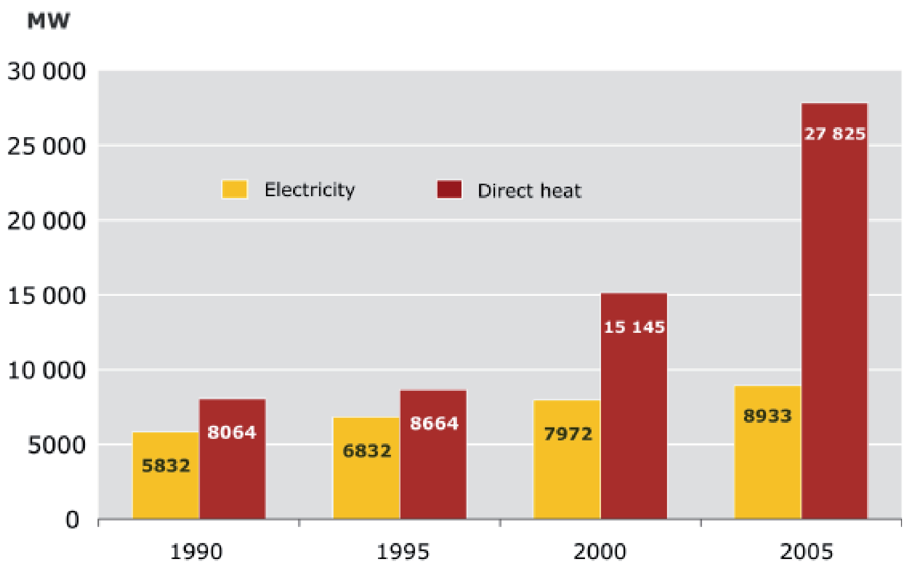

Figure 7.4: Global development of the direct use of geothermal heat and the installed power for geothermal electricity generation between 1990 and 2005.

7.3.3 Regional Distribution of Used Occurrences

Due to the inconsistent compilation of the resources and only incomplete data no globally uniform presentation of the geothermal resources and the current usage of geothermal energy is possible. The known projects and resources will be reported according to region below.

Europe

The geothermal resources are used very differently in the countries of Europe. High-enthalpy deposits exist in Europe in particular in countries with active volcanism, such as Iceland and Italy, but also in Greece and Turkey. In the past years, the geothermal electricity generation as well as the direct use of geothermal energy has been continuously developed. Besides Italy, Island and Turkey geothermal power is now also produced in Germany (Chapter 8.6) and Austria. In addition, power generation in the European HDR-research location Soultz-sous-Forêts in France started in June 2008. Mainly because of steeply rising heating costs of the private households but also because of state subsidies, the use of geothermal heat pumps in local heating systems has risen steeply between 2000 and 2007. Sweden (270 000 units) had taken up the pole position, followed by Germany (90 000), Austria (40 000) and Switzerland (30 000 units) (Forseo, 2008). Today Sweden is the largest user of direct geothermal energy in Europe (Fig. 7.5). Sweden replaced Iceland at the top position only in 2002, in Iceland 87 % of the houses are heated using geothermal energy (BGR, 2003). In Europe, 28 countries benefit from geothermal energy as primary energy with a total installed output of 13 344 MW_{th}.

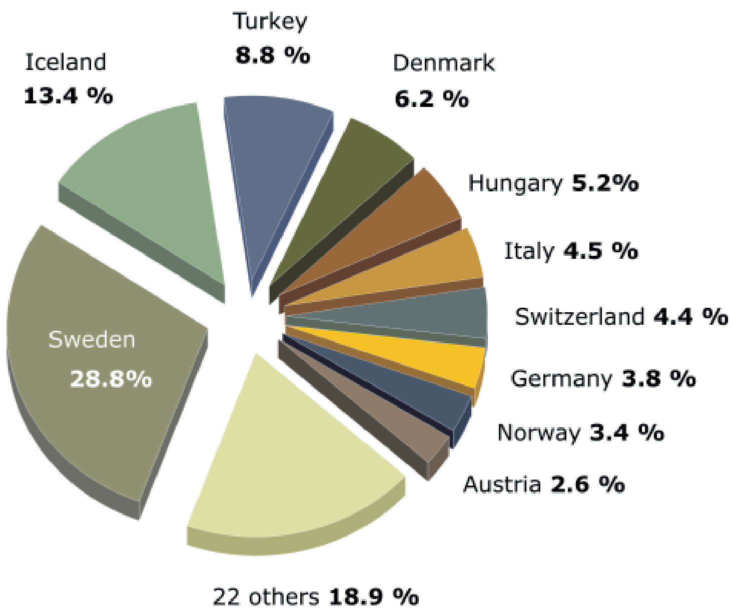

Figure 7.5: Distribution of the directly used geothermal heat installed in Europe, including near-surface geothermal heat (in total 13 344 MWth) according to countries (Lund et al., 2005).

Whereas in the Paris Basin large amounts of thermal water of low temperatures of 60 up to 80 °C can be used directly for heating purposes, in the other large user countries, such as Sweden, Germany, Austria or Switzerland mainly individual systems using heat pumps are employed, to draw heat even from lower temperature water.

For the non-electric usage of energy Hungary plays an important part, producing 694.2 MW_{th}. The Pannonian Basin is just like the Paris Basin a large recent depression area, from which large amounts of water can be extracted. A large part of the installed thermal output is used in agriculture for greenhouses and drying plants.

Italy with 791 MW_e is far in the lead of the European countries generating electricity from geothermal energy, followed by Iceland, Turkey, France (Guadeloupe), Italy, Portugal (Azores), Austria and Germany (Fig. 7.6). For electricity generation, Iceland at 202 MW_e took rank 2 behind Italy in 2005. In the meantime, three more power plants have taken up operation, thus the installed power is 569 MW_e by now. Iceland uses 1791 MW_{th} of geothermal primary energy and is thus after Sweden the second largest user in Europe.

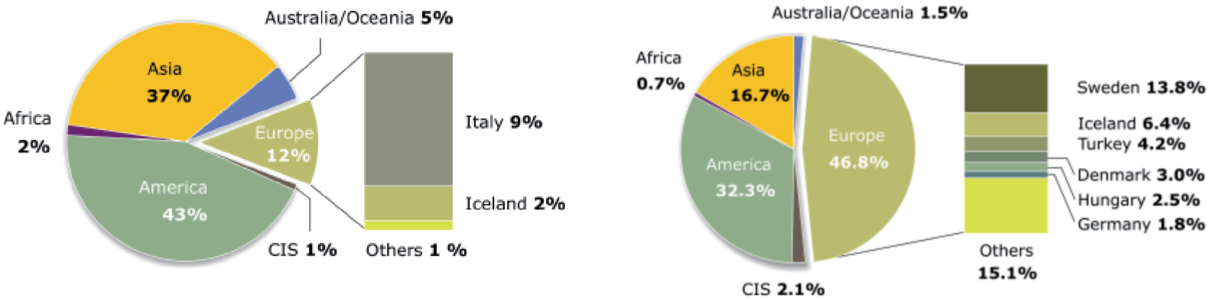

Figure 7.6: Regional distribution of the globally installed geothermal power for electricity generation (left side) and for direct use of geothermal energy (right) and individual percentages of single European countries in 2005 (Bertani, 2005; Lund et al., 2005).

In Turkey in the past years considerable efforts have been undertaken to use the existing geothermal energy deposits. For heating purposes, for pools and agriculture plants with a power of 1,177 MW_{th} in total were installed there in 2005. Electricity generation has remained unchanged at 20 MW_e for a long time; extensive increases are being planned, however.

Commonwealth of Independent States (CIS).

In all, the proportion of the CIS countries in the global use of geothermal energy in 2005 as power generation amounted to approximately 0.9 % and for direct use to about 2.1 % (Fig. 7.7). Russia used geothermal energy for electricity generation - 79 MW_e installed (Bertani, 2005) - as well as for heating purposes, for heating pools and as process heat (327 MW_{th}) in all in 2005 (Lund et al., 2005).

According to recent estimates, in Kamtchatka alone geothermal power plants with a capacity of about 1 GW_e can be installed. In Georgia thermal water is used for heating purposes, for greenhouses and for operating pools. The installed power of 250 MW_{th} has remained unchanged for a lengthy period of time.

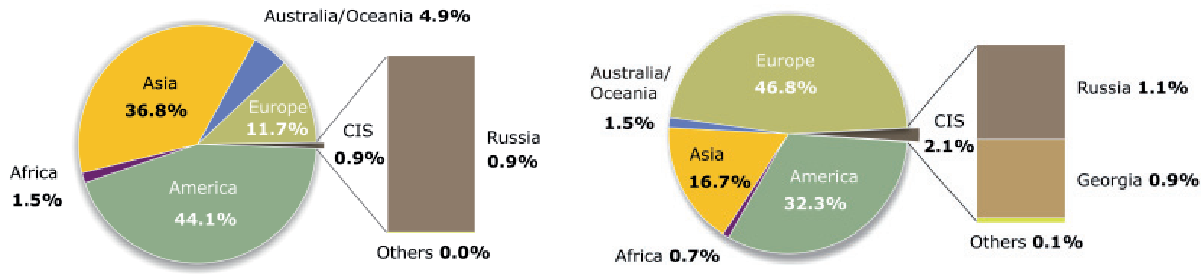

Figure 7.7: Regional distribution of the globally installed geothermal power for electricity generation (left side) and for direct use (right) and individual percentages of the CIS states in 2005 (Bertani, 2005; Lund et al., 2005).

Africa

In some African countries geothermal deposits have been explored increasingly in the past years with power generation in mind. They are mainly located in tectonically active areas of the east African Graben and have an immense potential of about 7000 MW_e (Gawel & Greenberg, 2007). These resources are still being used to a minor degree only, in spite of the increased efforts. The proportion of Africa in the global use of geothermal energy as primary energy source is comparatively low at 0.7 %. For electricity generation this percentage is approximately 1.4 % (Fig. 7.8).

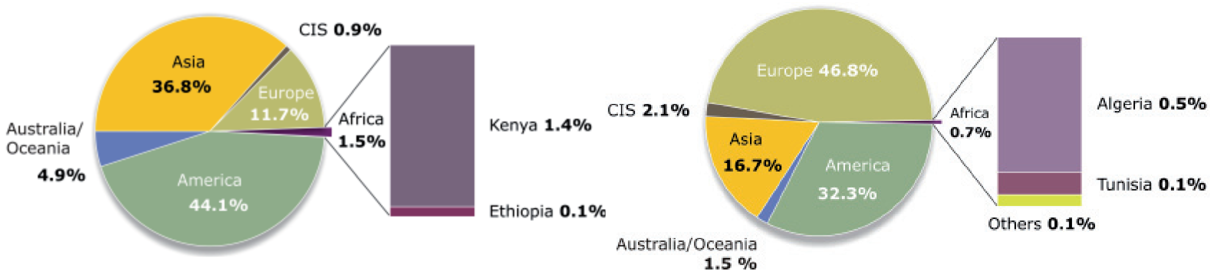

Figure 7.8: Regional distribution of the globally installed geothermal power for electricity generation (left side) and for direct use (right) and individual percentages of the African countries in 2005 (Bertani, 2005; Lund et al., 2005).

In Africa, Kenya is dominating the use of geothermal energy (Fig. 7.8). In contrast to other east African countries, Kenya has been continuously expanding the usage of geothermal resources for years due to specific government programs. Whereas in the last study on energy resources (BGR, 2003) for Kenya 45 MW_e were listed, by now already 129 MW_e of power have been installed. Further locations such as Eburru, Olkaria IV and Menengai have been extensively explored. The three currently existing geothermal power plants in Olkaria (Fig. 7.9) provide 11 % of the electricity supply of the country. Close to the Olkaria power plant geothermal heat with an energy of about 10 MW_{th} is directly used in greenhouses for growing flowers and there is a smaller binary-cycle power plant of 1.8 MW_e for supplying power to the large flower farms.

In Ethiopia there is a small plant of 8.5 MW_e, which only operated for a short period of time, however. It is currently being repaired with American aid. Feasibility studies have been conducted for further potential locations as part of GEOTHERM in Kenya (Menengai) and Uganda (Buranga). Currently such studies are also being conducted for Ethiopia, Eritrea, Djibouti, Rwanda and Tanzania (Info box GEOTHERM).

The direct use of thermal water has been reported apart from Kenya from different countries in Northern Africa: Egypt: 1 MW_{th}, Algeria: 152.3 MW_{th} and Tunisia: 25.4 MW_{th}. Thermal water is being used in particular for greenhouses, for the pool operations and therapeutic applications.

Figure 7.9: The geothermal power plant Olkaria I in Kenya started generating power from geothermal energy in 1981. Currently 45 MWe have been installed; the average availability is more than 98%.

America

In North America, as well as in Central and South America there are very large geothermal resources. The American users head the field at 44 % of the globally installed power for geothermal power generation, whereas they take second rank behind Europe in the direct use (Fig. 7.10). The US keep on being the largest consumer of geothermal energy in the world with an installed power for electricity generation of 2564 MW_e (Lund et al., 2005). Power generation from high temperature deposits has the largest percentages, which are mainly located in the western states, in particular in the geothermal field *The Geysers* in California. The installed power since 1989 was increased by only 110 MW_e. In 2005, Congress passed a tax incentive system for the use of geothermal energy (*Production Tax Credit*) due to which 61 new geothermal energy projects were started. This way in the next years an increase in output of 2,100 to 2,400 MW_e is expected (GEA, 2006). The direct use in the US comprises all known applications. Between 1994 and 2000 it has doubled from 1,874 to 3,766 MW_{th} (Lund & Freeston, 2001). A similar increase to 7,817.4 MW_{th} occurred until 2005 (Lund et al., 2005). The local near-surface use of geothermal energy using heat pumps has the highest growth rates.

Mexico possesses large high temperature deposits dominated by liquids, which have been used for many years for power generation purposes. The geothermal field Cerro Prieto, in which brine of a mean temperature of 316 °C is being extracted from nearly 200 drill i10

GEOTHERM – Technical Cooperation in Geothermal Energy

Since 2003 the BGR has been conducting the program GEOTHERM as part of the Technical Cooperation. To this end, projects for the use of geothermal energy in developing countries are supported by different actions in concrete regional development. GEOTHERM projects are mainly concentrated in the countries of eastern Africa. In this region, in parts there is a severe shortage of electrical power. Simultaneously there are significant high enthalpy geothermal resources. Thus, in particular projects for geothermal power generation are conducted.

Main tasks of GEOTHERM are geoscientific evaluation of resources, advisory services in technical implementation, geoscientific site investigations (pre-feasibility study) and training as well as educational measures. Environmental Impact Assessments, profitability analyses and financial advising can be conducted by suitable partners as part of GEOTHERM. The chance for a successful site development is decisive for the selection of a suggested project.

After the geothermal sites have been explored and evaluated in the first project phase, in the next stage the development of the site is to be continued based on Feasibility Studies with exploration wells and testing. Difficult are not so much the high costs of drilling, but rather the considerable prospecting and development risk. For positive results of the exploration wells and tests the BGR assumes that investors for production wells and the construction of power plants can be found, who will take over the further development of the site.

Production at an exploration well in the geothermal field Tendaho, Ethiopia

holes, has the highest installed power plant rating next to the Californian geothermal field *The Geysers*. Besides, currently in Los Azufres, Los Humeros and Las Tres Virgenes three more geothermal fields are being exploited. In 2005 the installed power amounted to 953 MW_e (Bertani 2005). In the next years a further expansion of the geothermal resources has been planned in the geothermal fields Acoculco, Domo San Pedro und La Soledad.

The data for the direct use of geothermal energy have remained virtually unchanged since 1999 with an installed power of 164 MW_{th} (Lund et al., 2005).

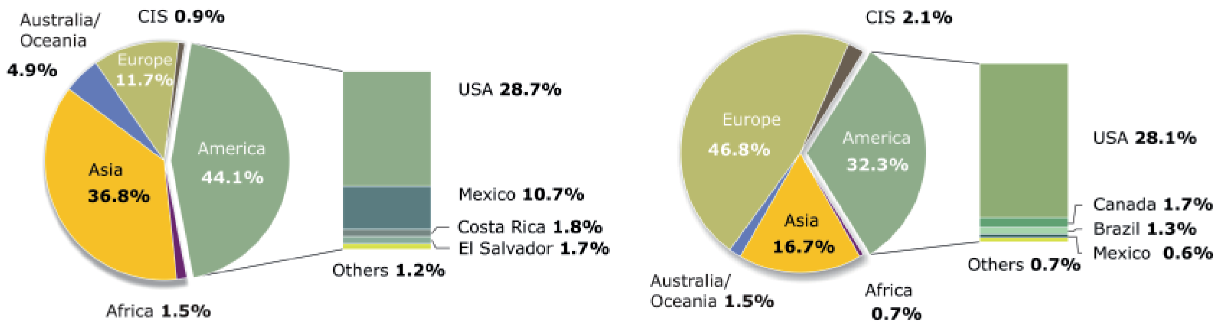

Figure 7.10: Regional distribution of the globally installed geothermal power for electricity generation (left side) and for direct use (right) and individual percentages of the American countries in 2005 (Bertani, 2005; Lund et al., 2005).

Canada is the third largest consumer of geothermal energy in America, even though it does not have high temperature deposits. This use is limited to the direct use for the approximately 36,000 local heating systems using heat pumps with an installed power of 435 MW_{th} which are being operated in Canada (Lund et al., 2005). In addition, thermal water is used for pools and water from shutdown mines is used for heating purposes. In total, the installed power for the direct use of geothermal energy in Canada amounts to 461 MW_{th}.

In Central America, in several countries high and low temperature deposits are being used either for power generation or for pools, drying plants or similar. Many countries in Central America, such as El Salvador, Guatemala and Honduras, are planning the construction of geothermal power plants. On a number of Eastern Caribbean islands, such as Nevis, St. Lucia or Dominica, exploration projects for finding geothermal energy have been started (Gawell & Greenberg, 2007). The largest electricity producers from geothermal energy are currently El Salvador (151 MW_e) and Costa Rica (163 MW_e). There are also geothermally operated generators in Nicaragua (77 MW_e), Guatemala (33.4 MW_e) and Guadeloupe (15 MW_e). Low temperature deposits are currently used for bathing in Honduras and on the Caribbean Islands. In Nicaragua and Guatemala drying plants and fish farms are supplied with geothermal heat.

In South America there are high temperature resources along the volcanic belt of the Andes in Venezuela, Columbia, Ecuador, Peru, Bolivia, Chile and Argentine. Due to the low energy demand in these frequently sparsely inhabited regions these resources have not been tapped up to now. Brazil is with 360.1 MW_{th} of installed power currently the largest user of direct heat, mainly for pools. Argentine is using 149.9 MW_{th} of geothermal heat as primary energy also for pools as well as for heating buildings and greenhouses, for melting snow and in fish farms. Columbia uses 14.4 MW_{th} in warm water in 41 public baths. In Chile, Ecuador, Peru and Venezuela public baths are heated by thermal water, which together supply only a few MW_{th} power.

Asia

Important hydrothermal high temperature occurrences, which have in part been used for several decades for electricity generation purposes, are located on the Japanese islands at the edge of the Eurasian plate. Another of the largest geothermal zones in the world is the geothermal belt of the Himalaya with huge hydrothermal high temperature occurrences in the countries India, China and Thailand. Great hot water occurrences and deposits with low temperatures exist in the sedimentary basin in Eastern China. Not long ago China was the largest direct user of geothermal heat in the world, but has been replaced by Sweden in this regard. For Asia China is up to today the most important direct user with an installed power 2005 of 3,687 MW_{th} (Fig. 7.11).

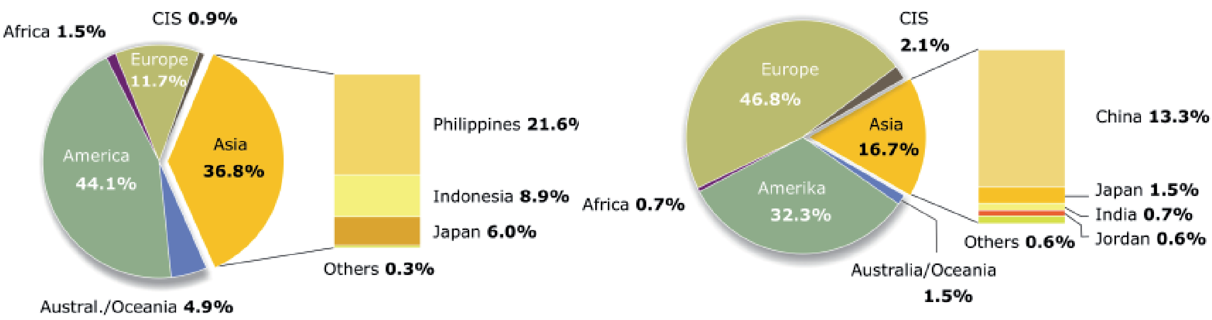

Figure 7.11: Regional distribution of the globally installed geothermal power for electricity generation (left side) and for direct use (right) and individual percentages of the Asian countries in 2005 (Bertani, 2005; Lund et al., 2005).

In comparison to 2000 this means an increase by slightly more than 1400 MW_{th}. The total consumption amounted to 45,373 TJ/a (Zheng et al., 2005). The heat is used for heating buildings and greenhouses, for pools, for industrial plants and fish farms. The electricity generation from geothermal energy in China with an installed power of 29.2 MW_e has not changed since 2000. Up to now geothermal energy for power generation in China is used only in Tibet and in Taiwan. In all, geothermal electricity generation, which started at the end of the eighties, is still in its infancy there, in view of the resources existing in China. The Tibetan capital Lhasa receives about half of its electric power from a geothermal power plant of a power of 24 MW_e, however.

The Philippines take top rank in the generation of electric power from geothermal energy in Asia (Fig. 7.11). With an installed power of 1,930 MW_e they even took rank 2 behind the US in 2005. In 2007 the power was even expanded by another 200 MW_e. The Philippines are seeking to become the largest power producer from geothermal energy in the world during the next two decades. Moreover, the Philippine government is aiming at expanding the direct use of thermal water (Benito et al., 2005), the installed power amounted to 3.3 MW_{th} in 2005 (Lund et al., 2005).

Japan is the third largest user of geothermal energy in Asia. Electricity generation from geothermal energy has been conducted there since 1966. The currently installed power amounts to 535 MW_e in 19 power plants on 17 geothermal fields of the three main islands and has remained practically unchanged in comparison to 2000. In Japan the use of thermal springs in baths has an age-long tradition. In 1998 2,839 thermal springs with 5,525 public baths and 15,638 hotels and guesthouses were registered as users of thermal water. The thermal springs were not included in the last report of the World Geothermal Congress (2005), i.e.

the older and current numbers cannot be compared (Kawazoe & Shirakura, 2005). Besides the baths, thermal water is also used as an energy source in agriculture and fish farms.

Indonesia is, with an installed power of 797 MW_e, the second largest producer of electrical power from geothermal energy in Asia (Abb. 7.11). Even though Indonesia is considered by many authors to be the country with the greatest geothermal potential worldwide, the installed power has not perceptibly changed since 2002. There are, however, advanced construction plans and since 2003 there is a Geothermal Law. On Java near Bandung there is the geothermal power plant Wayang Windu, which is currently under construction. Block I with an installed power of 110 MW_e is supplemented by block II (110 MW_e), which will be completed soon. Another block is being planned. Just as in the Philippines, in Indonesia the primary energy use (2.3 MW_{th}) is only of minor importance.

Several countries in Asia Minor, where thermal water of low temperatures is being used, range far behind the countries named above. Among these number Jordan (153.3 MW_{th}), followed by Israel (63.3 MW_{th}) and Yemen (1 MW_{th}). The geothermal energy is mainly used for public baths and for therapeutic purposes, in Israel also in greenhouses and fish farms.

In India the geothermal use of thermal water has been expanded from 80 MW_{th} in 2000 to 203 MW_{th} in 2005 (Lund et al., 2005). Increases in the use of thermal water have also been reported from Nepal from 1.1 to 2.1 MW_{th} and from Korea.

Australia /Oceania

New Zealand is the most important user of geothermal energy in the region Australia /Oceania (Fig. 7.12). New Zealand has important high temperature deposits with temperatures of more than 300 °C, which have already been used for power generation purposes since 1960. After a stagnation in the early 1990s the annual power generation rates have continually increased since 1995. In 2005 the installed power was 435 MW_e. The stable growth of the use of geothermal power in New Zealand relies on private investments as well as on government aid. The country is well on its way of making use of the total existing power generation potential. The numbers dealing with the direct use of geothermal energy have changed little in the past ten years, however. In 2005 the installed power was 308.1 MW_{th} and in total 7,086 TJ/a were used. The proportion of local heating systems is still comparatively low at 22 MW_{th}. The largest consumer is the paper industry, followed by fish farms, building and greenhouse heating systems, drying plants and pools.

Australia does not possess volcanic high temperature deposits. There are, however, extensive warm and hot water aquifers, whose utilization renders Australia the second largest direct user of geothermal heat in the region Australia /Oceania (Fig. 7.12). In the small town of Birdsville power is generated in a small ORC-plant of 0.12 MW_e mainly for cooling purposes in the summer. This baseload power plant is fed from a well that is 1,200 m deep, from which water of 98 °C is produced. The statement of the Australian government of generating 2 % of the annual power consumption from renewable energy sources by 2010, has stimulated HDR-research. Currently five HDR-projects for geothermal power plants are being planned in the Cooper Basin, of which the first is supposed to start operation in 2010. Large granite intrusions in a depth of approximately 3.5 km constitute the heat source. The measured temperatures in a depth of 4000 m surpass 240 °C. In Australia the installed power for the direct use of thermal energy amounted to 109.5 MW_{th} at a consumption of 2,968 TJ in 2005.

The use of heat pumps for air conditioning and heating is widespread, whereas in pools only approximately 8 MW_{th} were installed and 226 TJ/a were consumed.

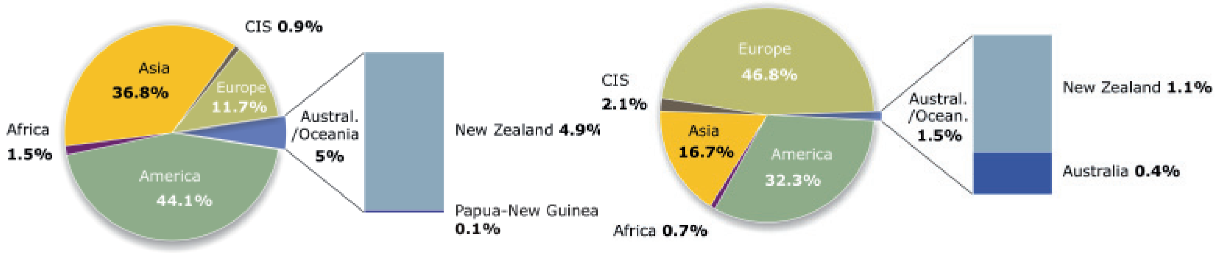

Figure 7.12: Regional distribution of the globally installed geothermal power for electricity generation (left side) and for direct use (right) and individual percentages of the countries of the region Australia/Oceania in 2005 (Bertani, 2005; Lund et al., 2005).

Papua-New Guinea has been using direct heat to a small extent of 0.1 MW_{th} as tourist attraction. Lately the power supply of a gold mine has been switched from diesel generators to geothermal power. To this end, water at 250 °C is extracted from mine drainage wells in a depth of 1000 m and used. Since 2007 the installed electrical output has therefore been 56 MW_e.

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8 Energy Resources in Germany

8.1 Petroleum in Germany

8.1.1 Petroleum Deposits and Production History

In the whole of Germany, only small volumes of crude oil are produced on an international scale, most of it in the Federal States of Schleswig-Holstein and Lower Saxony. However, the oil field Mittelplate (Fig. 8.1) is a large oil field even by international standards. Located in the North-Sea tidal flat area off the coast of Schleswig-Holstein, it is the largest of presently 44 productive oil fields in Germany. In 2007, it produced about 2.1 Mt of petroleum from Dogger sands at the margin of the Buesum salt dome. In total, this field contributed more than 60 % of the total German petroleum production of 3.4 Mt. A large portion of the remaining annual production originates from a petroleum province in the West of the Emsland district which geologically belongs to the Lower-Saxony Basin. The start of production there occurred a long time ago. For example, the large anticlinal oil reservoir Rühle has been producing since 1949 from the Bentheim sandstone of the Lower Cretaceous. Typical traps are anticlinal structures, but also stratigraphic traps and unconformity traps (Fig. 8.1). Approximately a quarter of the petroleum production in Germany originates from Lower Cretaceous sandstone reservoirs and about two thirds of the production comes from Dogger-sandstones. In Germany, light oils with a density between 0.8 and 0.93 g/cm^3 are being produced. The principal source rocks are of Lower Cretaceous and Lower Jurassic age. Other petroleum source rocks are known to occur in Permian and Tertiary strata.

Due to the increased oil prices, oil fields already abandoned or previously not developed due to a lack of economic viability have again moved into the focus of the petroleum industry in Germany. In general, however, significant investments are still required in order to be able to comprehensively evaluate the remaining reserves potential and, if economically viable, to develop and produce them.

The first reliable report regarding the discovery and extraction of petroleum in Germany dates back to the middle of the 15th century. Oil escaping to the surface of the earth was extracted at that time in Upper Bavaria by monks and used as medicine (Boigk, 1981). In Lower Saxony, which is one of the oldest petroleum regions in Europe, G. AGRICOLA described the use of petroleum which had accumulated due to natural escapes in tar pits as early as 1546.

The actual drilling for petroleum in Germany started much later, triggered by a rather accidental find (Hunäus borehole) in 1859 in the village of Wietze. In the following years, Wietze became the centre of the German oil industry and up to 90 000 tons of petroleum were produced there annually in the early 20th century. In the middle of the 1960s, oil production in Germany had already reached its maximum at around 8 Mt (Fig. 8.2). Until 1999 it then decreased continuously.

It was not until the start of production of the Mittelplate oil field at the end of 1987 that the so far declining overall production in Germany slowly started to level out.

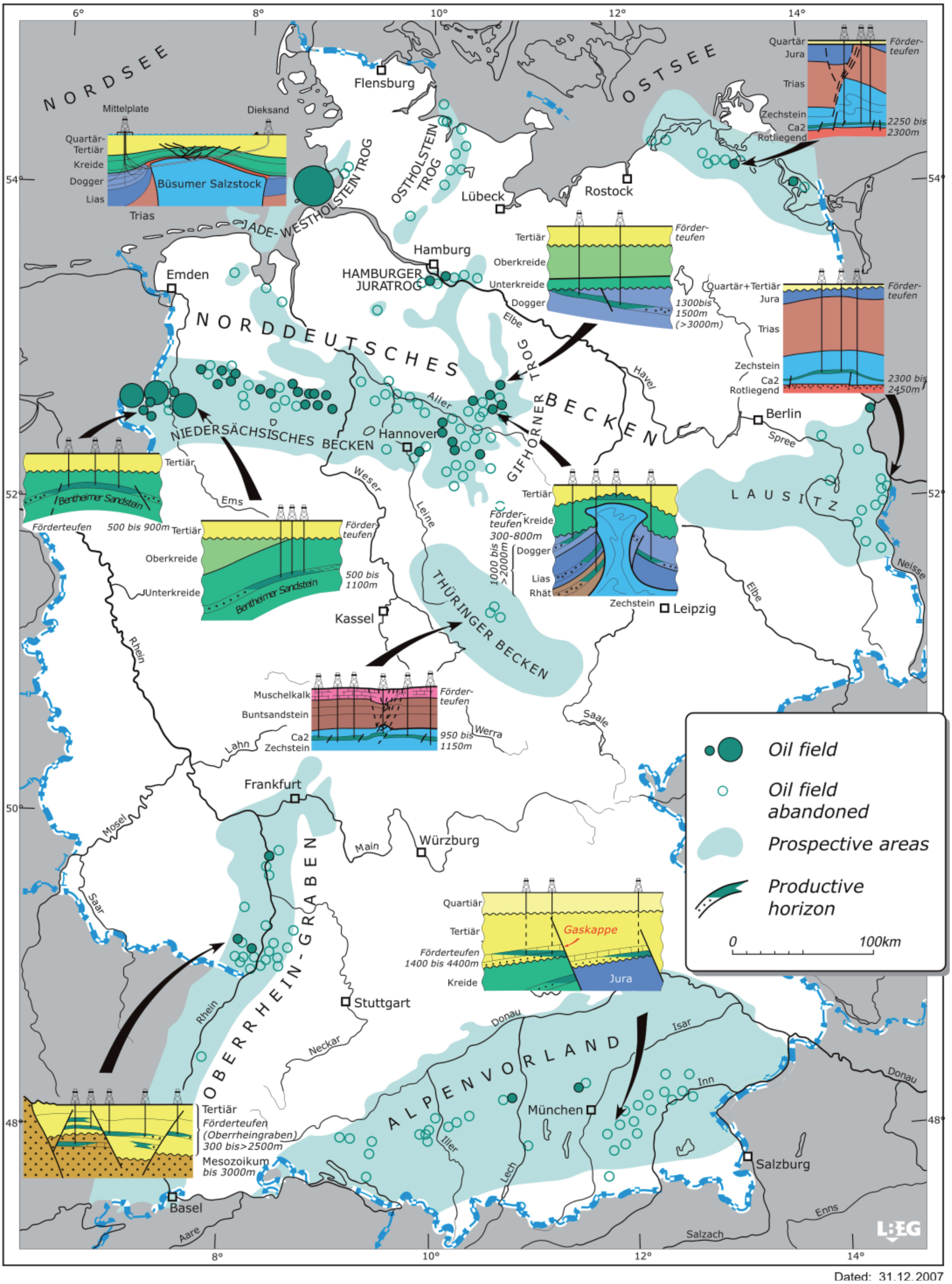


Figure 8.1: Prospective regions, oil fields and characteristic traps in Germany.

With the continued development of Mittelplate, the total production even increased, starting in the year 2000 (Fig. 8.2). The production of petroleum is also dependent on the economic framework conditions prevailing at a time. In this manner, the protective tariffs levied on imported petroleum until 1963 resulted in even marginally economic fields continuing to be produced. With the removal of these subsidies in 1963, some less productive fields were closed. The oil crisis in 1972 led to rising oil prices which in turn triggered increased exploration activities and the reactivation of marginal oil fields. The decline of oil prices in 1985/1986 on the other hand led to an economic consolidation of the field portfolio.

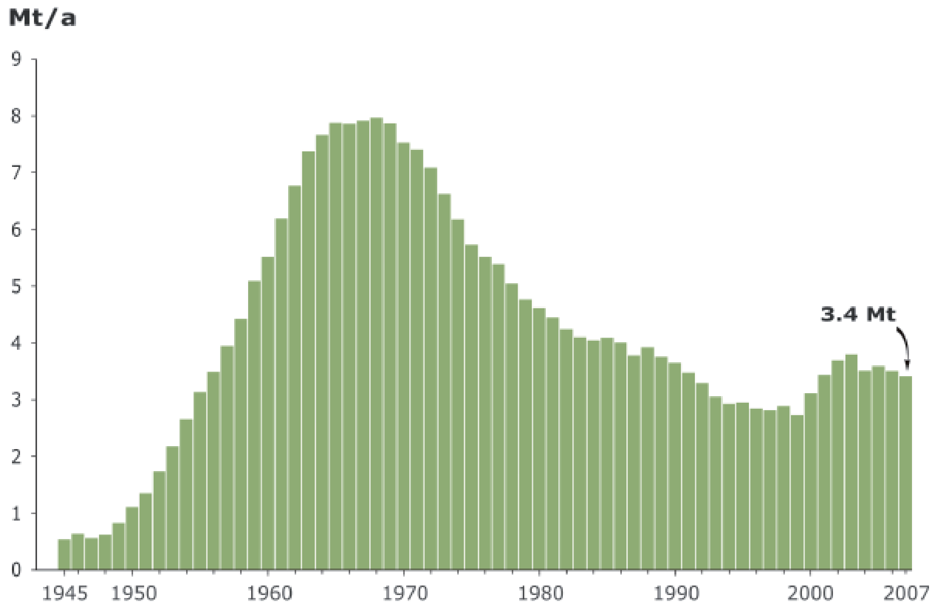


Figure 8.2: Oil production in Germany since 1945.

Up to the end of 2007, around 283 Mt of petroleum had been extracted in Germany. This corresponds to a recovery factor of 32 % of the estimated original total volume in all reservoirs.

8.1.2 Petroleum Production and Consumption in 2007

In 2007, 3.4 Mt of petroleum including nearly 2 % condensate were produced in Germany. Compared to 2006, the production has decreased by around 100 000 tons or 2.8 % but is still as high as in 2001 (Fig. 8.2). Based on operational production capacity, Hamburg based RWE Dea AG again produced the majority of German petroleum in 2007. The Mittelplate consortium, in equal shares consisting of RWE Dea AG (operator) and Wintershall AG, in 2007 delivered around 62 % of the total German oil production from the Mittelplate oil field. Further companies with oil production were ExxonMobil Production Deutschland GmbH (EMPG) with a share of 18.5 % of domestic production, followed by Gas de France - PEG (10 %), the Wintershall Holding AG (8 %) and the EEG - Erdgas Erdöl GmbH (0.7 %). In Germany, production costs excluding depreciation can range from about € 20 to 190/t of petroleum.

According to preliminary information from the "Arbeitsgemeinschaft Energiebilanzen" ("AGEB" – working group on energy balances), the mineral oil consumption in Germany in 2007 was around 109 Mt (AGEB, 2008). Compared to the previous year, this was a decrease of slightly more than 9 %. Adjusted for temperature and stockpiles, it only went down by about 5 % according to the AGEB. Nevertheless, this was the lowest oil consumption in re-united Germany so far. At slightly lower domestic oil production and significantly lower mineral oil consumption compared to 2006, domestic petroleum production covered slightly more than 3 % of the overall mineral oil consumption in Germany in the reporting year. The fields in the states of Schleswig-Holstein and Lower Saxony together produced 96 % of the total production in Germany in 2007 (LBEG, 2008).

8.1.3 Petroleum Reserves and Resources

The estimated proven and probable oil reserves in Germany as of January 1, 2008, were estimated at 37 Mt. This is about 4 Mt or nearly 10 % below those of the previous year and is in line with the continuing decline during the last few years (Fig. 8.3). When taking into account the production of 3.4 Mt in the reporting year 2007, it becomes apparent that even the initial reserves decreased. They are about 0.6 Mt lower compared to 2006. This was caused by the re-evaluation of deposits and other corrections, which ultimately led to an adjustment and to a reduction of the remaining reserves. The reserves growth in some fields due to the extension of their operational life time only compensated this to a small degree. The largest shares of remaining petroleum reserves are located in Schleswig-Holstein (63 %) and Lower-Saxony (34 %).

Without new discoveries or any other increase in reserves, the oil reserves in Germany would be depleted within a foreseeable time span. Although Germany is a mature hydrocarbon province, there are still undiscovered and undeveloped resources. For instance, as early as 1941 traces of low-viscosity residual oil were encountered in the Bentheim sandstone on a seismically proven structure in the region of the town of Nordhorn. The oil is probably biodegraded residual oil. Rough estimates of these deposits indicate total petroleum volumes in the order of tens of million m^3.

In case of conventional oil, an additional resource potential of around 40 Mt petroleum (pers. com. association of German oil and gas producers/WEG) is assumed to exist in Germany. This is comparable in magnitude to the current estimated proven and probable petroleum reserves. The degree of oil recovery from deposits on a global average is about 35 % (Info box 2). For all German oil fields, this value is currently estimated to be about 36 %, implying that 559 Mt of residual oil would remain in the reservoirs. Additional potential is therefore to be found in the increase of the recoverability for petroleum, using improved processes and technologies. A yield increased by 1 % would correspond to a reserve potential of about 9 Mt which is 2.6 times the amount of oil produced in 2007.

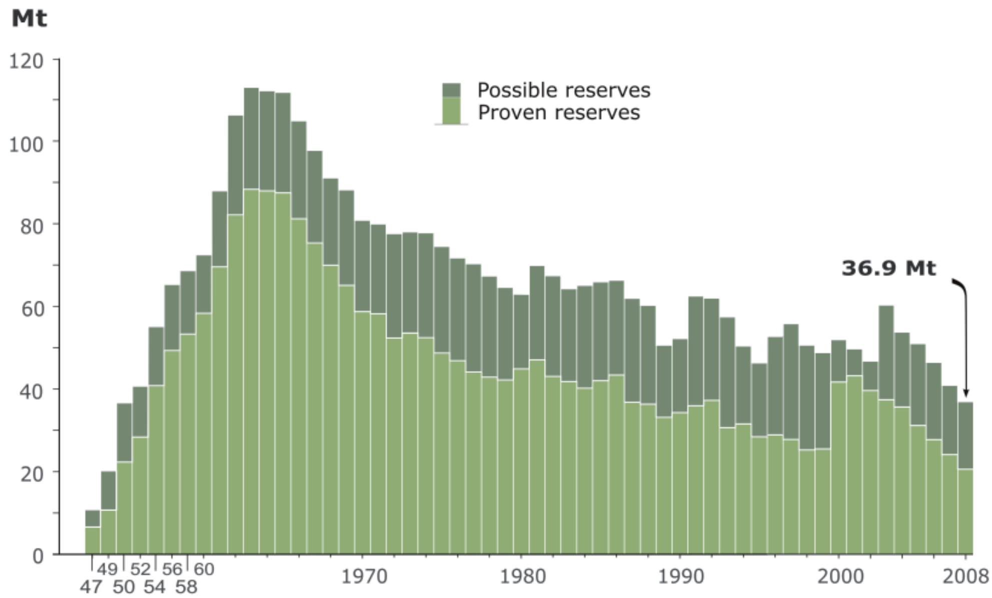


Figure 8.3: Petroleum reserves trend over time in Germany.

8.1.4 Germany's Supply with Petroleum

Just as most industrial states, Germany is to a large extent dependent on petroleum imports. Petroleum is the most important primary source of energy in Germany. The share of petroleum in the primary energy consumption in the last five years was at approximately 35 %. Since the beginning of the 1960s until the beginning of the first oil crisis in the year 1973, a continuous increase in the petroleum demand to about 130 Mt has been registered. It stayed at this level, with a temporary decrease to 110 Mt between 1975 and the beginning of the 1980s, and subsequently dropped to about 90 Mt owing to the second oil crisis at the end of the 1970s. Since 1990, the petroleum demand has increased to about 100 to 110 Mt. In the year 2007, the petroleum demand in Germany was around 109 Mt of which 105.5 Mt had to be imported.

With time, there was a change in the supply sources (Fig. 8.4). The most important crude oil supplier in 2007 was the Commonwealth of Independent States (CIS) at 42 %, of which Russia contributed the lion's share at 32 %. It is followed by the North Sea littoral states Norway and United Kingdom with a share of 29 %.

Africa's share, which dominated around 1970 (at that time predominantly Libya), today is just slightly more than 17 %.

The share of the Middle East has decreased significantly, from more than 50 % in the 1950s to around 6 % today. The OPEC share in crude oil imports has been in continuous decline since 1976, when the share reached about 80 %. In 2007 it was down to 19.4 % (Table A 8-1). Future developments in the most important supply countries for Germany will be discussed in Chapter 9.

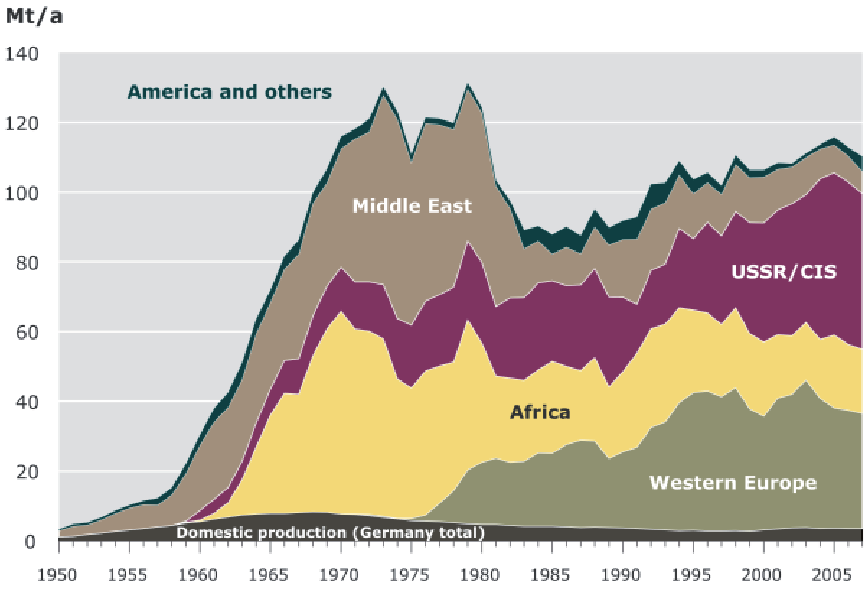


Figure 8.4: Crude oil supply in Germany between 1950 and 2007 and share of mineral oil in total primary energy supply (TPES).

In Germany, petroleum is stored and stocked underground in salt caverns in order to be prepared for any possible oil crises and bottlenecks in supply. Due to the enormous salt structures concentrated in the North of Germany, most of the cavern storage locations lie in this region. With 6.5 million m^3 of crude oil, the largest petroleum supplies are stored underground in the Wilhelmshaven area.

8.1.5 Unconventional Oil

There is no reliable data regarding the distribution and the precise resources of **oil sand deposits** (Chapter 3.3.1) in Germany. As early as 1652, tar outcrops near Wietze in Lower Saxony were mentioned in documents. Later, near Wietze asphalt was extracted by underground mining from steeply dipping Lower Cretaceous (Wealden) reservoir rocks strongly affected by salt tectonics. With increasing depth, the rather viscous oil in the sands there turns into light oil. Between 1920 and 1963, oil was produced at depths of 180 to 340 m via two shafts and over a length of 81 km, in total. Initially, only the seeped down oil was mined in the sections. After 1930, the oil sand itself was extracted and washed aboveground, using hot steam. In total, nearly 1 Mt of petroleum has been extracted from the oil sands in Wietze.

Around 1730, rocks containing asphalt were discovered near Hanover, but were at first not utilized. It was not until 1842, that the mining of the asphalt rock began there and H. D. Hennings founded Germany's first asphalt works in 1843 in Limmer. Asphalt mining had its boom time in the 19th century. Known are the deposits Ehingen (Baden-Württemberg), Eschershausen-Holzen (Ith) and Wietze to the north of Hanover. Since the beginning of the last century, asphalt has been mined from impregnated limestones of the upper Jurassic in Holzen in Lower-Saxony. Mining takes place sporadically in the only natural asphalt underground mining operation in Europe, depending on the demand. The asphalt is predominantly used for the manufacturing of flooring.

Oil shale deposits (Chapter 3.3.3) in Germany are mainly restricted to the Jurassic (Lias epsilon) of the North German Basin and the Swabian-Franconian Jurassic Trough in Southern Germany. Oil shales were mined from 1886 until 1971 from Eocene strata (Einecke, 1995) in the Messel pit in Southern Hesse. This location is well known all over the world due to its rich fossil content and was declared a Natural World Heritage site in 1995. In total, around 1 Mt pyrolysis oil were extracted during this time from more than 20 Mt of oil shale, in addition to 350 000 tons of special coke, 93 000 tons of ammonium sulphate and 60 000 tons of paraffin. In the South-East of Lower-Saxony, oil shales are common near the surface and to a larger extent in the area of Schandelah-Flechtorf and Hondelage-Wendhausen with a combined reserves potential of 2 to 2.5 Gt. The theoretically extractable oil volumes have been estimated at 150 to 180 Mt which is several times the amount of proven and probable petroleum reserves in Lower-Saxony.

Until now, the mining of oil shales in Lower-Saxony has remained limited to smaller areas of the Schandelah-Flechtorf deposit during both World Wars. In Baden-Württemberg, today it is also used to produce oil shale cement. In essence, the economic use of oil shale is dependent on the development of energy prices. Due to competing usage claims, potential extraction sites are increasingly being lost.

8.2 Natural Gas in Germany

8.2.1 Natural Gas Deposits and Production History

In Germany, only small volumes of natural gas are produced in comparison to an international scale. In 2007, however, domestic production again covered around 17 % of domestic consumption. The largest natural gas deposits and the highest production occur in Northern Germany. In 2007, Lower-Saxony alone accounted for approximately 93 % of German natural gas production.

The predominant portion of natural gas in German deposits was generated from Upper Carboniferous coals. Carboniferous, Rotliegend and Zechstein dominate as reservoir horizons. The largest gas field is the Rotliegend field complex Salzwedel in Saxony-Anhalt which is almost depleted today. More than one fifth of the cumulative production in Germany at the end of 2007 originates from this deposit. The field with the highest production rate in 2007 was Rotenburg-Taaken in Lower-Saxony, which produced around 2.3 billion m^3 of gas from sandstones of the Rotliegend.

In Lower-Saxony, sour gas (Chapter 4.1) is also produced in addition to sweet gas (Porth et al., 1997). Different compositions of the produced natural gas also induce variations in the natural calorific value, which can be different for every deposit in Germany and fluctuates between 2 and 12 kWh/m^3. In the German oil and gas industry, natural gas volumes are both quoted as *raw gas volumes* and *clean gas volumes.* The raw *gas volume* corresponds to the volume at natural calorific value as it occurs in the reservoir. The *clean gas volume* is a commercial quantity, as natural gas is not traded according to its volume but its energy content. The term clean gas therefore uniformly refers to a calorific value of 9.7692 kWh/m^3 which is also called the *Groningen calorific value* in the oil and gas industry. It represents a

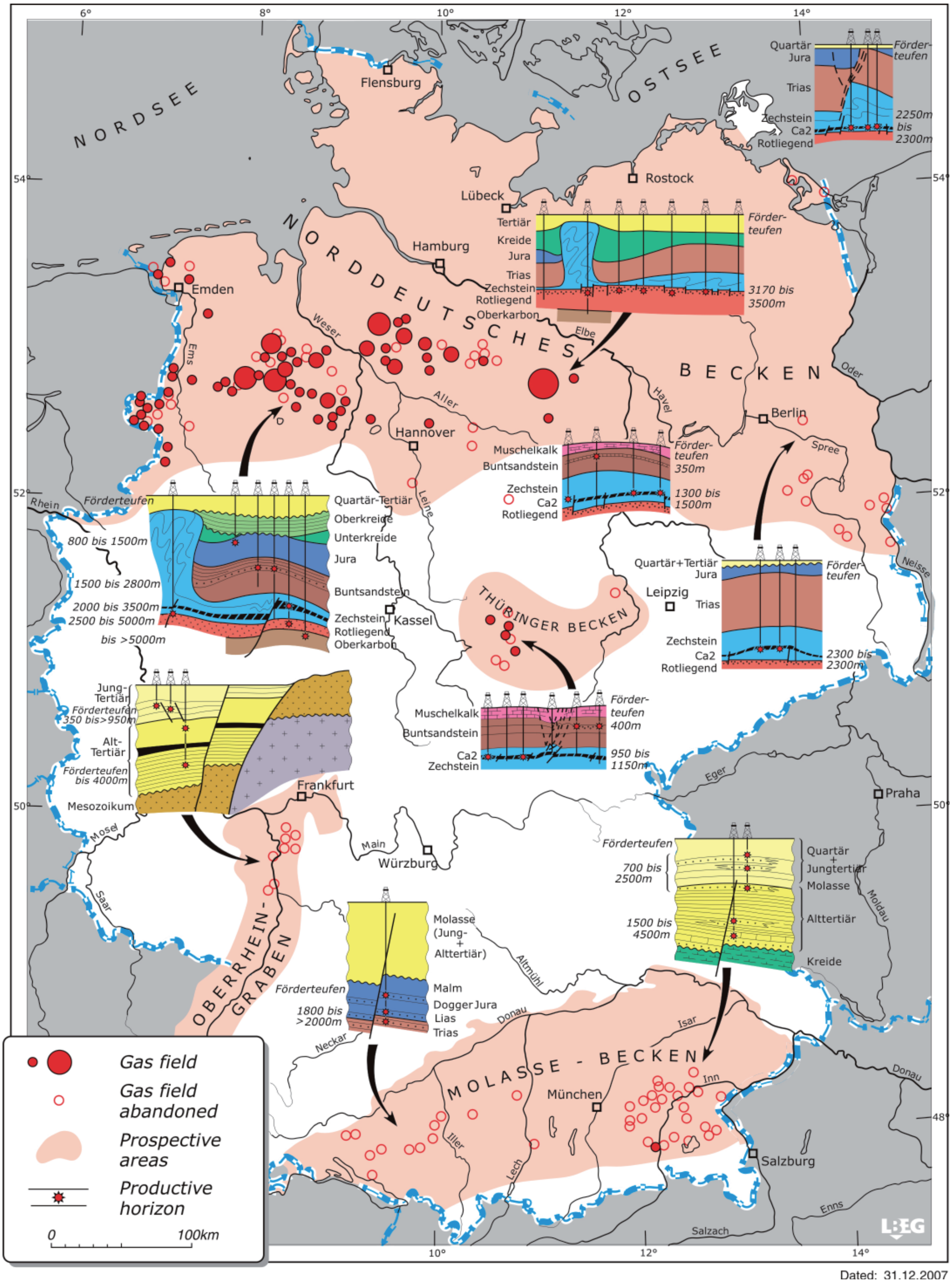


Figure 8.5: Prospective regions, gas fields and characteristic traps in Germany.

fundamental reference term. In other statistics, a calorific value of 11.5 kWh/m^3 is used as reference value in connection with the average quality (calorific value) of North Sea gas.

The first gas was found in 1910 by accident. When drilling for water, the Hamburg gas works unexpectedly struck a gas deposit at a depth of 240 m in Tertiary sandstone. However, compared to petroleum, the focused search for natural gas in Germany only started in the late 1950s.

Later, in the 1960s, larger-scale production of natural gas commenced (Fig. 8.6) due to the development of the Buntsandstein and Zechstein deposits discovered in Lower-Saxony. After the spectacular find of the huge Rotliegend gas field Groningen in the year 1959 in the Netherlands, this horizon became an important exploration target in the North German Basin as well. This led to the development of a number of further Rotliegend fields from the middle of the 1960s onwards. The last large gas find dates back to the year 1991 when the gas field Völkersen was discovered. In the south of Germany, in the Molasses Basin, natural gas was last found in economic quantities in 1982 in Tertiary sandstones of the Irlach gas field.

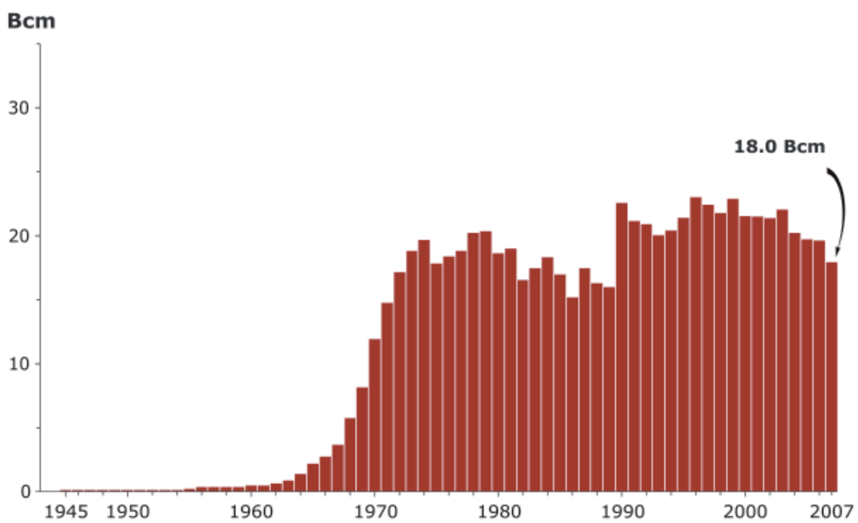


Figure 8.6: Natural gas production (raw gas) in Germany since 1945.

At the end of the 1970s, annual raw gas production in West Germany was around 20 billion m^3 which had dropped to 16 billion m^3 before the German reunification in 1990. From 1990 onwards, the production data of the East German fields were included in the production statistics and production increased to above 20 billion m^3/a. In the past years, raw gas production has declined to 18 billion m^3 in 2007 due to the increasing natural depletion of reservoirs (Fig. 8.6). The only German offshore gas field Nordsee A6/B4 was put into operation in September 2000 and in 2007 it produced around 667 million m^3 natural gas of high calorific value.

Cumulatively, around 929 billion m^3 of natural gas have been extracted in Germany until the end of 2007. Including the remaining reserves, this corresponds to a recovery factor of nearly 80 % of the estimated original total volume in the various reservoirs.

8.2.2 Natural Gas Production and Consumption in 2007

Compared to 2006, clean gas production in Germany decreased significantly by about 1.5 billion m^3 to 16.9 billion m^3. This corresponds to a reduction of slightly more than 8 %. The renewed decrease in production is partly a result of the mild winter and the correspondingly decreasing demand for natural gas. On the other hand, the decline in production clearly reflects the increasing natural depletion of reservoirs.

At around 73 % of the total German production, ExxonMobil Production Deutschland GmbH (EMPG) is the largest natural gas producer in Germany. Other producers in 2007 were RWE Dea AG with a share of 15.4 % in domestic production, followed by Wintershall Holding AG (6.4 %), Gaz de France – PEG (4 %) and EEG - Erdgas Erdöl GmbH (1.3 %). The range of production costs excluding depreciations varies between 20 and 110 € per 1000 m^3 of raw gas.

According to preliminary results published by the AGEB (2008), natural gas consumption in 2007 has decreased by 5.5 % to 98 billion m^3. At significantly lower domestic production and decreased gas consumption, domestic natural gas production has therefore covered about 17 % of the consumption.

8.2.3 Natural Gas Reserves and Resources

As of January 1, 2008, the estimated proven and probable natural gas reserves (raw gas) in Germany were around 218 billion m^3 (2001: 343 billion m^3). This is 14.3 billion m^3 or slightly more than 6 % less than in the previous year (Fig. 8.7). When taking into account the annual raw gas production of 18 billion m^3, this results in an overall increase of the initial proven and probable reserves for the reporting year 2007. Hence, part of the production was compensated by reserves gains. These can be traced back predominantly to re-evaluations and successful drilling in Lower-Saxony. 98 % of the total natural gas reserves of Germany are located in Lower-Saxony. Without new finds and the associated increase in reserves, the natural gas resources in Germany will be depleted within a foreseeable time. However, although Germany is a mature hydrocarbon province, there are still undiscovered and undeveloped gas resources, for instance in extremely tight sandstone reservoirs (Chapter 4.3.1). Gas resources in tight reservoir rocks are estimated to be between 100 and 150 billion m^3 in the North German Basin.

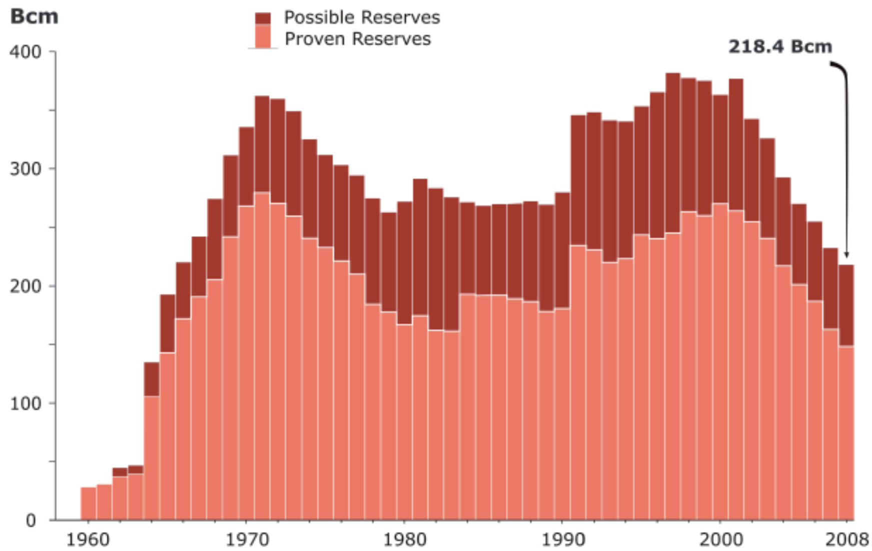


Figure 8.7: Natural gas (raw gas) reserves trend over time in Germany.

8.2.4 Germany's Supply with Natural Gas

Natural gas is the second most important source of energy with regard to the Total Primary Energy Supply (TPES) of Germany. The share of natural gas in the German TPES was approximately 22 % during the last five years (Fig. 8.8). Until 1995, the share of natural gas in the TPES increased continuously. Thereafter, the average share was 23 %. For years, more than 80 % of the German natural gas demand had to be imported. As pipeline transport is a necessity and owing to the long contract duration regarding gas deliveries, Germany is currently tied to only a few supplier countries. For Germany these are predominantly Russia, followed by Norway, the Netherlands and, to a lesser extent, Denmark and the United Kingdom (Table A 8-2). The future development of the most important supplying countries for natural gas in Germany will be discussed in Chapter 9.

Germany does not have its own LNG import terminal (Chapter 4.2.6), but there is the possibility to get access to LNG via Bruges in Belgium. There were concrete considerations by the energy company E.ON to build a LNG terminal in Wilhelmshaven. Instead, E.ON now participates in the LNG terminal GATE in Rotterdam in the Netherlands, which is under construction. Therefore, the building of an LNG terminal in Wilhelmshaven seems rather unlikely in the foreseeable future, at least by this energy company. There are also plans by the energy company RWE for an offloading terminal for LNG on the German North Sea coast and the company has started negotiations with the Federal government and the State government of Lower-Saxony (EID, 2009) to this end.

Underground gas storage is one of the measures taken to ensure steady gas supply of the Federal Republic of Germany. These gas storage facilities provide a balance between daily and seasonally fluctuating consumption and between the domestic production and the need for imports. Germany is the fourth largest natural gas storage nation in the world after the US, Russia and the Ukraine. Gas is stored temporarily in permeable rocks of depleted gas and oil fields as well as in suitable aquifers, and salt caverns. A purely strategic gas supply in case of *force majeure* could be an additional safeguard if one considers the growing gas consumption, conceivable terrorist attacks on gas networks, the increasing significance of energy resources being used as leverage and the reliance of natural gas on pipelines. Such stock-piling already exists for petroleum since the oil crisis in 1973. A national gas reserve, however, would not be a commercial storage location but be strictly separate from the gas storage market.

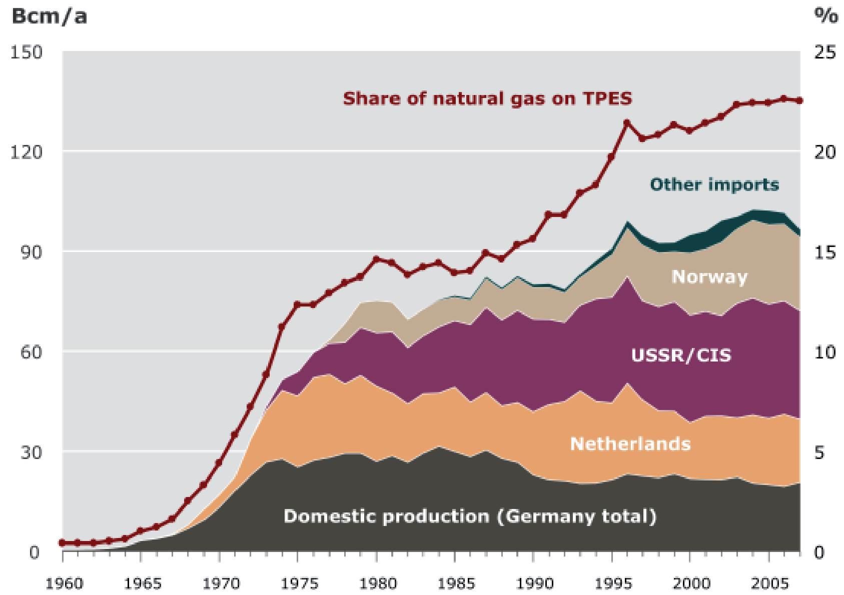


Figure 8.8: Supply of natural gas in Germany between 1960 and 2007 and share of natural gas in total primary energy supply (TPES).

8.2.5 Unconventional Natural Gas

In the North German Basin, deposits of unconventional natural gas (Chapter 4.3.1) are known to occur. They predominantly comprise so called *tight gas*, which is trapped in deep and extremely dense reservoir rocks. Contrary to international terminology (Chapter 4.3.1), in Germany natural gas contained in source rocks is not termed *tight gas*, but is treated separately as *shale gas*.

Due to the increasing depletion of conventional sources and rising gas prices, a continually growing interest in unconventional natural gas can be noticed in Germany. Concessions for the targeted extraction of *shale gas*, however, have only been granted in the neighboring countries Poland, the Netherlands and Sweden.

Tight gas deposits in Northern Germany, however, have already been successfully exploited. The exploitation of these resources is only possible using state-of-the-art technology wells although drilling and completing these wells is very expensive. In addition, high reservoir pressures (60 MPa) and high temperatures (150 °C) make it difficult to develop these gas deposits, which are often found at large depths (5 km). Furthermore, there are also economic risks with regard to the achievable long-term production rates and production volumes. Resource estimates for *tight gas* suggest significant quantities in the order of 100 to 150 billion m^3 for the North German Basin. Main target horizons are sandstones in the Rotliegend and the Carboniferous.

Based on current knowledge, the domestic potential of gas from tight rocks to contribute to Germany's gas supply should be rated as rather low. However, even small gains in domestic production from unconventional sources are positive in the long term. For the medium-term use of these non-conventional deposits, the development of natural gas prices is the main decisive factor due to the high level of investment required. In addition, the availability of drilling rigs is a limiting factor as the development of tight gas and in particular shale gas requires a large number of multi-frac horizontal wells. A research program of the German gas producing companies is dealing with the optimization of frac projects and other measures to increase production from tight deposits (DGMK, 2009).

Methane is present worldwide in many coal mines as **coalmine methane**. Especially in hard coal mines, miners today still live with the danger of firedamp explosions caused by the ignition of methane at a certain mixing ratio. Nowadays, coalmine methane, however, is not just a threat but is also used as an energy resource representing a special form of coalbed natural gas (Chapter 4.3.2). Both coal deposits presently being mined as well as abandoned mines can be considered for utilizing coalmine methane. The USA and many European countries such as Germany, the United Kingdom, Poland and the Czech Republic use this energy resource. Frequently, small power stations with regional importance are built at the location of these mines, such as in the Ruhr Basin. They are used for power generation but also for cogeneration of heat and power. In Germany, coalmine methane is utilized in particular in the coalfields in North-Rhine-Westphalia and in the Saarland. Since the introduction of the Law on Renewable Energies in April 2000, the use of combined heat and power stations (CHP) has undergone a dramatic development. In 2007 slightly more than 1600 GWh/a electricity were generated in 175 CHPs in Germany (Fig. 8.9). Previous investigations regarding coalbed natural gas production (Chapter 4.2.2) in Germany had raised no hopes of economic production due to the complicated geological conditions.

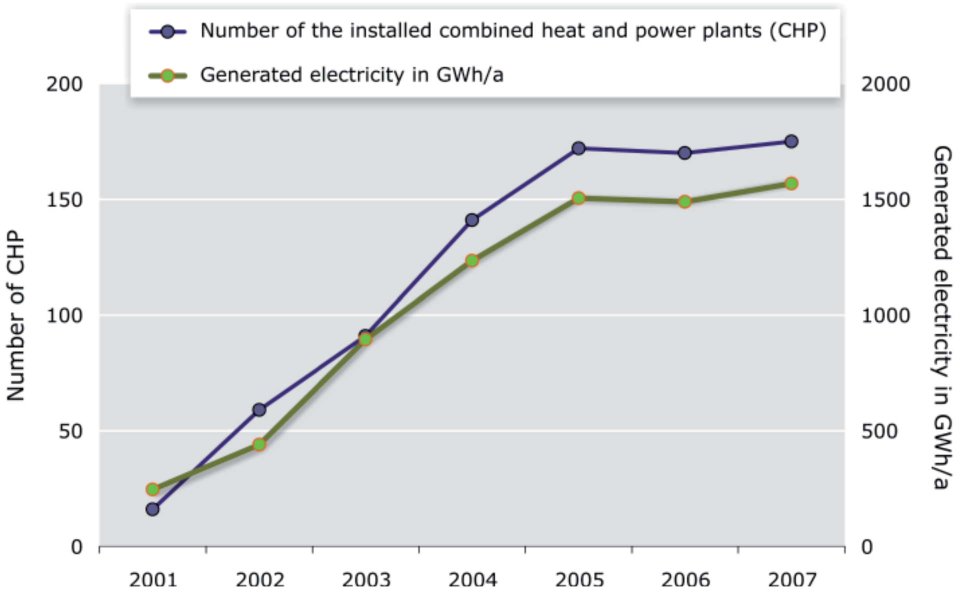


Figure 8.9: Trend in mine gas use in Germany between 2001 and 2007.

The BGR has examined different mines in the Ruhr Basin to figure out the origin of the coalmine methane present there. In doing so, the gas source was found not just to be coal but also the mining timbers used for mine construction. According to these findings, a relevant proportion of the coalmine methane was recently formed by microbial decomposition of pit prop material in the coal mines (Thielemann et al., 2004).

8.3 Coal in Germany

8.3.1 Coal Deposits and Production History

Germany has large hard coal and lignite deposits. The main hard coal-bearing successions are of Carboniferous age and primarily to be found in Westphalian aged strata. The lignite-bearing successions in Germany are younger and mostly date back to the Miocene. Currently there are three operating mining districts for hard coal in Germany (Fig. 8.10). The Ruhr and Ibbenbüren hard coal mining districts belong to the Ruhr Basin.

The Upper Carboniferous (Namur C to Westphalian D) hard coal-bearing successions of the Ruhr Basin can reach a thickness of up to 4200 m. They contain up to 300 coal seams. However, only about 160 seams are thicker than 0.3 m. The maximum cumulative coal thickness in the Ruhr Basin is approximately 135 m and the typical coal content ranges from 2 to 10 %. The third operating hard coal mining district in Germany is located in the Saar area (Fig. 8.10), where a 3000 m Westphalian aged hard coal-bearing succession with up to 400 seams exists. The maximum cumulative coal thickness can reach up to 210 m and about 150 seams have a seam thickness of more than 0.3 m. The already abandoned mining district of the 500 km^2 covering Aachen-Erkelenz Basin near the Dutch border consists of Namurian B to Westphalian C aged successions. Here, 125 seams occur with thicknesses of more than 0.3 m. The average coal content is up to 4% (Dehmer, 2004; Drozdzewski, 1993; Füchtbauer, 1993; Juch et al., 1994).

The currently most significant lignite mining district, the Rhineland (Rhenish) district, is located west of Cologne (Fig. 8.10). The 600 m thick Miocene successions contain three major formations. The most productive formation, the so called main seam (Hauptflöz) in the Ville formation, has a maximum lignite thickness of 100 m. The Miocene to Eocene successions of the Central-German area (Helmstedt and Central-German mining district) with up to eight workable seams are located between Brunswick and Leipzig (Fig. 8.10). The currently worked seam thickness in this area is varying from 10 to 30 m. The Lusatia mining district situated in the eastern part of Germany near the Polish border contains four seam horizons of Miocene age. At the moment extraction occurs only in the second Lusatian seam horizon. This horizon has a lignite seam thickness of 5 to 14 m and covers an area of up to 4000 km^2 (Debriv, 2000, 2007; Luzin et al., 1984; Pätz et al., 1989; Vulpius, 1993).

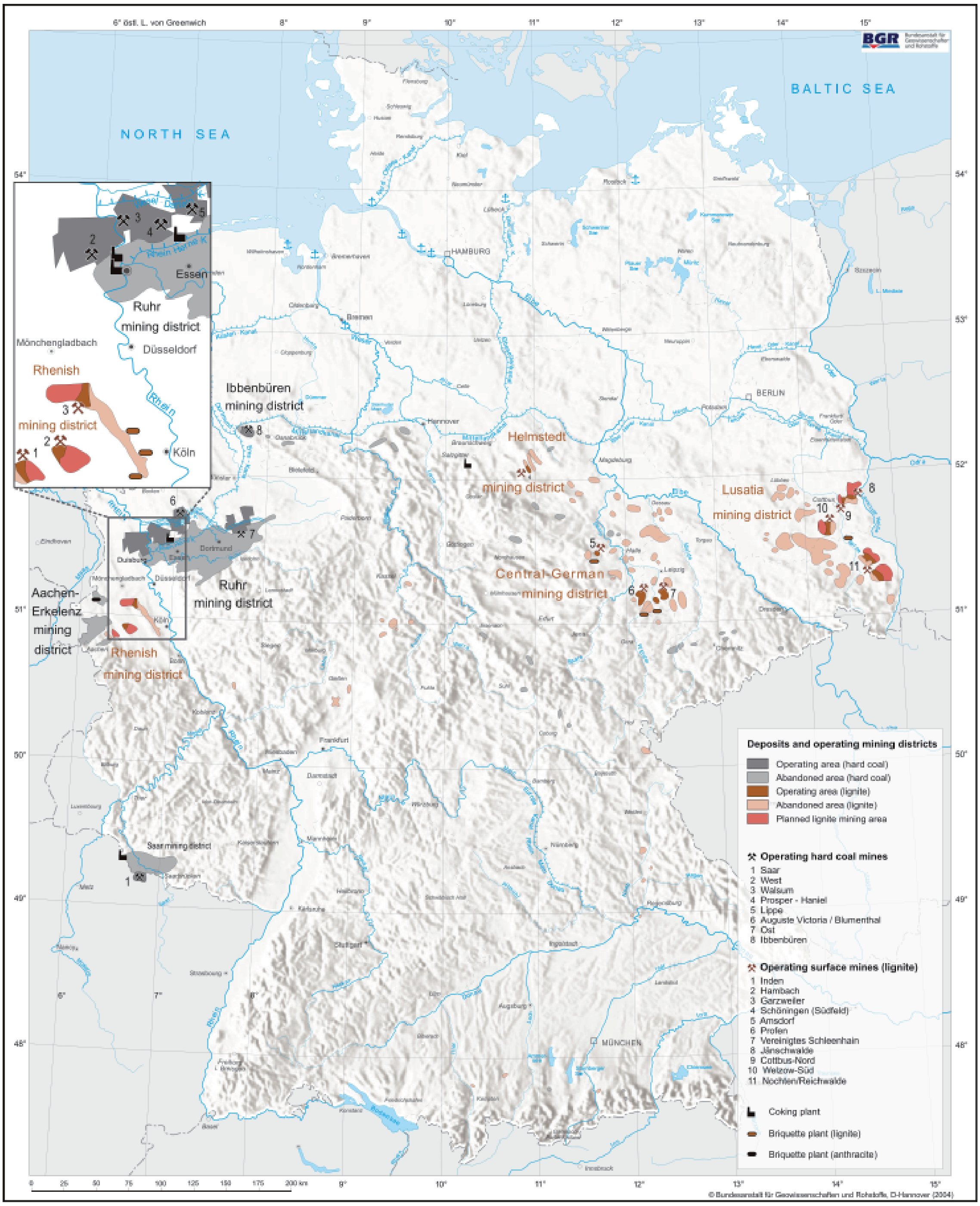


Figure 8.10: Hard coal and lignite deposits and mining districts in Germany (modified after Thielemann, 2005).

The Carboniferous hard coals of the Ruhr and Aachen-Erkelenz Basins are humic coals, which were predominantly created from land plants in coastal swamps. Anthracite, a strong thermal overprinted hard coal, which is found in the Ibbenbüren and Erkelenz mining districts covers only a minor amount of the German hard coal resources. In contrast, the Saar Basin is a limnic coal basin, which was filled with fresh water at the time the organic material was deposited. The majority of Tertiary German lignites were deposited under paralic conditions. High sulphur contents up to 3 % (table 8.1) occur particularly in the Helmstedt and Central-German mining districts (BGR, 2008; Dehmer, 2004; Juch et al., 1994; Pohl, 1992).

Table 8.1: Coal qualities of different mining districts in Germany (BGR, 2008).

Coal type	Mining district	Heating value (MJ/kg)	Ash content (%)	Volatile matters (% $_{waf}$)	Total sulphur content (% $_{wf}$)	Moisture (% $_{wf}$)
Hard coal	Ruhr	28–33	5–10	8–45	0.5–4	
Hard coal	Ibbenbüren	32.5	3–4	5–6	0.6–0.9	
Hard coal	Saar	28.5–30.1	3.3–20.8	39–43	0.23–1.26	
Lignite	Rhineland	7.8–10.5	1.5–8		0.15–0.5	50–60
Lignite	Helmstedt	8.5–11.5	5–20		1.5–2.8	49–53
Lignite	Central-Germany	9–11.3	6.5–8.5		1.5–2.1	40–50
Lignite	Lusatia	7.6–9.3	2.5–16		0.3–1.5	48–58

As in other European countries, coal in Germany was and still is the most important indigenous fossil energy resource. Hard coal was one of the key drivers for economic growth especially in the years after World War II in the western part of Germany. In the eastern part of Germany lignite was the most important primary energy source until the mid of the 1990s. Mainly due to low import prices for hard coal and rather low oil and gas prices at that time a continuous reduction in hard coal mining from more than 153 Mt v. F. in 1956 to around 21 Mt v. F. (24,2 Mt) in 2007 occurred. The German lignite production reached its maximum of 433 Mt in the year 1985 (Fig. 8.11). The German lignite production in the year 1985 reached its maximum with around 433 Mt (Fig. 8.11). Despite several mine closures primarily in the Lusatian and Central-German mining districts Germany remains by far the most important lignite producer of the world with 180.4 Mt in the year 2007.

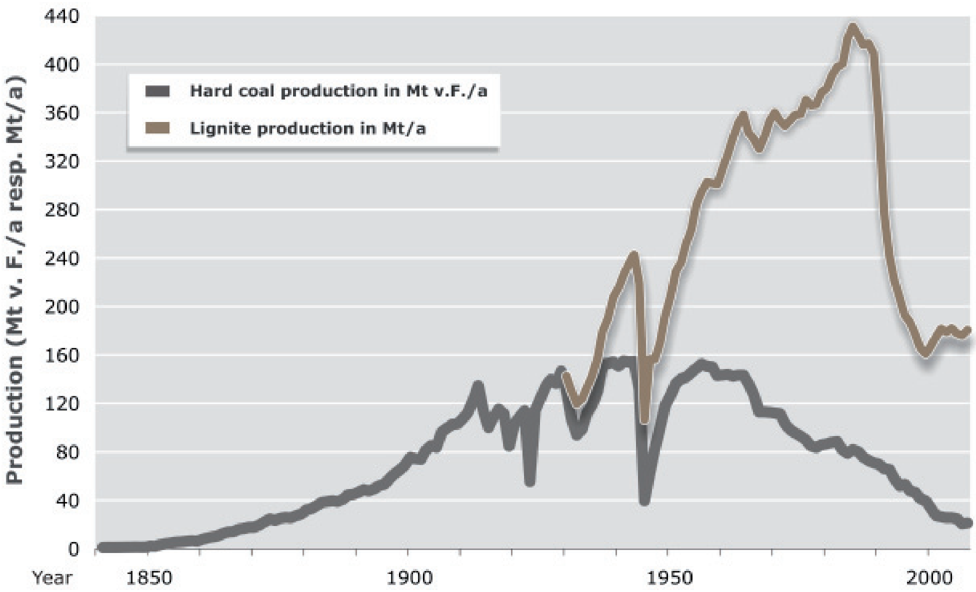


Figure 8.11: Trend in the German coal production between 1840 and 2007 (SdK - different volumes).

8.3.2 Coal Production and Consumption in 2007

In 2007, hard coal and lignite had a share of 25.9 % (14.3 % hard coal and 11.6 % lignite) in the German primary energy consumption. In this context, hard coal and lignite in Germany are mainly used for power generation. With a share of 47.3 % (22.8 % hard coal and 24.5 % lignite) nearly half of the electricity produced in Germany was generated from hard coal and lignite in 2007, followed by nuclear power (22.1 %) and electric power from renewable energies (14.1 %) (AGEB, 2008).

Today hard coal mining in Germany is only possible in underground mines due to the remaining deep lying seams. The average hard coal mining depth in the currently operating German hard coal mines was 1145 m in 2007 (SdK, 2008). The sole method used for extraction of the usually 1-2 m thick hard coal seams is longwall mining. Depending on the seam thickness and the coal strength either shearers or plow systems are applied. In 2007, six hard coal mines in the Ruhr mining district and one hard coal mine each in the Ibbenbüren and the Saar mining district were in operation. These eight large underground mines together produced 21.3 Mt v. F. (corresponds to 24.2 Mt). Furthermore, around 0.2 Mt v. F. were minded from the Fischbach mine in the Saarland. This operation was closed as of December 31, 2008, however. Until the year 2012, German hard coal production is to be cut back to around 12 Mt. The number of operating underground mines will probably have been reduced to four by then. On June 30, 2008 the underground mine Walsum has been closed, on January 1st, 2009, the underground mine Lippe has been closed. The closure of the underground mine Ost has already been decided for September 30, 2010. The combined underground mine Saar/Ensdorf whose production capacity was halved following the earthquake caused by the operation in February 2008, is to be closed in July 2012. According to the hard coal mining financing law ("Steinkohlefinanzierungsgesetz"; *Law on the financing for the termination of subsidized hard coal mining for the year 2018*), the subsidized hard coal production in Germany will be terminated until the end of the year 2018. But in 2012 the German Federal Parliament will review if subsidizing of hard coal mining will be continued, taking into consideration aspects of economic viability, security of energy supply and the other objectives of energy policy.

Lignite in Germany today is mined exclusively in surface mines using large bucket wheels. Via conveyor belt systems and partially following short rail transport, around 92 % of the total German lignite production is transported directly from the surface mine to power plants for power generation. In the Rhineland mining district, lignite is mined from depths of only a few tenths of meters up to 350 m, in the Central-German and in the Lusatia mining districts generally from a depth of 80 to 120 m. The thickness of the lignite seams mined in Germany today rarely is less then 5 m but can reach more than 70 m.

In contrast to hard coal, German lignite can compete without subsidies with imported energy sources. In this connection, favorable geological conditions of the deposits constitute positive factors as well as the proximity of coal-fired power plants to the deposits. Since the beginning of industrial lignite production, Germany tops the producer countries worldwide by far. In 2007, German lignite production amounted to 180.4 Mt (Fig. 8.11). More than half of the German production comes from the Rhineland mining district (Table 8.2) where lignite is produced in the three surface mines Garzweiler, Hambach and Inden. Around a third of the production comes from the four surface mines Jänschwalde, Cottbus-North, Welzow-South and Nochten/Reichwalde of the Lusatia mining district. In the Central-German mining district, with a production share of approximately 11 %, lignite is produced in the three surface mines Profen, Vereinigtes Schleenhain and Amsdorf, in which the Amsdorf lignite production of around 0.5 Mt/a is predominantly used to manufacture montan waxes, which are in demand worldwide. Around 1 % of the German lignite production comes from the surface mine Schöningen in the Helmstedt mining district.

Tabelle 8.2: Production as well as reserves and resources of hard coal and lignite at the end of 2007 (BGR, 2008; Juch et al., 1994; SdK, 2008).

Type of coal	Mining district	Production (2007)	Reserves (Mt)	Resources (Mt)
Hard coal	Ruhr	15.874 Mt v. F.	87.9[1)]	45 706
Hard coal	Ibbenbüren	1.907 Mt v. F.	10.6[1)]	14 434[2)]
Hard coal	Saar	3.526 Mt v. F.	19.5[1)]	16 357
Hard coal	Aachen-Erkelenz	closed in 1997	0	6 437
Lignite	Rhineland	99.752 Mt	35 000	20 000
Lignite	Helmstedt	2.116 Mt	18	360
Lignite	Central-Germany	19.082 Mt	2 100	7 900
Lignite	Lusatia	59.460 Mt	3 700	8 500

t v. F. Tons of saleable output (see chapter 5)

[1)] economic, subsidised extractable reserves 2008 to 2018, taking into account the production in 2007 of 21.307 Mt v. F. and the planned production of 12 Mt v. F. in the year 2012 as well as the expiring subsidies in the year 2018 according to current knowledge

[2)] incl. hard coal resources of the Münsterland area

8.3.3 Coal Reserves and Resources

Germany has total hard coal resources of approximately 83.1 Gt, of which probably 118 Mt can be extracted using subsidies between 2008 and 2018 and can be classified as reserves (Table 8.2). About 6.3 Gt of lignite are accessible in Germany in operating and concretely planned surface mines. Further mineable reserves outside the operating and planned surface mines amount to 34.5 Gt. Additionally there are lignite resources of about 36.8 Gt (BGR, 2008).

8.3.4 Germany's Supply with Coal

While the consumed lignite in Germany comes almost entirely (99.9 %) from domestic production, currently already around two thirds of the consumed hard coal is imported. Due to decreasing domestic production (Fig. 8.11), the German hard coal imports continuously increased during the past years (Fig. 8.12). In 2007, German hard coal imports including the hard coal products like briquettes and coke amounted to 47.5 Mt. The imported hard coal came predominantly from Russia with 8.6 Mt, followed by Columbia with 6.9 Mt as well as Australia and South Africa with 6.5 Mt each (Fig. 8.12). The imports from Poland in the last year fell by around one third to 6.4 Mt (BGR, 2008; VDKI, 2008).

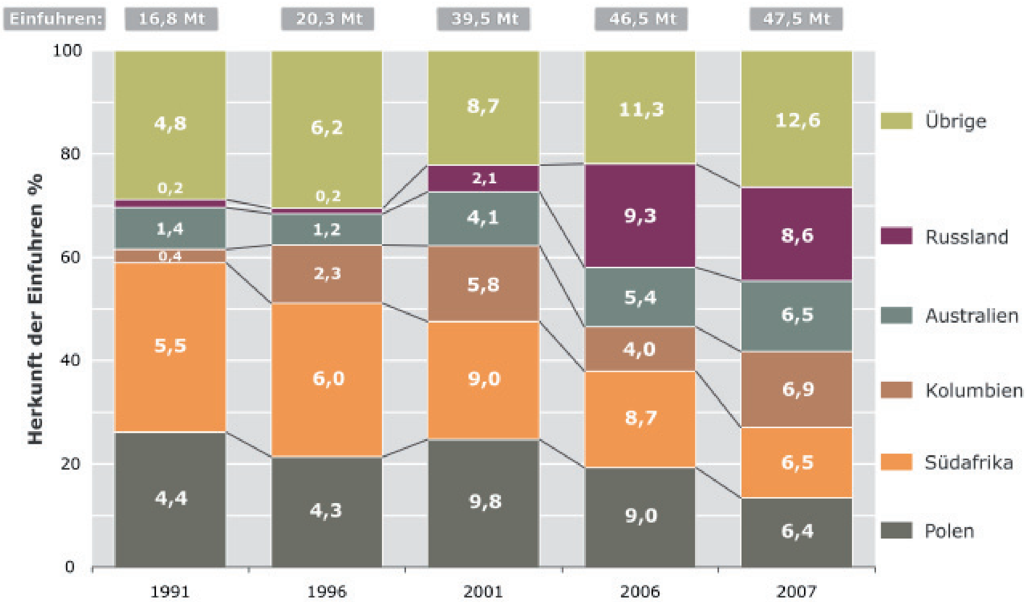


Figure 8.12: Development of German hard coal imports of selected years since 1991 (according to different annual reports of the VDKI).

8.4 Cross-Border Prices of Fossil Fuels

As a country which is heavily dependent on imports of fossil fuels, Germany pays large sums for their importation. While the expenses for fossil fuel imports amounted to about € 25 billion in 1999, they already reached € 43.4 billion in the year 2004 and increased to € 67.6 billion in the year 2007. This increase was to a large extent determined by price trends.

The Federal Office of Economics and Export Control (BAFA) specifies cross-border prices (Tables A 8-3 and A 8-4) for fossil fuels, which are average prices for long term and spot market contracts free German State borders. They are composed of the producer price, the cargo handling charges in the producer- and shipment country and the applicable transportation costs via pipeline, ship or rail to Germany. If the applicable fossil fuel is not transported directly to Germany, further costs must be taken into account. In this manner, the predominant part of coal imported by Germany arrives first in the ARA ports (Amsterdam, Rotterdam, Antwerp). Only afterwards the coal is transported by rail or barge to Germany (Fig. 8.13). Accordingly, there are additional transportation fees to the cross-border price. Petroleum reaches Germany partly by oil tanker and is transported to the refineries by pipeline from the German ports Wilhelmshaven, Hamburg and Rostock. A large part of the petroleum is transported by pipeline to Germany from foreign ports such as Trieste, Rotterdam and Lavena. Petroleum from Russia arrives in Schwedt via the Druzhba pipeline (Fig. 8.13). Natural gas is imported to Germany from Russia, Norway, the Netherlands and Denmark exclusively using pipelines.

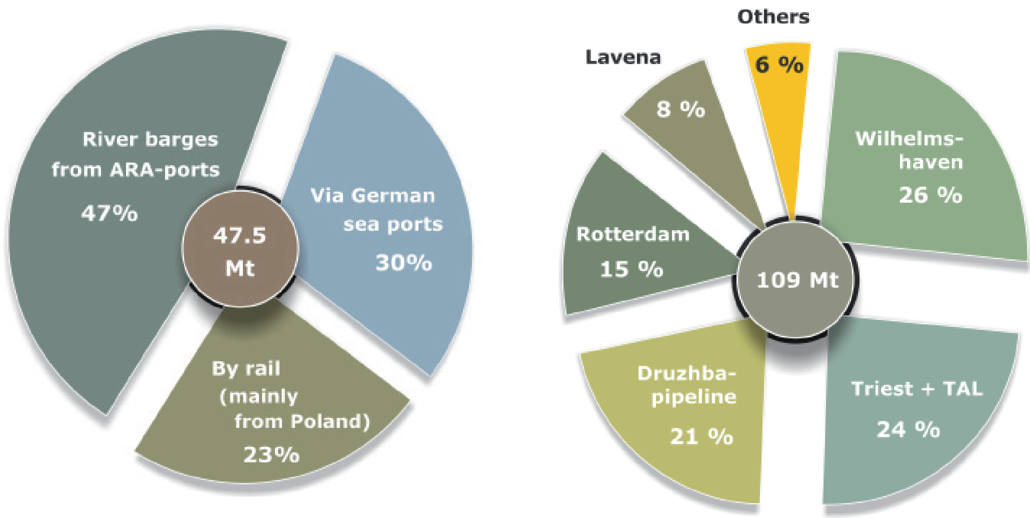


Figure 8.13: Routes of imported hard coal (in 2007) (left-hand side) and crude oil (in 2006) (right-hand side) to Germany (VDKI, 2008; MWV, 2007).

The average cross-border prices for steam coal from third countries outside the EU-27 amounted to € 112.48/tce in 2008, the price for crude oil was € 338.80/tce and for natural gas € 218.34/tce (Fig. 8.14). Therefore, the cross-border prices for crude oil in 2008 were three times as much and for natural gas nearly twice as much as those for steam coal of the same energy content. At the same time, the prices in 2008 for all three fossil fuels were at a record high never seen before.

The price increases during the last eleven years were different for each of the three fossil fuels. While the prices for imported steam coals increased by a maximum of 293 % (4th quarter 1998 to 3rd quarter 2008), the prices for imported natural gas rose by 507 % (April 1999 to November 2008) and crude oil by 854 % (December 1998 to July 2008). As a result of the global financial crisis from August 2008 onwards, a noticeable decrease began for crude oil and following that also for coal and natural gas.

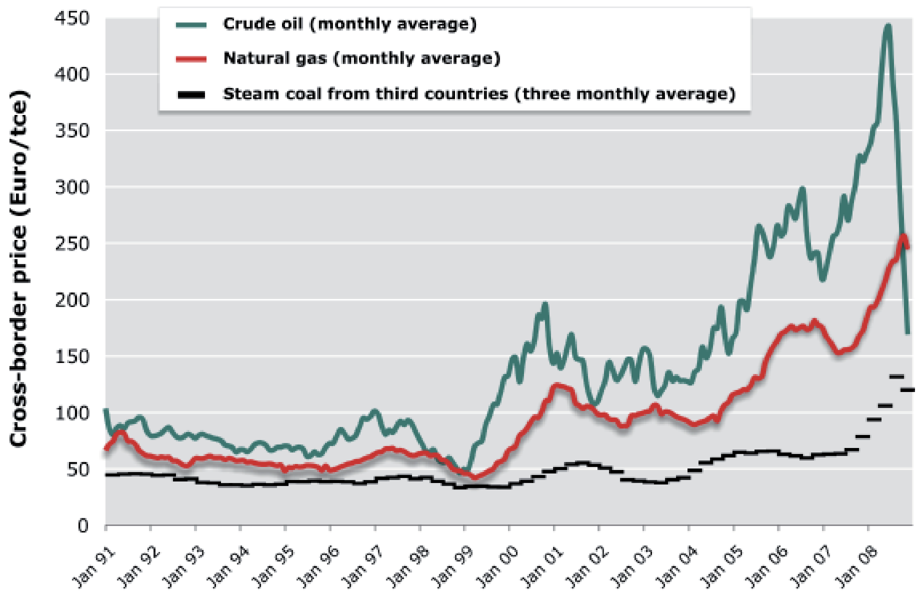


Figure 8.14: Comparison of German cross-border prices by fuel from January 1991 to December 2008 (BAFA, 2009; BMWi, 2009).

Over the period under review here from January 2002 until December 2008, the cross-border price for coking coal was on average 40 % higher than the price for steam coal (Fig. 8.15). This corresponds to the common price difference between steam and coking coal. From late summer 2007 until August 2008, the prices for imported steam coal doubled from € 67.05/tce to € 136.86/tce. The average cross-border price for coking coal increased from € 96.22/t in 2007 to € 132.62/t (+37.8 %) in 2008 (VDKI, 2003-2009). In November 2008, the prices for imported coking coal reached their maximum value of € 211.57/t.

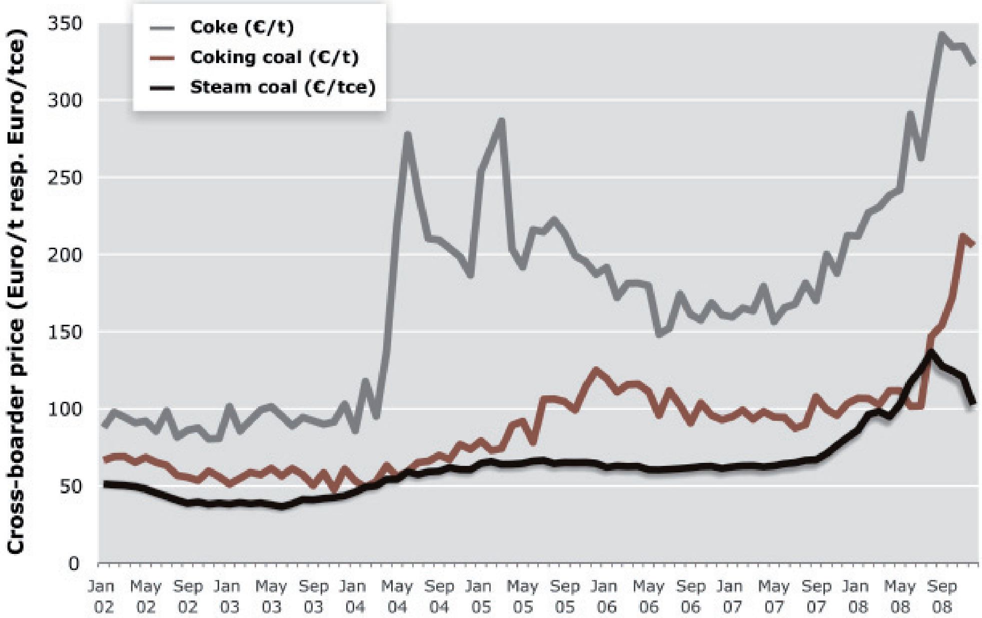


Figure 8.15: Trend for German cross-border prices for coke, coking coal and steam coal from January 2002 until December 2008 (VDKI, 2003-2009).

A major reason for these increases is the sharply increasing coal demand in Asia. Thereby coal became the fossil fuel with the highest year-on-year growth rates in consumption over the last five years. Due to investment in the extension of coalmines and infrastructure capacities, which was hesitant in relation to the large growth rates, various bottlenecks resulted and therefore prices rose. At the beginning of 2008, the situation came to a head due to external influences on the market: There were disruptions in the coal mining operations and in the railway transport of coal to the export ports in South Africa. The sudden onset of winter in the PR of China lead to production outages and temporarily prevented domestic coal transport which raised the danger of increased Chinese imports in view of a strained market situation on the world markets. In Australia, production in some mines had to be stopped as heavy rainfalls had flooded them. Since Australia is the most important coking coal exporter by far (Chapter 5), the events there had a dramatic impact on the worldwide coking coal price in 2008. Every spring, Japanese steel producers negotiate contract prices for a term of one year for coking coal with the Australian coking coal exporters, which then act as global benchmark prices. In the spring of 2008, this benchmark price for high-quality hard coking coal *(HCC)* rose from slightly under USD 100/t (fob) in the month of the previous year to around USD 300/t (McCloskey, 2003-2009).

The cross-border price for imported coke already increased markedly in the years 2004 and 2005 compared to the previous years (Fig. 8.15). Resulting from shortages on the world coke market dominated by the PR of China (Chapter 5), the prices rose sharply by more than 200 % to as much as € 277.47/t in only a few months. Thereafter, the price leveled off at between € 160 and 170/t from the start of 2006 until summer 2007. Since late summer of 2007, the cross-border prices for coke rose comparable to the developments described for cross-border prices for steam coal and coking coal and reached their nominal all-time high in September 2008 at € 342.13/t. The increase in coke demand worldwide due to the continual growth in pig iron production, fears as well as actual delays in the granting of Chinese coke export licenses and coking coal prices, which had sharply risen since 2008, were the main reasons for this price trend. The average cross-border price for coke increased by 60 % compared to the year 2007 to € 281.20/t in 2008 (VDKI, 2003-2009).

Along with sharply falling oil prices and the expanding global financial and economic crisis, the cross-border prices for coke, steam coal and coking coal decreased from summer 2008 onwards.

8.5 Nuclear Fuels in Germany

8.5.1 Uranium Deposits and Production History

Until the reunification, exploration and mining of uranium was carried out in both parts of Germany. In the German Democratic Republic, the Soviet joint-stock company SAG Wismut explored from 1946 to 1953. These activities were concentrated on known vein mineralization of silver, bismuth, cobalt, nickel and other metals in the Erzgebirge in Saxony and in the Vogtland area. Here, the main focus of uranium mining initially was on mines rich in cobalt and bismuth near Johanngeorgenstadt and Oberschlema. In this early phase, more than 100 000 miners were employed in exploration and mining. The rich uraninite and pitchblende ore from the hydrothermal vein deposits was concentrated by hand and transported to the former U.S.S.R. for further processing. Lower grade ore was processed locally in small plants.

In 1954, the SAG Wismut became the Soviet-German Joint-Stock Company (SDAG Wismut); equal shares were held by both governments. The entire uranium production, manually enriched, gravitative or chemical concentrates, was transported to the U.S.S.R. for further processing. The pricing of the final product was established between both national partners.

At the beginning of the 1950s, uranium mining in Eastern Thuringia began. The mines in Eastern Thuringia supplied around two thirds of the annual production of the SDAG Wismut.

From 1946 until 1990, a total of 231 000 tons of uranium was produced from the uranium fields in Thuringia and Saxony by the Wismut Company. The field in Thuringia in the Gera-Ronneburg area consisted of the sites Schmirchau, Paitzdorf, Beerwalde, Drosen and individual open-pit mines, and produced approximately 116 000 tons of uranium. In the Erzgebirge, approximately 90 000 tons of uranium were produced from the Niederschlema/Alberoda and Poehla deposits. Approximately 17 000 tons of uranium came from the Koenigstein deposit near Dresden. From the mid 1960s until the end of the 1980s, around 45 000 workers were employed by the SDAG Wismut. In 1990, there were still approximately

32 000 employees of the Wismut Company, of which 18 000 employees worked in the areas of uranium mining and uranium processing.

For the uranium exploration, a combination of on-ground and airborne methods was used particularly in the south of the former GDR. These activities covered a large area of approximately 55 000 km^2. The costs of these uranium exploration programs were approximately GDR marks 5.6 billion.

From 1960 onwards, the SDAG Wismut operated two processing plants. The Crossen plant near Zwickau in Saxony began ore processing in 1950. The ore was transported by road or rail from various mines in the Erzgebirge. The composition of the ores from the hydrothermal deposits required processing techniques using carbonate pressure solution. The plant had a maximum capacity of 2.5 Mt ore per annum. Crossen was finally closed on December 31, 1989. The second processing plant near Seelingstadt in Thuringia was put into operation in 1960 for the uranium deposits hosted by black shales in Ronneburg. The maximum capacity of the plant was 4.6 Mt of uranium ore per annum. The ore bound by silicate was extracted by acid solution until the end of 1989. Ores rich in carbonate could by treated using carbonate pressure solution.

The uranium exploration in the Federal Republic of Germany started in the Hercynian crystalline massifs in the Black Forest, Odenwald, Frankenwald, Fichtelgebirge, Upper Palatinate, Bayerischer Wald, Harz, in Paleozoic sediments of the Rheinisches Schiefergebirge, in Permian volcanic rocks and continental sediments of the Saar-Nahe region as well as other areas with suitable sedimentary formations. In the course of this work, survey photographs and detailed examinations in prospective areas were made using hydro-geochemical studies, radiation measurements, field work, drilling and aerogeophysical surveys. Based on these investigations, three deposits of economic interest were identified: The hydrothermal deposit near Menzenschwand in the Southern Black Forest, the sedimentary deposit Muellenbach in the Northern Black Forest and the Großschloppen deposit in the Fichtelgebirge. This uranium exploration was abandoned in 1988. Until then, approximately 24 800 boreholes with an overall length of 354 500 m were sunk. The exploration costs amounted to around USD 111 million.

In West Germany, a processing plant existed in Ellweiler, Baden-Wuerttemberg, which was operated by the Gewerkschaft Brunhilde from 1960 onwards. The plant primarily acted as a testing plant for different ore types and had a capacity of only 125 tons per annum. It was closed on May 31, 1989, after a total production of approximately 700 tons of uranium.

8.5.2 Uranium Production and Consumption 2007

German demand for natural uranium as fuel can be calculated at approximately 3300 tons per year. In 2007, 3191 tons Unat were imported. There is no domestic commercial uranium production. Since 1990, there have been no exploration activities in Germany, either. Different German mining companies continued their exploration activities overseas, especially in Canada, until 1997. Since 1998, there is no commercial German uranium industry any more. Since 1991, uranium is only produced in the course of remediation activities in the area of former deposits and production centers of the Wismut GmbH (Fig. 8.16). Between 1991 and 2008 this amounted to 2471 tons of uranium.

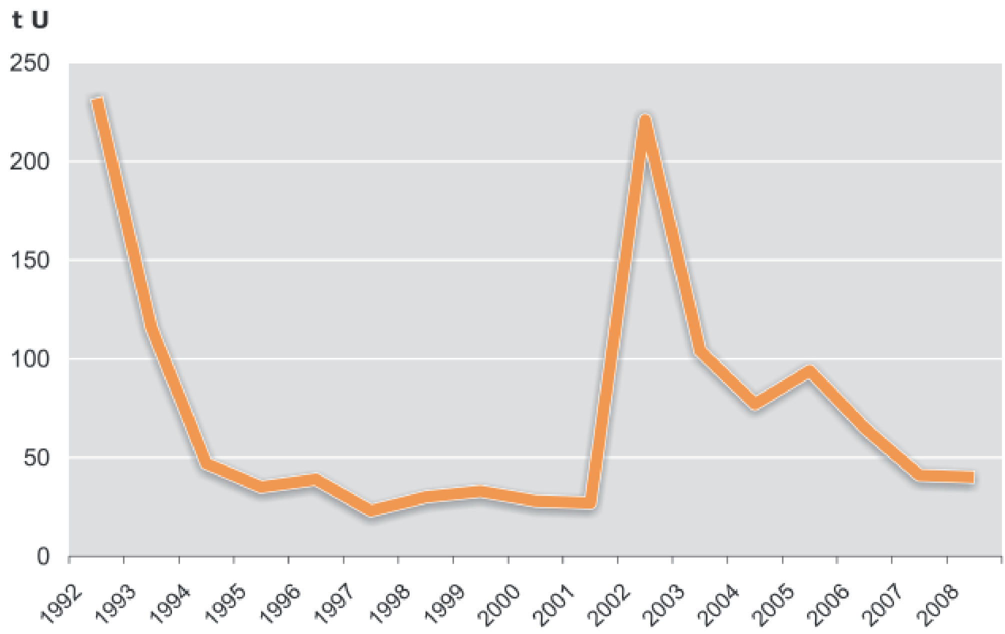


Figure 8.16: Trends in uranium volumes between 1992 and 2008 from the remedial action taken by the Wismut Gmbh (in tons of natural uranium).

As a consequence of high commodity prices on the international markets, the remaining uranium resources in Germany have, however, become the focus of foreign exploration companies. Several requests of national consultants as well as Canadian and Scandinavian companies for the Großschloppen deposit in the Fichtelgebirge have been received. Up to now, there were no reports or plans regarding exploration projects and boreholes. Preparations for the exploration of tungsten and tin in the Poehla mine in the Erzgebirge, which also contains uranium, have started.

8.5.3 Uranium Reserves and Resources

German uranium reserves and resources were last evaluated in 1993. In total, identified uranium reserves which are minable in the price category < 130 US$/kg uranium amount to about 7,000 tons. The known conventional reserves and resources mainly occur in closed mines of the East German mining areas, which have been renaturalized, and remediated since 1991. The future exploitation and availability is uncertain and is subject to political and economical framework conditions. Germany, in addition, has speculative uranium resources of 74 000 tons of uranium with mining costs exceeding 130 US$/kg of uranium.

8.5.4 Germany's Supply with Nuclear Fuels

With the amendment to the Atomic Energy Act in the year 2002, which represents the implementation of the agreement between the Federal government and energy supply companies dated June 14, 2000, the phasing out policy from the nuclear energy program for the peaceful use of nuclear energy in Germany has been regulated by law. Based on an average operating term of 32 years, a cut-off electricity limit has been fixed for each nuclear power plant. Once this has been reached, the appropriate nuclear power plant must be taken off the national grid. In accordance with this, it is envisaged that the last nuclear power plant in Germany will by switched off around 2022. The future uranium requirements in Germany will be reduced accordingly.

German demand for natural uranium is limited to the fuel supply of German nuclear power plants. In 2008, the installed base was 17 nuclear power plants with a gross output of 20 339 MW_e. The contribution of nuclear energy towards primary energy consumption in 2007 had a share of 11.1 % with 52.3 Mtce. With a share of 22 %, nuclear energy was in third position after brown coal (25 %) and hard coal (23 %) in the context of public energy supply and in second position for base load power supply with a share of 45 %. Owing to a slight overall increase in gross power generation, nuclear energy output reached 141 TWh. This was possible because plant utilization remained at a high level. Net power generation was 133 TWh.

The demand for natural uranium in fuel amounted to 3332 tons. It was covered by imports and from stocks. The volume of natural uranium needed for fuel production of 3191 tons U_{nat} was almost exclusively obtained via long-term contracts with producers in France, Canada, the USA and the United Kingdom.

8.5.5 Remediation of Uranium Mines

The closure and remediation activities of the former production sites of the SDAG Wismut were in their 17th year in 2007. The work is carried out on behalf of the German Federal Ministry of Economics and Technology (BMWi) by the Wismut GmbH. Of the € 6.4 billion made available for the major project in 1991, € 5.1 billion had been spent by the end of 2008, which amounted to 80 %. Until the end of 2008, the budget had been mainly spent on the landfill remediation in the Ronneburg area, the backfilling of the open-cast mine Lichtenberg, the flooding of the underground mining pits and the tailings remediation of the Crossen and Seelingstädt processing plants. Approximately 99 % of the underground backfilling work has been completed. Beside the activities in the areas of landfill remediation and site rehabilitation as well as the filling up of industrial tailings ponds, the remaining focal points will be the treatment of contaminated water from the pit flooding and the industrial tailings ponds. A particular challenge is posed by the driving of a hydraulic connecting gallery, the WISMUT-Stolln, with an overall length of around 2900 m from the pit fields in Dresden-Gittersee to the Elbestolln. It is envisaged that this work will be completed in 2011.

8.6 Geothermal Energy in Germany

8.6.1 Geothermal Energy Resources

In Germany, there are no hot steam resources from active volcanoes that can be used directly and with limited effort for the generation of geothermal power. Germany has, however, hot water reservoirs. Their thermal energy can be used for heating purposes and, with an appropriately high temperature, even for geothermal power generation. While heat generation, in particular from geothermal energy near the surface, is already well-established, geothermal power generation in Germany is still in its infancy. At the end of 2003, a demonstration project in Neustadt-Glewe produced electricity from geothermal energy for the first time in Germany. Current research efforts and pilot projects urge an increase in the use of geothermal energy in Germany.

8.6.2 Near-Surface Geothermal Energy

The use of geothermal energy from the ground near the surface for direct use (heating and production of domestic hot water) in Germany is economically viable in many cases. Experience with this technology exists since the 1970s. The development risk is low and the costs for the construction of small plants are manageable. For these reasons, the use of decentralized heat pump heaters in small dwelling units is suitable for the substitution of fossil energy sources.

According to Kaltschmitt & Wiese (1997), around 360 MJ per m^2 and year can be extracted in Germany from the soil layers near the surface. The technically realistic potential for development (Chapter 7) is considerably smaller, since the heat generated must be extracted in the immediate vicinity of the building to be heated and restrictions for land use have to be taken into account. The usable surface area is therefore reduced to approximately 7 ‰ of the total surface area of Germany; the reasonably exploitable energy amount is reduced to 940 PJ/a (Kaltschmitt & Wiese, 1997).
The number and output of small heat pump units installed currently in Germany can only be estimated since there is no central registration system. As of late, sales figures for heat pumps are published by the Bundesverband für Wärmepumpen e.V. (BWP, 2007) (Fig. 8.17), showing evidence that they have doubled for 2006 compared to the previous year. These sales figures do not, however, make any predictions with regards to the replacement of older plants using new technologies. Conservative estimations put the number of small plants for Germany in 2006 at 65 000 with a total output of 740 to 810 MW_{th} (Schellschmidt et. al., 2007). The installed output of these heating systems typically amounts to between 8 and 15 kW_{th}.

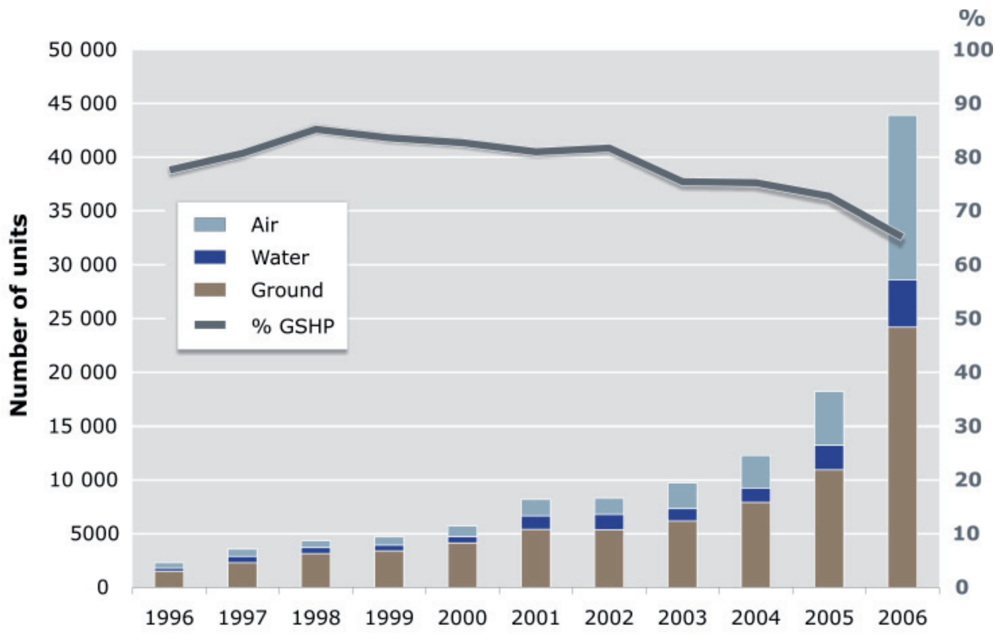


Figure 8.17: Sales statistics for geothermal heat pumps in Germany between 1996 and 2006 (BWP, 2007).

8.6.3 Hydrothermal Resources

Hydrothermal resources of high temperature are mainly limited to areas with recent volcanism where ascending igneous magma bodies intensely heat the rocks in situ at comparatively shallow depths. There are no active volcanoes in Germany; therefore, underground temperatures that do not differ far from the normal geothermal gradient are mainly encountered there. If one excludes depths below 5000 m, in essence, only hydrothermal resources of low temperature (up to 150 °C) can be considered in Germany. These resources are found in areas where water bearing rocks are encountered in depths that can be considered for the use of geothermal energy. The most important of these areas are the Southern German Molasses Basin, the Upper Rhine Valley and the North-German Basin (Fig. 8.18).

Normal temperature gradients found in the North-German Basin down to a depth of 5000 m are generally approximately 30°C/km. Potential hydrothermal resources are water-bearing strata from the Lower Cretaceous, the Middle and Upper Jurassic, the Late Triassic, the Middle Bunter and the Rotliegend. In the South-German Molasses Basin, the hydraulically permeable Malm karst forms the most important geothermal resource. Its potential for geothermal heat generation was estimated at the end of the 1980s in a comprehensive research project (Frisch et al., 1992; Schulz & Jobmann, 1989). The estimated amount of geothermal energy that can be gained regionally has been confirmed through a number of drillings.

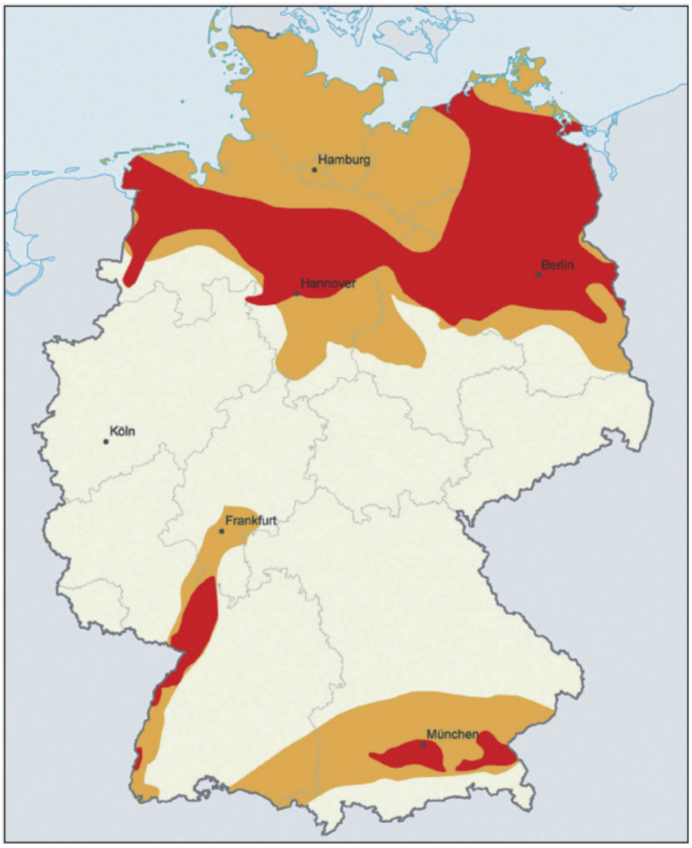


Figure 8.18: Hydrothermal resources in Germany (Schulz et al., 2007). Red areas highlight areas with temperatures above 100 °C, while yellow areas designate temperatures above 60 °C.

The areas with the highest temperature gradient are in the Upper Rhine Valley. In the southern part, the gradient can reach almost 110°C/km, in the northern part up to 44°C/km can still be encountered down to a depth of 3000 m. In the Upper Rhine Valley, the Upper Lacustrine Limestone, the Bunter and the crystalline basement can be considered as suitable aquifers and hydrothermal resources. Apart from the areas specified, other basin structures can also be considered in principle as possible hydrothermal deposits, such as the Sub-hercynian Basin, the Thuringian Basin and the South-German Basin.

According to table 8.3, the potentially usable energy content of the North-German Basin is the largest with 293 EJ, mainly due to its large surface area. Estimations are, however, subject to large uncertainties as the determination of the recoverable geothermal energy is largely dependent on hydraulic permeability and porosity in the target formations. Their distribution and due amount is generally not well known.

Table 8.3: Estimates for the maximum geothermal energy by regions (Hurter & Haenel, 2002) and for the maximum extractable geothermal energy for power generation (Jung et. al., 2002).

Region	mineable thermal energy (EJ)	extracable geothermable energ for power generation (EJ)
North-German basin	293	59
Molasses Basin	64	13
Upper Rhine Valley	156	18
total	*513* *approx. 16 300 GWa*	*90* *approx. 2 900 GWa*

Only part of the total amount of energy recoverable, detailed in Table 8.3, can be considered for power generation: Those areas where the temperature of the thermal waters exceeds a minimum value and where the residual temperature after use does not drop beneath a lower limit for technical reasons. Jung et al. (2002) include potentially water-bearing formations with temperatures above 100 °C and limit the residual temperature to 70 °C after power generation without further utilization of heat. For the selection of preferred development areas, the figures in Table 8.3 are not decisive, though. In this case it is very important in which areas the highest yields and thermal outputs for each drill hole pair can be achieved and how high the non-discovery risk for hydraulically favorable structures will be.

The currently largest geothermal power plant in Germany was put into operation in 2007 in Landau, Rheinland-Pfalz. Here, hot water with approx. 150 °C and a flow rates of 50 to 70 l/s is brought to the earth's surface via a borehole at a depth of around 3,300 m and cooled down in two stages (Fig. 8.19). In the first step, the temperature range between 150 and 70 °C is used in an ORC power plant to generate the electricity for around 6000 homes. The installed electrical output is 3 MW_e. The residual heat of the thermal water is then used for the district heating supply of approximately 200 to 300 homes in a second step, which corresponds to a residual heat between 3 and 6 MW_{th}.

The largest geothermal heating plant in Germany so far was put into operation in 2005 in Unterschleißheim near Munich. Here, hot thermal water with a temperature of 81 °C and a production rate of 90 l/s from a depth of around 1960 m is produced. The energy of the thermal water is used to supply residential areas and public buildings via a district heating network. The annual geothermal production is 28.25 GWh. Additional heat generation using natural gas and light fuel oil is required only during peak load times and the geothermal share of it is at least 61 %.

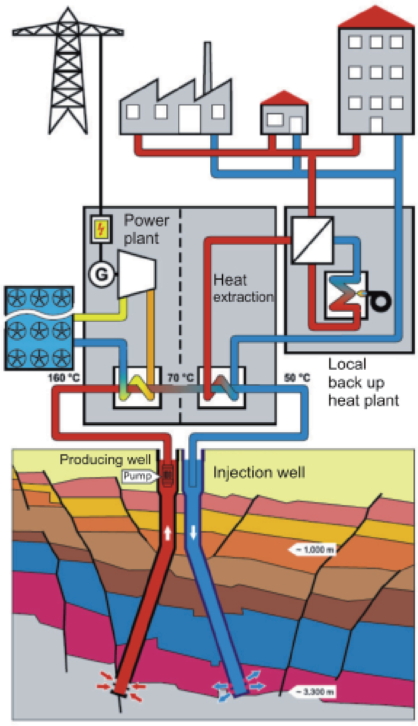


Figure 8.19: Geological situation and technical implementation of the largest geothermal power station in Germany, Landau (www.geox-gmbh.de).

8.6.4 Hot Dry Rock Resources

Hot dry rock deposits for geothermal energy comprise rocks where the temperature is high enough, but without additional treatment only insufficient amounts of hot water can be extracted (Chapter 7.2.4). Areas potentially usable for power generation using hot dry rock technology in Germany are the Central and Southern German crystalline area, the crystalline in the Upper Rhine Valley and the occurrence of Rotliegend volcanics in the North-German Basin (Fig. 8.20). Based on the assumption of optimum functioning and usability of the HDR technology, the maximum extractable thermal energy quantities detailed in Table 8.4 are

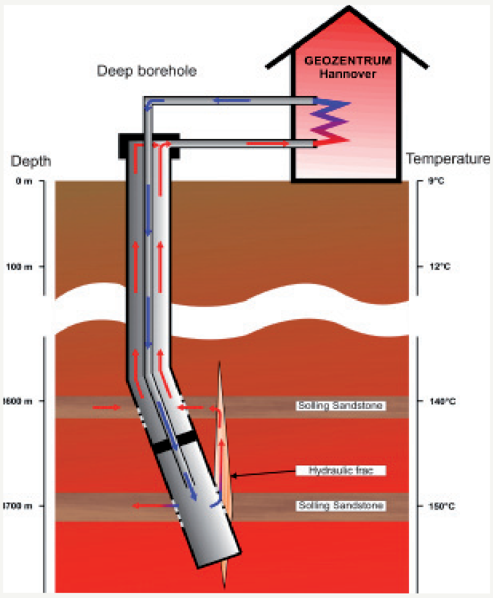
Tabelle 8.4: Maximum extractable thermal energy for power generation with optimum usability of HDR technology (JUNG et al., 2002).

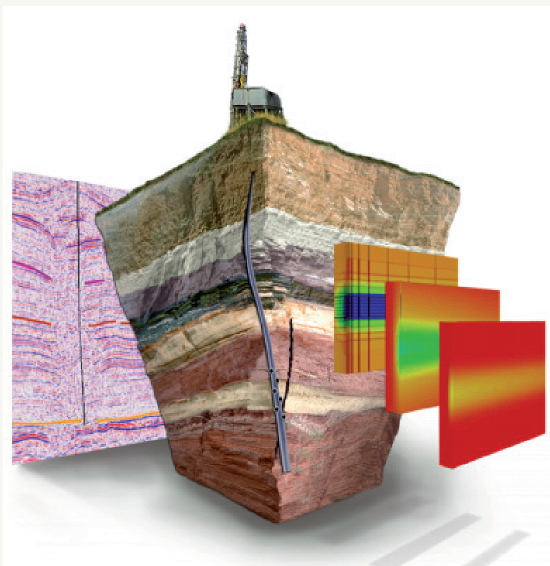
Region	usable energy for power
North-German basin	540 EJ
Upper Rhine Valley	480 EJ
Central and South German crystalline area	7 600 EJ
Total	8 620 EJ = approx. 274 000 GWa

achieved. Jung et al. (2002) include crystalline rocks in the depth range between 3000 m and 7000 m and estimate a residual temperature of 70 °C for power generation without further utilization of heat. This way, they estimate the maximum extractable energy quantity for power generation with optimum usability of the HDR technology in Germany to be 8620 EJ (Table 8.4).

GeneSys – Heat Generation Using Single Borehole Method

The GeneSys project (Generated Geothermal Energy Systems) is carried out by the BGR and the Leibniz Institute for Applied Geophysics (LIAG) in Hanover in order to develop and implement innovative concepts for geothermal heat generation from large depths. Emphasis is on heat generation for medium-sized customers (a few Megawatts of thermal output), independent of location and even from sediment rocks with little permeability. The implementation of a single borehole method for the reduction of development costs is planned using the heat supply of office and laboratory buildings of the Geozentrum Hanover as an example. To this end, next to the Geozentrum a borehole up to the rocks of the Middle Bunter at a depth of approximately 3800 m is sunk. Based on the single borehole concept previously developed in a research project at the natural gas exploration well Horstberg Z1 water must then be made available at a temperature of approximately 130 °C with a mean flow rate of 25 m^3/h for use. The creation of large artificial fractures in the deep underground is the basis for water flow and geothermal energy extraction in low permeable sedimentary rock. This is done by breaking up the rock strata (*Frac*) by injecting water at high pressure. Good hydraulic conductivity of such artificially made fracs in the rock and its high storage capacity could be proven in Horstberg Z1 in a so-called cyclic test for heat recovery. Cold fresh water was injected into the crack and recovered as hot water after a certain delay. By repeating this process, cyclic energy recovery from the crack could be demonstrated in principle. In another process, the hydraulic communication between two sandstone strata created by the crack is used to realize water circulation. Drilling of the GeneSys well is planned to start in 2009.





Source: LIAG

Methods to assess the stored heat in low permeable rock are still under development. Only in 2008, electricity was produced from a hot dry rock system in the **pilot project in Soultz-sous-Fôrets** in Alsace. The extraction of geothermal energy from deep, dense rock formations by means of artificial crack generation had been investigated for 20 years in the European research project. To develop the reservoir, a borehole triplet consisting of a single injection and two production wells was sunk down to 5000 m in the granite (Fig. 8.21) and connected to a fissure system extending over several square kilometers by enormous injections of water. The artificial geothermal reservoir created this way enables circulation of water in a closed-loop circuit between several boreholes (Schindler et al., 2008). Following a successful circulation test in 2005, the trial operation for power generation started in summer 2008. The thermal output of 13 MW_{th} is converted to an electrical output of 2.1 MW_e by means of an ORC power station.

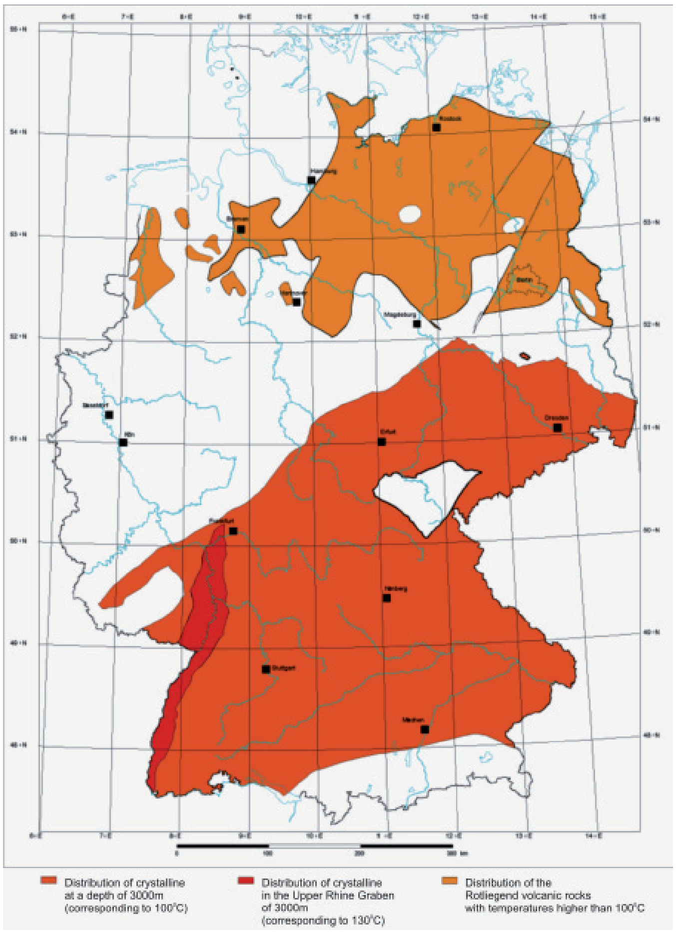


Figure 8.20: Occurrence of crystalline rocks in Germany which can be considered for geothermal power generation using the hot dry rock method (Jung et al., 2002).

Despite the achievements in the Soultz HDR project, current experience is not sufficient to ensure success of the hot dry rock technology at any desired location. Site conditions, especially rock properties, tectonic stresses, fissure grids and the existence of faults have significant influence on formation and properties of created or stimulated crack systems. Therefore, it is currently not certain if the hot dry rock method is usable at all locations in the crystalline areas and beyond and which proportion of the huge potential is actually usable.

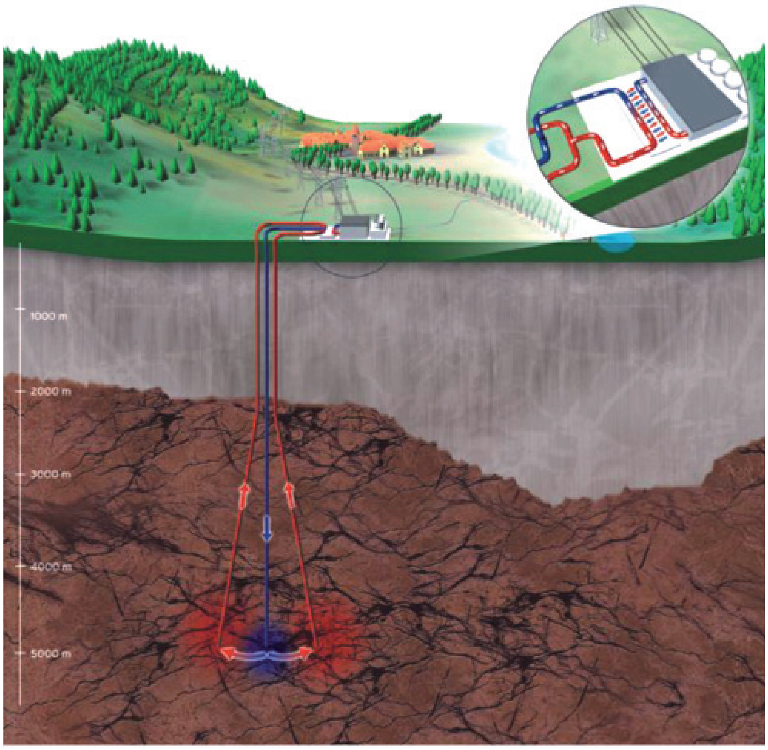


Figure 8.21: Geological situation and technical implementation of the hot dry rock project Soultz-sous-Fôrets. Source: GEIE „Exploitation Minière de la chaleur".

8.6.5 The Future of Geothermal Energy in Germany

The development of the utilization of geothermal energy in Germany has benefited significantly from law changes and measures of the integrated energy and climate package of the German Federal Government. In connection with the ecological tax reform, the Federal Government published a support program for *measures for the utilization of renewable energies*. In 2004, the Amendment of the Act on Renewable Energies (EEG) was adopted and modified in 2008. Thus, electricity from geothermal power stations up to 10 MW is paid at 16 ct/kWh and from plants larger than 10 MW at 10.5 ct/kWh. Additional payments result for plants that are put into operation before 2015, for the utilization of residual heat and the use of petrothermal technology for artificial crack generation.

The dramatic development of thermal utilization of geothermal energy has resulted in 30 geothermal installations larger than 100 kW_{th} (Fig. 8.22) with a total installed output of 104.6 MW_{th} being operated by 2004 in Germany (Schellschmidt et al., 2005). Further 15 projects are planned to be completed until 2010. This would mean a total of 231 MW_{th} installed, the electrical output from geothermal plants would then be 18 MW_e.

An overview of sites and details of the geothermal projects currently being planned or implemented provides the geothermal information system for Germany. This is developed by the Leibniz Institute for Applied Geophysics (LIAG) in the Geozentrum Hanover and can be researched using the Internet (www.geotis.de).

The research regarding deep geothermal energy in Germany is aimed mainly at reducing the costs for exploration and utilization of geothermal resources through technical innovation. Examples of research projects are the hot dry rock plant in Soultz-sous-Fôrets just put into operation and the GeneSys project that is to supply the offices and laboratories for around 1000 employees of the Geozentrum Hanover with heat from a geothermal plant using innovative single borehole technology (Info box 11).

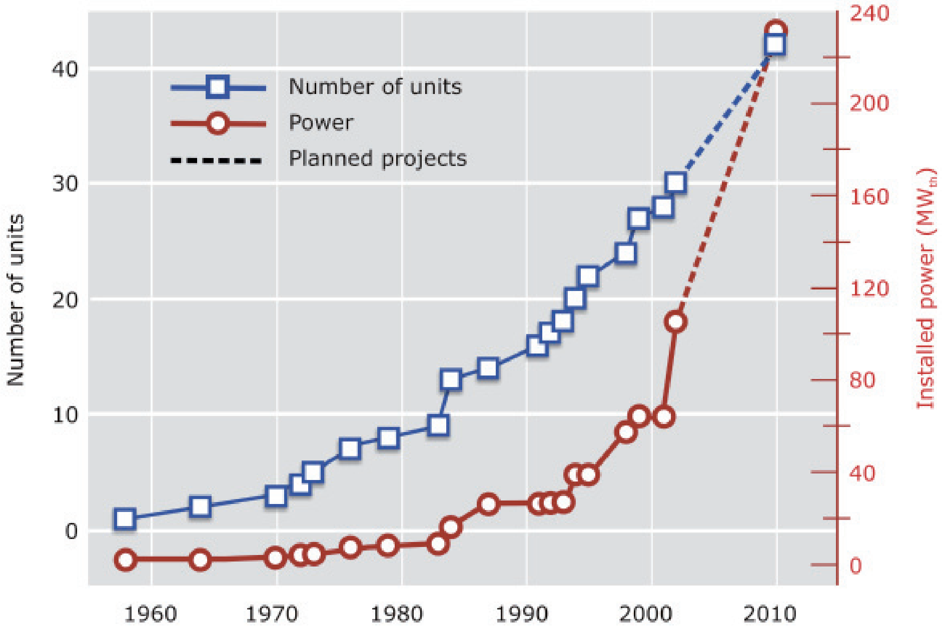


Figure 8.22: Geothermal installations with more than 100 kW_{th} and their output in Germany since 1955 as well as a scenario of the development until 2010 (Schellschmidt et al., 2005).

8.7 The Supply of Germany with Energy Resources

With the exception of brown coal, Germany is highly dependent on imports of energy resources. Germany receives nearly 90 % of its uranium from France, Canada, the United Kingdom and the US. For this reason and in view of a good stock of uranium, supply bottlenecks are not expected. The situation in the most important supplying countries regarding individual fossil energy resources like petroleum, natural gas and coal will be discussed in the following section. In this context, the trends in reserves and production as well as the estimated resources still available have been analyzed. In addition, further potential supplier countries will be discussed.

8.7.1 Petroleum Supplier Countries

We will take a closer look at the seven leading supplier countries, each having delivered more than 2.5 Mt of oil in 2007. Together they account for more than 83 % of all imports (Table A 8-1). The trends in reserves and production since 1960/1970 are shown in Figure 8.23, ranked according to the amount of petroleum supplied to Germany in 2007. It should be noted that separate reserves figures for Russia, Kazakhstan and Azerbaijan only exist since 1990. In addition, the resources figures at the end of 2007 are given.

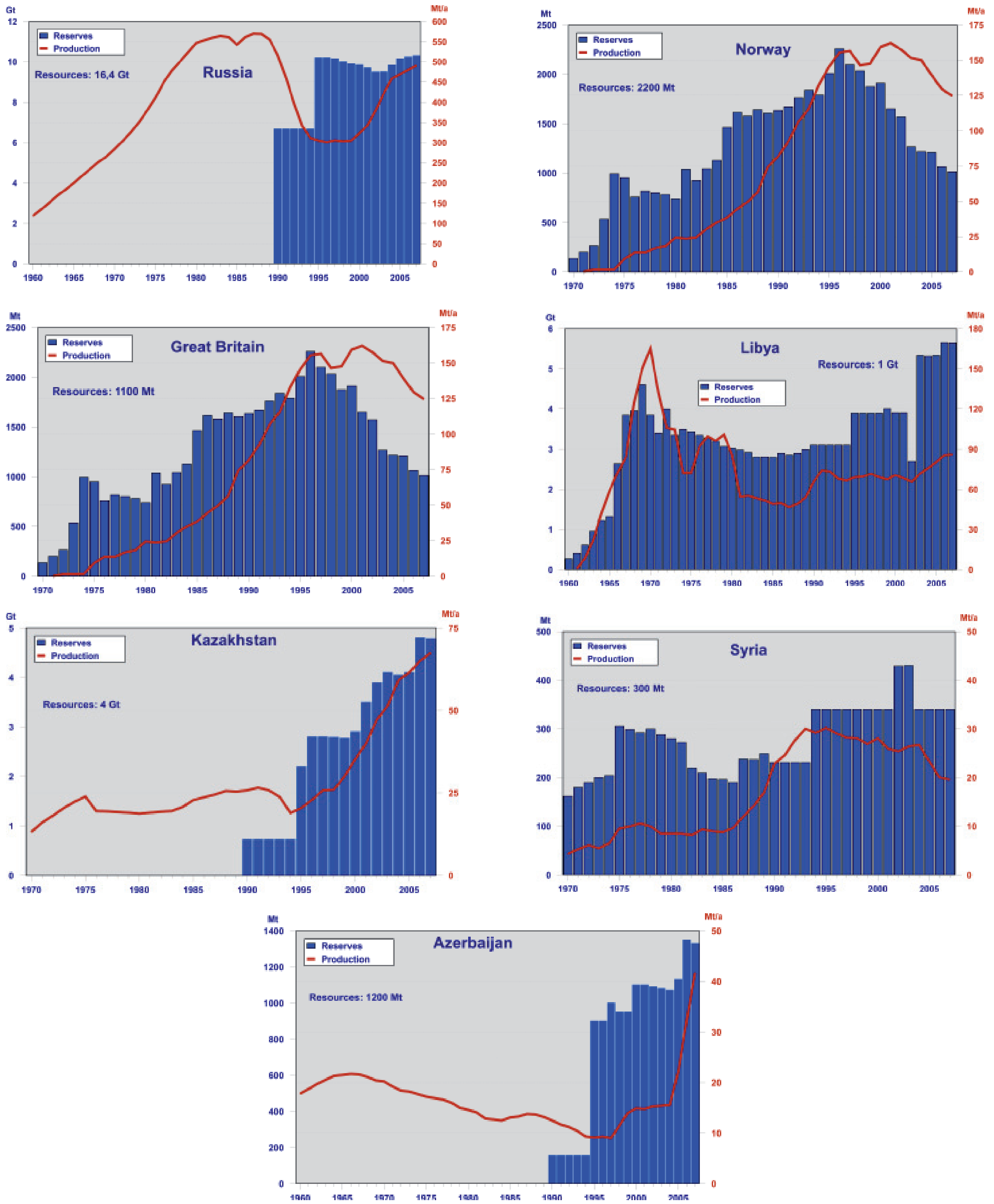


Figure 8.23: Trends in reserves and production as well as estimated resources at the end of 2007 for major crude oil supplying countries of Germany.

Based on the presented figures, the above countries can generally be grouped into two categories:

1. Countries with decreasing reserves and falling production. These include Norway, the United Kingdom and Syria, which will also face falling production in the future.
2. Countries with rising or constant reserves and rising production. These particularly include Kazakhstan and Azerbaijan, but also Libya and Russia.

In accordance with this grouping, the importance of these countries for future German petroleum imports will change. While the proportion of North Sea oil, which together with the Danish supplies currently reaches approximately 30 %, will decline, the share of countries such as Kazakhstan and Azerbaijan but also Libya will probably increase. The volume of Russian supplies, however, depends on other factors. A deciding factor is the further development of production, on the one hand, which has been decreasing slightly in 2008, and the development of exports to other regions, particularly to the Asian markets, on the other hand.

Because petroleum is a product traded worldwide, other suppliers could be of interest to Germany, too. In accordance with the amount of remaining potential (Fig. 3.3), the OPEC states on the Persian Gulf, Nigeria, Angola, Brazil and Venezuela are obvious candidates. This, however, would increase the OPEC share in German imports. The availability of energy resources on the world market depends on the global situation of supply and demand. In this respect, it seems important that German oil companies get involved in exploration and production abroad in order to help safeguarding supplies.

8.7.2 Natural Gas Supplier Countries

In the following, the three leading supplier countries Russia, Norway and The Netherlands will be looked at more closely. In 2007, they had a share of more than 96 % of the imported gas (Table A 8-2). The trends in reserves and production since 1950 are shown in Figure 8.24, ranked according to the amount of the natural gas volume supplied in 2007. In addition, the estimated size of resources at the end of 2007 is given.

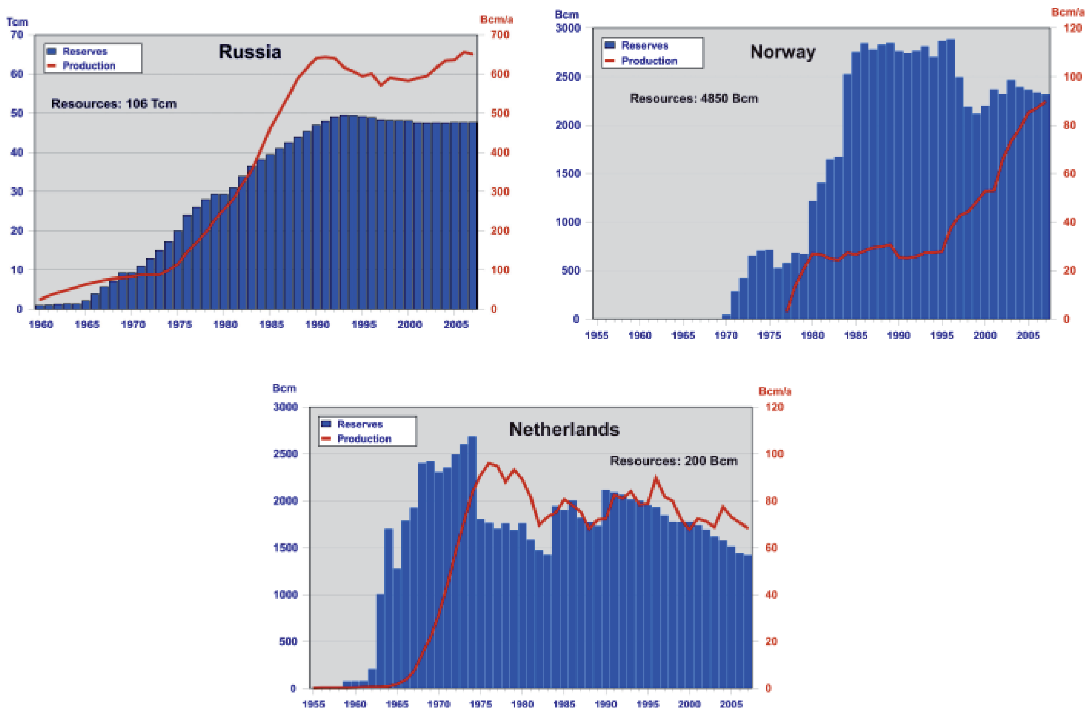


Figure 8.24: Trend in reserves and production as well as estimated resources at the end of 2007 for major natural gas supplying countries of Germany.

Based on these graphs, the supplying countries can be grouped into two categories for natural gas just like oil:

1. Countries with decreasing reserves and falling production. These include the Netherlands, who only have a low amount of resources.
2. Countries with constant reserves and rising production. These include Russia and Norway, which both still possess major resources. These two countries will keep playing an important part in supplying Germany with natural gas in the future. For Russia, it should be considered that the reserves not yet exploited in the Arctic regions, particularly the Jamal peninsula and the Shtokman field, must be developed in the near future to be able to meet long-term supply obligations (Bittkow & Rempel, 2009).

The following countries are rich in natural gas and can be considered to be potential supplier countries: the Middle East (Iran, Qatar, Iraq), North Africa (Algeria, Libya, Egypt), the Caspian region (Kazakhstan, Turkmenistan, Azerbaijan) and Nigeria. Appropriate diversification of natural gas imports, however, presupposes the creation of the required infrastructure. Apart from the construction of new or the extension of existing pipelines, the foundations for the import of liquefied petroleum gas have to be laid.

8.7.3 Coal Supplier Countries

Lignite coal used in Germany almost exclusively comes from domestic production (Chapter 8.3.4). In contrast to this, the declining domestic production of hard coal over the last few years has been balanced largely by rising hard coal imports. German hard coal imports 1990 only came to 11.7 Mt, but in 2007 they were already four times as high (47.5 Mt) and covered around two thirds of the German demand for hard coal. The five leading supplier countries for hard coal (Fig. 8.12), which are Russia, South Africa, Columbia, Australia and Poland, accounted for nearly 74 % of imports in 2007. Because of the continuous increase in Russian imports seen since the turn of the millennium, Russia has risen to the position of largest coal supplier for Germany in the years 2006 and 2007. Almost in parallel to this, the imports from Poland decreased, which is primarily due to the decrease in production there. All these countries have sufficient reserves for many decades to maintain current production. In addition, major resources have been reported for these countries.

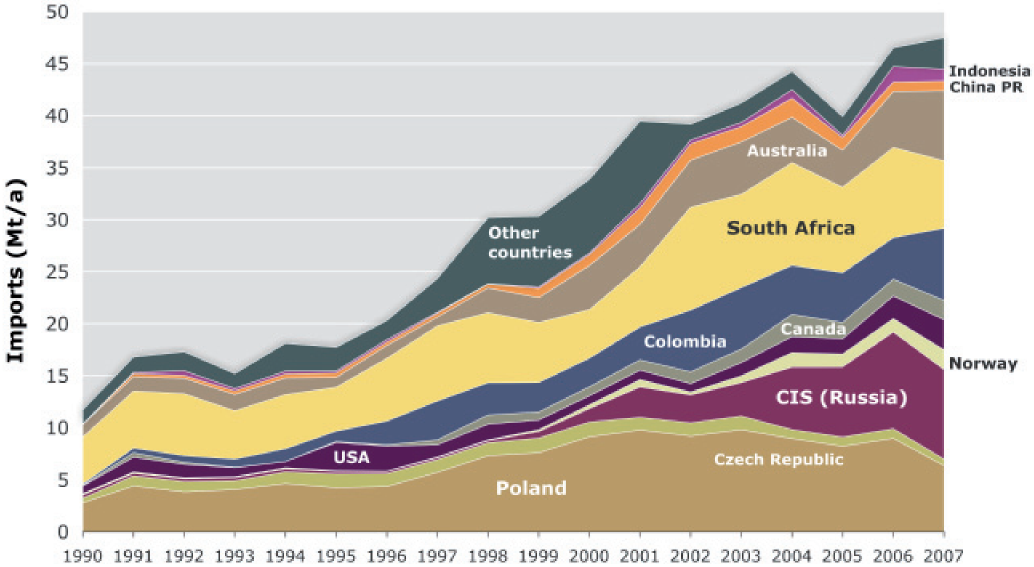


Figure 8.25: Trends in the import of hard coal and hard coal products such as coke and coal briquettes into Germany since 1991 (according to various annual reports by the VDKI).

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9 Availability of Energy Resources

9.1 The Dynamics of Exhausting Finite Resources

In the discussion about the finite nature of resources, in particular of energy resources, various terms such as reach, static reach, maximum production, peak oil or availability are supposed to provide statements or guidelines on the degree of depletion of the resources. The term reach, in particular, directly implies the question as to how long the resources will last. Generally, it is not defined whether "how long the resource will last" means the point in time up to which all demands for the resource can be met, or the last production before all deposits are exhausted, or any other scenario in-between these two extremes.

9.1.1 Static Reach

Static reach represents a certain specification of the term *reach. The static reach* is calculated as the ratio of the reserves and the current annual production. The result is a number of years, for example 40 years for oil, which indicates the point in time when oil from the currently known reserves would be exhausted, if production were to continue in a constant manner, i.e. statically, each year from now on, and the initial reserves would stay constant. However, because the quantity of oil production has varied each year to date, and the known quantity of producible oil has also changed every year, the *static reach* needed to be modified every year in an unpredictable way. In fact, for many resources, including oil, relatively constant *reserves-to-production ratios* have been observed over the years (Fig. 9.1). For example, between 1945 and now, the *static reach* for oil ranged between 20 and 45 years. For the past 20 years, this value has been fluctuating only between 40 to 45 years. This is due to the fact that the oil industry is continually exploring, discovering new deposits, and using technical means to expand the potential of deposits that are already in production. Therefore the term "static reach" should be understood rather as a situational report of the

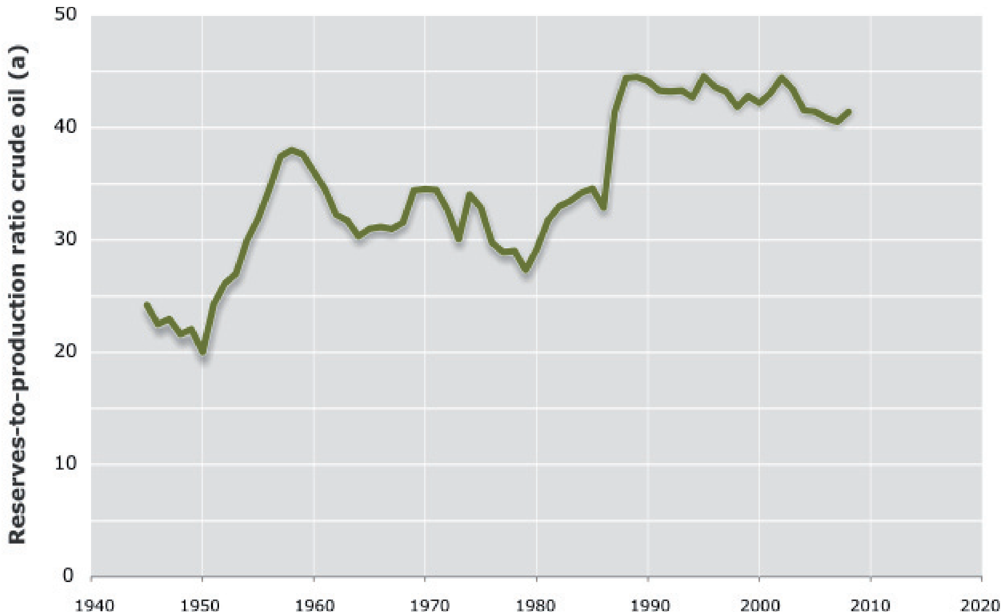


Figure 9.1: Static reach (= reserve to annual production ratio) of oil between 1945 and 2008.

industry that is extracting the respective resource. A sudden clear drop in that *static reach* could mean that in the aforementioned ratio the quantity of producible oil, i.e. the reserves and resources, vanish faster than required by demand. This could be interpreted as a sign that the industry's economic interest in developing new deposits is waning, or that the exploration and development is no longer in step with the required increase in production.

It follows from the situation described above that the *static reach* is not suitable to predict future developments with respect to the production of energy resources. Thus, there is no correlation between the name and the value of evidence of the *static reach*, and therefore, the use of *static reach* is mostly misleading. For this reason, the present study does not use the term *static reach* to characterize the availability of energy resources.

9.1.2 Peak Oil

Peak Oil is generally considered to be the all-time maximum of oil production, i.e. the maximum quantity of crude oil ever produced in a year. The model was initially developed to forecast oil production, but several authors now also use it for natural gas (peak gas) and even for coal (peak coal). The peak oil theory was derived from the assumptions of the Hubbert curve, which was developed by the American geologist Marion King Hubbert (1903—1989). According to Hubbert, the worldwide production of oil will initially increase steadily, and then decline irreversibly as soon as half of the oil has been produced. Because in this theory half of the oil will have been used at peak oil, this point is also called the depletion midpoint. The reason given for the correctness of the assumptions with respect to peak oil is that Hubbert's predictions about the course of oil production did in fact prove correct for the United States.

According to the peak oil theory, it is possible in the ideal case to predict the future course of the worldwide oil production, including that of peak oil, at an early time based on the production up to then and the finding history of the oil fields by adapting type curves. However, calculations, representations, definitions and compiled data of various peak oil models are not uniform, which results in a broad spectrum of potential production courses based on that theory (Fig. 9.2, 9.3). Although the initial peak oil discussion was primarily based on so-called Hubbert curves, recent forecasts also use approaches such as the backdating method, creaming curves, the hotelling model and probability models.

The scenarios of the potential development of oil production shown in Figs. 9.2 and 9.3 point at peak oil between 2007 and 2070. Some differences arise when taking unconventional oil into account. It is remarkable that there are strong fluctuations in the various models with respect to the total quantity of producible oil, i.e. the areas under the production curves in the relevant figures. This can be attributed to varying assumptions about the total potential (EUR). For better comparison, the representation of ASPO (2008) includes the production of NGL and oil from the arctic and deep-water regions, although according to Campbell, they are considered to be unconventional oil. It is obvious that the order of magnitude of the assumed EUR in itself is a significant uncertainty factor in the prognosis of future production developments. A combination of conventional and unconventional oil (Fig. 9.3) shows only a slight fluctuation of the peak oil, aside from the Odell curve (2000), which puts the maximum in 2070.

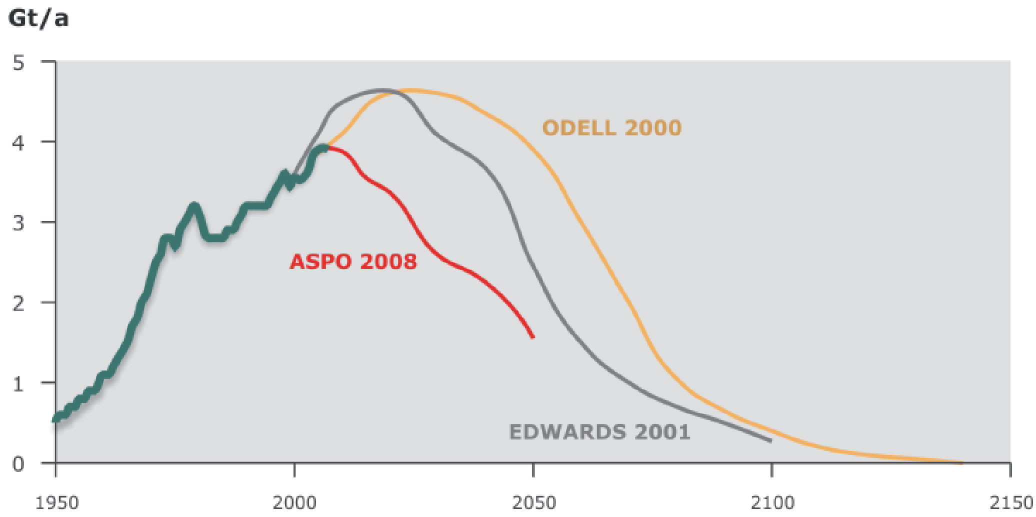


Figure 9.2: Examples of the prognosis of production courses with peak oil of conventional oil.

Contrary to the *peak oil* models, which have *per se* the objective of predicting the point in time of maximum oil production, demand scenarios, and the underlying growth prognoses, in general predict a steady increase of oil consumption into the distant future. However, these scenarios do not take the supply situation into account.

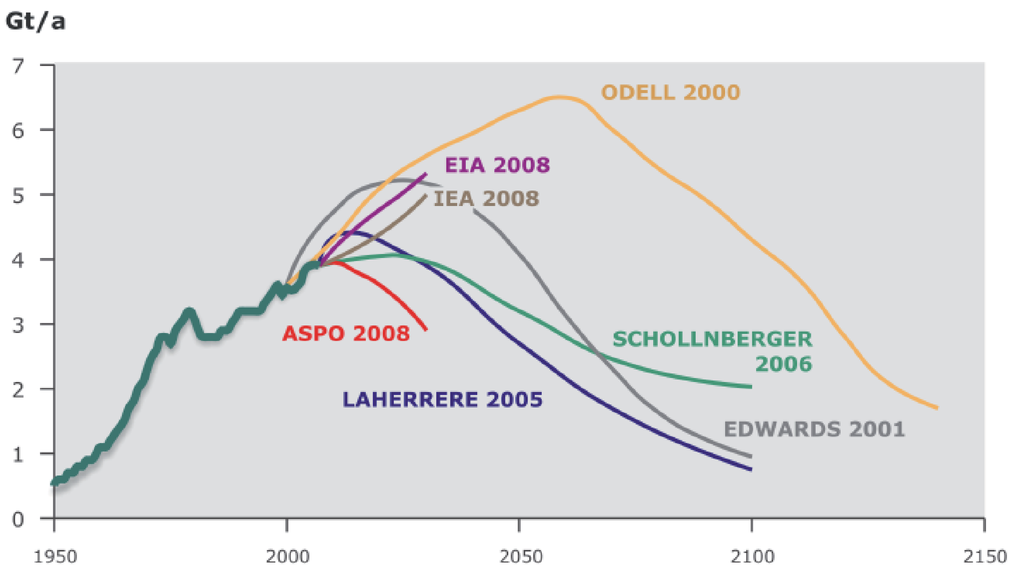


Figure 9.3: Examples for predicted production courses with peak oil of conventional and unconventional oil.

9.1.3 Availability

The production history of fossil fuels carriers to date shows that until now, geological availability was not the major factor affecting production. Rather, the increasing demand developed as a consequence of technological progress, macroeconomic and geopolitical processes, the high added value, and the respective investment climate. That demand, and the high profits were a steady incentive to find and develop new deposits. In the face of the limitation of fossil energy, this may change in the future, but in the past, the interplay of supply and demand was the driving force behind the development of new deposits and new locations, as well as for the abandonment of fields that were no longer profitable.

Therefore, the term *Reserve* is not only defined by geological criteria, but also by the requirement that production has to be profitable from an economic point of view (Chapter 2.4.2). Because of technical progress, and for lack of more economical alternatives, more and more deposits were categorized as profitable in the past, and thus contributed to an increase of the reserves. To what extent this development can continue largely depends on whether the economy and government accept the challenges related to a greater exploration and production effort in frontier areas. From this aspect, geological availability is not an independent variable, but can be considered only in the context of the economic environment.

The interaction of geological, political and economic factors, together with the technological development, can lead to unpredictable dynamics of the availability of energy resources. For example, phases with strong oil price increases represent additional burdens for oil-importing countries, with the side-effect that there is a greater desire for a careful use of oil. And as energy prices rise, there is also a greater willingness to explore and develop deposits that previously were not considered economical. A strong drop in oil prices, which initially appears lucrative for the consumer, leads to a strong loss of income for the companies that produce and export oil, and in the long term to a decline of their exploration activities. The resulting drop in the reserves can in time affect the future energy supply and price levels, boosting the prices because of a lack of supply.

An intermediate loss of income can lead to a decline of the respective economy of oil exporting countries that strongly depend on oil. For example, because 85 % of Nigeria's national income originate from the oil industry, it sank from USD 4.4 billion in October 2008 to about USD 2.09 billion in November 2008. After the Asia crisis and the decline of the demand for oil, as well as the disputes within OPEC, the OPEC countries suffered income losses of about USD 50 billion in 1998, which corresponds to one third of the planned revenue from the oil business. This experience was an important reason for the OPEC countries to make a greater effort of adhering to their self-imposed production discipline.

Historically, there have been repeated interferences that affected the availability of energy resources, for various reasons (Fattouh, 2007 b). Complementary interests of producers and consumers, governmental exertion of influence, as well as insecurities about the investment behavior due to economic, financial and political framework conditions have played an important role in this respect.

For example, the behavior of OPEC and IEA indicates **complementary interests** of producers and consumers. Having the option to establish production quotas gives OPEC an effective instrument for influencing the oil market. OPEC's goal is to produce enough crude oil to satisfy the demand at a uniformly high price. Excessive supply - as well as shortages - is unfavorable for trade. As protection against unexpected interruptions, the objective is to keep the production capacity always a few percentage points above the actual production (Fig. 9.4). The difference between capacity and production, called spare capacity, is considered a potential indicator for the risk of short-term supply bottlenecks and influences the spot price (Fattouh, 2007 a).

As a counterbalance to the OPEC cartel, the OECD countries founded the International Energy Agency (IEA) in 1974. IEA estimates the short- and long-term demand for fossil fuels. The oil producing countries also use these analyses, which are published in monthly Oil Market Reports and annual World Energy Outlooks (cf. IEA, 2008 a), as an indicator for investments. Because of the quick economic development in countries outside of the OECD, global demand has increased to an unexpected extent in recent years, causing the spare capacity to shrink. The low spare capacity is seen as one potential reason for the price increases in recent years until 2008 (Fig. 9.4).

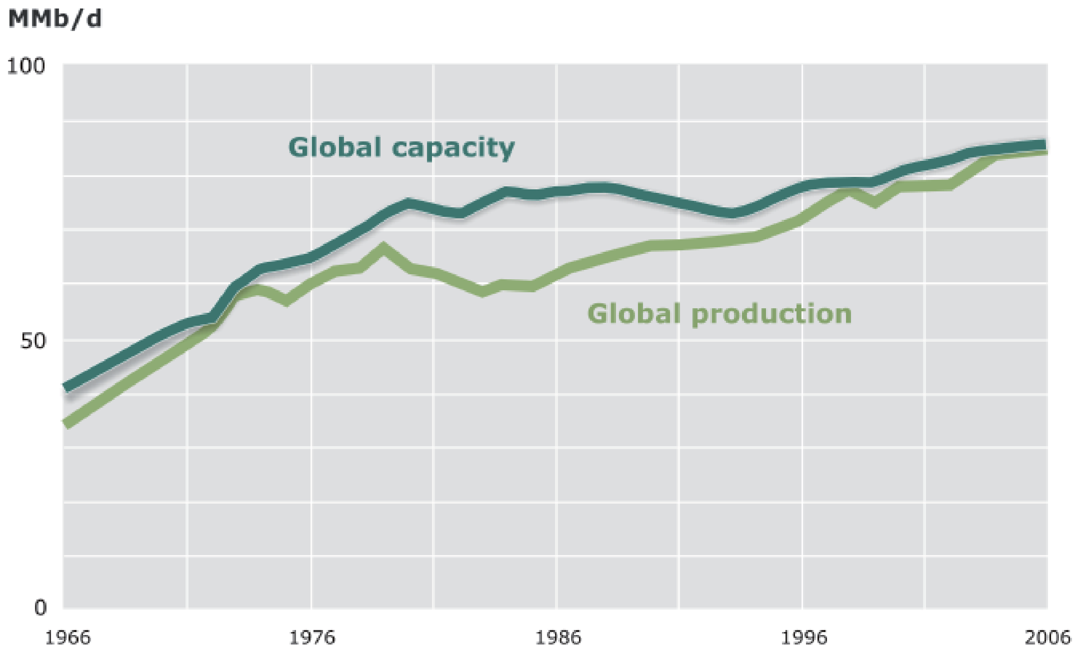


Figure 9.4: Worldwide production capacity and production between 1966 and 2006. The difference is called "spare capacity" (Kloppers & Yaeger, 2008).

Analog to the spare capacity on the production side, there is the national strategic reserve on the consumer side, which is intended to absorb unexpected supply bottlenecks. The national strategic reserve may be used only in case of physical interferences, but never to influence pricing. It is monitored by the IEA and can maintain the current supply of the OECD for about 52 days. In Germany, the German National Petroleum Stockpiling Agency [Erdölbevorratungsverband (EBV)] is responsible for maintaining a stock of oil and oil products in a range of at least 90 consumption days. All companies producing the respective products domestically or importing them to Germany are mandatory EBV members. Correspondingly, there are also buffer capacities for the gas market. However, these buffer capacities are not mandated by law, but rather compensate daily or seasonal fluctuations in supply and demand (Chapter 8.2.4) and therefore have been more of a business management tool so far than a political control.

The relation between the large international (IOC) and national oil and gas companies (NOC) (Info box 1) exemplifies an increasing **governmental influence** on the production of energy resources. Until the early seventies, the IOCs controlled the international oil market, and then this *era of the seven sisters* was replaced by the *OPEC era* (Fig. 9.15). Even today, in the *global market era*, the IOCs and the independents still wield considerable influence (Info box 1). The increasing influence of the NOCs raises the question if and to what extent an NOC must be considered a governmental institution, and how the political goals of governments affect corporate strategies. Combining national, social or military interests in the actions of NOCs may cause a drop in economic efficiency. Furthermore, in certain cases, NOC profits may not be applied to optimal corporate use. According to Jaffe (2007), the most of the NOCs lag behind the IOCs with respect to profitability because they subsidize oil products and do not work as efficiently as the IOCs. Because of the lack of profits, greater difficulties can be expected in the development of new deposits and the increase of production than it was the case in the past with IOCs.

The availability of energy resources may be further influenced by subsidies or legislation. For example, a few nations, such as China and India, but also OPEC countries, use subsidies to promote the consumption of fossil energy resources to stimulate their economy in a prominent place. According to IEA, the subsidies in the Asian region were approx. USD 100 billion in 2007. However, in view of the high oil prices, Asian governments had to cut the subsidies in mid-2008 (EID, 2008). Other countries try to curtail the use of individual energy resources with the help of legislation. They cite environmental protection, the reduction of CO_2 emissions, the desired independence from finite energy resources, as well as market advantages due to technical innovation, as some of the reasons. These developments are often accompanied by supporting measures to increase energy efficiency, the stimulation of the use of other energy resources, and the development and market introduction of environmentally safe, sustainable, regenerative forms of energy.

Investments are the central factor for discovering new deposits, developing technologies for the production efficiency of energy resources, and providing the infrastructure for the production, processing and transportation. It is known that investments lag behind energy prices time-wise. In the correlation between oil prices and investments in Fig. 9.5, it must be taken into account that when oil prices are high, the cost of exploration, for example the cost of deep-water drilling ships or prices for raw materials such as pipes, also rises. High prices for iron ore, steel and other raw materials are therefore the cause as well as the effect of high oil prices and oil products. The *IHS/CERA Upstream Capital Cost Index* (Yergin, 2008) shows that worldwide the cost of exploration and production almost doubled between 2005 and 2008. On the other hand, there is no obvious direct correlation between investments and oil production because a decade or more can pass between exploration, development and production from an oil field. This time is significantly longer in cases of exploration and development in frontier areas. Therefore, the judgment that a safe supply is guaranteed only if investments are made early and regardless of short-term economic developments, is all the more important.

This judgment is contradicted in some aspects by the situation in the energy markets. The fact that by far the greatest growth in the future oil and gas deposits is expected to be under the control of NOC in non-OECD countries leads to insecurities about whether future investments will be made at the right time, and to a sufficient extent. Furthermore, in times when oil prices are low, decisions to request and grant credit for investments are made rather hesitantly. Sufficient and timely investments can be made in particular when energy and financial markets are stable and predictable in the long run. Investments that are made too early can lead to an oversupply, price drops and losses. However, if there is

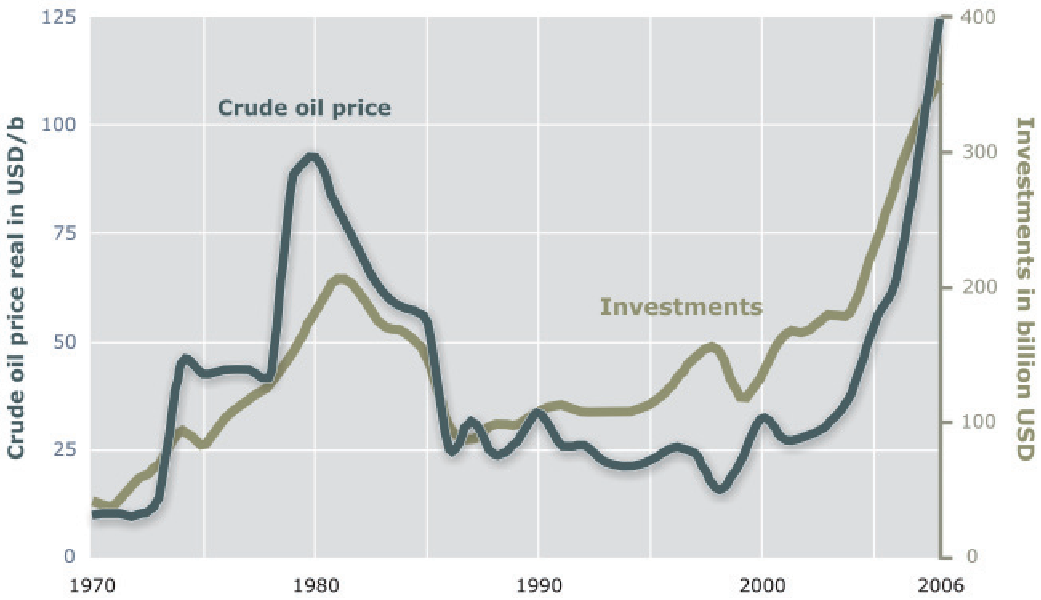


Figure 9.5: Comparison of the development of crude oil prices and investments in the oil sector since 1970 (NPC, 2008).

no prospecting, exploration and development of oil deposits in frontier areas, the result may be supply bottlenecks in the oil importing countries.

This implies that the term *availability of energy resources* has a different meaning at every point in the process chain, from the deposits up to the end usage. For example, a country with rich oil reserves will attribute a different meaning to availability than a company that produces oil, a refinery, or the driver of a car at the gas station. With respect to the entire process chain, the availability of energy resources may be influenced by geological conditions, the technical feasibility of the production, transport restrictions, the infrastructure situation, the political framework conditions, and specifics of the economic situation in the markets. The following discussion about the availability of the individual energy resources focuses specifically on the geological availability, and also discusses consequences on the remaining variables that influence availability.

9.2 Availability of Geothermal Energy

In recent decades, the development of geothermal power generation was limited largely to countries where high-temperature deposits could be exploited because of favorable geological conditions. Power generation from low-temperature hydrothermal deposits and impermeable rocks with the help of *Hot Dry Rock* (HDR) technology is still worldwide in the pilot phase, and a prognosis about its future development can be made only after the methods employed so far have proven effective. The significant influential variables for the development and prognosis of geothermal energy use are primarily the development of energy costs, especially for coal and natural gas, technical advancements in the development of geothermal energy, as well as political guidelines and funding measures for geothermal energy.

Between 1975 and 1980, the installed geothermal power strongly increased worldwide. From 1980 to 2005, the increase remained nearly constant at about 200 to 250 MW_e annually and continued until 2007 (Bertani, 2008). Extrapolating this trend to 2010 results in 11 GW_e, which corresponds approximately to the prognosis of the *International Geothermal Association* (IGA) (Fig. 9.6; IGC, 2007).

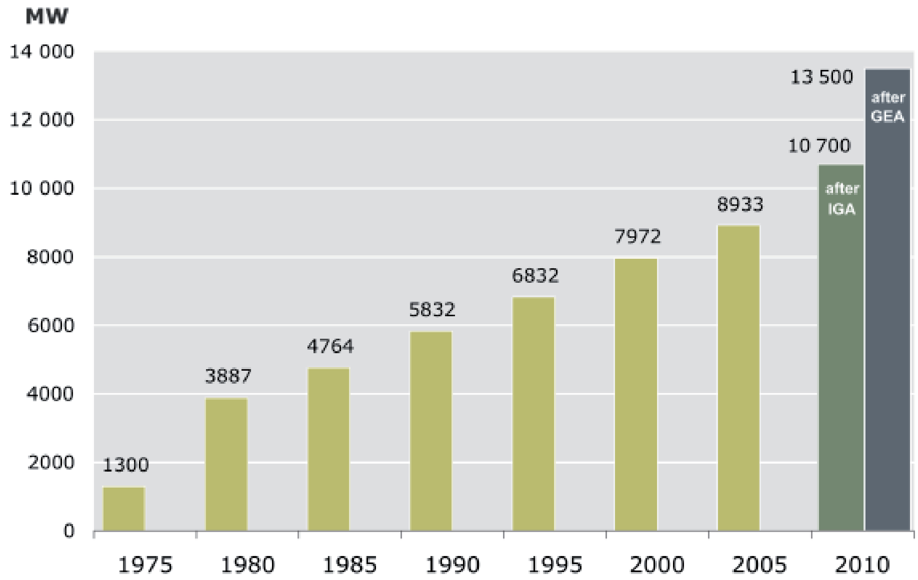


Figure 9.6: Development of power installed worldwide for electricity generation from geothermal energy between 1975 and 2005, as well as two prognoses for the year 2010 (data from Lud et al, 2005; Bertaini, 2005; Prognoses for the year 2010: International Geothermal Association (IGA); US Geothermal Energy Association (GEA); Gawell & Greenberg, 2007).

The cost of drilling and the quality of the reservoir significantly influence the economic efficiency of geothermal power generation. The higher the energy content of the reservoir, the less drilling is required for the same power plant performance. Binary power plant technology with the help of the *Organic Rankine Cycle* (ORC) and *Kalina* methods also plays a role in this context (Chapter 7.2.2). In many cases, the economic efficiency of a standard steam power plant can be increased significantly with a downstream binary power plant. The condensed liquid is normally injected back into the deposit at a high temperature after it has passed the steam turbine. This means that the residual energy of that liquid is not utilized. In an ORC- or Kalina facility, it would be possible to draw additional energy from the liquid without additional drilling costs. In many cases, this multi-stage utilization would be a very efficient option of generating additional energy and increasing efficiency, which can already be employed.

Another aspect that is currently discussed is the so-called crude oil co-production. Many oil wells that have existed for years also produce a significant amount of water with a temperature of up to 200 °C. The energy of these waters is currently not being used to generate electricity. On the contrary – the disposal of these waters often comes at a significant cost. After the oil has been separated from the water in separators, the energy can be used in ORC or Kalina plants without any additional development effort, and a resulting geothermal power of 1000 to 5000 MW_e is considered feasible (Forseo, 2008).

The further development of methods already existing such as using supercritical fluids, improving transmissivity in HDR doublettes, better and more cost-efficient drilling and power plant technology could push the rising rates of geothermal power production worldwide in the near future. Gawell & Greenberg (2007) as well as the World Energy Outlook (IEA, 2006) are assuming significant increases. The latter considers an annual geothermal power production of 185 TWh accomplishable by 2030. Gawell & Greenberg predict an installed power of 140 GW_e, resp. 1400 TWh annually by 2050 (Fig. 9.7). With the use of artificial geothermal systems (HDR or *Enhanced Geothermal System,* EGS), a geothermal capacity of considerably more than 150 GW_e is predicted by 2050 (Rybach, 2008).

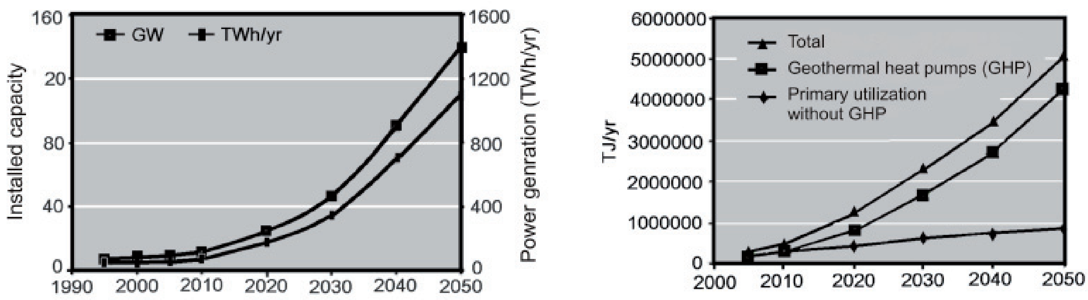


Figure 9.7: Prognoses on the development of geothermal power generation (left, Bertani, 2008) and direct thermal utilization (right, Friedleifsson et al, 2008).

Another aspect in the utilization of geothermal energy is the reduction of CO_2 emissions (Rybach, 2008). Geothermal processes work without combustion and thus cause little to no emission of greenhouse gases. The CO_2 emission of current geothermal power plants is around 120 g/kWh. It is expected that improved technology can reduce these emissions to about 10 g/kWh (Rybach, 2008). With an estimated geothermal power production of 1000 TWh/a by 2050, the emission of CO_2 could be reduced by several hundred million tons, depending on which fossil fuel source is substituted. Geothermal heating installations with heat pumps using electricity from fossil-fired power plants reduce CO_2-emissions by 50 % compared to oil burners. If the heat pump power is based on renewable sources such as hydropower, that reduction is 100 %. Because of the expected growth in direct usage, including geothermal heaters with heat pumps, geothermal energy could reduce emissions by more than 300 million tons CO_2 annually, according to Friedleifsson et al. (2008).

9.3 Availability of Uranium

Despite a sustained invigoration of the market, which made the mining of higher cost categories more economical, uranium reserves are defined conservatively and, for reasons of comparability, in quantities that can be economically mined up to USD 40/kg. In 2007, this was about 1.77 Mt of uranium in *reasonably assured resources* (RAR). A comparison between these uranium reserves and the current annual consumption of 0.041 Mt uranium shows that there is enough uranium available for several decades, even without using any secondary supply sources. In the past, the uranium reserves with mining costs up to USD 80/kg were taken into consideration when uranium prices were high, and in view of still higher prices, even the category minable up to USD 130/kg was taken into account. The

RAR of uranium, minable up to USD 80/kg, amount to 2.60 Mt, and those up to USD 130/kg amount to 3.34 Mt of uranium respectively, including the RAR at lower mining costs. With increased demand, and the higher prices that are most likely related to an increased demand, this would mean another significant extension of the life cycle of conventional uranium as energy resource.

The reserves of the category *"inferred resources"* (IR) can also be included into the availability analysis because they can be transformed into reserves with little effort. For example, it can be assumed that the large quantities of IR minable up to USD 40/kg of uranium will be developed before the RAR at extraction costs of more than USD 40/kg of uranium. All known reserves (RAR + IR) are listed in the following overview (Table 9.1).

Table 9.1: Known uranium reserves by extraction costs (IAEA/NEA, 2008).

Reserves/Resources	Reserve Category USD/kg U	Quantity (t U)
RAR	< 40	1 766 400
Inferred resources	< 40	1 203 600
RAR	40 – 80	831 600
Inferred resources	40 – 80	654 800
RAR	80 – 130	740 300
Inferred resources	80 – 130	272 200
Known resources minable up to USD 130/kg U		*5 468 900*

The known reserves of 5.4 Mt in conventional uranium deposits can be considered a workable quantity available for future supply. This is based on the assumption that extraction cost does not play a decisive role, and that these reserves do indeed reach circulation if there is appropriate demand, because the cost of uranium mining accounts for only 6 to 10 % of the power generation costs.

In 2007, there were about 2598 million tons of known reasonably assured uranium resources worldwide, which could be mined at costs of up to USD 80 per kg uranium. Currently, about 60 % of the world's uranium demand is covered by mining production; thus the currently known worldwide RAR would cover the demand for about 63 years, and with coverage of the entire demand of 64 615 t of uranium for only about 40 years. The additionally IR are 4456 million tons of uranium up to USD 80/kg and 5468 million tons of uranium up to USD 130/kg. Furthermore, there are resources totaling 7771 million tons of uranium. These figures represent the current status as of 2008 and do not take into account current and future exploration activity. Based on the existing figures, the calculated availability is more than 200 years.

For several years, the additional supply sources (Chapter 6.1.5) have attributed to the fact that less uranium is produced than is being consumed. It can be inferred that these supply sources will also play a major role in the future. According to an IAEA analysis (2001) on the availability of uranium until 2030 and beyond, it is estimated that until 2050, plutonium will be available as a mixed oxide (MOX) at up to 3600 tons of uranium annually, and up to 2500 tons of reprocessed uranium (REPU) will be available annually. Accordingly, they represent between 6 and 8 % of the respective annual demand.

The current stock of inventory could drop to zero by 2013. An important role is attributed to highly enriched uranium (HEU), which can cover about 15 % of the annual demand and, according to the current contractual situation, is available until the early 2020s. The re-enrichment of *Tails* is supposed to account for shares between 2 and 8 % until 2011. When viewed in five-year segments, the supply contribution of the additional sources could account for the following quantities (Table 9.2):

Table 9.2: Estimate of the available annual uranium quantities from additional sources until 2050.

Year	Uranium from additional sources
2007	23 336 t U
2010	22 500 t U
2015	17 500 t U
2020	18 000 t U
2025 to 2050	6 100 t U

According to the 2007 NEA and IAEA analysis, a *Low* and *High* scenario is created for the development of the uranium demand until 2030, which indicates that the cumulative uranium consumption from 2007 to 2030 may be 1.98 Mt respectively 2.35 Mt. According to the IAEA analysis, consumption is estimated at approx. 2.15 Mt uranium in the *middle scenario* between 2007 and 2030. The IAEA models, which are based on an older study, assume a cumulative consumption of 3.27 Mt uranium (*low*), 5.27 Mt *(middle)* and 7.45 Mt (*high)*.

Based on surveys of commercial facilities, the World Nuclear Association (2001) presented a projection of the uranium demand until 2020 in three scenarios (*lower, reference, upper*). The *lower* scenario expects a cumulative uranium demand of 1.16 Mt by 2020; this expectation is 1.3 Mt in the *reference* scenario and 1.5 Mt in the *upper* scenario.

It can be derived from the IAEA and WNA analyses that by 2030, up to 450 000 tons of uranium may be available from additional sources (inventory, HEU, MOX, REPU, re-enrichment). These quantities would not have to be produced during that period and, under optimal conditions, could be used to cover demand. Depending on the scenario, the total uranium demand from mining production would amount to 1.5 to 1.9 Mt between 2007 and 2030, which would be an average of approx. 65 000 to 82 000 tons annually. This is feasible, given the uranium reserves of 1.77 Mt. However, sufficient production facilities will have to be operated during that time, and new ones may have to be set up, if necessary. The situation of the current production facilities is as follows:

The analysis of production options submitted by NEA and IAEA in 2008 proceeds on the assumption of RAR + IR resources that can be mined up to USD 80/kg uranium. The facilities operated in 2007 have an annual gross capacity of about 54 370 tons of uranium. In view of the expansion of known deposits and the development of new production capacities, these capacities will increase to more than 95 630 tons of uranium annually by 2015. At approx. 80 % load, more than 76 500 tons of uranium would be available in 2015. Overall, 1.57 Mt of uranium could be produced between 2007 and 2030. When including the planned production sites, about 101 200 tons of uranium could be produced annually between 2007 and 2030. At 80 % load, this would lead to a producible quantity of almost 1.86 Mt of uranium.

These considerations show that even with a significant global expansion of nuclear energy, the supply from production and additional sources is guaranteed beyond 2030. In this context, it must be taken into account that the existing companies have developed only part of the reserves so far and that uranium resources of the higher cost categories and with a low exploration status, which may additionally increase the potential reserves, have not been included in these calculations.

Another factor that must be taken into account in the availability analysis is that the additional supply sources are not constant. In 2007, about 23 300 tons of uranium were available from these sources. This quantity will most likely drop to 17 500 tons annually by 2015. Their contribution will probably drop to less than 10 000 tons of uranium annually after 2030. The resulting quantities that would be theoretically required from production (Tab. 9.3) show that at 100 % capacity load the demand (high) can be met at high capacity until 2025. New deposits to be developed and potential additional sources must cover any difference that may develop in subsequent years. There is an IAEA model calculation for developments beyond 2030, which reaches to 2050. For 2040, a demand of 128 000 tons of uranium is estimated in the *middle demand case*. With the assumed increase in demand, uranium production would have to reach about 160 000 tons by 2050. Consequently, it is noted that given these assumptions, the demand in 2050 can be met adequately only if new production facilities are established based on the predicted and speculative resources. This requires significant exploration efforts to transform these uncertain quantities into reserves.

Table 9.3: Comparison between predicted uranium demand and assumed existing production capacities (t U/a) by 2030.

Year	Demand			Existing Capacities		
	Low	Medium	High	Low	Medium	High
2010	70 395	72 700	75 020	80 685	83 700	86 720
2015	76 870	81 600	86 385	95 630	106 500	117 420
2020	85 390	92 000	98 600	88 525	105 550	122 620
2025	90 935	100 700	110 510	83 840	100 950	118 060
2030	93 775	107 850	121 955	83 130	100 500	117 850

A large number of countries are turning to utilizing nuclear energy because of the clearly increasing energy demand, future energy security, and the climate development that is a worldwide topic of discussion.

9.4 Availability of Coal

Coal is the most abundantly available non-renewable energy resource worldwide. Even at a clearly increased demand, a limitation of the geological availability of hard coal or soft brown coal supply is not expected for decades. This becomes clear when comparing the figures of the worldwide demand of roughly 5.5 Gt of hard coal and 0.9 Gt of soft brown coal to the verified reserves in a quantity of 729 Gt of hard coal and 269 Gt of soft brown coal for 2007. Even if only a small part of the resources in the amount of 15 675 Gt of hard coal and 4076 Gt of soft brown coal is transferred to reserves, the geological availability of coal is still guaranteed over many more decades.

Contrary to soft brown coal, which is traded internationally only to a very limited extent, hard coal is traded worldwide and is therefore subject to the limitations of the world market. Between 2003 and 2008, the availability of hard coal was at times quite tight on the world market which is reflected in particular by the volatile coal prices (Fig. 5.22). This was attributed to the above average increase in consumption and the fact that capacity was not expanded accordingly with respect to production as well as transport infrastructure. These cyclical demand and price fluctuations are typical for all resource markets. They are relevant only for short-term considerations, but not for long-term availability.

The concerns about supply shortages in the world market related primarily to steam coal because this is where the strongest absolute growth was experienced. Most of all China, which currently produces and consumes about 45 % of all hard coal worldwide, doubled its hard coal demand in 2007 in comparison to 2000. India, which produces about 8 % of all hard coal is the third-largest hard coal producer and with a 9 % share the third-largest consumer, increased its consumption by almost 50 % during that time period. During that time period, hard coal consumption increased by about 49 % worldwide, or almost 15 % without taking China and India into account (IEA, 2008b). At the same time, primarily India and the People's Republic of China increased their imports in addition to local production and were for the first time among the five-largest hard coal importers in 2007. In addition, exporters important for the pacific coal markets, such as Indonesia, Vietnam, but also Russia announced with national energy strategies an increased coal demand for the future, which would lead to a reduction of the export capacities.

Because only 16 to 17 % of all hard coal produced worldwide is currently traded on the world market, the development of the Asian hard coal consumption and the related Asian imports and exports have a particular impact on the availability of hard coal in the world market. In 2007, Europe produced only about 41 % of its hard coal consumption. Against the background of a continually decreasing hard coal production in Europe and the related increase of export dependency, a shortage would have a particularly harsh effect on the European region. During the current financial and economic crisis (status of late 2008/early 2009), investments to increase the capacities have already been stopped and the first coal-mines have already been shut down because of the reduced demand for coal, so the supply situation on the world coal market is relaxed. This development could also reverse quickly if the economy recovers, resulting in increasing demand and rising prices. In view of the much smaller per capita consumption of hard coal in emerging and developing countries, in comparison to that of industrialized countries (Table 9.4) and in connection with an energy demand that will continue to rise in the future, primarily in the Asian region, an increase in worldwide coal consumption can be expected. It also remains open to what extent the future demand, in particular in Asia, can be met by local production.

Table 9.4: Per capita hard coal consumption of selected industrialized countries as well as threshold and developing countries in 2007.

	Industrialized Countries				Threshold and Developing Countries			
Country	**Germany**	**Great Britain**	**Japan**	**USA**	**India**	**Indonesia**	**Vietnam**	**China**
Per capita hard coal consumption (tons/person)	0.8	1.4	1.4	3.1	0.4	0.1	0.4	1.9

9.5 Availability of Natural Gas

The estimated total global conventional natural gas potential for 2007 was 509 trillion m^3. Of these approx. 182 trillion m^3 are reserves and 239 trillion m^3 are resources, approx. 86.8 trillion m^3 of natural gas have been produced (Fig. 9.8). Even with the expected significant growth rates in the consumption of natural gas, no limitation in the availability of natural gas is expected in the coming decades from a geological perspective.

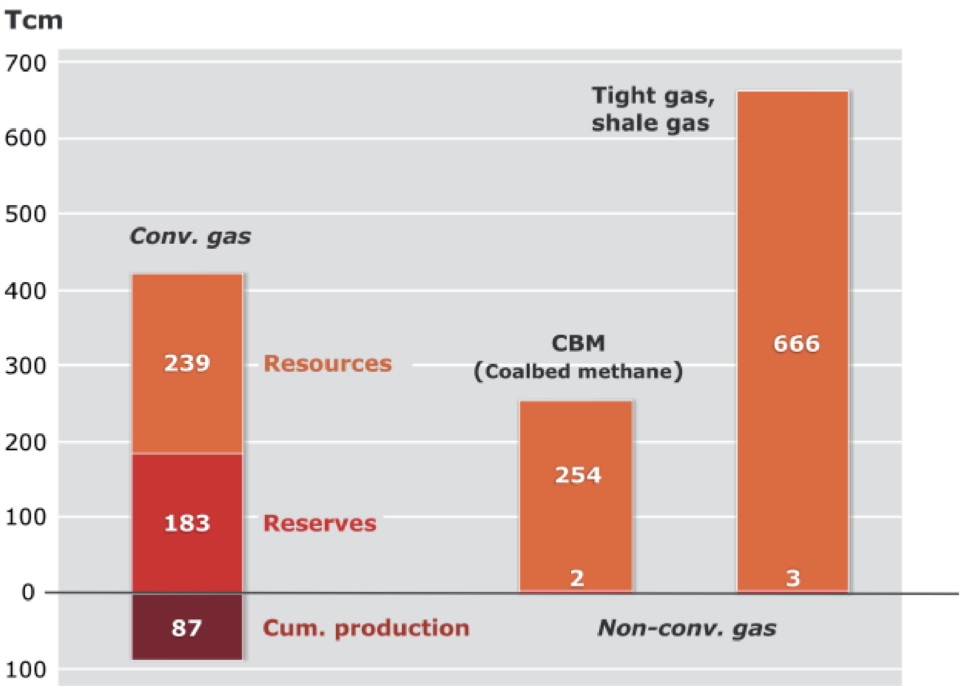


Figure 9.8: Worldwide total potential of conventional natural gas with reserves, resources and cumulative production as well as coal bed gas and natural gas from dense rock in 2007.

Despite current developments in the LNG market, the global trade of natural gas by sea will continue to play only a secondary role in comparison to pipeline transport (Chapter 4.2.6). Insofar, supplying regional natural gas markets with insufficient domestic resources may become a problem in the future. Although the European market is in a comfortable situation because it is located in close proximity to large production regions (Chapter 4.2.8), the North American market, for example, may experience shortages.

It is difficult to gauge how the development of non-conventional natural gas will advance. However, the production of CBM and natural gas from tight rocks has started worldwide, including Germany, and is progressing. It remains to be seen whether its share in the total worldwide production will meet the current level of about one third in the United States. Proof of efficient utilization of the huge natural gas potential in gas hydrate from a technical, economic and ecological perspective is still lacking. The years to come will demonstrate to what extent natural gas from gas hydrate can be utilized as an energy resource. Further innovation is also needed for the economic production of natural gas from aquifers. These could either be based on a desired continued use of the infrastructure of the hydrocarbon industry already existing, or on the other hand on technical combinations with geothermal facilities.

Because the cumulative natural gas production until now represented only a comparatively small proportion of the actual total potential (Fig. 9.8), it can be assumed that the information on the actual natural gas resources – in particular compared to oil – is still undervalued. This makes any prognosis of future production developments difficult because the exact knowledge of the total potential is the most important starting variable for such models. A compilation of various published prognoses on the course of natural gas production, which is shown in Fig. 9.9, shows the great differences in the assumptions about the producible quantities, perceptible in the enfolded areas under the production trends. Most of the scenarios relate to conventional natural gas and expect a maximum of the worldwide total production after 2025, in part even 2050 or later.

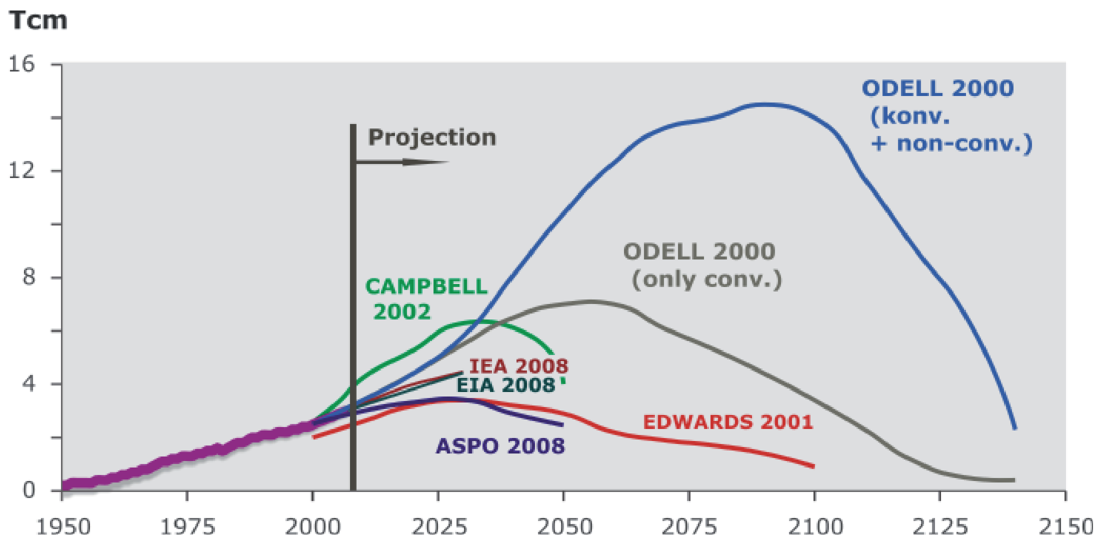


Figure 9.9: Development of natural gas production between 1950 and 2007, and a few published scenarios until 2150.

Edwards' scenario (2001) appears to be based on estimates of the total potential and the growth potential of the production that are too low (Fig. 9.9). Campbell's scenario (2002) shows relatively high production values until 2030, which can be attributed to the fact that this scenario was based on a reduction of oil production from 2005 on, with natural gas as the replacement. After 2030, Campbell's scenario (2002) shows a sharp drop in production. The ASPO scenario appears to be conservative although it incorporates the use of unconventional natural gas. Odell (2000), on the other hand, who also includes the use of unconventional natural gas, including a significant natural gas production from gas hydrate starting in 2025, draws a very optimistic picture of production development.

In summary, the aspects of the future availability of natural gas, as derived from the supply data, are as follows:

From a geological perspective, natural gas is available in sufficient quantities to cover the estimated demand for decades. A moderately increasing demand can also be covered for most natural gas markets with additional deliveries. Possible future bottlenecks, for example in the North American natural gas market, would have to be compensated with LNG deliveries from other markets. The specific transport costs, which are clearly higher compared to oil and coal, and the partly great distances between producers and consumers may influence the price of natural gas significantly. In the future, the transport of natural gas will continue to proceed largely via pipelines, even if a disproportional increase of the LNG transport and the establishment of a spot market for natural gas are likely. The IEA (2004) estimates the LNG share in the global natural gas trade to exceed 50 % for 2030. The growing LNG capacities will contribute to a relaxation of the natural gas market because even natural gas deposits far away from infrastructure can be developed for the world market in this way. The increasing activities for the production of synthetic fuels from natural gas (*gas to liquid,* GTL) could take away volumes from the natural gas market in the future. Overall, creating the necessary new capacities for the production and transportation of natural gas requires long-term financial commitments as well as close cooperation between producers and consumers.

9.6 Availability of Oil

9.6.1 Geological Availability of Oil

The current annual consumption of oil corresponds to approximately the quantity formed in the earth crust in about 500 000 to 1 000 000 years. This comparison emphasizes the finality of the oil resources and thus raises the question how long our economy can depend on the demand-oriented annual increase in the oil production. There are various and in part strongly diverging opinions in this respect. Some predict the end of the oil era in only a few years, while others predict that oil availability will last for several centuries. In any case, the period called the age of oil, which describes the beginning of the use of this resource until the time when the mass use of oil will have been replaced by other energies, will be just an episode in the history of mankind.

Oil is the energy resource that has been exhausted to the greatest extent. Of the known total potential of conventional oil in the amount of 400 Gt; 151 Gt, e.g. almost 38 %, have already been produced to date (Fig. 9.10). Given the fact that there are verified reserves of 157 Gt, this means that 49 % of the initial reserves (Fig. 2.5) have already been extracted from the deposits. Relative to these currently known initial reserves of 308 Gt, the *depletion midpoint*, where half of the known supply has been used up, would be reached in a few years, even without any increase of production (Chapter 9.1.2). When the conventional oil resources are included as well, this point could be reached in ten to twenty years. At an annual increase in production by one to two percent, which is within the scope of the IEA reference scenario (IEA, 2007), about half of the remaining oil would have been produced within the next 20 to 25 years, and a large part of the known reserves would be exhausted. Several authors have discussed production prognoses. Different production scenarios are usually the result of a different valuation of the available total oil potential, and of different model approaches (Fig. 9.2, 9.3). The BGR study includes an independent projection of the future oil production based on BGR data (Chapter 9.6.3).

In addition to the unpredictable dynamics of the development of demand and changes in the world oil market, various geological and geotechnical factors determine the development of future production. For example, in addition to the total potential of producible oil and its regional distribution (Chapter 3.2.1), the distribution of the deposits, and here in particular the remaining and still undiscovered large oil fields, the so-called *giants, super-giants* and *mega-giants*, play a particularly important part. For one, the discovery of large new fields has decreased steadily in recent years. The quantity of oil reserves discovered in

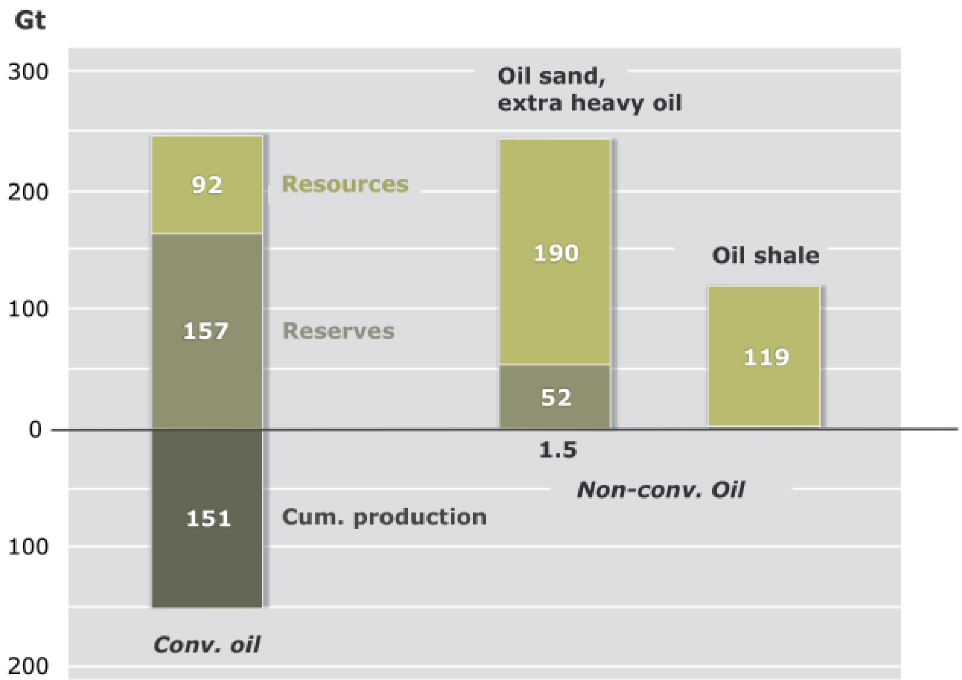


Figure 9.10: Worldwide total potential of conventional oil with reserves, resources and cumulative production as well as oil sands, heavy oil and shale oil for 2007.

giants during the past ten years only corresponds to about the current worldwide annual oil production. Furthermore, as the largest fields are increasingly being exhausted, the burden of oil supply will be focused on the few large fields. These large fields are mainly located in the most important production regions, i.e. the Middle East and Russia. All in all, about 70 % of the conventional oil reserves and also 70 % of the conventional natural gas reserves are located in those regions (Fig. 9.11). This regional concentration of the important reserves will presumable lead to a further progressive world polarization in producing and consuming countries (Chapter 3.2). Because of their strategic importance for the future world supply of energy resources and the political consequences arising from this, this region is called the *strategic ellipse*.

Other parameters that influence the development of the future worldwide production are the production schedules of large oil fields and important producing regions. Limitations can also be experienced as a result of a limited development of fields, for example for ecological reasons, or a limitation of the production quantity, for example in the scope of OPEC production rate quotas to stabilize the oil price.

In summary, the following statements concerning the geological availability of oil and their consequences can be made:

From a geological perspective, the remaining potential of conventional oil is sufficient to safeguard the supply for the next decade even at a moderate increase in oil consumption. The share of oil from the OPEC countries, in particular the Gulf region, which still has significant reserves to expand production capacities, is increasing. The share of unconventional oil will increase in the coming years if oil prices remain at a relatively high level, but will probably not exceed a share of 5 to 10 % of the total production by 2020.

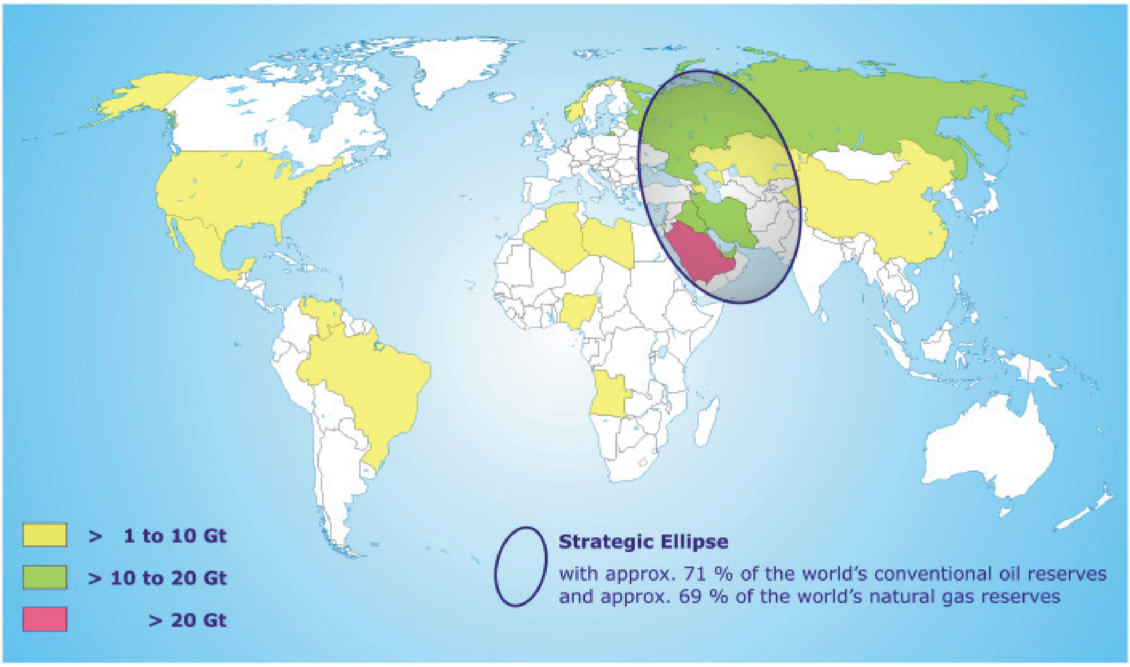


Figure 9.11: Worldwide distribution of countries with more than 1 Gt of conventional oil reserves, and location of the Strategic Ellipse where more than two thirds of the worldwide reserves of conventional oil and natural gas, respectively, are located.

There are many uncertainties which may additionally impact on the availability of oil. For example, the availability of oil may be reduced if OPEC revises their reserves which in a partly politically motivated step had been increased to secure the production quotas in the years 1986/88. On the other hand, the inherent uncertainties when assessing reserves could also contribute to an increased availability. Generally, the reserves figures do not include probable and possible reserves. Even if proven reserves were risk discounted, particularly those in the OPEC, the oil potential would be greater than indicated in this study. Past experience has shown that production prognoses based on the respective current production potential fell short of reality and usually had to be adjusted later. This is where *reserve growth* leads to an increase in the producible quantities beyond the reserves indicated today, in particular because of improved production technologies (Chapter 9.6.3).

Despite these options, it is obvious that in the near future oil production can no longer be increased arbitrarily. In view of the long time periods required for a reorientation in the energy sector, it is therefore necessary to look for alternatives to oil now, and to promote the development of new technologies to that effect.

9.6.2 Future Potential of Oil

In addition to the non-conventional oil resources, there are other options to improve the future oil supply situation. Besides expanding the utilization of technical measures for a more effective oil recovery from oil fields (EOR, Info box 2), a significant additional oil as well as natural gas potential is expected in Arctic frontier areas and in the deep-water areas of the continental margins. This is where oil exploration has started just recently.

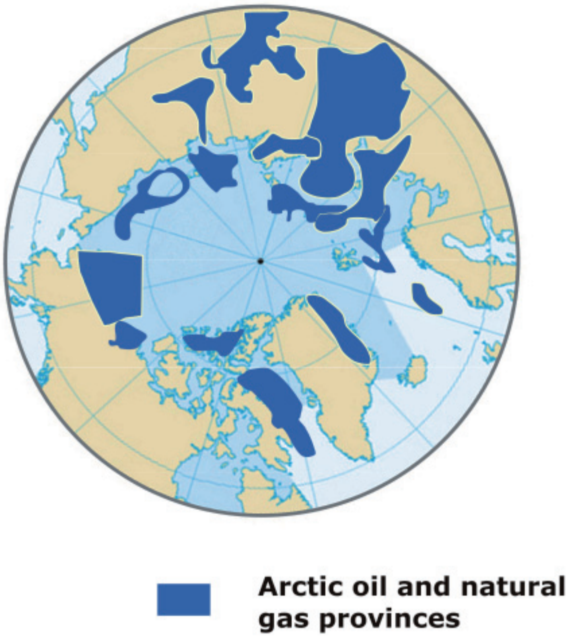
The prospecting and development of oil and natural gas fields in the deep-water area is progressing as quickly as the development of special deep-water technology allows. In this context, deep-water is generally considered the water depth where a normal drilling platform can no longer be used, e.g. about 500 meters. Water depths greater than 1500 meters are generally called *ultra deep water*. The formation of oil and natural gas deposits requires sufficient sediment thickness (greater than 2000 to 3000 meters). These thickness are generally obtained only directly at the continental margins. The large abyssal plains between the continents can be omitted.

However, at a few continental margins the geological conditions are excellent, and only the great water depth has prevented a more effective development of deposits so far. Of special significance are the Atlantic continental margins, with the deep-water areas off the Brazilian coast and at the conjugate Angolan shelf currently being the center of activities. From an oil-geological perspective, the conditions here are exceptionally favorable. An excellent oil host rock in a magnitude of more than 400 meters is located under an enormous salt layer. When the Atlantic first formed, special climatic conditions led to the formation of extended neritic zones, which allowed the deposit of the host rock as lacustrine black shale and the formation of huge carbonates as reservoir rocks. They were subsequently covered with a huge salt layer, which created a very effective sealing horizon for the oil generated afterwards.

In the Santos basin, the national Brazilian oil company Petrobras has already started developing very large fields. At a water depth of about 2000 meters, and under another 4000 meters of rock- and salt layers, the oil and natural gas supplies discovered there were estimated all in all 7 to 15 Gtoe. Because of the great depth and the challenge in deep water, a regular production is not expected until the next decade. However, an experimental production will probably start as early as 2009 in the Tupi field. The cost of development and subsequent production, with drilling ships, half-diving drilling platforms and production systems, is immense. For example, the cost of only one of the seven production systems is estimated to be USD 7 billion.

The deep-water discoveries became feasible and economically attractive only after significant scientific and technological developments. For example, specifically in recent years, the method for imaging geological structures in the underground was improved significantly (Info box 5). This led to a reduction in the drilling risks, the development of new exploration concepts, and a more effective recovery rate of individual fields. A breakthrough in the understanding of deep-water deposit systems was accompanied in particular by the development of the three-dimensional reflection seismics and wide-angle seismic and the resulting possibilities to render previously *non-transparent rock* formations such as salt rock transparent for acoustic methods. This data, in combination with multi-beam echo sounder data, offers deep insights into complex sedimentation systems typical for deep-water areas. Furthermore, drilling and production technologies adapted to the situation in the deep-water area, such as production installations on the ocean floor, *floating production, storage and offloading vessels (FPSO)* and special directional and horizontal drilling methods were and are being developed. In offshore fields, directional drilling is now the usual form of development. In view of the fast-paced technological advancements, the deep water and ultra-deep water regions will be able to supply a huge, still inestimable oil potential as well as natural gas potential in the future. However, because of the required technological effort, the production costs for energy resources from deep-water regions will definitely be higher than for most of the conventional deposits.

The Arctic is considered the most important frontier area for the exploration of oil and gas. The prospective sediment basins run in particular along the gigantic shelf areas of the polar sea and along the north shores of the North American and the Eurasian continent (Fig. 9.12). On the Eurasian landmass, a few onshore sediment basins are also counted among the arctic provinces. The West Siberian basin deserves particular attention; its northern part is known as the largest natural gas province worldwide, and its southern part has been Russia's most productive oil producing region for decades. Western Siberia is also Germany's main supplier of natural gas. About a third of the natural gas consumed in Germany comes from that region. The exploration of the arctic sediment basins in the European northern part of Russia – Kara Sea, Timan-Petschora basin and Barents Sea – has also made significant progress. In addition to the reserves already verified, a significant potential can be expected in particular for natural gas, but also for oil. For example, the giant Shtokman field in the northern Barents Sea will probably start production in a few years.



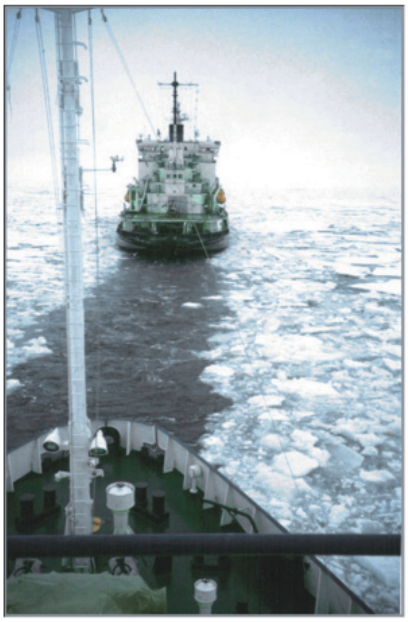


Figure 9.12: Left: Arctic gas and oil provinces (as per USGS data); right: research ship accompanied by icebreaker conducting seismic exploration of the Siberian Laptev Sea by the BGR.

The farther the prospective arctic regions are located from the huge consumer centers in Europe, Asia and North America, the less they have been explored. For example, far regions of the Siberian coast in the Asian north of Russia have been barely examined for oil from a geological aspect so far. In a first estimate of the presumable occurrence of oil and natural gas in the entire Arctic region north of the polar circle, the USGS (2008) specifically pointed out that the Arctic, in particular the offshore region, is largely unexplored from the aspect of hydrocarbon exploration. The estimates in the study are based largely on analogies to known, geologically comparable oil provinces, and have not been verified by concrete findings. Therefore, the degree of certainty of these statements is low. Furthermore, this assessment of the Arctic does not include any prognosis as to how many of the potentially existing resources can in fact be discovered and produced. Overall, the mean statistical prediction for the Arctic is about 12 Gt oil and 47 billion m^3 of natural gas. This corresponds to about 30 % of the natural gas resources and 13 % of the oil resources. Together with natural gas, it is assumed that there are economically substantial quantities of condensate (NGL) in the Arctic. The greatest part of the arctic oil and natural gas resources by far, e.g. 84 %, is assumed to be under the Arctic Ocean.

BGR is performing geological research work in various arctic regions. This research allows an independent assessment of individual provinces, which essentially corresponds to the USGS assessment for the western arctic region and the western Barents Sea. However, BGR data cast doubt on the USGS statement that the deep ocean basins of the Eurasian basin and the central arctic basin as well as the sunken continental fragment of the Lomonosov ridge are more promising rich yields than, for example, the continental shelves of the East Siberian Sea or the Chukchi Sea. With the deep water basins, only their outermost regions, e.g. the shelf regions, are potential hydrocarbon provinces. According to current data, the sediment coverage of the Lomonosov ridge is barely sufficient to form hydrocarbon. However, because of their geological structure, the Russian marginal seas, and in particular the East Siberian Sea, are indeed considered promising provinces.

Overall, however, it remains questionable to what extent and when the arctic oil and natural gas provinces, which lack infrastructure, and in particular those primarily considered as having natural gas potential, will start producing. The extreme environmental conditions, e.g. cold, pack ice and drift ice during most of the year, represent a tremendous challenge for the drilling, production, processing and transportation technology. Ice drifts, icebergs and the weather-conditioned freezing of technical facilities would require a great effort, or even make it impossible to use floating facilities, or facilities that are firmly mounted at the water surface. One way to avoid these problems would be to assemble production facilities on the ocean floor, as it is practiced on the Snøhvit field in the Norwegian Barents Sea. However, in large parts of the arctic shelf such installations are also at risk of being destroyed by icebergs. Because of the long distances to the consumer centers, transport infrastructure must be provided as well. With natural gas, this would most likely mean transport as LNG. Russia's planning also includes considerations of using the Northeast Passage to develop the arctic oil and natural gas fields. This ambition would be made easier by the potential receding of the polar ocean ice.

Much development work is needed to meet these technical challenges. Because of the high technological effort, the IEA estimates the production cost of arctic oil at up to USD 100 per barrel (IEA, 2008). Investments for the development of faraway arctic regions would therefore be made only if the price level for oil remains high over an extended period of time. However, if arctic oil is supposed to close a future supply gap, investments to that effect must be made well in advance.

9.6.3 The Future Development of Oil Production

Chapter 9.1.3 describes the relationship between the state of production and the known energy supply. It is found that the estimate of the total oil-potential is more certain, than the estimate of the remaining fossil energy sources. Under these conditions, it is possible to examine prospective developments of oil production using a mass balance of the resources, reserves and cumulative production.

This approach can circumvent two difficulties of previous oil production development models: By avoiding the peak oil premise, the model is not fixed primarily on a short-term production maximum. Furthermore, concentrating on supply-specific variables and the historic production schedule does not take into account direct economic variables such as the development of global demand. Thus, the resulting projection will be independent of the development of the global economy, but it can also be interpreted in the light of the expected economic developments.

The principal plan of action is a continuous transformation of resources into reserves, and the production of oil from the reserves on a corresponding annual basis. In doing so, reserves and resources are based on the data of the present study. The respective transitions are neither forced nor fixed, but rather result from taking parameters into consideration, which have characterized the oil production system and the supply dynamics in the past decades. For example, the ratio between known supply and current annual production (Chapter 9.1.1) of conventional oil without condensate, which is known as *static reach*, has been fixed at 38 years for the projection, according to the known development of this parameter (Fig. 9.1). From a geo-scientific perspective, a ratio of 38 years indicates that the production schedule is at an optimum if $1/38^{th}$ of the available minable reserves are produced annually. The projection defines the value as the optimal production ratio from the current point of view taking into account technical and economical aspects. This limits the projection to the current framework conditions in an open global market where oil companies can develop and then produce the reserves required to meet the demand. Other parameters defined in this sense are the transition from resources to reserves and reserve growth.

The process of reserve growth describes the observation that reserves of developed deposits grow during the course of the production history. The reason for this is the reassessment of the deposits, which either categorizes more oil in the reservoirs as extractable or locates new oil reserves for production in the deposit, based on better and more efficient exploration and production technology. This process becomes apparent in a comparison of the course of annual global oil production and the new reserves reported by new discoveries of deposits. Fig. 9.13 shows the discoveries of new fields between 1945 and 1994 and their backdated annual initial reserves (Robelius, 2007). The reserve growth and other revisions were backdated to the year the deposit was discovered. Only the reserves from new discoveries were attributed to the current year. Whereas annual production increases to date, with brief interruptions, reports of new discoveries have been decreasing since the 1960s. A comparison of this timeline and the annual production, which is also shown in Fig. 9.13, suggests that since the 1980s, more oil has been consumed than has been discovered. In fact, though, the reserves have also grown to date.

This apparent contradiction is resolved in the comparison of cumulative reserve figures backdated to various years (Fig. 9.14), which makes clear that in the reassessment, oil discoveries even from less than recent years are being corrected upward annually. If one wants to analyze the development of the initial reserves according to this differentiated method, a new curve would have to be added to the family of curves in Fig. 9.14 for each annual revision. The USGS (2000) stated a total value of 46.1 Gt oil for the future expected reserve growth. Until 2003, half of this had already been realized with 23 Gt (Klett el al., (2005).

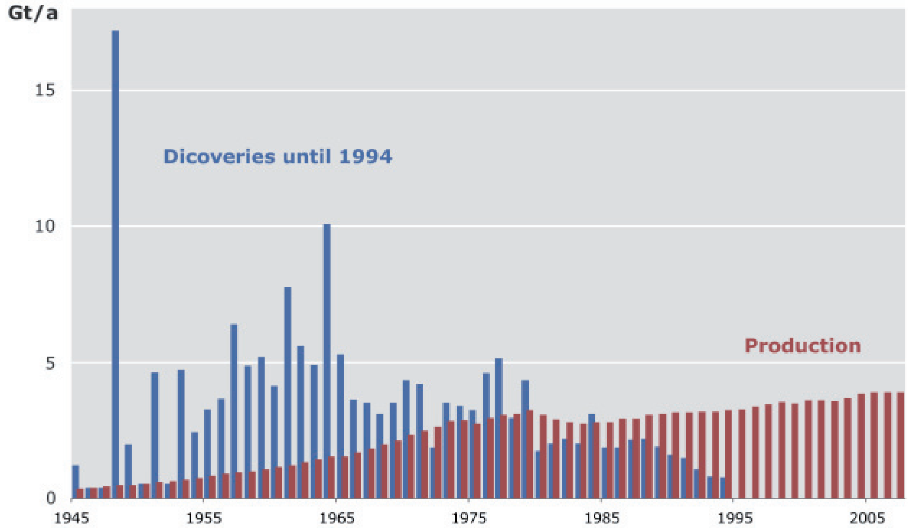


Figure 9.13: Annual production and reserves of new oil discoveries, backdated to the year the fields were discovered (BGR data base; Robelius, 2007).

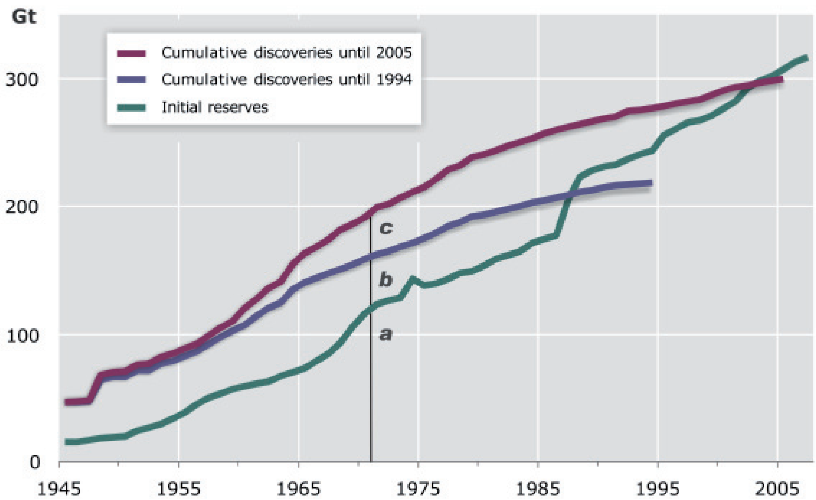


Figure 9.14: Comparison of the initial cumulated reserve figures for oil up to 2007 (green) and the backdated reserve figures as known in 2005 (red) and 1994 (blue); data from (Robelius, 2007). Example: In 1971, the initial reserves were 123 Gt (a). By 1994, this estimate was corrected to 163 Gt because of the reserve growth of the deposits discovered before 1971 (b); in 1995, these deposits were again revised to 200 Gt (c).

Thus, reserve figures are always only snapshots that by definition change over time. This means that by themselves, they are not suitable to establish prognoses for future production. This is where the total potential must be applied as the ultimate producible quantity. The partial quantities of the total potential – reserves, resources and cumulative production – develop dynamically over the life cycle of the oil energy resource.

Based on the chosen approach, the following projection can indicate how production may develop when adhering to previous dynamics, but not what it will ultimately indeed look like. This limitation is important as in the past the oil market has repeatedly been subject to drastic changes that could not even have been foreseen with the help of this projection. These changes are obvious from the historical oil production schedule. Three ages can be distinguished: The age of international oil companies and an accelerated increase in production, the OPEC age during times of oil crises and repeated drops in global production, and the current age of globalization with a nearly linear increase (Fig. 9.15). Each of these ages is subject to specific framework conditions; the changes in these conditions cannot be captured in the projection. The projection is based on laws derivable from the current globalization age.

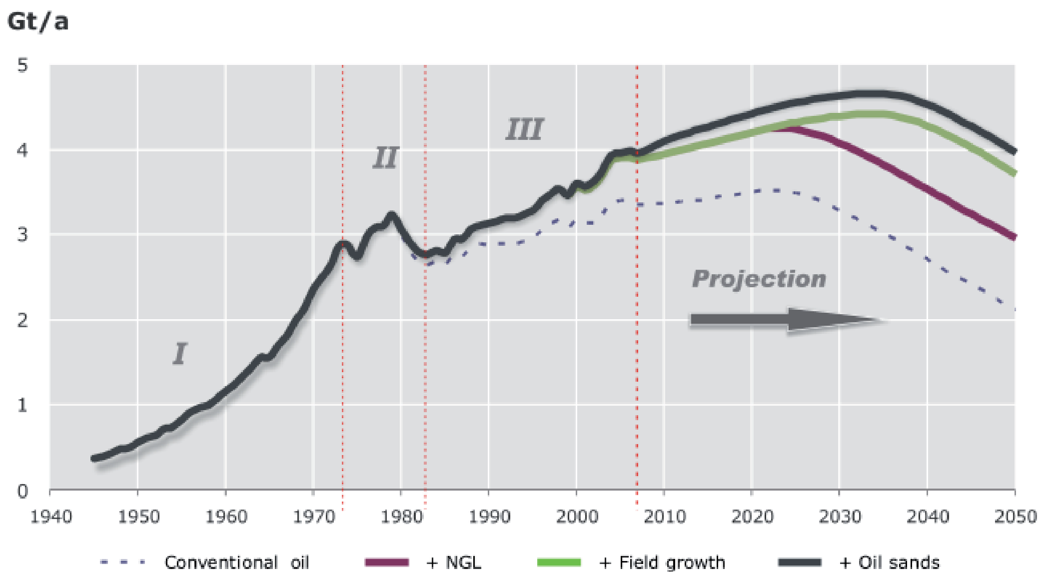


Figure 9.15: Historic development of oil production and projected production schedule for conventional oil with and without condensate (NGL) and with condensate and oil sands, taking into account reserve growth (field growth). Shown ages of historical oil production: Age of international oil companies (I); OPEC age (II); age of globalization (III).

Overall, the projection essentially confirms the previous statement based on the current supply data, e.g. that for conventional oil, a production maximum can be expected by 2020 (BGR 2008). After that, an increase of production is not possible from the currently known supply beyond 2023 under the given framework conditions (Fig. 1.3). Taking into account reserve growth, a growing share of condensate in oil production resulting from the expected increase of natural gas production, and the development of the production of oil from oil sands and heavy oils (Chapter 3.3), the picture changes: The reserve growth moves maximum oil production into the years between 2030 and 2035 (Fig. 9.15). This means that the reserve growth has the potential of increasing oil production by ten to fifteen more years.

The influence of the increase of condensate production and oil production from oil sands, on the other hand, has barely any influence on the projected timeline of maximum oil production. However, the potential growth rates of oil production according to the projection are increased significantly by condensate (NGL) and the use of oil sand. Without condensate and oil sands, the projection only reaches maximum annual production rates of about 3.6 Gt. Condensate already accounts for more than 500 Mt of the annual oil production. This share will increase even further with the expected growth of natural gas production. According to the projection, a share of 800 Mt of condensate in the annual oil production is possible by 2030. With the expected increase in condensate production, maximum oil production could be increased to about 4.4 Gt. When additionally taking oil from oil sand into account, the projection reaches a maximum production of about 4.7 Gt (Fig. 9.15).

The projection does not allow any statement on the development of oil prices because oil prices essentially depend on economic developments and less on the supply situation. As described above, the results of the projection are also subject to the provisions that arise from the defined framework conditions. Actual development of oil production may already deviate clearly from the projected course in the next few years if the lesser increase in demand resulting from the global economic crisis becomes noticeable. Furthermore, the projection assumes that the progress made in technological developments will be able to master the more difficult problems in exploration and production of oil. Likewise, the conditions for making the necessary investments in research, development, production and infrastructure in a timely manner must be met. If significant drops are experienced in that area compared to previous years, the projected production schedule for oil will not be realized.

Overall, the projection results in a maximum possible oil production schedule as it might develop at realistic assumptions from the current perspective. All conceivable changes in the oil market indicated above would mean that the projection falls short.

9.7 Energy Resources 2030, 2050

The data on the supply and availability situation of energy resources provided in this study and the projection for future oil production (Chapter 9.6.3) allow a few statements about trends for the coming decades, which have been summarized below for the horizons 2030 and 2050.

2030

If energy prices remain at a sufficiently high level, the use of **geothermal energy** will probably have multiplied by 2030. The result of current pilot projects on the wider use of deep geothermal energy, for example with single borehole methods and HDR technology, will be an important factor in the development of geothermal energy.

For the **nuclear fuel**, no bottlenecks are expected with respect to geological availability until 2030. Political decisions about if and to which extent nuclear energy may contribute to the energy supply in future will have a far greater influence than the geological availability of the fuel. With an expansion in the worldwide use of nuclear energy, new reactor types will make more efficient use of the nuclear fuel by 2030. Thorium might also start being used in that case.

For **coal**, the IEA reference scenario (IEA, 2008) assumes an annual increase in demand of 2% on average, from approx. 5 billion tons of coal equivalent units in 2007 to 7 to 7.3 billion tons of coal equivalent units in 2030. These growth rates would not lead to any limitations in geological availability for either soft brown coal or hard coal in the coming decades. It is apparent that the results of the current pilot projects on CCS (Information Box 7) will have an influence on the future use of coal. If the price level for oil is sufficiently high in the coming years, it is also likely that a few large-scale projects on coal hydrogenation (Info Box 8) will be implemented. Then coal would be used as a substitute for oil, although to a low extent from a global perspective.

For **natural gas**, there are also no obvious bottlenecks until 2030, even with increased demand. It remains to be seen how the concentration of the natural gas reserves in the *strategic ellipse* will lead to noticeable consequences as early as 2030. Until then, the results of the current research and development programs, which are focused on a production of natural gas from the huge offshore deposits of gas hydrate, will be an important milestone for the development of the natural gas production until 2030. If this work is successful and energy prices are high enough to permit the necessary investments to develop this resource, natural gas production from gas hydrate could already have started by 2030.

Whether **oil** production can be increased until 2030 at the rates of the past 20 years depends on a number of factors that are not based on geological availability. According to the results of the projections in the present study, such an increase is possible until 2030 with an optimal utilization of the supply, including unconventional deposits, under current market conditions. The resulting maximum annual oil production for 2030 is about 4.6 Gt. However, this projection must be categorized as optimistic because many influential factors could cause the development described in the projection to fall short. With a look at 2030, it is therefore likely that even despite the measures for the substitution of oil, which are already underway, there will be a noticeable physical shortage. An annual production in 2030 that is higher than the annual production shown in the prognosis would be possible, for example, if the oil industry were to make drastic and disproportionate increases in the reserve base in the coming decades. This would require enormous investments in projects that are currently not foreseeable.

2050

Statements founded on the availability of geothermal energy, nuclear fuels, coal and natural gas for 2050 beyond the statements made for 2030 are not possible on the basis of the supply data on hand and the predictable developments.

However, for **oil**, there is no possibility of an increase by 2050 (Fig. 9.15), according to current knowledge. What is possible and likely is a peak demand clearly before 2050 for the substitution of oil. This means that the main burden of the current load of the world's energy supply must be redistributed from oil to other energy carriers. In this new energy mix, economically sensible regenerative energies should play an important role. Most likely, oil will be produced nevertheless far beyond the year 2050 for specific applications and in particular for the chemical industry.

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A

AAPG	American Association of Petroleum Geologists
af	ash-free
Anticline	rocklayers folded in the shape of an arch, slopes moving downwards on all sides.
°API	unit of measure for the gravity of liquid hydrocarbons, low grades correspond to heavy oil (American Petroleum Institute).
Aquifer	an underground zone of permeable rock saturated with water under pressure.
Aquifer gas	natural gas dissolved in formation water
assoc. gas	associated natural gas; natural gas occurring in connection with oil accumulations in the same reservoir. This gas may be dissolved in the oil under reservoir conditions (solution gas) or may form a cap of free gas above the oil in the reservoir (gas cap gas).
Authigenic	name for rocks whose components originated at the site (e.g. from magma).

B

Biogenic	produced by living organisms
BSR	Bottom Simulating Reflector. Seismic reflector indicating the lower edge of the stability zone of the gas hydrate
BTL	biomass to liquid. Synthetic fuel produced from biomass.
Btu	British thermal unit. The amount of heat required to rise the temperature of one pound of water by one degree Fahrenheit. (1 million Btu = about 28 m^3 of natural gas) → *cf. Units of measurement*

C

CBM	coalbed methane. Natural gas (methane) found in coal seams.
C/H	carbon to hydrogen ratio.
cif	cost, insurance, freight. Usual transportation clause in the overseas trade, when the seller bears the costs of the delivery, the insurance and the freight up to the port of destination in addition to the fob-clause (s. below).

CIS	Commonwealth of Independent States. → *cf. groups of countries*
Clean gas	natural gas with a standardized heat value of 9.7692 kWh/Nm³ (valid in Germany: Reingas).
Coalification	conversion of organic raw material due to an increase in temperature in the course of geological periods.
Condensate	mixture of light hydrocarbons that are gaseous under reservoir conditions and liquid under conditions at the surface (condensed), which are produced together with natural gas (density: > 45°API or < 0.80 g/cm³).
Continental shelf	zone, adjacent to the shoreline of a continent, that extends from the lower water line to the continental slope (app. 200 m water depth).
Continental slope	the marine areas adjacent to the shelf with water depths down to more than 2000 m (in some cases).
Conventional oil	crude oil capable of flowing, >20°API.
CTL	coal to liquid. Production of synthetic fuel from syngas using Fischer-Tropsch process.
Cumulative production	amount of fuels produced since the start of production

D

depletion mid-point	time at which half of the estimated ultimate recovery (EUR) has been produced.
Depletion rate	rate of reduction of initial reserves (percentage thereof).
Discordance	angled or irregular adjoining rock layers; e.g. reservoir rock can be cut by an impermeable layer.
DOE	Department of Energy of the USA.
Downstream	activities beyond the wellhead such as treatment, transportation, processing, supply.
Dry gas	natural gas containing few or no hydrocarbons other than methane.

E

EAR	estimated additional resources; deposits, which are not reserves. Nomenclature of the NEA/IAEA-task force "Uranium, Resources, Production, and Demand". → *cf. Uranium*

Efficiency is the ratio of power output to power input. Is used in the area of energy conversion and energy transmission, respectively.

Enriched uranium uranium, for which the percentage rate of the fissionable isotope U-235 has been increased above the percentage of 0.7205 % in the natural uranium. Nuclear reactors use degrees of enrichment between 3 % and 4 % U-235.

Enthalpy state variable of ideal gases, [J]; measure of the technical work, which a given amount of gas can perform; J depends on the temperature and pressure.

EOR enhanced oil recovery; process for improving the natural degree of oil recovery of a petroleum deposit, secondary and tertiary production processes.

EU European Union (EU-27).
→ *cf. Economic policy divisions*

EUR estimated ultimate recovery. The sum of cumulative production, reserves and resources. see: *BGR Definition of Reserves and Resources*

Exploration the search for reservoirs of a natural resource in the earth's crust, including prospecting, geophysical and geological surveys and drilling of wildcats.

Extraction costs costs of the mining extraction and treatment up to the finished product (yellow cake).
→ *cf. Uranium*

F

Field growth increase/growth of the reserves in an oil or gas field due to increased recoverability, e.g. new drilling results.

fob free on board. The price of a product actually charged when loaded onto a ship at the port of loading. From this point onwards, the purchaser is responsible for the goods.

FPSO floating production, storage and offloading units. FPSO's are vessels for exploiting offshore oil fields.

Frac artificially created crack starting at a borehole, for increasing permeability and thus stimulating production.

Frontier area area, in which little exploration work has been conducted up to now for instance for climatic or logistic-geographic reasons.

FRS financial reporting system. System of the EIA, comprising about 30 US-based oil companies, which provide data of their global operations.

G

Gas hydrate solid compounds formed under certain pressure and temperature conditions (even above 0 °C) from water and methane.

GECF Gas Exporting Countries Forum. Association of fifteen countries exporting natural gas (cf. Info box 4).

Giant, Supergiant Megagiant categories of hydrocarbon fields according to their size; with reserves greater than 500, 5000 and 50 000 Mb (68, 680, 6800 Mt) respectively for petroleum and greater than 3, 30 and 300 tcf (85, 850, 8500 Bcm) respectively for natural gas.

Ground water that part of the underground water, which is located in the water-saturated (waterlogged) zone. It is separated from the capillary fringe by the phreatic surface. The phreatic zone reaches down into the crust areas, in which virtually no connected network of fissures and pores exists any more.

GTL gas to liquid. Production of synthetic fuel from natural gas using different processes, amongst others Fischer-Tropsch.

H

Hard coal anthracite, bituminous coal and hard brown coal; calorific value >6,500 kJ/kg.

Hydrocarbons (HC) chemical compounds of carbon and hydrogen, in which small amounts of other elements (e.g. sulfur, nitrogen, oxygen, metals) can be bonded chemically. Hydrocarbons exist as solids, liquids or gases, which are petroleum, condensate and natural gas.

higher-order HC: HC with more than one carbon atom.

HDR-process Hot-Dry-Rock process. In rocks with very low hydraulic permeability and temperatures of > app. 150 °C, flow-paths in hydraulically generated cracks between deep boreholes are produced, which serve as heat exchangers. Heat energy is extracted from the circulating water.

Heat capacity measure for the heat storage capacity of a material; [J/(K • kg)]; symbol: c.

Heat flow amount of heat that flows per unit of time through an area of one square meter in the earth's crust; [J/s • m²] = [W/m²]; symbol: q.

Heat flow density amount of heat flowing through an area of 1 m² per second, [W/m²]; (0.001 W/m² = 1 mW/m²); symbol: q

Heat pump technical system, which draws heat from a heat store of low temperature and moves it to a heat store of higher temperature.

HEU	highly enriched uranium (> 90 % U-235), mainly used for military purposes.
High temperature deposit	geothermal deposit with a temperature > app. 150 °C.
hydrostatic	corresponding to the pressure of the head of water above
Hydrothermal high enthalpy deposit	vapor or hot water occurrences with a temperature > 150 °C. → *cf. Geothermal energy*
Hydrothermal low enthalpy deposit	hot or warm water deposits with a temperature < 150 °C. → *cf. Geothermal energy*

I

IAEA	International Atomic Energy Agency; UN-authority based in: Vienna (= Internationale Atomenergie Organisation, IAEO). → *cf. Economic policy divisions and uranium*
IEA	International Energy Agency; intergovernmental organization established by the OECD, based in Paris.
IGU	International Gas Union.
In place	total amount of a fuel accumulated in a deposit.
In-situ	at the site. Located in the reservoir; but also designation of a response or of a process at the place of origin, also used as a synonym for *in place*.
IOC	International Oil Companies, e.g. supermajors: Chevron Corp., ExxonMobil Corp., BP plc, Royal Dutch plc, Total.
IOR	improved oil recovery. Process for improving the recovery rate of a petroleum deposit (more comprehensive than EOR), comprises amongst others additional stimulation measures, reservoir management, cost reduction.

J

J	Joule. Unit of measurement for Energy. → *cf. Unit of measurement*

K

Kalina-process	mechanical power generation by evaporation of an ammonia-water mix. → *cf. Geothermal energy*

kcal Kilocalories → *cf. Unit of measurement*

kJ Kilojoule → *cf. Unit of measurement*

L

lb Pound (1 lb = 453.59 g).

Licence permission provided to a company for exploration and/or production purposes for a certain time.

Licence area area provided to a corporation for exploration and/or production purposes for a certain time.

Lignite brown coal; calorific value < 16,500 kJ/kg

lithostatic corresponding to the pressure of the rock layers located above.

LNG liquefied natural gas. Natural gas that has been liquefied for transport; 1 t of LNG contains about 1400 Nm^3 natural gas, 1 m^3 of LNG weighs about 0.42 t).

Low temperature deposit geothermal deposit with a temperature of < app. 150 °C.

LPG liquefied petroleum gas. Propane, butane or a mixture of both which has been liquefied by reducing the temperature, increasing the pressure (< 25 bar) or a combination of both.

M

Methane simplest hydrocarbon, first member in the alkane series (CH_4).

Migration underground process in the course of the generation of hydrocarbons, during which petroleum and natural gas migrate from the source rock to the reservoir rock.

Mineral oil petroleum and petroleum products manufactured in refineries.

MOX mixed oxide; enriched uranium oxide with plutonium oxide; used as nuclear fuel.

MW_e electrical power in MW.

MW_{th} thermal power in MW.

N

NAFTA North American Free Trade Association. → *cf. Economic policy divisions*

Natural gas — gas produced from an underground reservoir. Mixture of gaseous hydrocarbons; may also contain varying amounts of other gases.
conventional: free natural gas and associated gas.

unconventional: natural gas in shale beds, tight reservoirs, coalbed methane, aquifer gas and gas hydrates.

Natural uranium (U_{nat}) — uranium with natural isotopic composition, a mixture of U-238 (99.2739 %), U-235 (0.7205 %) and U-234 (0.0056 %).

NEA — Nuclear Energy Agency; linked with OECD, based in: Paris.
→ *cf. Uranium*

NGL — natural gas liquids; those hydrocarbons, which are gaseous under reservoir conditions and are extracted in liquid form when produced. Typically ethane, propane, butane and pentane will be the predominant components (no common definition available).

NOC — National Oil Companies; largely state-owned oil companies, e.g. Saudi Aramco, Petrobras, China National Petroleum Company.

O

OECD — Organization for Economic Cooperation and Development based in: Paris.
→ *cf. Economic policy divisions*

OGJ — Oil & Gas Journal (periodical).

OPEC — Organization of Petroleum Exporting Countries; based in: Vienna.
→ *cf. Economic policy divisions*

ORC plant — Organic-Rankine-Cycle plant/system; power generators, whose turbines are powered by (organic) substances with low boiling temperature.

P

Permeability — the capability of a rock to allow the flow of liquids or gases in the presence of a pressure difference. Unit of measure: Darcy [D] and Millidarcy [mD], respectively [$m^2 = 10^{12}$ Darcy]; symbol: k.

Plutonium — fission product of the nuclear chain reaction; made from U-238, by neutron capture Pu-239 is formed.

Porosity — the ratio of the pore volume to the total volume of a solid rock in the formation; unit: percent [%].

Potential — **technical potential:** amount of heat of a geothermal type of deposit in a certain area extractible per year in consideration of all technical restrictions.
→ *cf. Geothermal energy*

theoretical potential: amount of heat of a geothermal type of deposit in a certain area available per year.
→ *cf. Geothermal energy*

Pour point — temperature, at which a liquid (in this case: petroleum) reaches a viscosity that just prevents it from flowing.

Primary energy, use of — direct usage of the geothermal energy (e.g. for heating purposes, i.e. no conversion into electrical energy).

Primary energy consumption refers to the amount of energy required in total for the supply of a national economy.

PSC — production sharing contract or agreement (PSA); contract between a country and an oil/gas company, which divides the produced amount of petroleum or natural gas according to a certain ratio.

R

RAR — reasonably assured resources; in the lowest cost class: reserves, otherwise resources (cf. EAR).
→ *cf. Uranium*

Raw gas — untreated natural gas produced from a reservoir.

Recovery efficiency — the recoverable amount of original hydrocarbons in place in a reservoir, expressed as a percentage of total HC in place.

Recycled uranium — uranium that was not consumed after employment in the nuclear reactor; return to fuel elements.

Remaining potential — sum of reserves and resources. see: *BGR Definition of Reserves and Resources*

Reserves — proved amounts of an energy resource in a deposit, at today's prices economically extractible, using the current state-of the art technology. Original reserves: cumulative production plus remaining reserves. see: *BGR Definition of Reserves and Resources*

reserve growth — (or field growth) increase in reserves in an oil or gas field resulting from the use of enhanced production methods and improved knowledge of the deposit.

R/P ratio — reserves to production ratio: ratio of reserves and last year's production.

Reservoir rock — porous and permeable rock (e.g. sandstone, limestone), in the pore space of which liquids (petroleum, water) or gases (natural gas) are present.

Resources	proved amounts of an energy resource in a deposit that cannot be recovered at current prices with current technology but might be recoverable in the future, as well as quantities that are geologically possible but not yet proven. see: BGR Definition of Reserves and Resources
Royalties	are the best-known and most frequent dues in the extractive industry. Royalties are usually levied as percentage rate of the market value of the produced crude oil or natural gas.

S

scf	standard cubic foot/feet.
Source rock	rock with high proportion of organic material from which curde oil and/or natural gas can be generated.
SPE	Society of Petroleum Engineers.
Spot market	a regional market (e.g. for Northern Europe: Rotterdam), where mineral oil products and crude oil are traded on a short-term basis.
Stimulation	improvement of the production characteristics of a borehole by technical measures.
Surface fees	a state can demand payment of the so-called surface fees proportional the surface of a petroleum field. There are surface fees for exploration areas (exploration surface fees) and for production areas (exploitation surface fees).
swing producer	producer of a natural resource, who can compensate fluctuations in demands due to its large production capacity.

T

tce	tons of coal equivalent (~29.308 GJ = 7 Gcal).
Temperature	degree Kelvin (absolute temperature), [K]; T [K] = T [°C] + 273.2; symbol: T.
toe	ton(s) of oil equivalent (app. 1.428 tce).
TPES	total primary energy supply; equivalent to total primary energy demand. This represents domestic demand only and, except for world energy demand, excludes international marine bunkers.
Transmissibility	measure for the hydraulic permeability of a layer of rocks; 1 m³ ≅ 1012 Darcy m; symbol : T.

U

UAE	United Arab Emirates. → *cf. Groups of countries*
Unconventional oil	Oil not capable of flowing in the deposit. API degree < 10°, very heavy oil, crude oil of oil sand (bitumen, asphalt), or shale oil from oil shale.
UN-ECE	United Nations Economic Commission for Europe, based in: Geneva.
upstream	searching for and recovering and production of hydrocarbons up to the wellhead: exploration, development, production.
upgrading	improvement in quality, increase of the API-Grade (extraction of unconventional petroleum).
USGS	United States Geological Survey.

V

Vertical temperature gradient	change of the temperature with depth; [K/m] or [°C/m]; symbol: dT/dz.

W

waf	water and ash free.
WEC	World Energy Council; based in; London also used for: World Energy Conference
WGC	World Gas Conference
WPC	World Petroleum Congress

Regional Definitions and Country Groupings

Regional division of the countries of the world

Europe

Albania, Andorra, Belgium, Bosnia-Herzegovina, Bulgaria, Cyprus, Czech Republic, Denmark, Germany, Estonia, Faroe Islands (Denmark), Finland, France, Gibraltar (GB), Greece, Great Britain, Hungary, Ireland, Iceland, Isle of Man (GB), Italy, Channel Islands (GB), Croatia, Latvia, Liechtenstein, Lithuania, Luxemburg, Malta, Macedonia, Monaco, Montenegro, Netherlands, Norway, Austria, Poland, Portugal, Romania, San Marino, Sweden, Switzerland, Serbia, Slovakia, Slovenia, Spain, Turkey, Vatican City

CIS (Commonwealth of Independent States; 12 countries)

Armenia, Azerbaijan, Georgian Republic, Kazakhstan, Kyrgyzstan, Moldova, Russia (Russian Federation), Tadzhikistan, Turkmenistan, Ukraine, Uzbekistan, Belarus

Africa

Algeria, Angola (incl. Cabinda), Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, Central African Republic, Chad, Comoros, Congo (Democratic Republic, formerly Zaire), Congo (Republic), Côte d´Ivoire (Ivory Coast), Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Mayotte/Maore, Morocco, Mozambique, Namibia, Niger, Nigeria, Rwanda, Sao Tome & Principe, Senegal, Seychelles, Sierra Leone, Somalia, St. Helena (GB), South Africa, Sudan, Swaziland, Tanzania, Togo, Tunisia, Uganda, Western Sahara (Democratic Arab Republic), Zambia, Zimbabwe

Middle East

Bahrain, Iraq, Iran, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, United Arab Emirates, Yemen

Regional Definitions and Country Groupings

Regional division of the countries of the world - continued

Austral-Asia

Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia, China (Republic; also: Taiwan), China PR (People's Republic), India, Indonesia, Japan, Korea (Democratic People's Republic; also: North Korea), Korea (Republic; also: South Korea), Laos, Malaysia, Maldives Islands, Mongolia, Myanmar, Nepal, New Caledonia, Pakistan, Papua New Guinea, Philippines, Singapore, Sri Lanka, Thailand, Vietnam

Australia, Belau (of Palau Ils. (USA), Cook Islands (New Zealand), Fiji, French Polynesia, Guam (USA), Kiribati (Gilbert Islands), Marshall Islands, Micronesia, Nauru, New Caledonia, New Zealand, Norfolk Island (Australia), Northern Marianas, Palau, Pacific Islands (USA), Pitcairn Island (GB), Ryukyu Islands, Solomon Islands, Samoa (Western Samoa), Samoa (USA), Tokelau Islands (New Zealand), Tonga, Tuvalu (Ellice Island), Vanuatu (New Hebrides), Wallis & Futuna (France)

North America

Canada, Greenland, Mexico, USA

Central and South America (Latin America without Mexico)

Anguilla, Antigua & Barbuda, Argentine, Bahamas, Barbados, Belize, Bermudas, Bolivia, Brazil, Caiman Islands, Chile, Costa Rica, Dominica, Dominican Republic, Ecuador, El Salvador, Falkland Islands (GB), French Guyana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Colombia, Cuba, Martinique, Montserrat, Nicaragua, Netherlands Antilles, Panama, Paraguay, Peru, Puerto Rico (USA), St. Kitts & Nevis, St. Lucia, St. Pierre & Miquelon, St. Vincent & the Grenadines, Suriname, Trinidad & Tobago, Turks & Caicos Islands, Uruguay, Venezuela, Virgin Islands (GB), Virgin Islands (USA)

Regional Definitions and Country Groupings

Economic groupings

European Union (EU-27)

Austria, Belgium, Bulgaria[2], Cyprus[1], Czech Republic[1], Denmark, Estonia[1] , Finland, France, Germany, Greece, Great Britain, Hungary[1], Ireland, Italy, Latvia[1], Lithuania[1], Luxemburg, Malta[1], Netherlands, Poland[1], Portugal, Romania[2], Sweden, Slovakia[1], Slovenia[1], Spain

IAEA (International Atomic Energy Agency; 129 countries)

Afghanistan, Albania, Algeria, Angola, Argentine, Armenia, Australia, Austria, Bangladesh, Belgium, Benin, Bolivia, Bosnia-Herzegovina, Brazil, Bulgaria, Burkina Faso, Byelorussia, Cambodia, Cameroon, Canada, Chile, China, Colombia, Congo, Costa Rica, Croatia, Cuba, Cyprus, Czech Republic, Denmark, Dominican Republic, Egypt, Ethiopia, Germany, Ecuador, El Salvador, Estonia, Finland, France, Gabon, Georgian Republic, Ghana, Great Britain, Greece, Guatemala, Haiti, Hungary, India, Indonesia, Iran, Iraq, Ireland, Island, Israel, Italy, Ivory Coast, Jamaica, Japan, Jordan, Kazakhstan, Kenya, Kuwait, Latvia, Lebanon, Liberia, Libya, Liechtenstein, Lithuania, Luxemburg, Macedonia, Madagascar, Malaysia, Mali, Malta, Marshall Islands, Mauritius, Morocco, Mexico, Moldova, Monaco, Mongolia, Myanmar, Namibia, Netherlands, New Zealand, Nicaragua, Niger, Nigeria, Norway, Pakistan, Panama, Paraguay, Peru, Philippines, Poland, Portugal, Qatar, Romania, Russia, Saudi Arabia, Senegal, Sierra Leone, Singapore, Slovakia, Slovenia, Spain, Sri Lanka, South Africa, South Korea, Sudan, Sweden, Switzerland, Syria, Tanzania, Thailand, Turkey, Tunisia, Uganda, Ukraine, Uruguay, USA, Uzbekistan, United Arab Emirates (UAE), Venezuela, Vietnam, Yemen, Yugoslavia (Serbia), Zambia, Zimbabwe

NAFTA (North American Free Trade Association, 1994)

Canada, Mexico, USA

OECD (Organization for Economic Cooperation and Development, 1949; 30 countries)

Australia (1971), Austria (1996), Belgium (1949), Canada (1960), Czech Republic (1995), Denmark (1949), Germany (1949), Great Britain (1964), Greece (1964), Finland (1969), France (1964), Hungary (1996), Iceland (1964), Ireland (1964), Italy (1964), Japan (1964), Luxemburg (1964), Mexico (1994), Netherlands (1996), New Zealand (1973), Norway (1996), Poland (1996), Portugal (1959), Slovakia (2000), South Korea (1996), Spain (1959), Sweden (1959), Switzerland (1959), Turkey (1996), USA (1960)

OPEC (Organization of the Petroleum Exporting Countries)

Algeria, Angola (since January 1st, 2007), Ecuador (since January 1st, 2007), Gabon (until June 10th, 1996), Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates (UAE), Venezuela

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[1] member since 2004
[2] member since 2007

Natural Gas Markets

European Gas Market

Europe, Russia (west of the Yennisey river), other European countries of the CIS, Algeria, Egypt, Libya, Morocco, Tunisia, Western Sahara (Democratic Arab Republic)

Asian Gas Market

Australasia, Russia (east of the Yennisey river)

Transition Zone European/Asian Market

Middle East, Central Asian countries of the CIS (Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan, Uzbekistan, Kyrgyzstan)

North American Gas Market

North America

Latin American Gas Market

Argentine, Bolivia, Brazil, Chile, Paraguay, Peru, Uruguay

Units of measurement

b, bbl	barrel	1 bbl = 158.984 Liter
Btu	British thermal unit	1 Btu = 1060 Joule 1000 Btu = ca. 1 cf natural gas
boe	barrel(s) of oil equivalent	
bopd, b/d	Barrel(s) oil per day	
cal	calorie	1 cal = 4.1868 J
kcal	kilo calorie	1 kcal = 10^3 cal
bcf	billion cubic feet	(= billion cf) 10^9 cf
cf, cuft	cubic feet	1 cf = 0.02832 m^3
cf/d	cubic feet/day	1 cf/d corresponds to app. 10 m^3/year
(m)mcf	million cubic feet	(= million cubic feet) at times one „m" means 1000 und two „m" mean million
tcf	trillion cubic feet	(= trillion cubic feet) = 10^{12} cuft
D	Darcy	unit for the specification of the permeability of a rock (1 mD (milli Darcy) = 0.001 D)
J	Joule	1 J = 0.2388 cal = 1Ws
kJ	Kilojoule	1 kJ = 10^3 J
MJ	Megajoule	1 MJ = 10^6 J
GJ	Gigajoule	1GJ = 10^9 J = 278 kWh = 0.0341 t SKE
TJ	Terajoule	1 TJ = 10^{12} J = 278 x 10^3 kWh = 34.1 t SKE
PJ	Petajoule	1 PJ = 10^{15} J = 278 x10^6 kWh = 34.1·10^3 t SKE
EJ	Exajoule	1 EJ = 10^{18} J = 278 x 10^9 kWh = 34.1·10^6 t SKE
m^3	cubic meters	
Nm^3	standard cubic meters	amount of gas in 1 m^3 at 0°C and 1013 mbar [also abb. m^3(Vn)]
Mcm	million cubic meters	= 10^6 m^3
Bcm	billion cubic meters	= 10^9 m^3
Tcm	trillion cubic meters	= 10^{12} m^3
W	Watt	
kW	Kilowatt	1 kW = 10^3 W
MW	Megawatt	1 MW = 10^6 W
GW	Gigawatt	1 GW = 10^9 W
kWh	Kilowatt-hour	1 kWh = 3.6 x 10^6 J
MWh	Megawatt-hour	1 MWh = 3.6 x 10^9 J
GWh	Gigawatt-hour	1 GWh = 3.6 x 10^{12} J
MWa	Megawatt-year	1 MWa = 3.15 x 10^{13} J

Units of measurement - continued

Pa·s	**Pascal-seconds**	= $kg \cdot m^{-1} \cdot s^{-1}$ specification of the viscosity of a liquid; e. g. water has a viscosity of 1 mPa·s at 20°C
ppm	**parts per million**	$=10^{-6}$ = 0.0001 %
t	**ton**	1 t = 10^3 kg
t/a	**metric ton(s) per year**	
tce	**tons of coal equivalent**	
kt	**Kiloton**	1 kt = 10^3 t
Mt	**Megaton**	1 Mt = 10^6 t
Gt	**Gigaton**	1 Gt = 10^9 t
Tt	**Teraton**	1 Tt = 10^{12} t

Conversion factors[1]

1 t petroleum 1 toe = 7,35 bbl = 1,428 t SKE = 1101 m^3 natural gas = 41,8 x 10^9 J

1 t LNG 1380 m^3 natural gas = 1,06 toe = 1,52 t SKE = 44,4 x 10^9 J

1000 Nm^3 natural gas 35 315 cf = 0,9082 toe = 1,297 t SKE = 0,735 t LNG = 38 x 10^9 J

1 tce 0,70 toe = 770,7 m^3 natural gas = 29,3 x 10^9 J

1 EJ (10^{18} J) 34,1 Mio. t SKE = 23,9 Mio. toe = 26,3 Mrd. m^3 natural gas = 278 Mrd. kWh

1 t Uranium (nat.) 14 000 bis 23 000 t SKE; different values depending on the utilization factor

1 kg Uranium (nat.) 2,6 lb U_3O_8

1 As natural products, fossil energy resources are subject to variations; the specific energy contents represent average values, which may deviate significantly in some cases.
For natural gas the conversion factors have been adapted to international standards, which are significant higher than the values used for Germany. This allows a better world-wide comparison of natural gas with other energy resources. As conversion factor for natural gas 38 MJ per m^3 was used according to „Energie Daten 2003" by German BMWi (p. 52). According to IEA „Natural Gas Information 2006" (p. XXIX/XXX) heat values of natural gas varying from 33,32 MJ/m^3 (Netherlands) to 43,717 MJ/m^3 (Tunisia). Values for Germany of 33.337 MJ/m^3 range at the lower end. Heat value of natural gas produced by the 'Top Ten' countries in 2006 averages 38.3 MJ/m^3. Other conversion factors range between 37.68 MJ/m^3 (BP 2007) and 41.4 MJ/m^3 (E.ON Ruhrgas). Thus the value of 38 MJ/m^3 is on the safe side.

Geological Timechart

Era	System		Series	General	Time (Ma)
Cenozoic	Quaternary		Holocene (Recent)		
			Pleistocene		2,6
	Tertiary	Neogene	Pliocene	Piacenzian	
				Zanclean	
			Miocene	Messinian	
				Tortonian	
				Serravallian	
				Langhian	
				Burdigalian	
				Aquitanian	24
		Paleogene	Oligocene	Chattian	
				Rupelian	
			Eocene	Priabonian	
				Bartonian	
				Lutetian	
				Ypresian	
			Paleocene	Thanetian	
				Danian	65
Mesozoic	Cretaceous		Upper	Maastrichtian	
				Campanian	
				Santonian	
				Coniacian	
				Turonian	
				Cenomanian	
			Lower	Albian	
				Aptian	
				Barrêmian	
				Hauterivian	
				Valanginian	
				Berriasian	142
	Jurassic		Upper (Malm)	Tithonian	
				Kimmeridgian	
				Oxfordian	
			Middle (Dogger)	Callovian	
				Bathonian	
				Bajocian	
				Aalenian	
			Lower (Lias)	Toarcian	
				Pliensbachian	
				Sinémurian	
				Hettangian	200
	Triassic		Upper	Rhaetian	
				Norian	
				Carnian	
			Middle	Ladinian	
				Anisian	
			Lower	Olenekian	
				Induan	251
Paleozoic	Permian		Upper	Tatarian/Kaz.	
				Kunjurian/Art.	
			Lower	Sakmarian/Ass.	296
	Carboniferous		Pennsylvanian	Stephanian	
				Westphalian	
				Namurian	
			Mississippian	Visean	
				Tournaisian	358
	Devonian		Upper	Famennian	
				Frasnian	
			Middle	Givetian	
				Eifelian	
			Lower	Emsian	
				Pragian	
				Lochkovian	418
	Silurian		Upper	Pridolian	
				Ludlovian	
			Lower	Wenlockian	
				Llandoverian	443
	Ordovician		Upper	Ashgillian	
				Cradocian	
			Middle	Llandeilian	
				Llanvirnian	
			Lower	Arenigian	
				Tremadocian	495
	Cambrian		Upper		
			Middle		
			Lower		545
Pre-cambrian	Proterozoic		Early		
			Late		
	Archaen		Archaen		>3800

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