ENERGY RESOURCES 2009



Reserves, Resources, Availability

Crude Oil
Natural Gas
Coal
Nuclear Fuels
Geothermal Energy

BGR

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

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Bundesanstalt für Geowissenschaften und Rohstoffe (BGR)
Federal Institute for Geosciences and Natural Resources
Stilleweg 2
30655 Hannover
Germany

Phone.: +49 (0)511 – 643-0
Fax: +49 (0)511 – 643-23 04
e-mail: poststelle@bgr.de
web: http://www.bgr.bund.de

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With contributions from:

Coordination
Bernhard Cramer, Harald Andruleit

The availability of energy resources - an overview
Bernhard Cramer and coauthors

Crude Oil
Hilmar Rempel (Conventional Oil)
Hans-Georg Babies (Unconventional Oil)

Natural gas
Hilmar Rempel (Conventional Natural Gas)
Stefan Schlömer (Tight and Shale Gas)
Sandro Schmidt (Coalbed Methane)
Harald Andruleit (Natural Gas in Aquifers, Gas Hydrate)

Coal
Sandro Schmidt

Nuclear Fuels
Ulrich Schwarz-Schampera

Geothermal Energy
Norbert Ochmann

Energy Resources in Germany
Jürgen Meßner (LBEG) and coauthors

Availability of Energy Resources
Sönke Rehder, Bernhard Cramer and coauthors

Layout
Gabriele Ebenhöch, Claudia Kirsch, Elke Westphale

Graphics
Uwe Benitz

Source of photos on cover sheet
Wintershall Holding AG, BGR

With contribution from
Ulrich Berner, Christian Bönnemann, Dieter Franke, Peter Gerling, Hans Keppler, Martin Krüger, Christian Ostertag-Henning, Britta Pfeiffer, Thomas Pletsch, Barbara Teichert, Torsten Tischner

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 %.

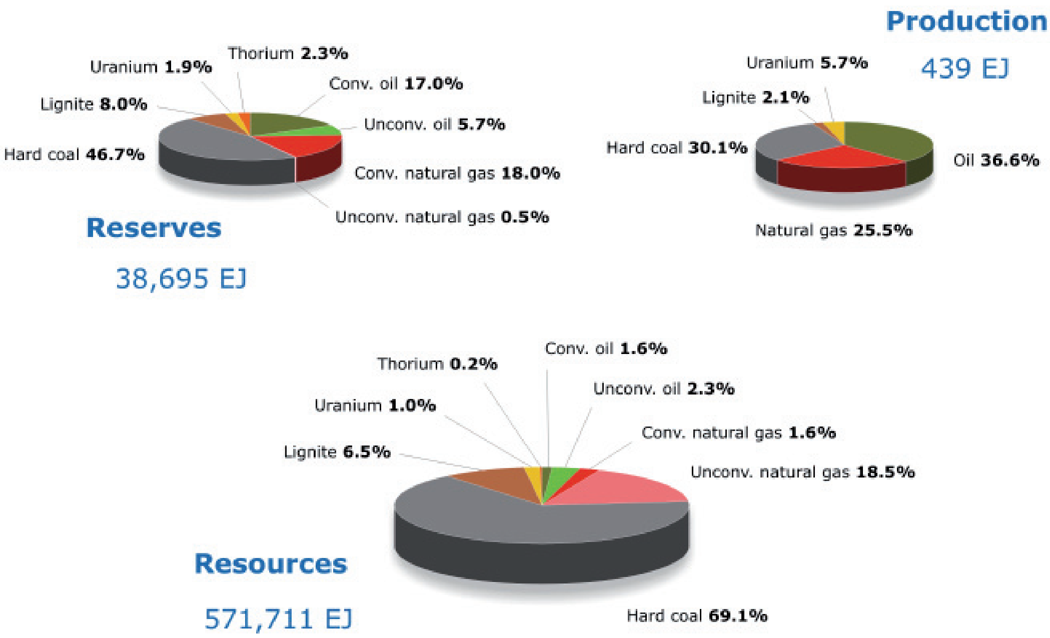


Figure 1.1: Annual production, reserves and resources of the individual non-renewable fuels in 2007.

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 measure-ment**	**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.

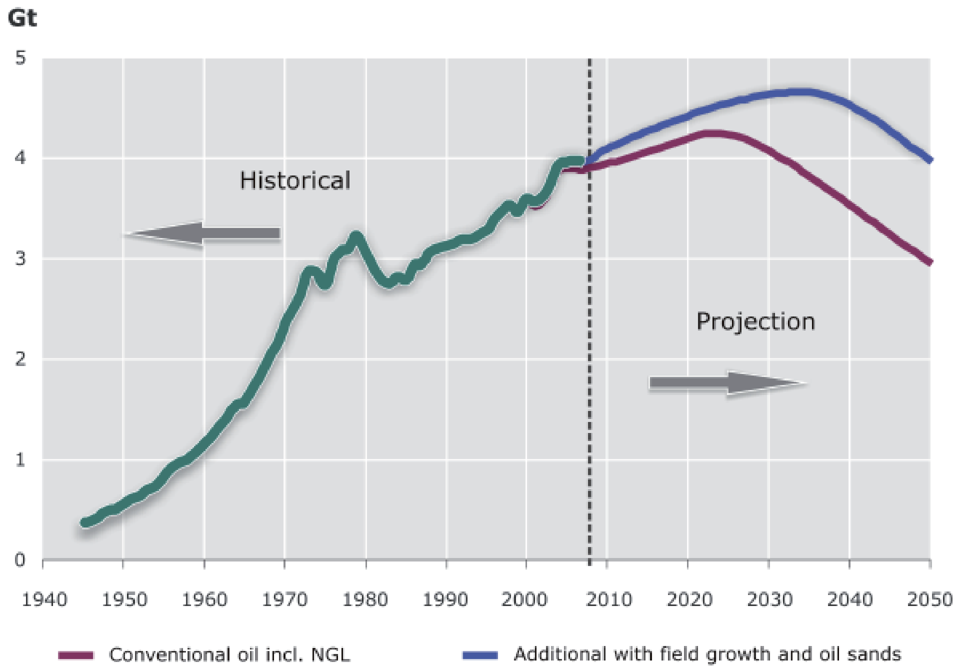


Figure 1.2: Historic development of oil production and projected course of production for conventional oil including condensate (NGL) and additionally taking into account the oil sand production and increases in reserves (Field Growth).

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.

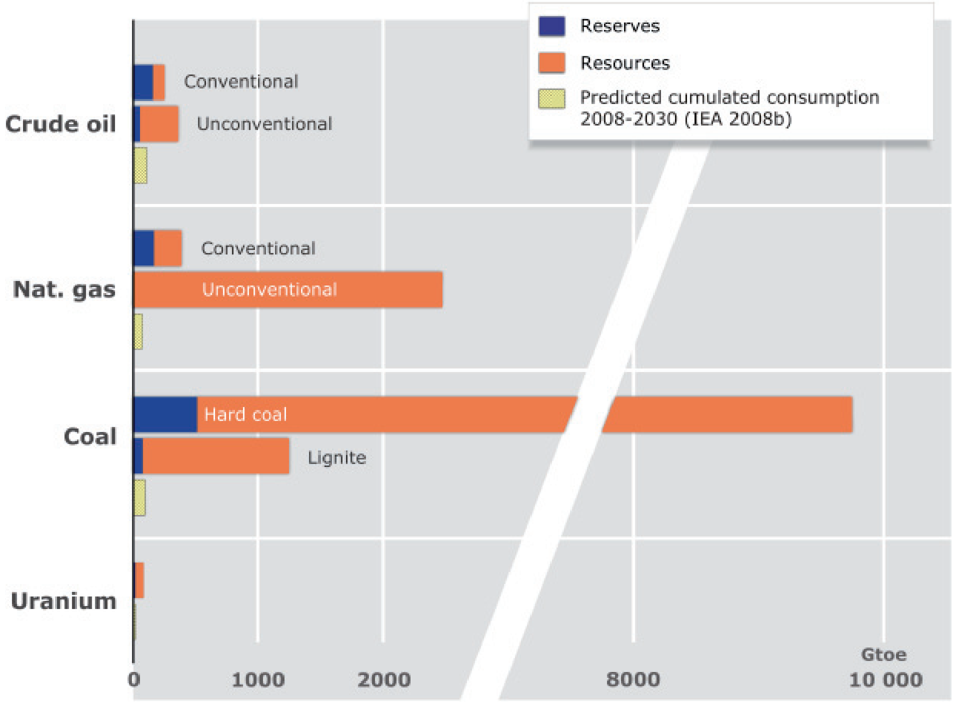


Figure 1.3: Supply situation (reserves and resources) of non-renewable energy resources in comparison with a demand scenario by the IEA (2008) to 2030.

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).

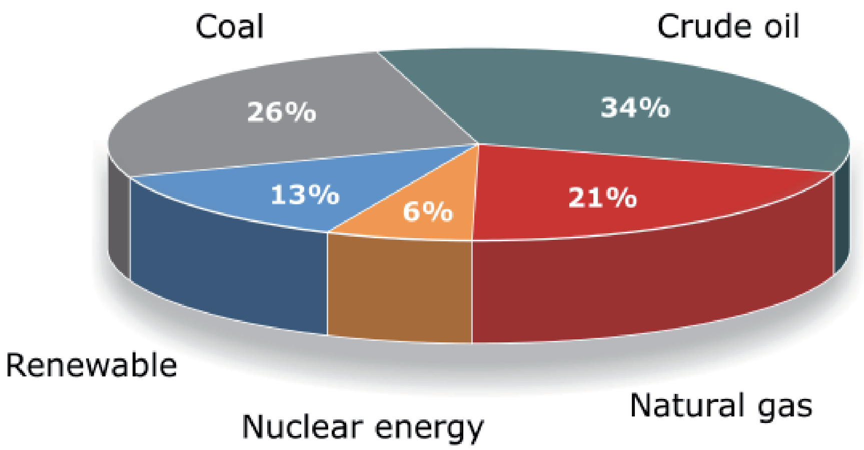


Figure 2.1: Proportion of the individual energy resources on the total primary energy supply in 2006 worldwide (IEA, 2008).

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).

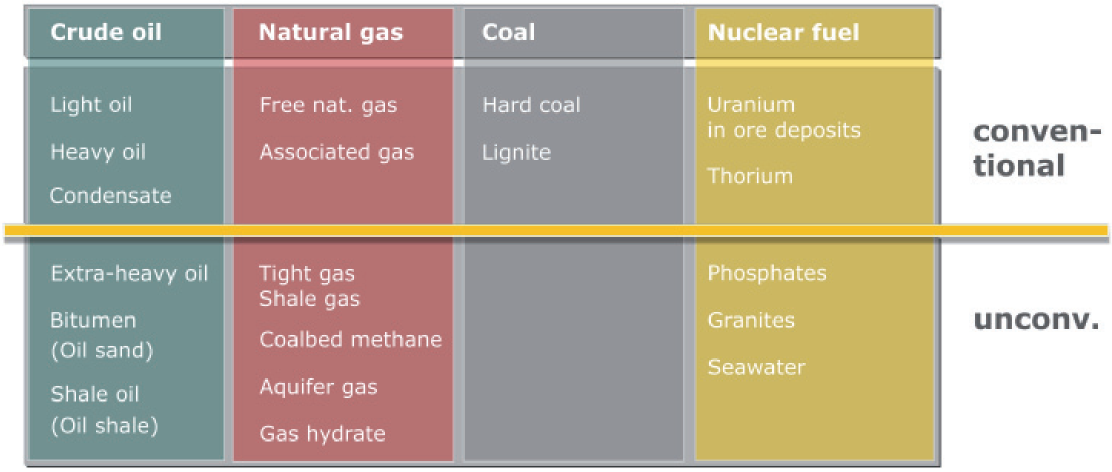


Figure 2.2: Classification of the non-renewable energy resources.

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).

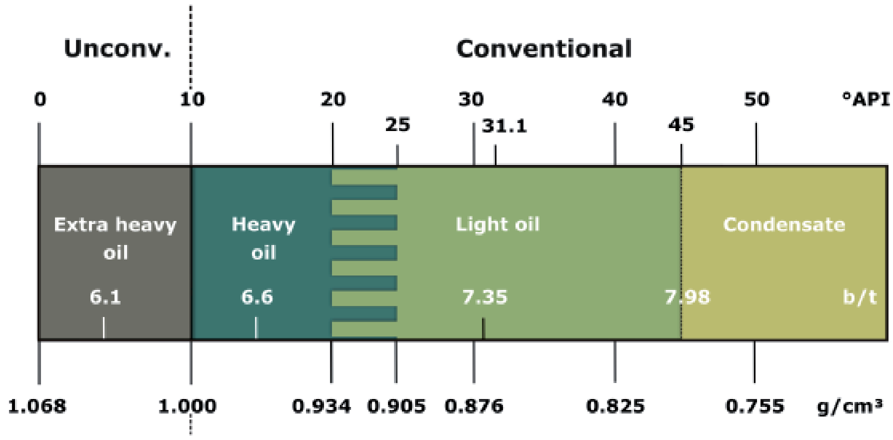


Figure 2.3: Classification of crude oil according to its density.

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.

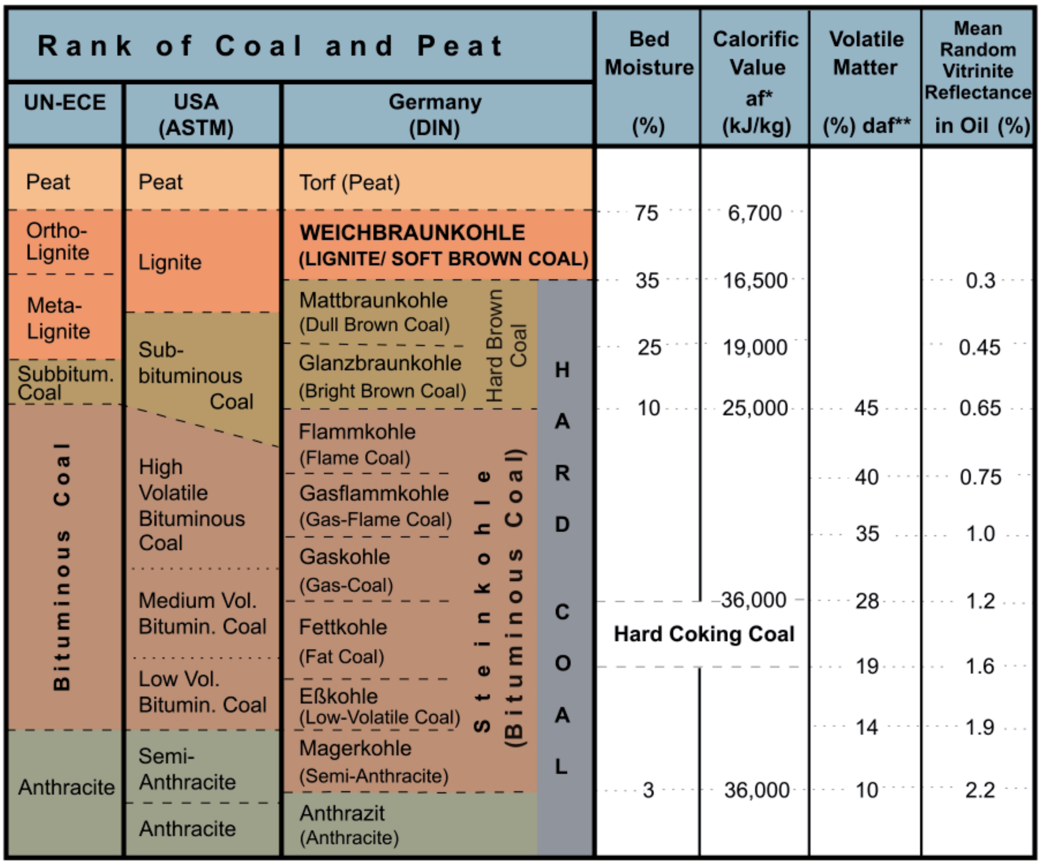
Coalbed methane, CBM, is natural gas which occurs in coal bearing basins in coal seams in absorbed form or in micro-fissures and micropores. It is also extracted through drill holes and the influx is stimulated by cracking open the coal seams using artificial fractures.

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.

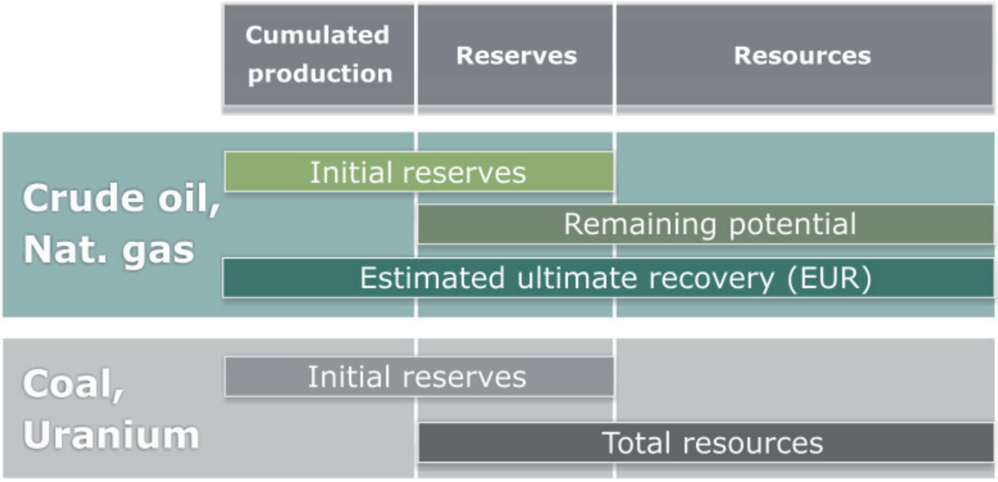


Figure 2.5: Reserve classification of the energy resources

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).

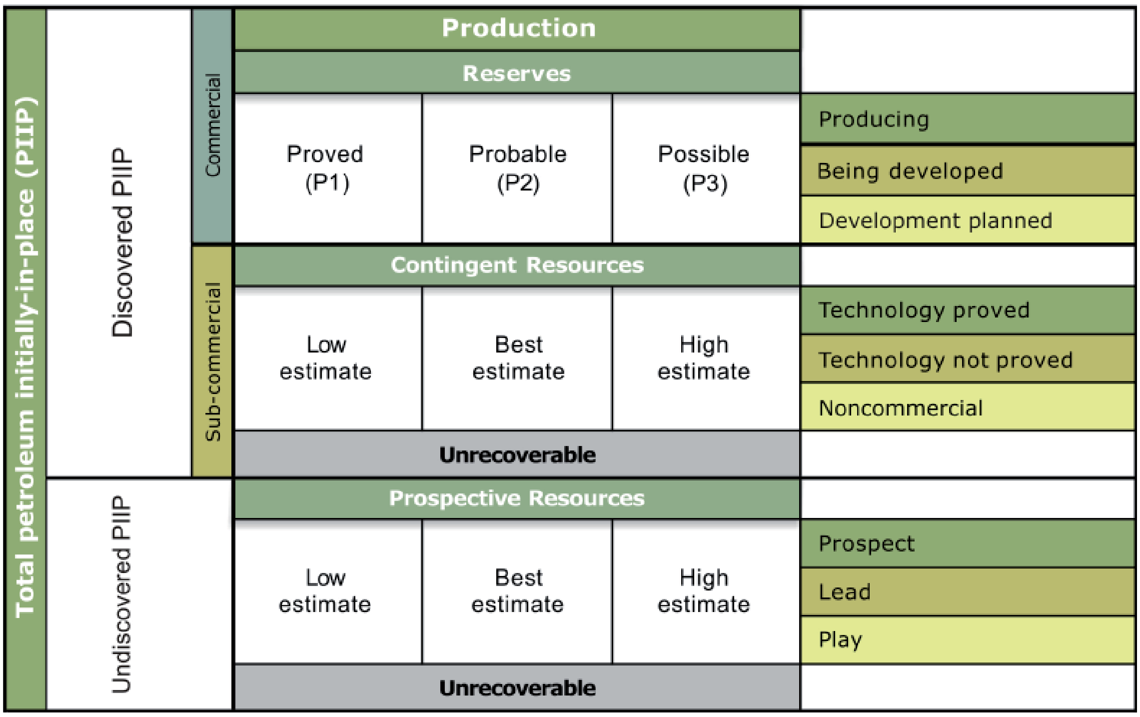


Figure 2.6: Petroleum resource management system SPE/WPC/AAPG/SPEE (SPE, 2007).

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.

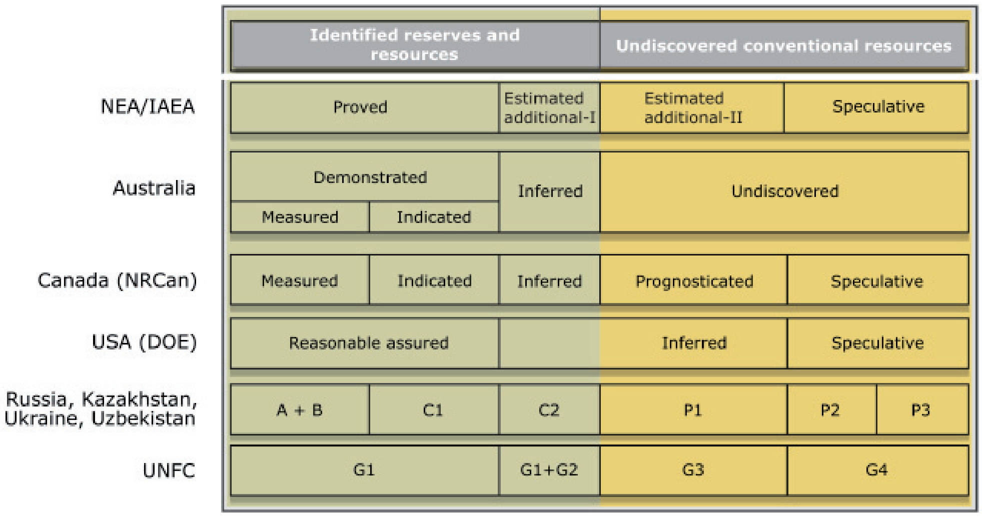


Figure 2.7: Comparison of common resource classifications for uranium deposits (NEA, 2005).

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

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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.

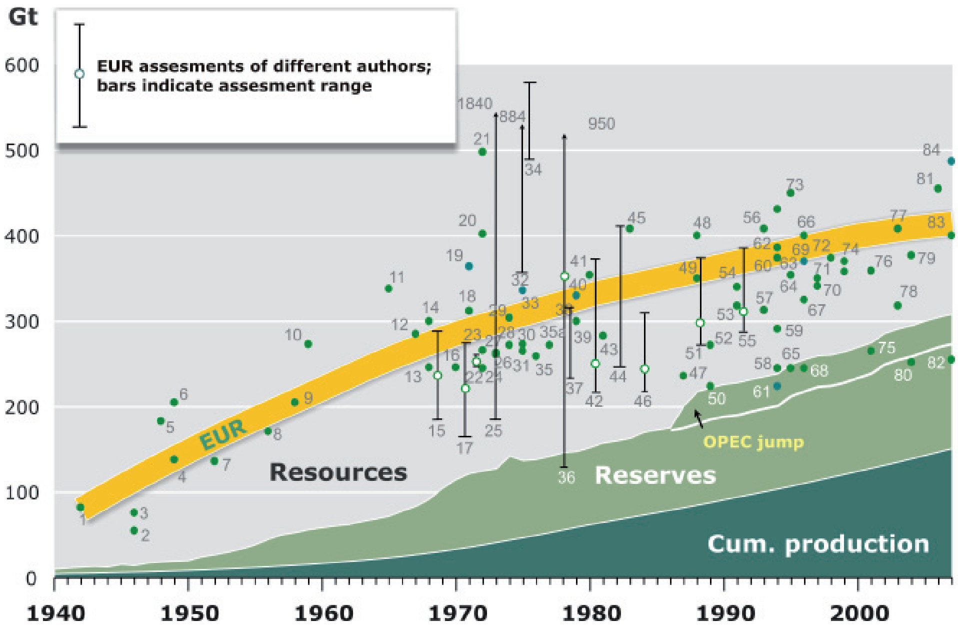


Figure 3.1: Development of the estimates concerning the Estimated Ultimate Recovery (EUR) of conventional oil, the cumulative production and reserves from 1940 to 2007 (sources for numbered references cf. Tab. A 3-1).

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.

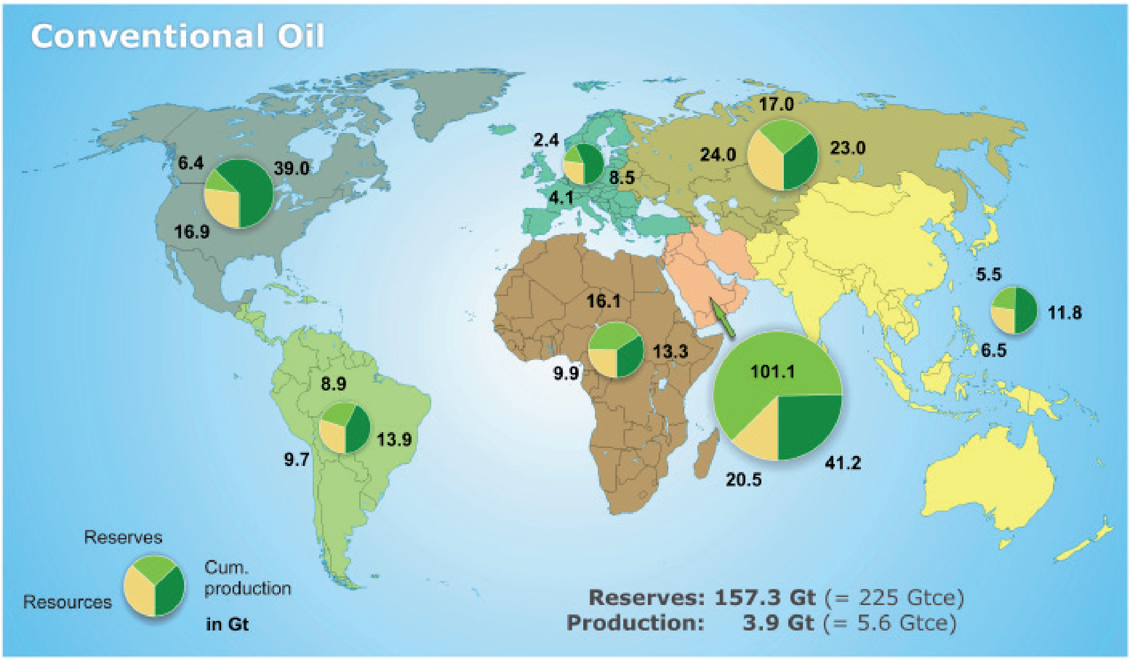


Figure 3.2: Regional distribution of the EUR of conventional crude oil in 2007 (total 400 Gt).

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.

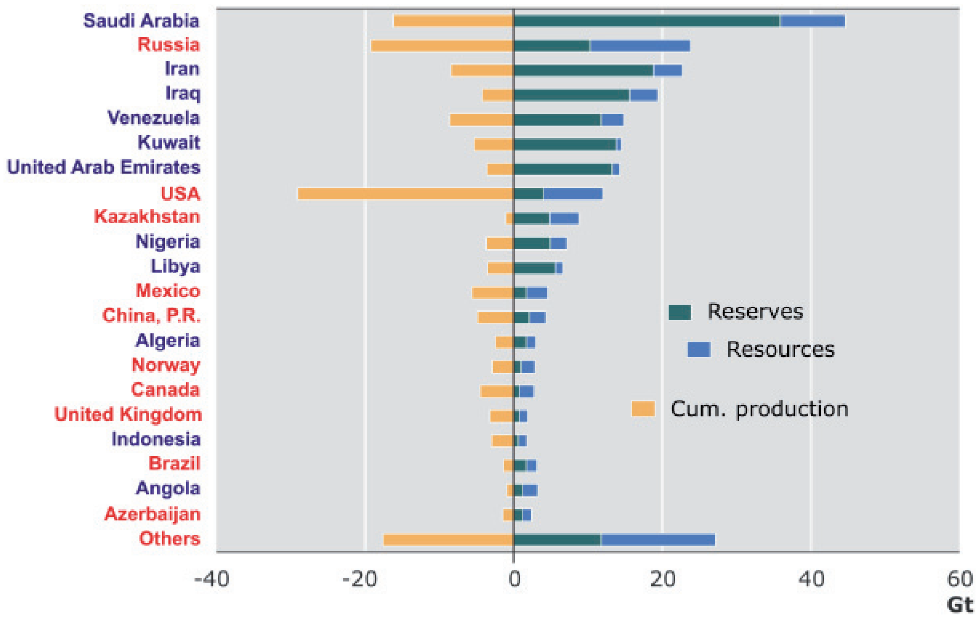


Figure 3.3: EUR of conventional crude oil in 2007: The top twenty countries sorted according to remaining potential (OPEC countries in blue bold-face type).

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.

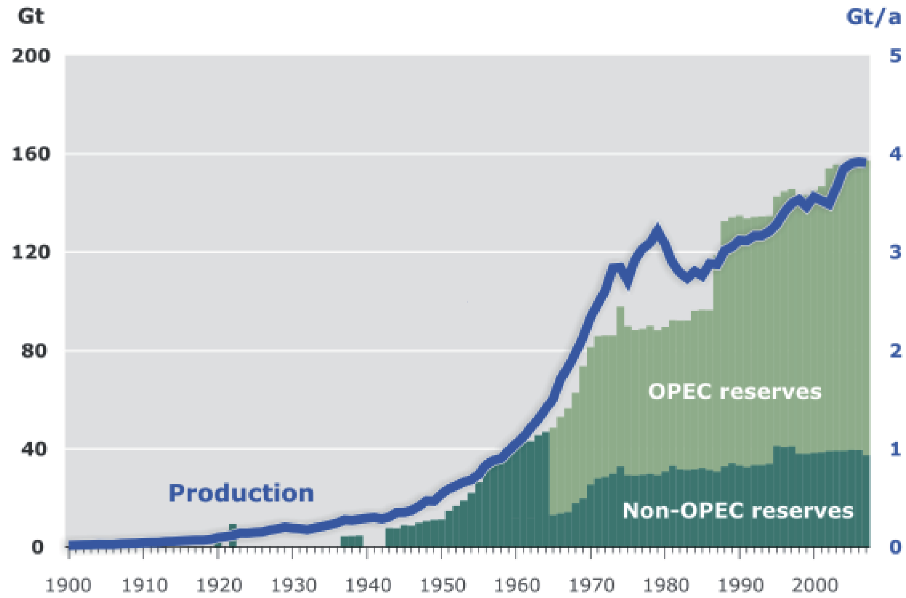


Figure 3.4: Development of the reserves and production of conventional oil from 1900 to 2007.

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.

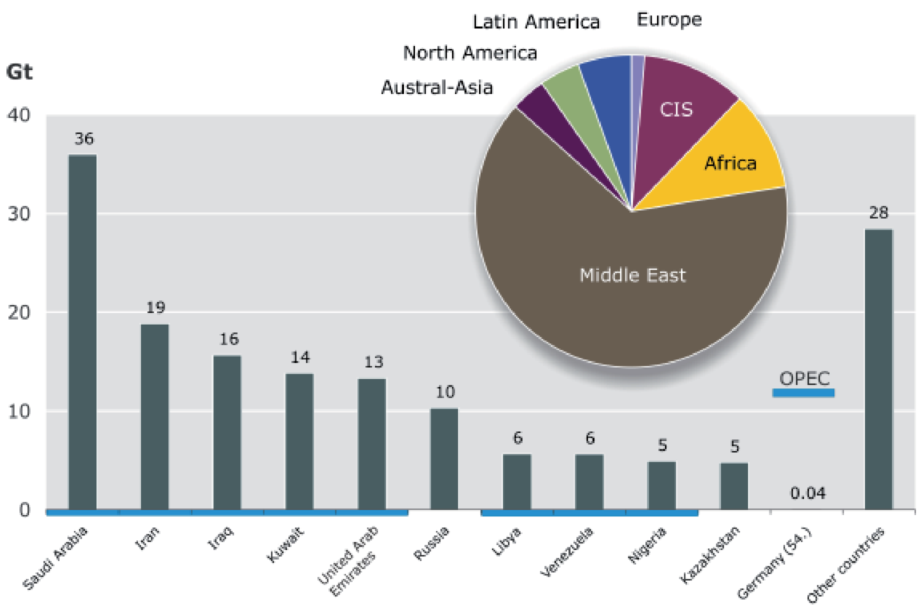


Figure 3.5: Reserves of conventional oil (Total 157.3 Gt) in 2007 of the top ten countries and Germany as well as their distribution by region.

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.

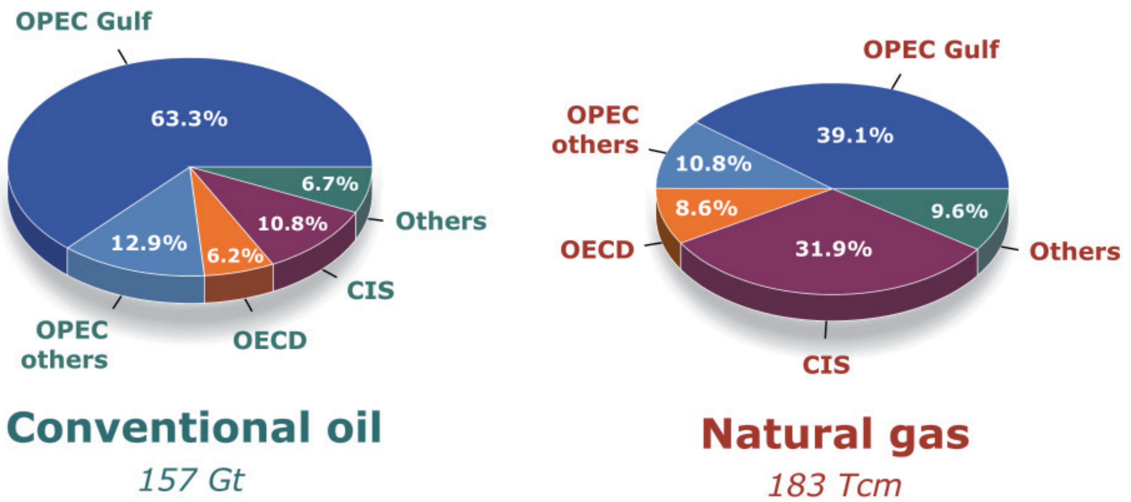


Figure 3.6: Distribution of the reserves of conventional oil and natural gas in 2007 according to economic groupings.

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.

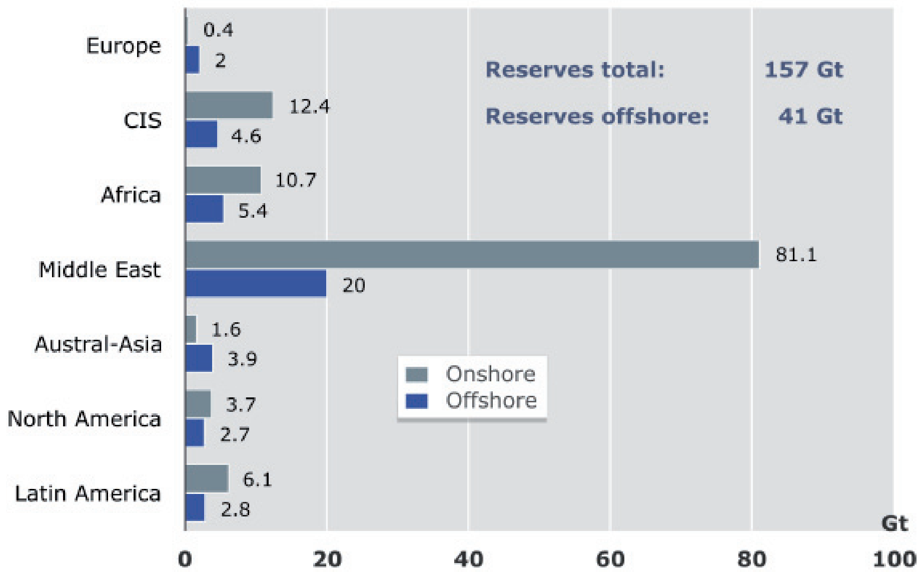


Figure 3.7: Distribution of the reserves of conventional oil in 2007, onshore and offshore, by region.

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.

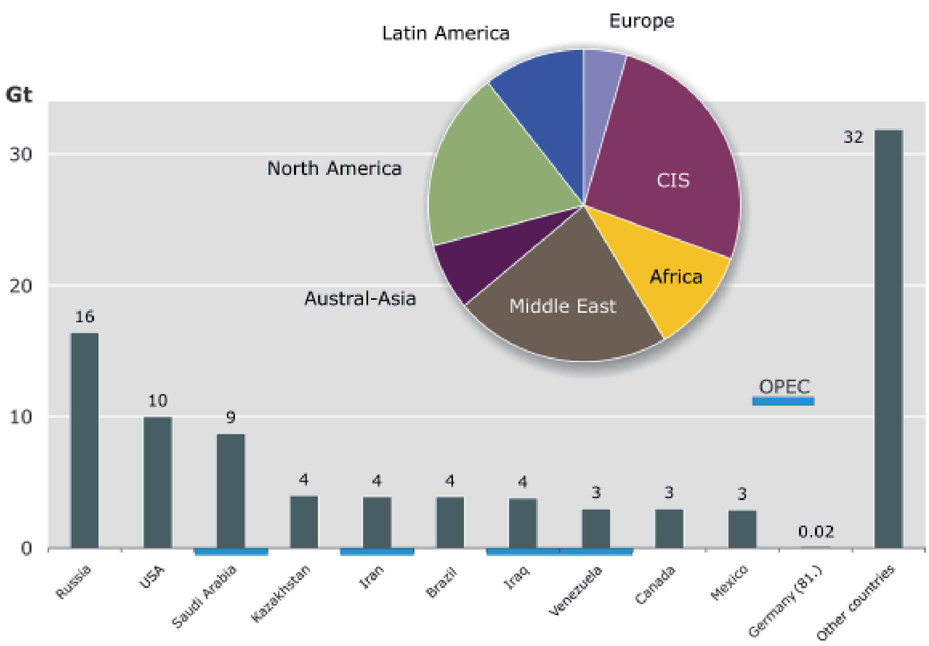
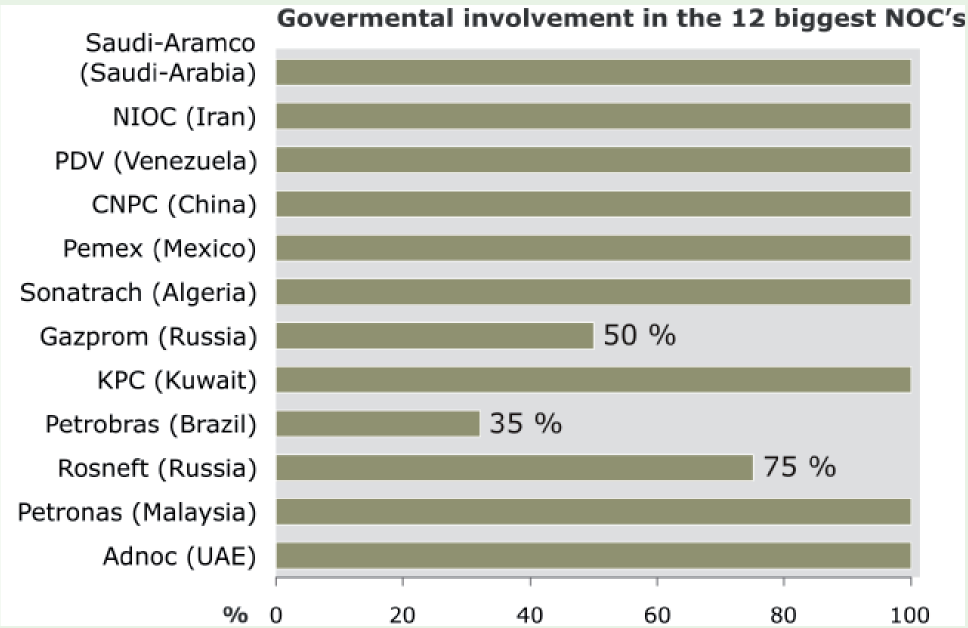


Figure 3.8: Resources of conventional oil (total 91.1 Gt) in 2007 of the top ten countries and Germany as well as their distribution by region.

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).

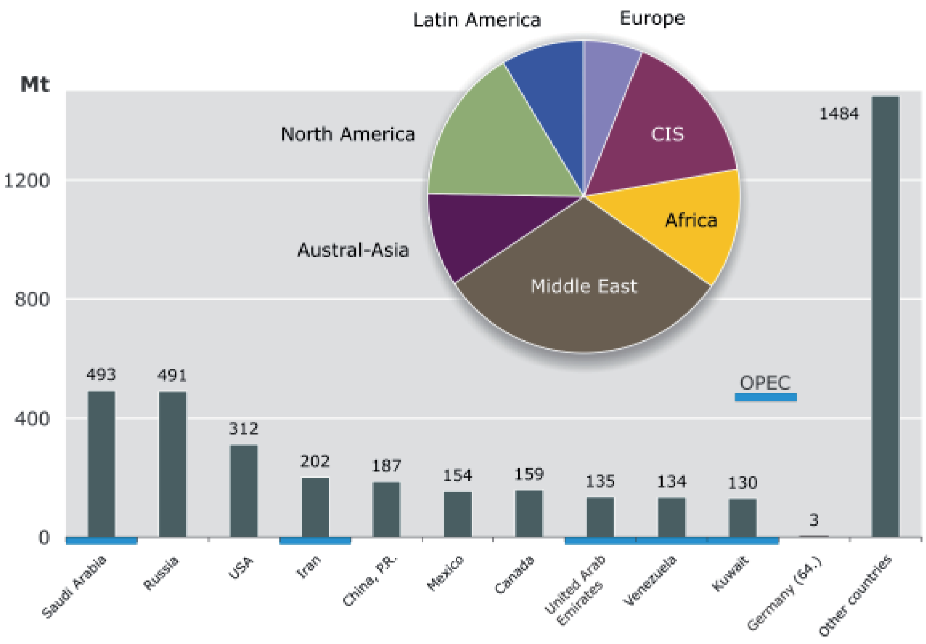


Figure 3.9: Production of conventional oil (Total 3.9 Gt) in 2007 of the top ten countries and Germany as well as their distribution by region.

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.

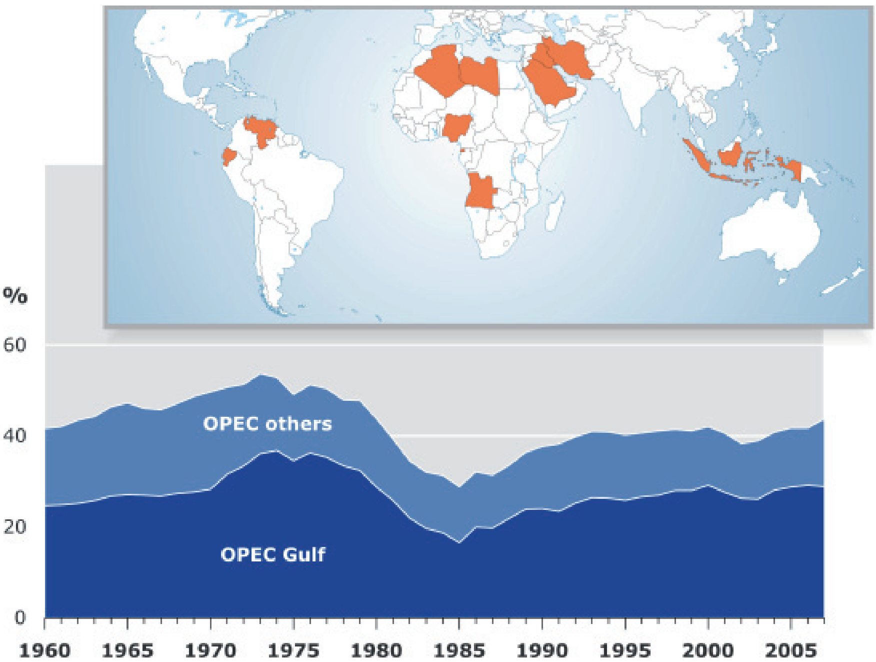


Figure 3.10: Share of the OPEC countries (orange) in the global petroleum production from 1960 to 2007.

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.

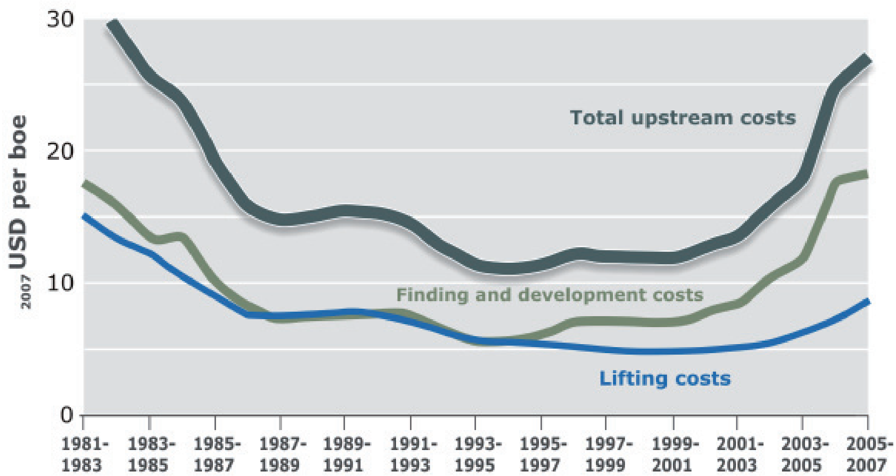


Figure 3.11: Finding and development costs, lifting costs and specific upstream costs for FRS companies, 1981-1983 to 2005-2007 (EIA, 2008b).

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.

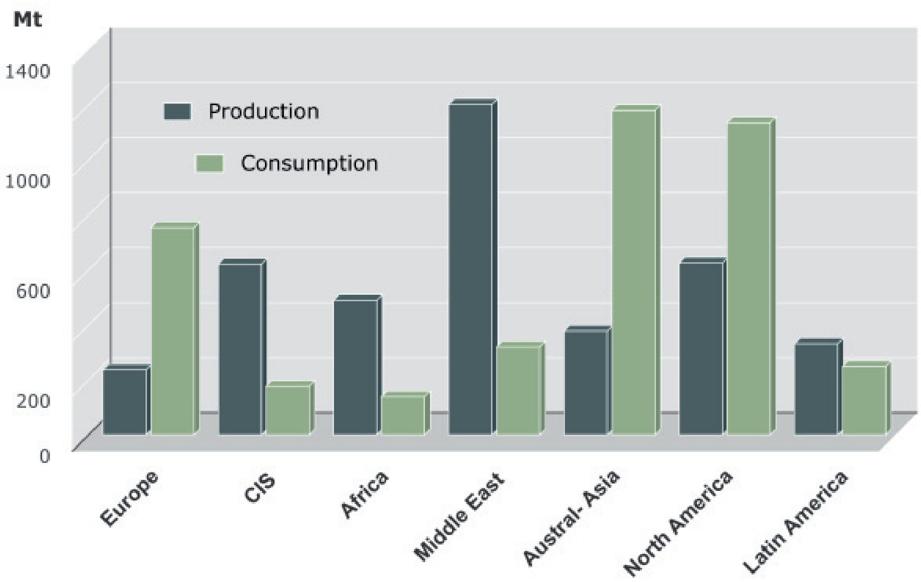


Figure 3.12: Comparison of oil production and consumption in 2007 by region

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.

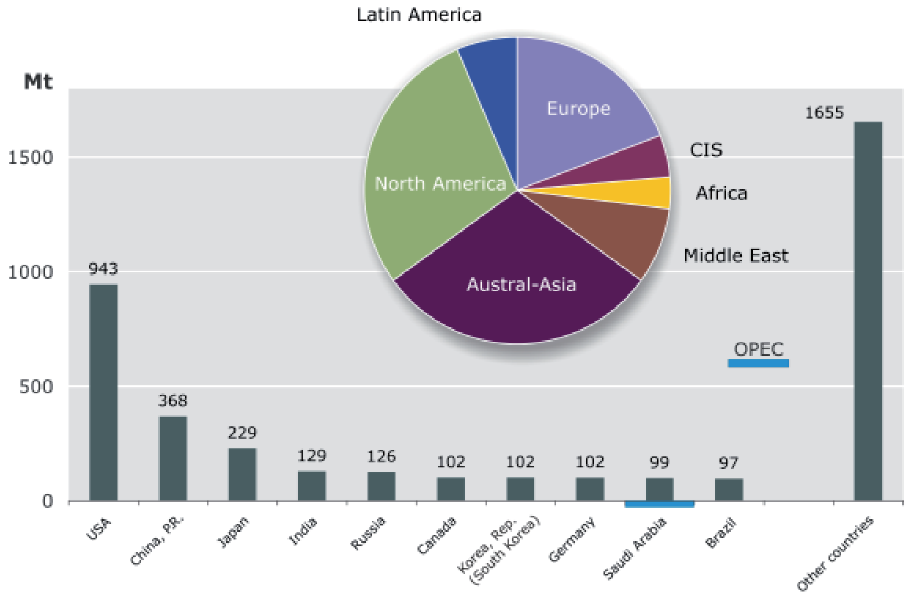


Figure 3.13: Consumption of oil in 2007 (total 3.8 Gt) of the top ten countries as well as distribution by region.

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).

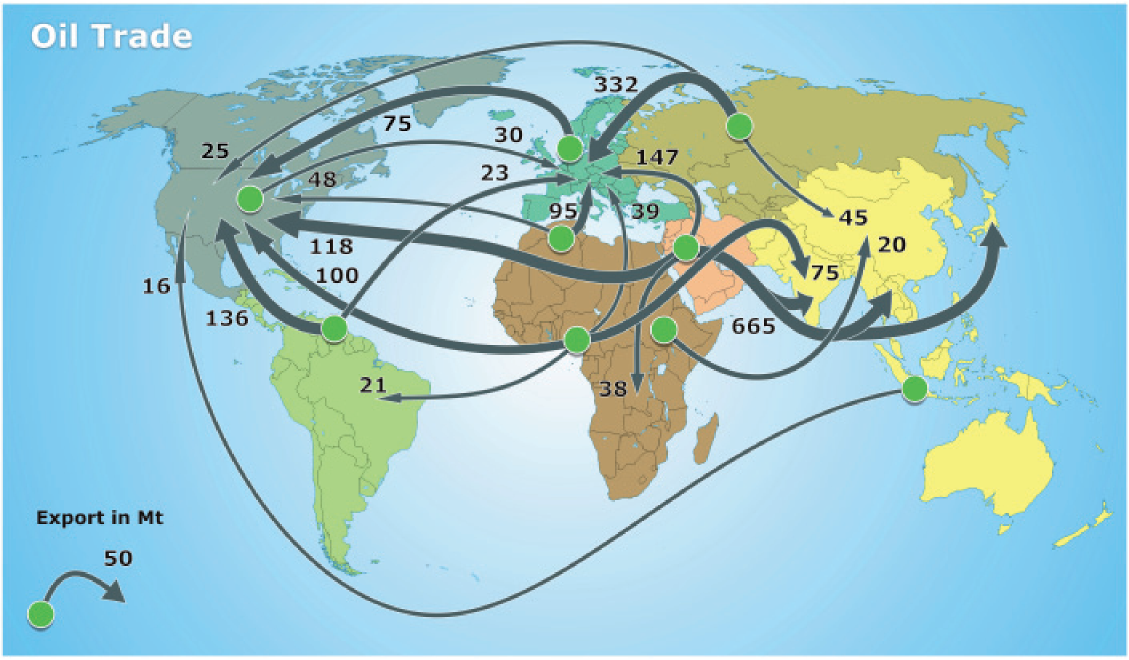


Figure 3.14: Global oil trade movements (crude oil and petroleum products) in 2007 in Mt (according to BP, 2008) without consideration of intraregional trade

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.

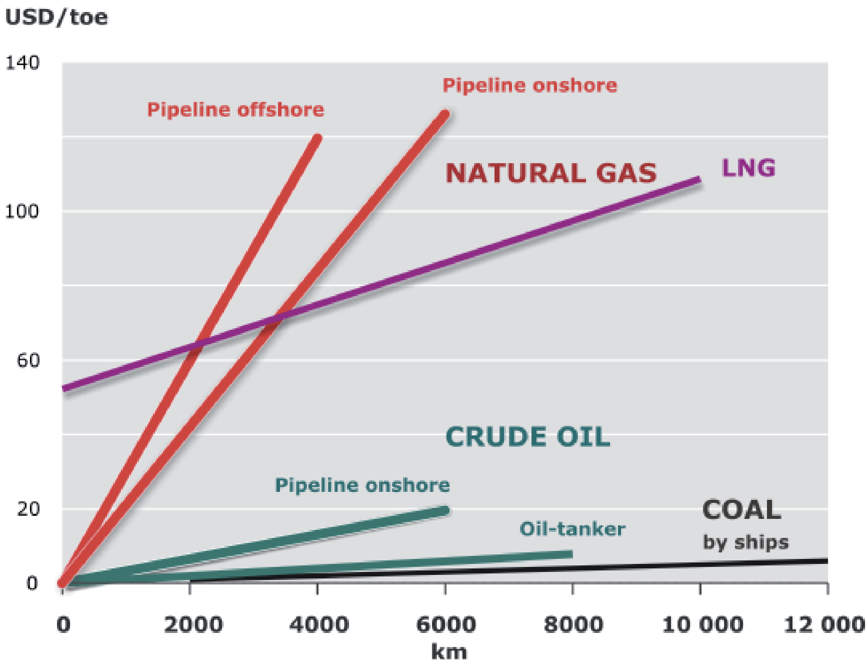


Figure 3.15: Comparison of the transportation costs for oil, natural gas and coal (according to Hatamian, 1998 and VDKI, 1999).

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.

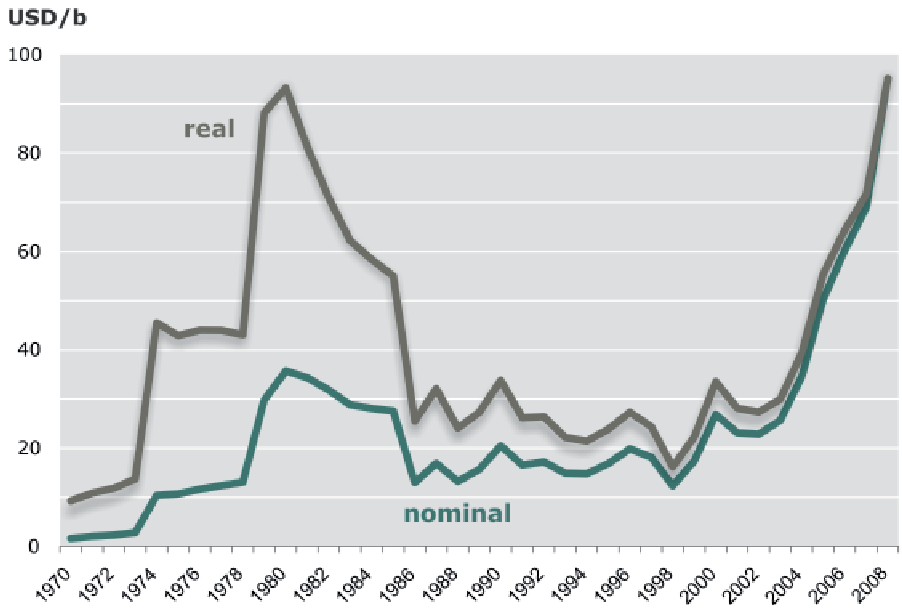


Figure 3.16: Development of the prices for crude oil between 1970 and 2008 real ($_{2008}$USD) and nominally (current rate of the currency) for the oil type Arabian Light in mean annual values.

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.

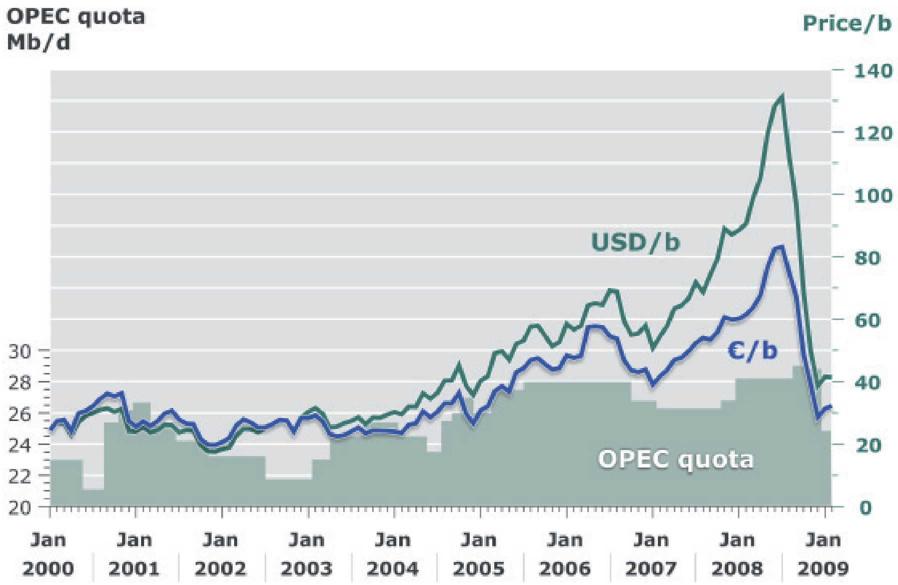


Figure 3.17: Development of the oil prices for OPEC basket in USD and Euro per barrel (monthly mean) as well as the OPEC-10/OPEC-11 (from 9/2008) production quota.

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).

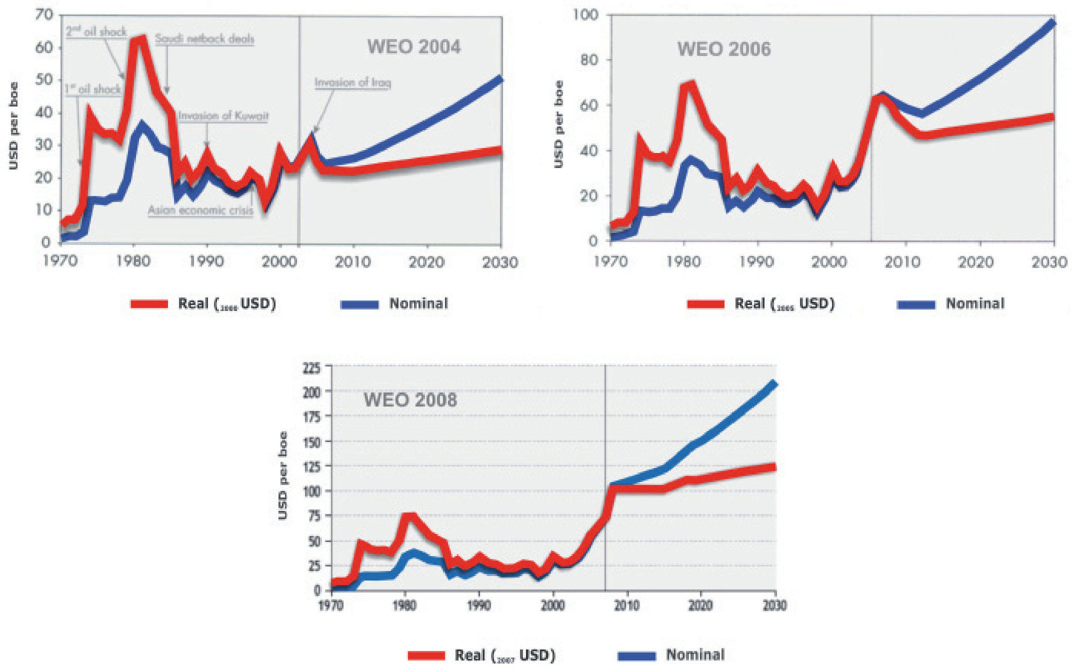


Figure 3.18: Comparison of different oil price forecasts of the IEA (IEA, 2004, 2006, 2008a)

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.

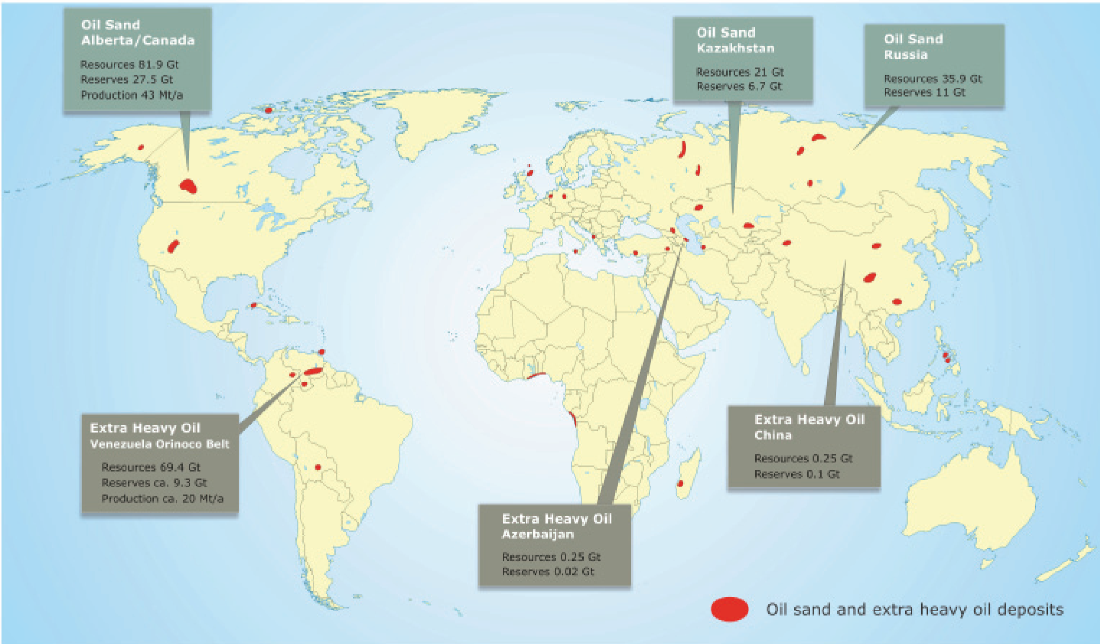


Figure 3.19: Distribution of the known worldwide occurrences of oil sand and extra heavy oils with information on reserves, resources and production.

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).

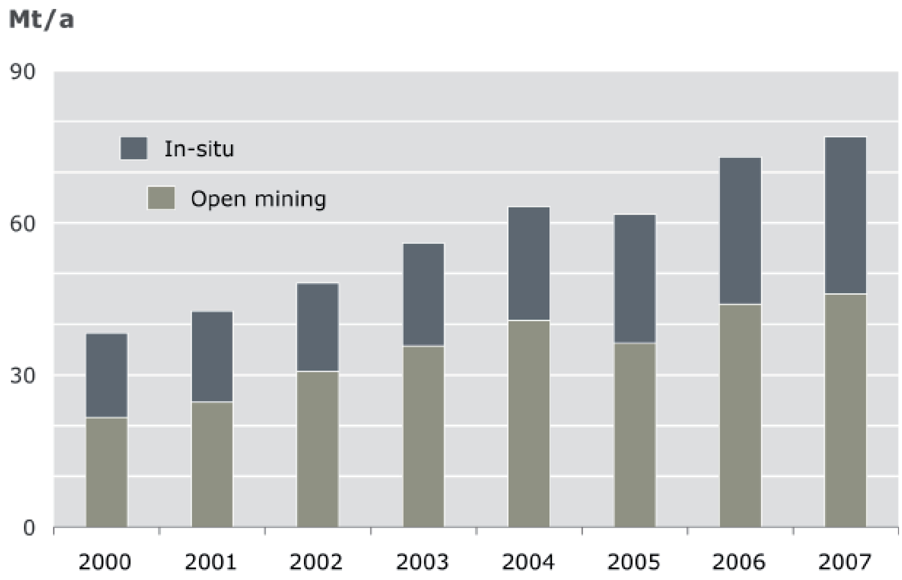


Figure 3.20: Proportions of surface mining - and in-situ processes of the oil production from oil sands in Alberta from 2000 to 2007.

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 m^3 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.

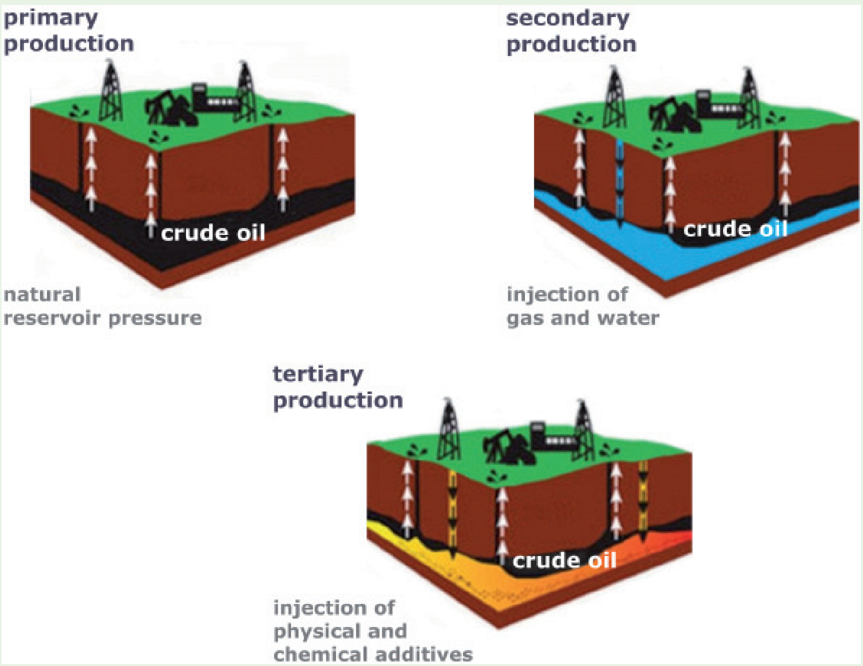
The worldwide largest occurrences of extra-heavy oil are located in the so-called Orinoco Belt in Venezuela with 46.8 Gt of petroleum resources and 6.4 Gt remaining reserves (Fig. 3.21). In 2005, the annual production of conditioned extra-heavy oil was approximately 33 Mt and thus 20 % of the total oil 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 %.

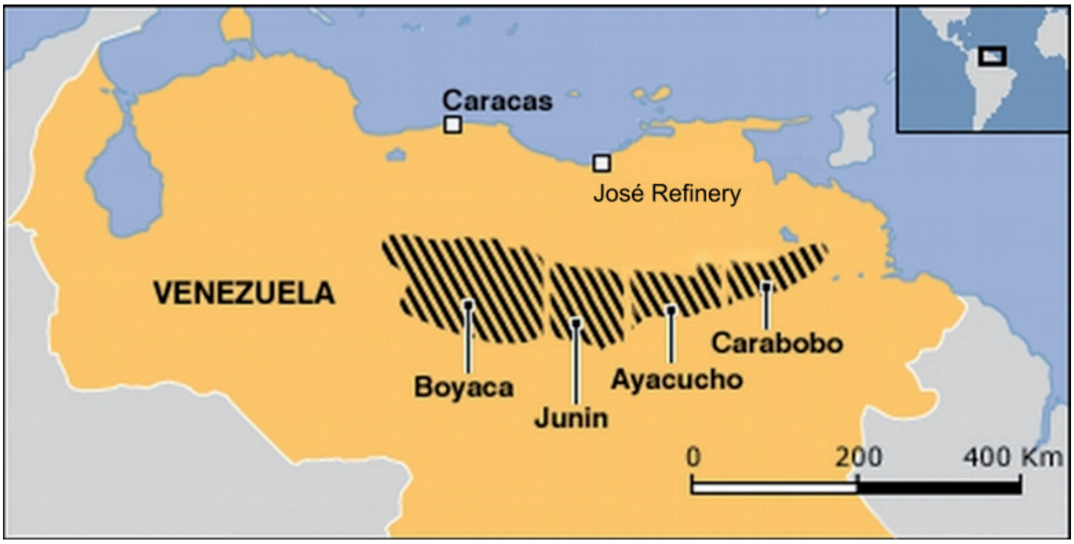


Figure 3.21: Major projects in the Orinoco Belt (hatched), source: PDVSA.

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.

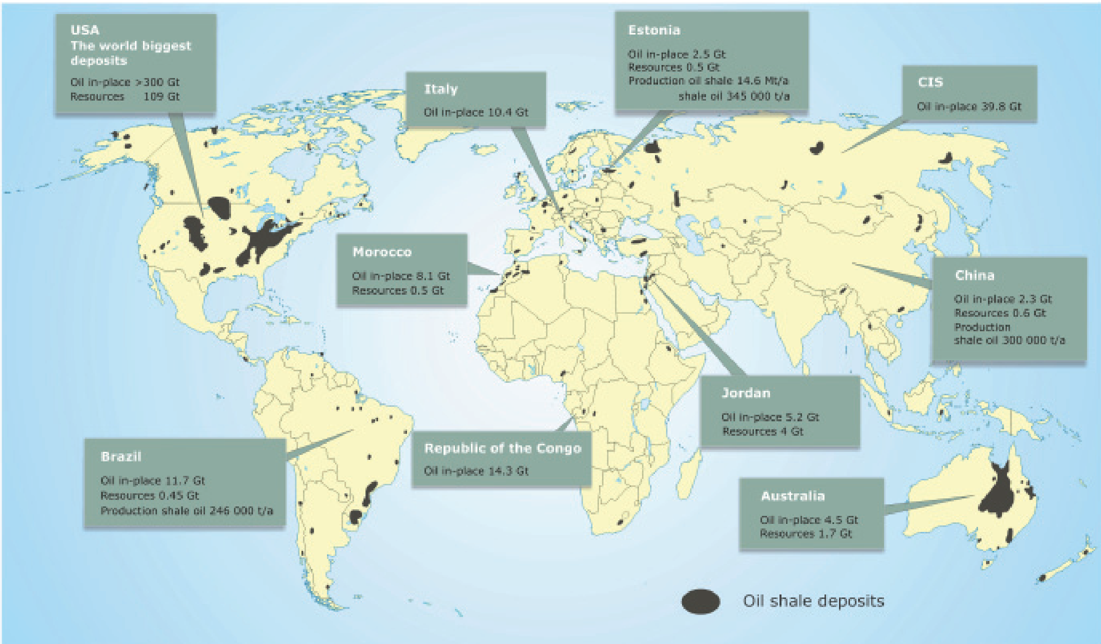


Figure 3.22: Regional distribution of the oil shale occurrences worlwide with data concerning reserves, resources and production.

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).

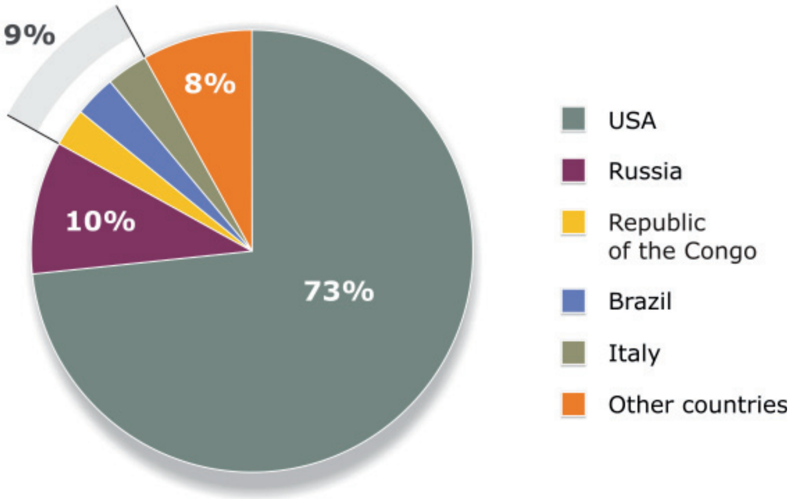


Figure 3.23: In-place shale oil resources (total 413 Gt) according to countries (%).

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.

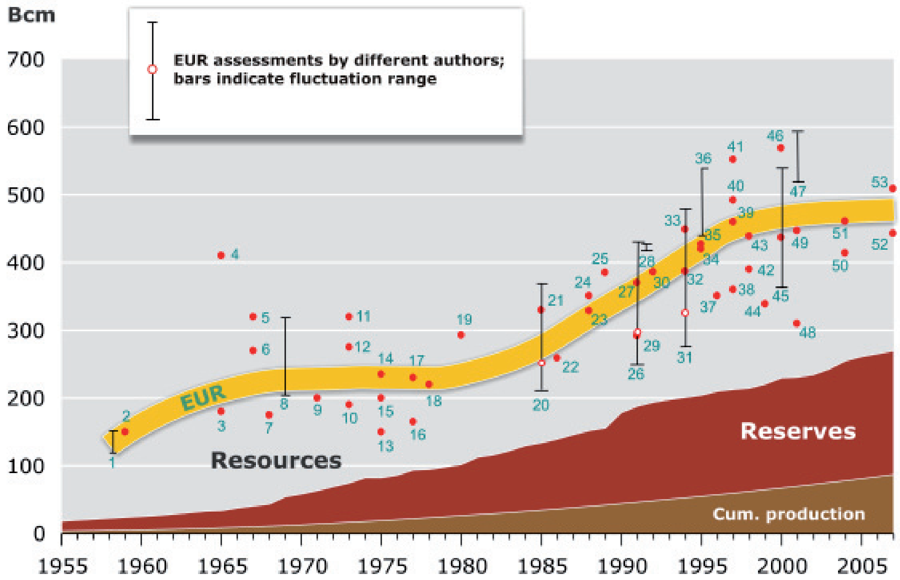

Figure 4.1: Development of the estimates of the Estimated Ultimate Recovery (EUR) of conventional natural gas, the cumulative production and reserves from 1955 to 2007 (sources for numbered references cf. Tab. A 4-1).

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.

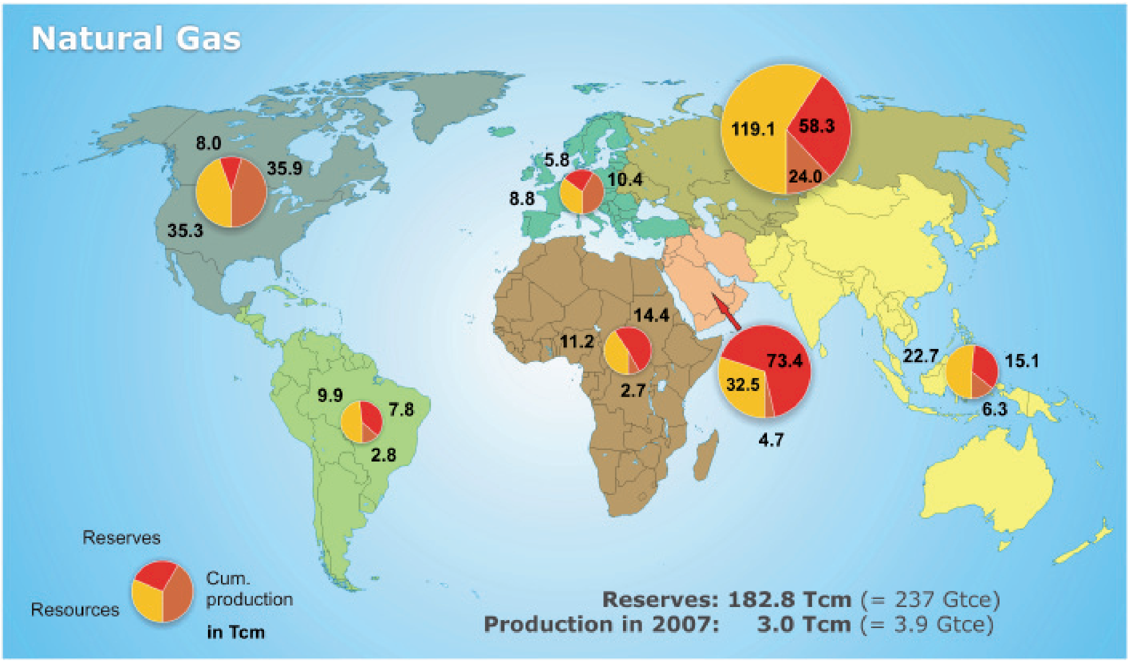

Figure 4.2: EUR of conventional natural gas in 2007 (total 509 Tcm): regional distribution.

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).

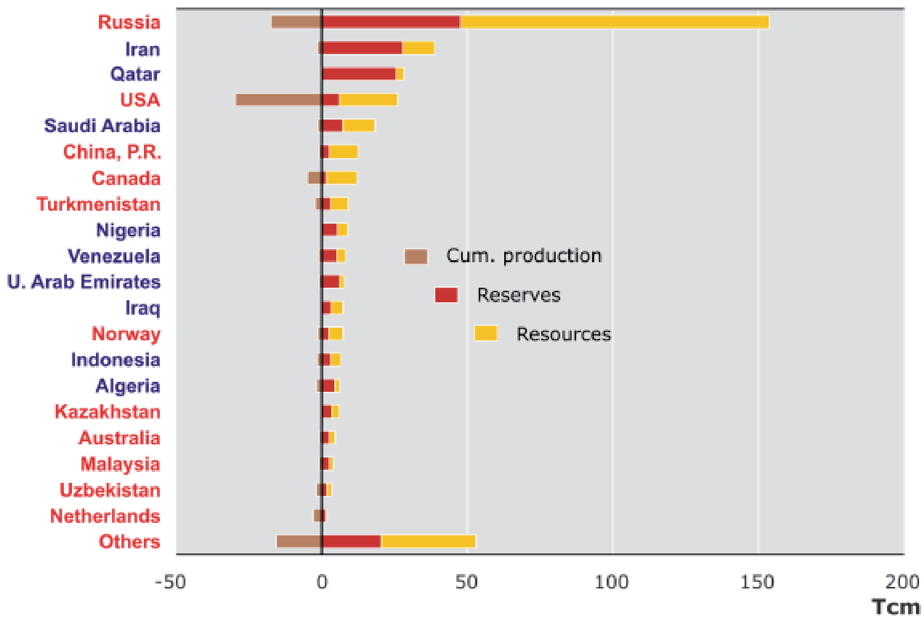

Figure 4.3: EUR of conventional natural gas in 2007: The top twenty countries sorted according to remaining potential (OPEC countries in blue bold-face type).

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.

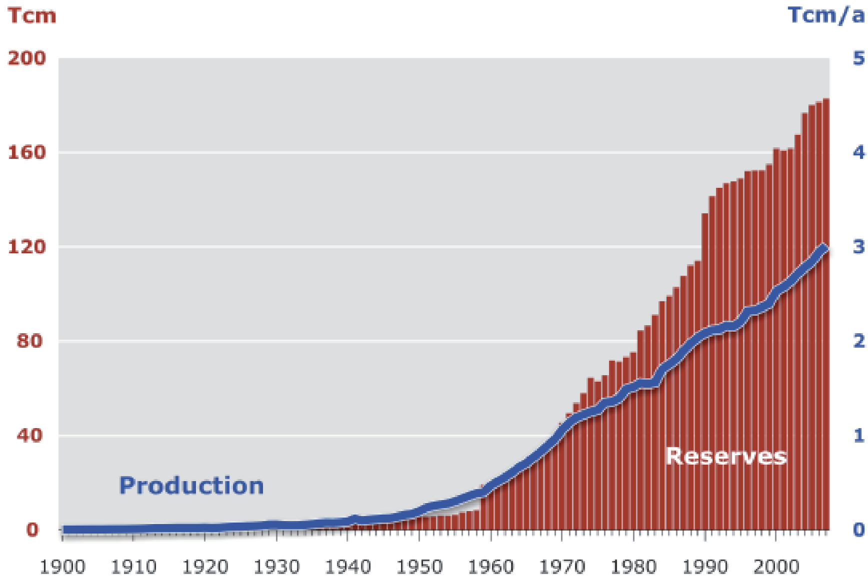

Figure 4.4: Development of the reserves and production of conventional natural gas from 1900 to 2007.

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).

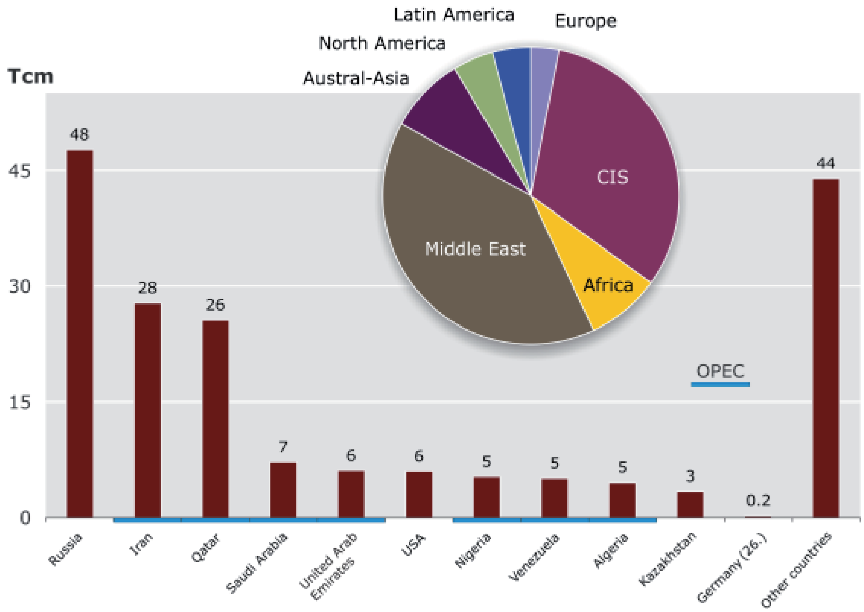

Figure 4.5: Reserves of conventional natural gas (total 183 Tcm) of the top ten countries and Germany as well as their distribution by regions in 2007.

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.

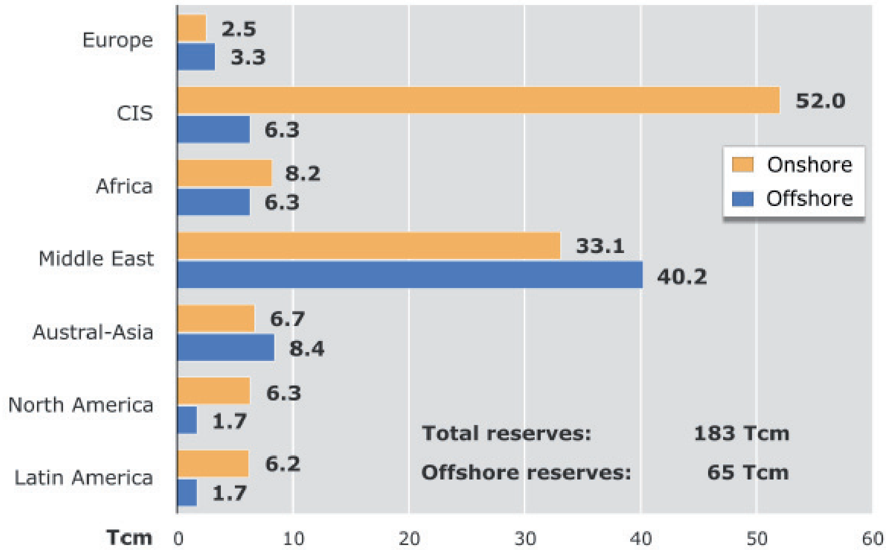

Figure 4.6: Reserves of conventional natural gas in 2007: Regional distribution onshore and offshore.

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).

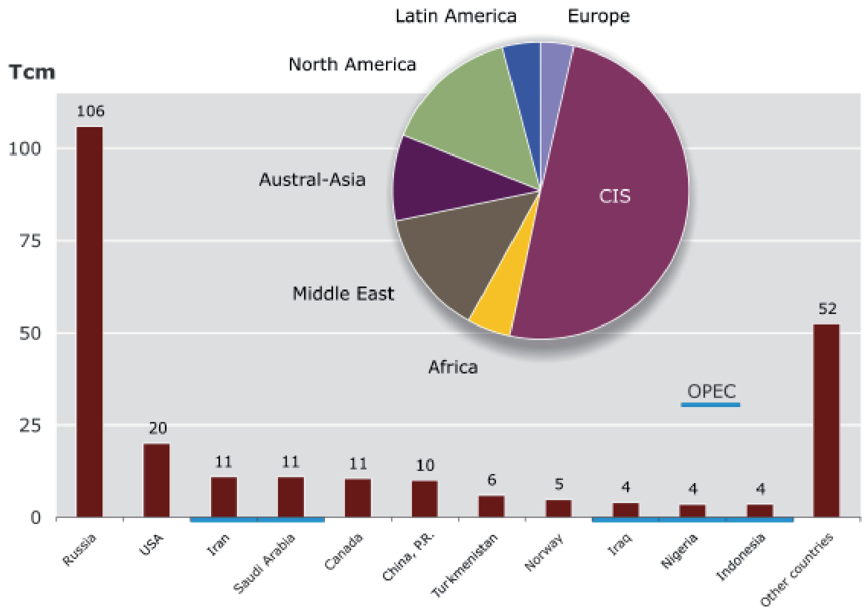

Figure 4.7: Resources of conventional natural gas (total 239 Tcm) of the top ten countries and Germany as well as their distribution by region in 2007.

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.

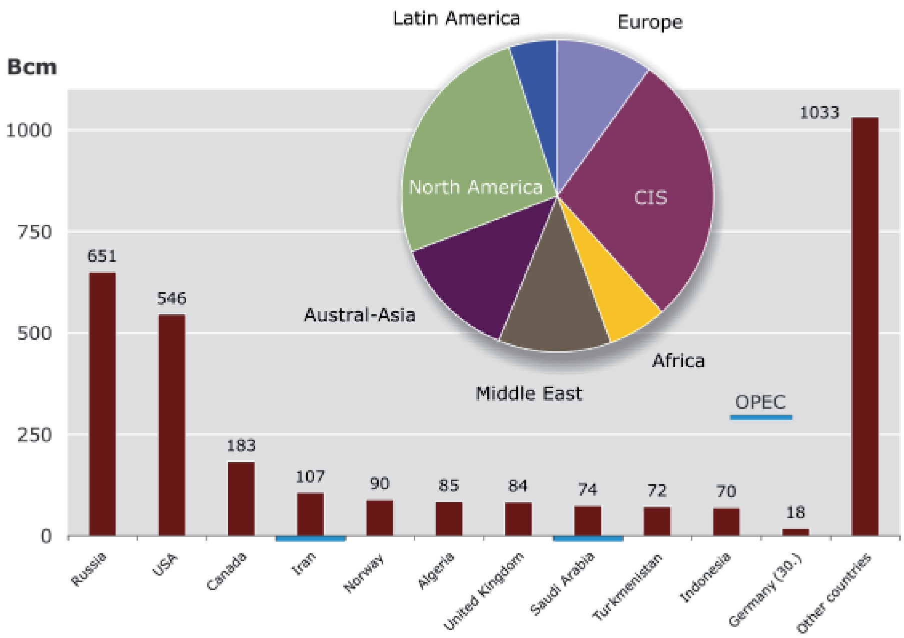

Figure 4.8: Production of natural gas (totall 3 Tcm) of the ten most important countries and Germany as well as their distribution according to region for 2007.

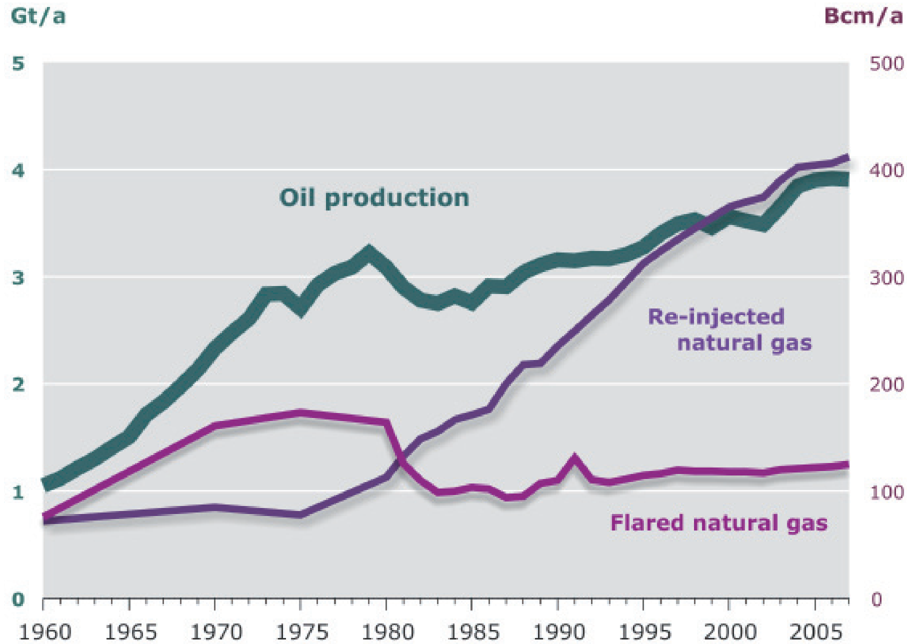

Figure 4.9: Development of the amounts of natural gas globally flared and re-injected and the world production of petroleum.

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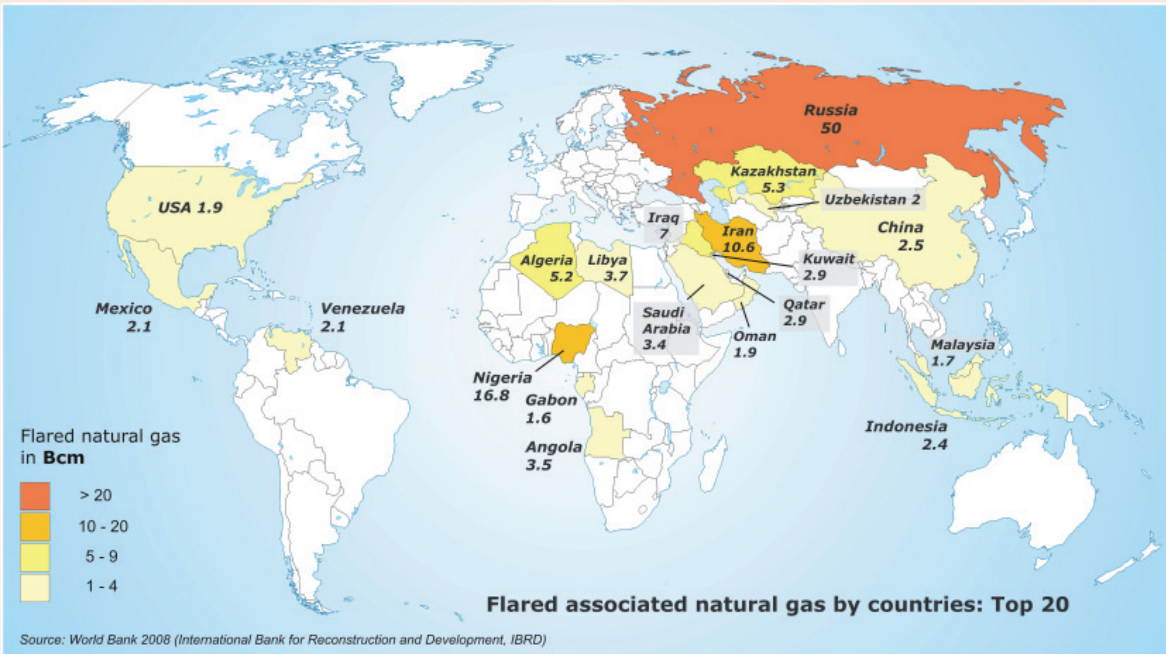
Associated Gas – Unused Potential

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.



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.

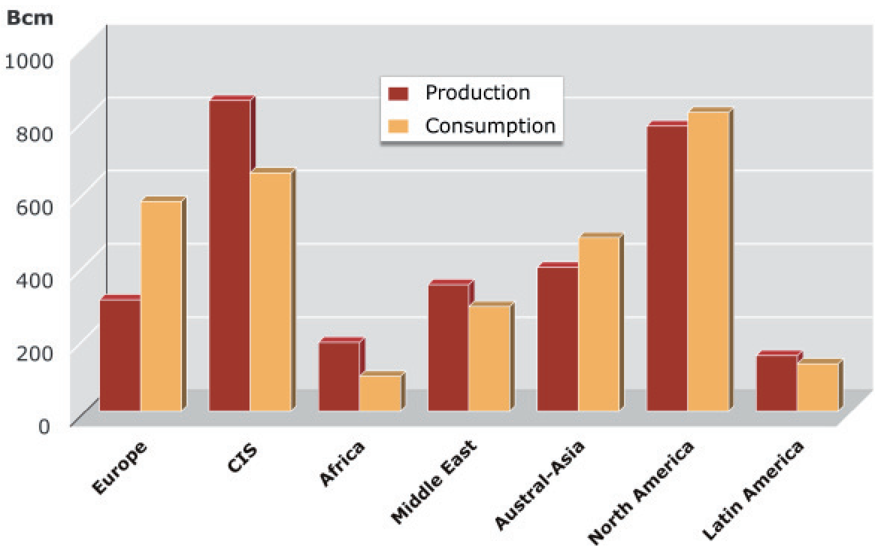


Figure 4.10: Production and consumption of natural gas 2007: Regional distribution.

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).

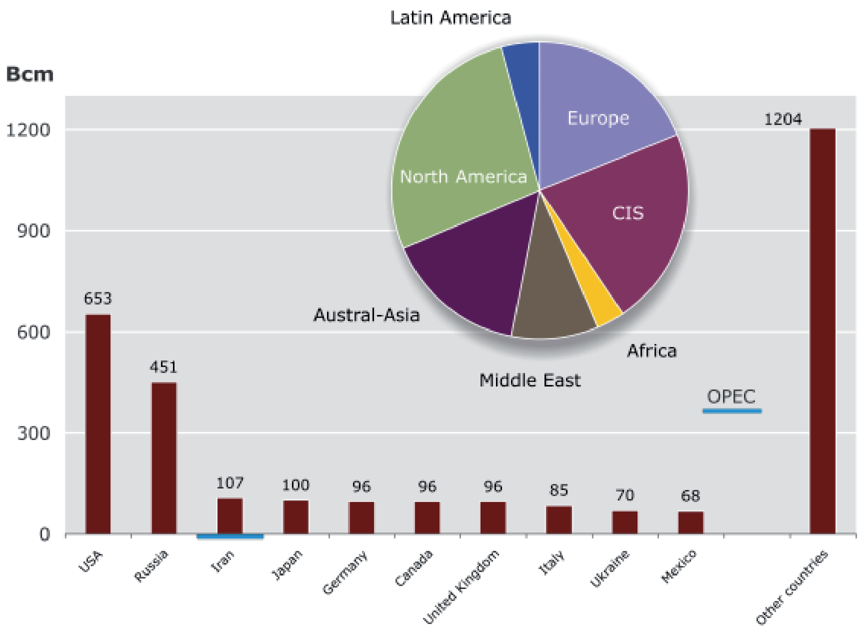


Figure 4.11: Consumption of natural gas (total 3 Tcm) of the top ten countries and Germany as well as their distribution by region in 2007.

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.

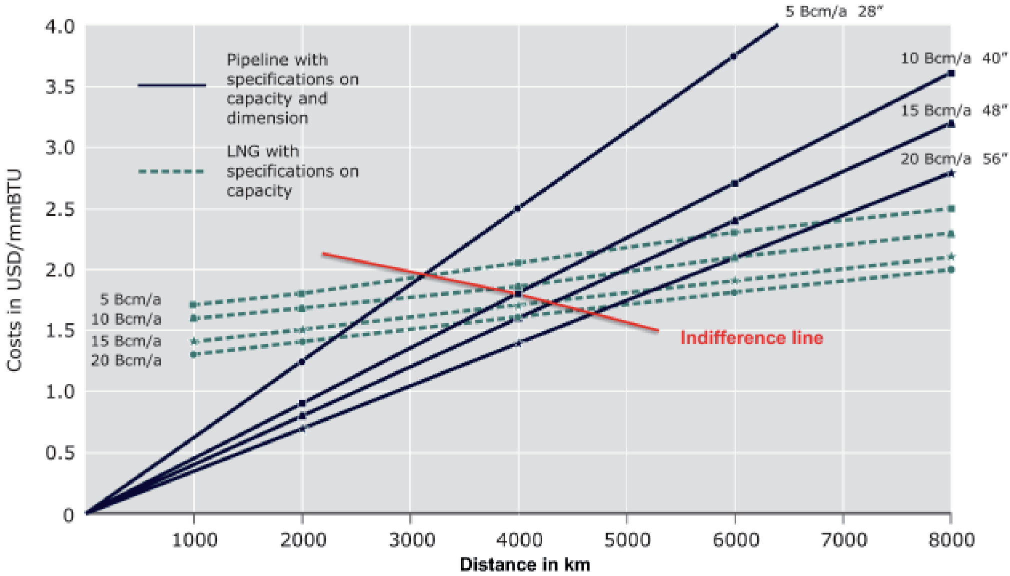


Figure 4.12: Transportation costs for natural gas via pipeline and as LNG as a function of the capacity (according to Schwimmbeck, 2008).

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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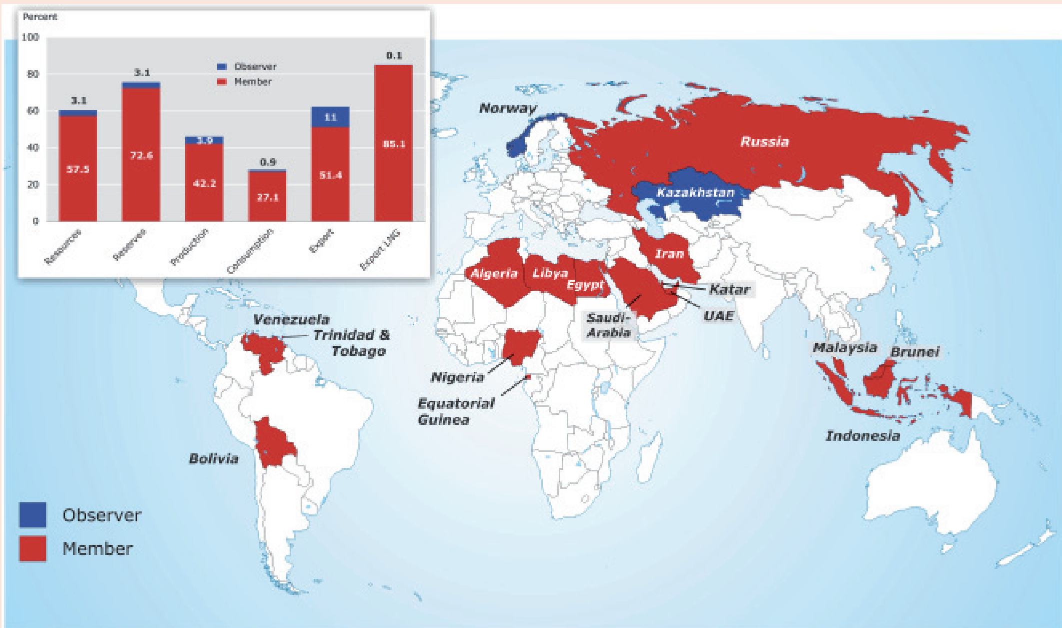
Will There Be a Natural Gas Cartel Analog to OPEC?

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.



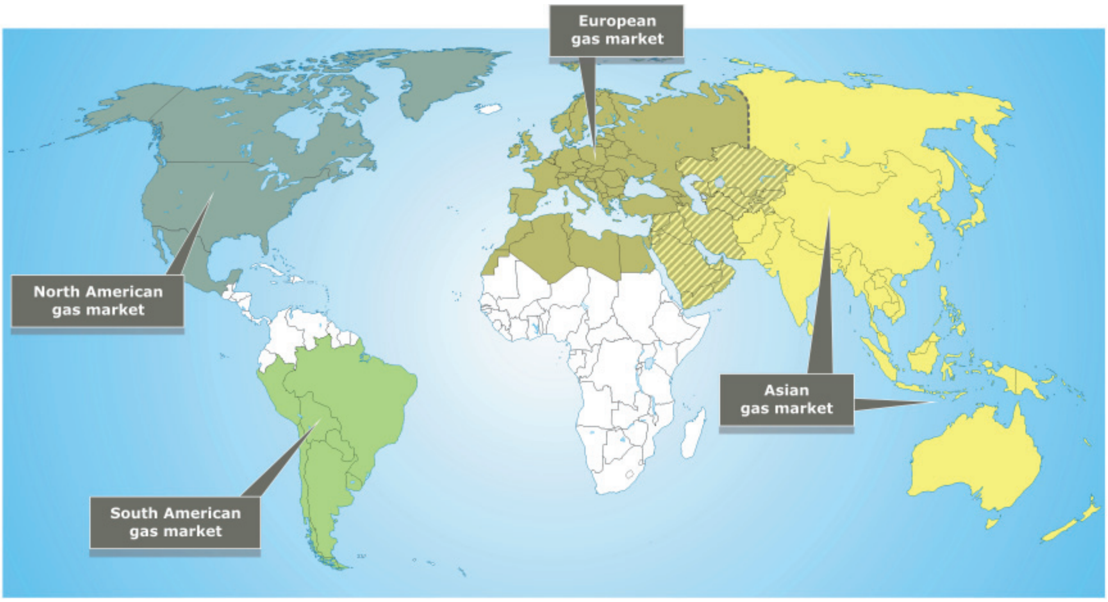


Figure 4.13: The four regional markets for natural gas in the world. Dashed: Transition area between European and Asian market.

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.

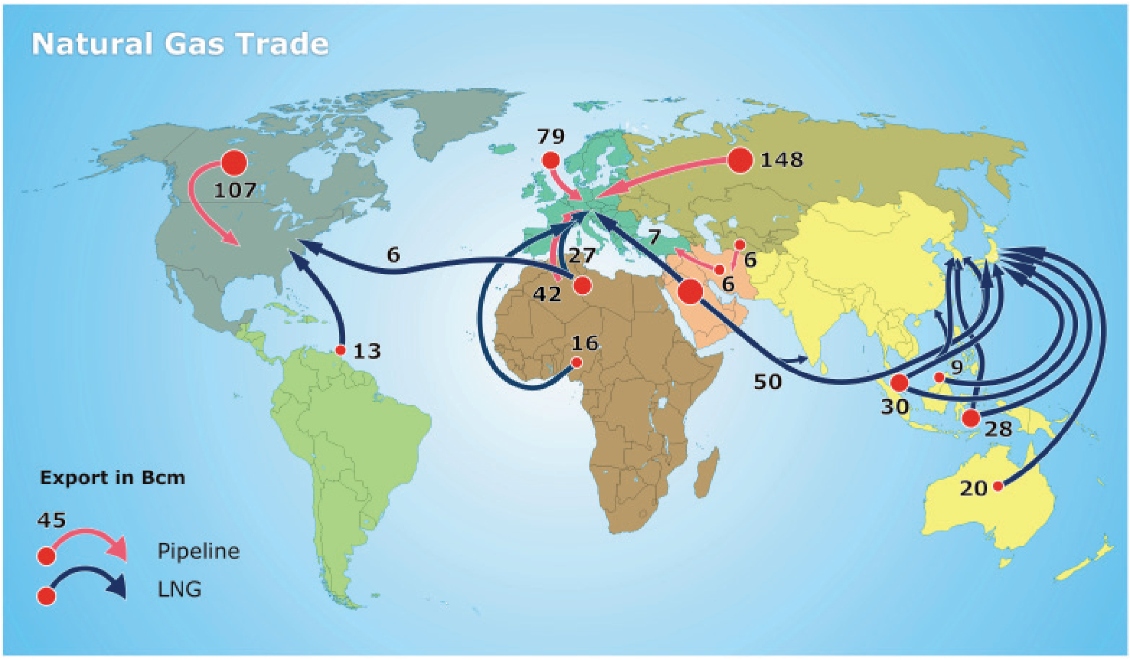


Figure 4.14: Global trade in natural gas in 2007 in Bcm (data according to BP, 2008).

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

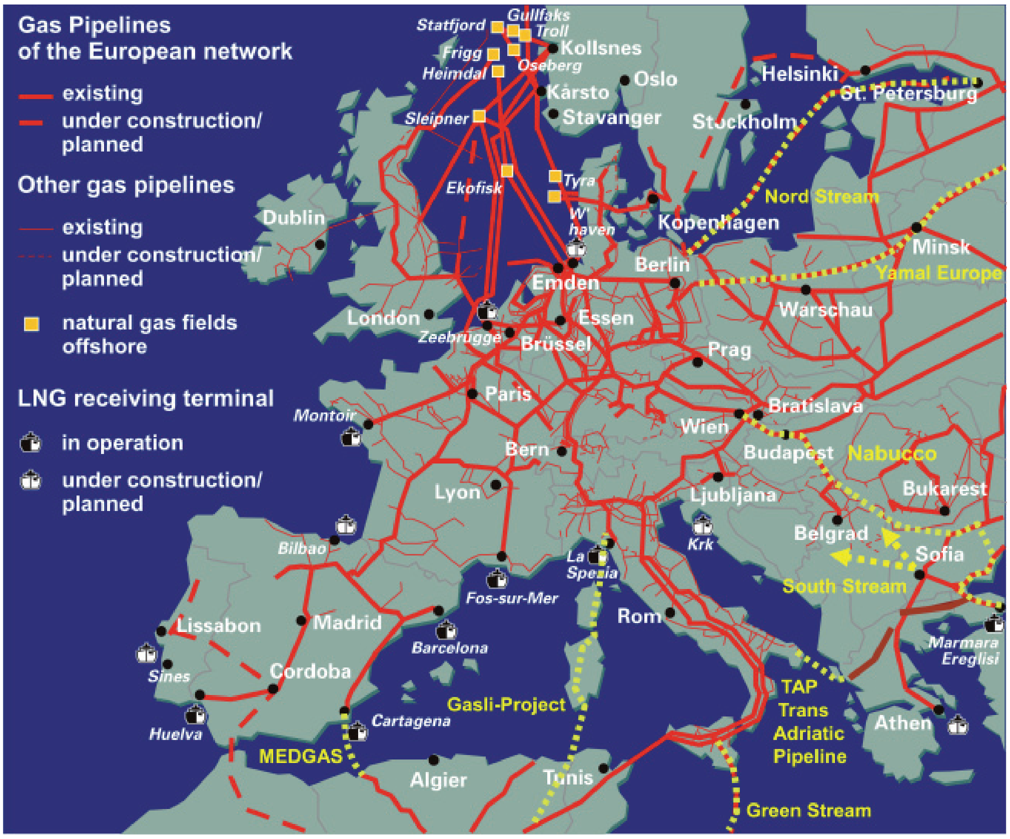


Figure 4.15: European natural gas network and pipeline projects (From Ruhrgas, 1999, updated).

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).

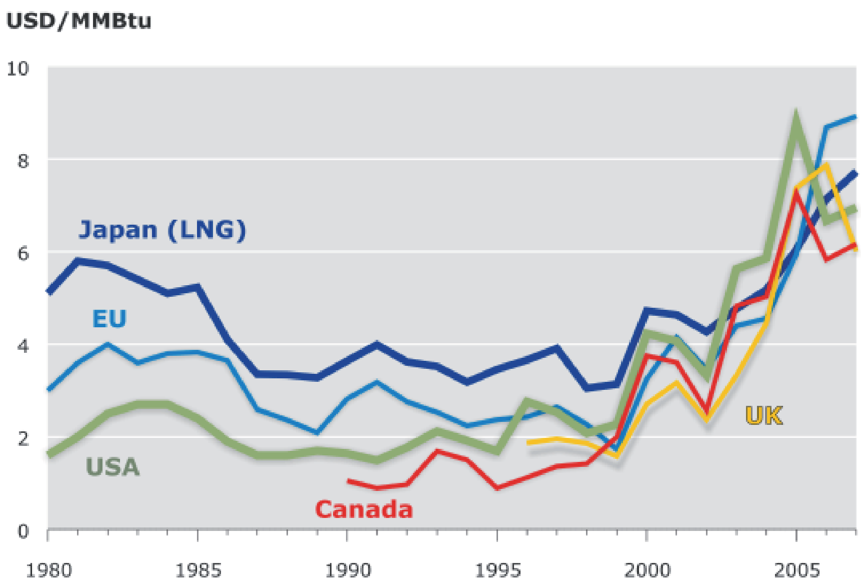


Figure 4.16: Development of the prices for natural gas from 1980 to 2007 (1 MMBtu – Million British Thermal Units – corresponds to approximately 28 m³ natural gas or approximately 0.023 toe).

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-

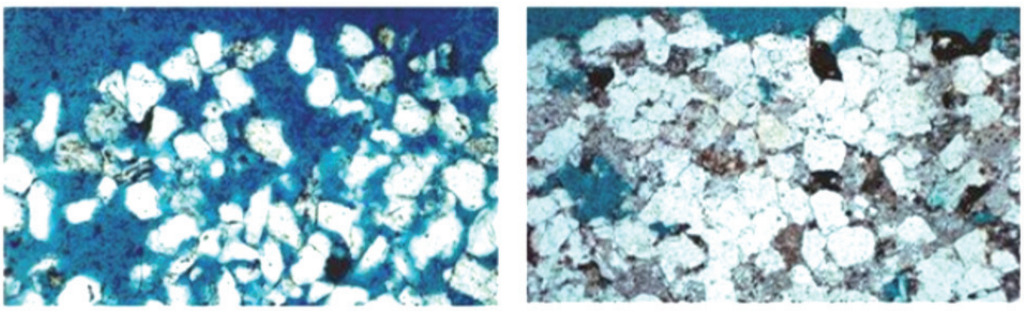


Figure 4.17: Comparison of a sandstone (grain size about 0.5 mm) with high porosity and permeability as conventional natural gas reservoir rock (left photo) to a low permeable sandstone as tight reservoir (right photo). For both specimens the pore spaces have been dyed blue (photos: Naik).

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.

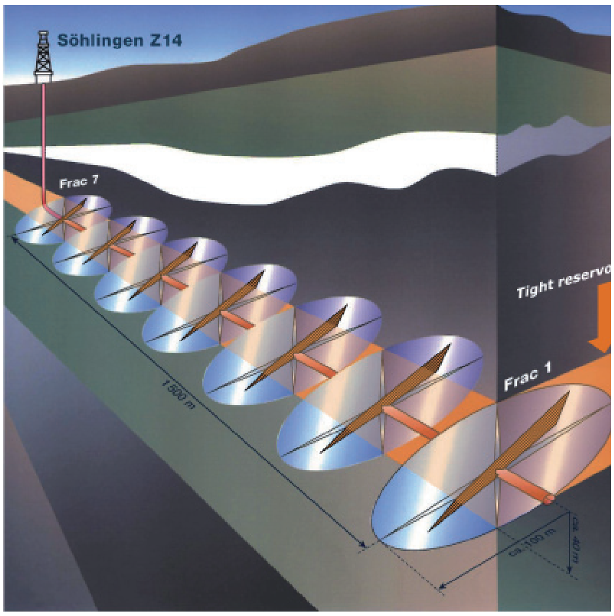


Figure 4.18: Development of a gas in a tight reservoir using artificial fracture systems, so-called fracs (changed in accordance with Mobil Erdgas-Erdöl GmbH).

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.

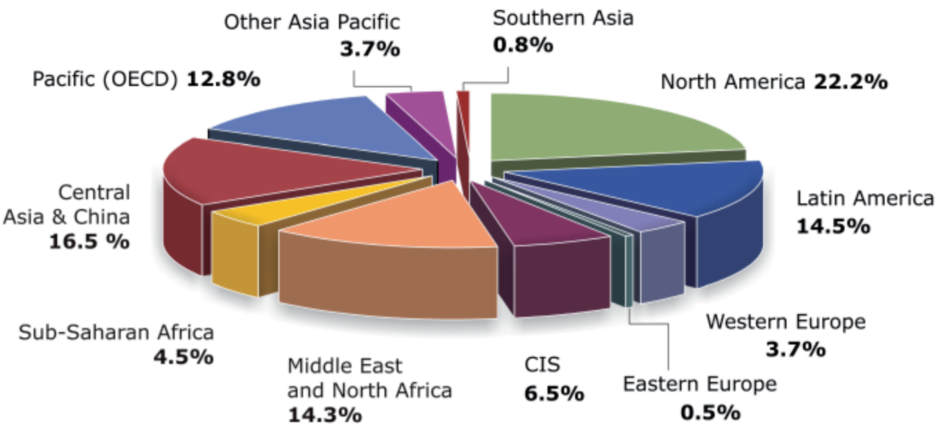


Figure 4.19: Regional distribution of tight sand and shale gas resources.

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.

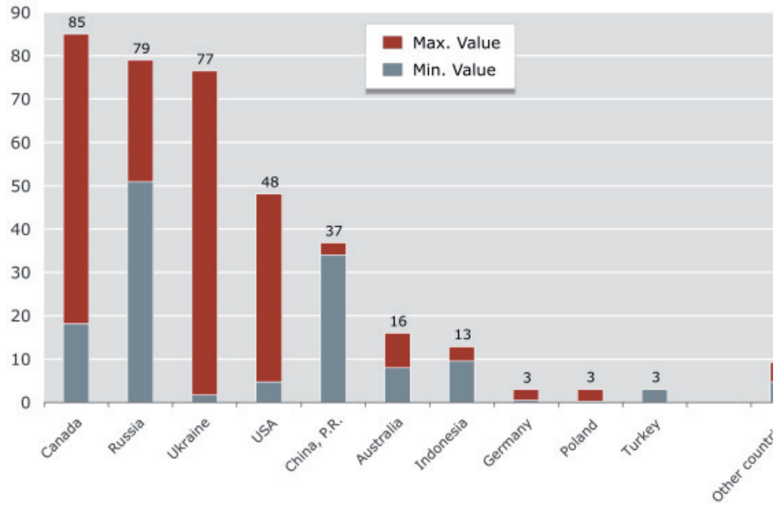


Figure 4.20: CBM resources in 2007: Minimum and maximum values for the top ten countries.

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).

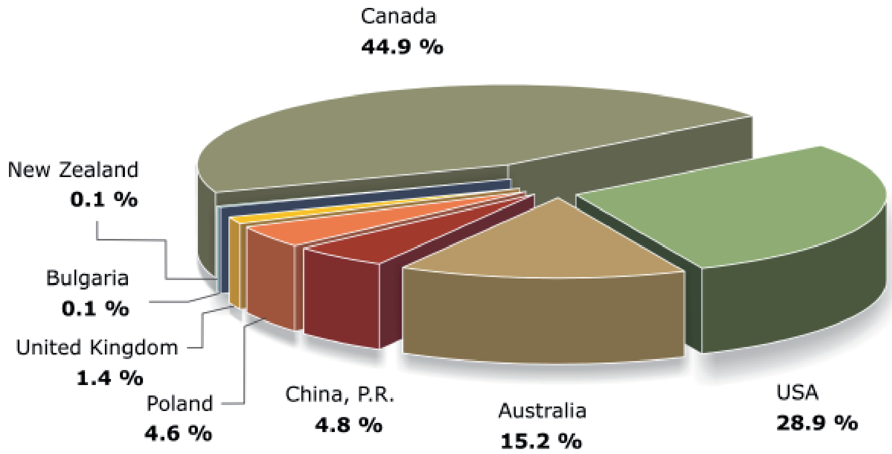


Figure 4.21: CBM reserves by countries in 2007. The percentages refer to CBM reserves of 2.15 Tcm. This value results from the inclusion of the mean value of the Canadian CBM reserves of 963 Tcm.

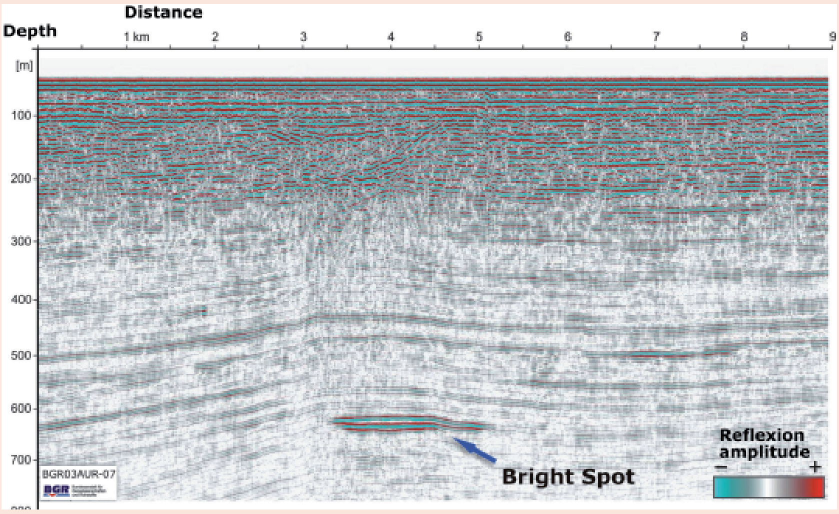
Drillholes can be driven in the virgin coal seams for development and **production of coalbed methane** (Fig. 4.22). In these drillholes, the individual target horizons are hydraulically stimulated through fracturing using highly pressurized drilling liquid. The cracks developing in the target horizons 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).

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.



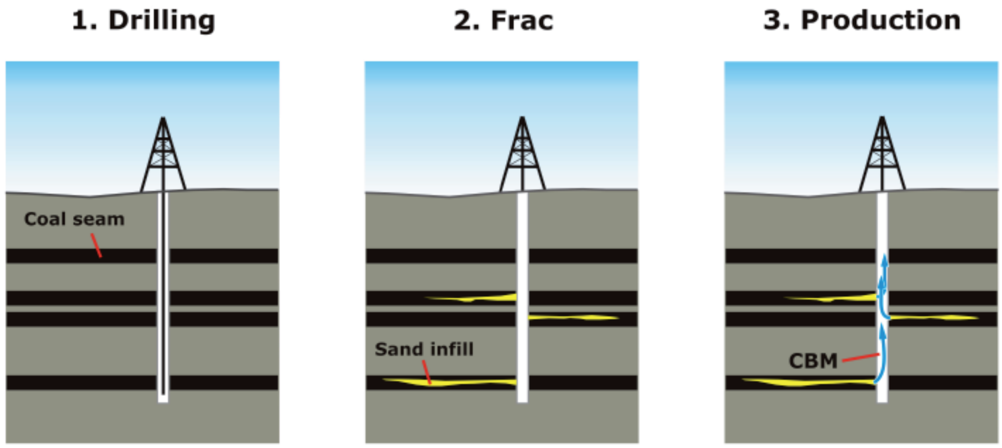


Figure 4.22: Production steps for CBM production.

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

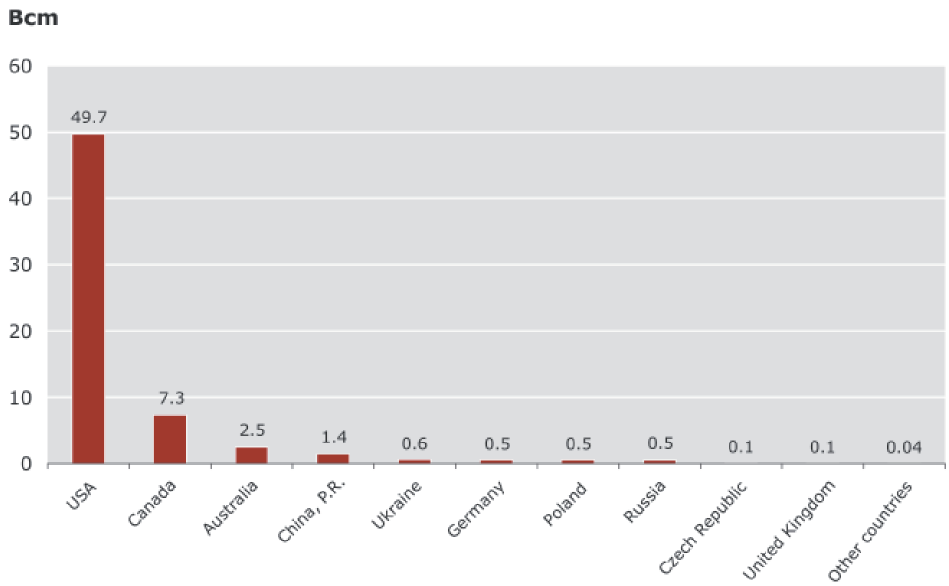


Figure 4.23: CBM production (total 63.3 Bcm) in 2007: top ten countries.

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.

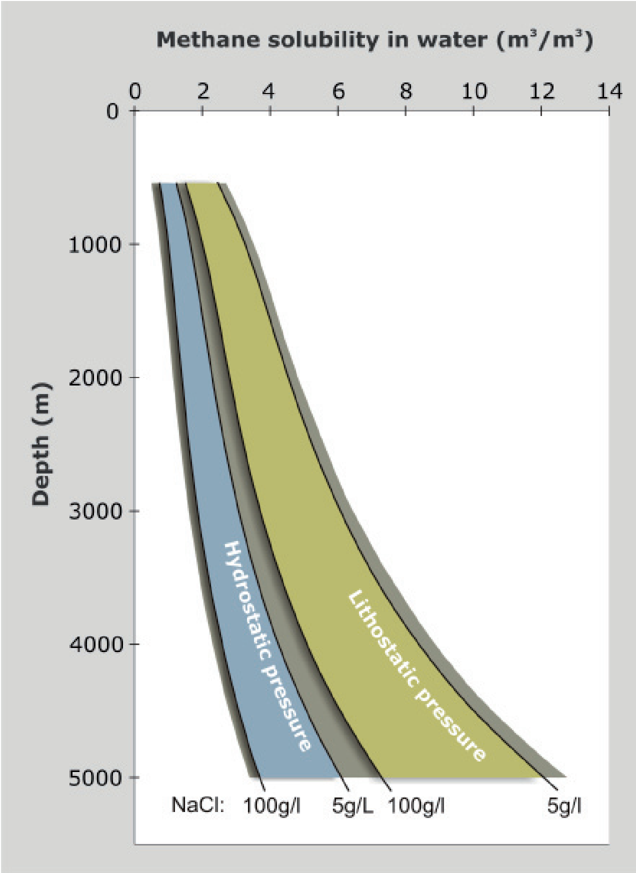


Figure 4.24: Solubility of methane in ground water as a function of the depth calculated in accordance with Battino (1984) and Haas (1978).

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.

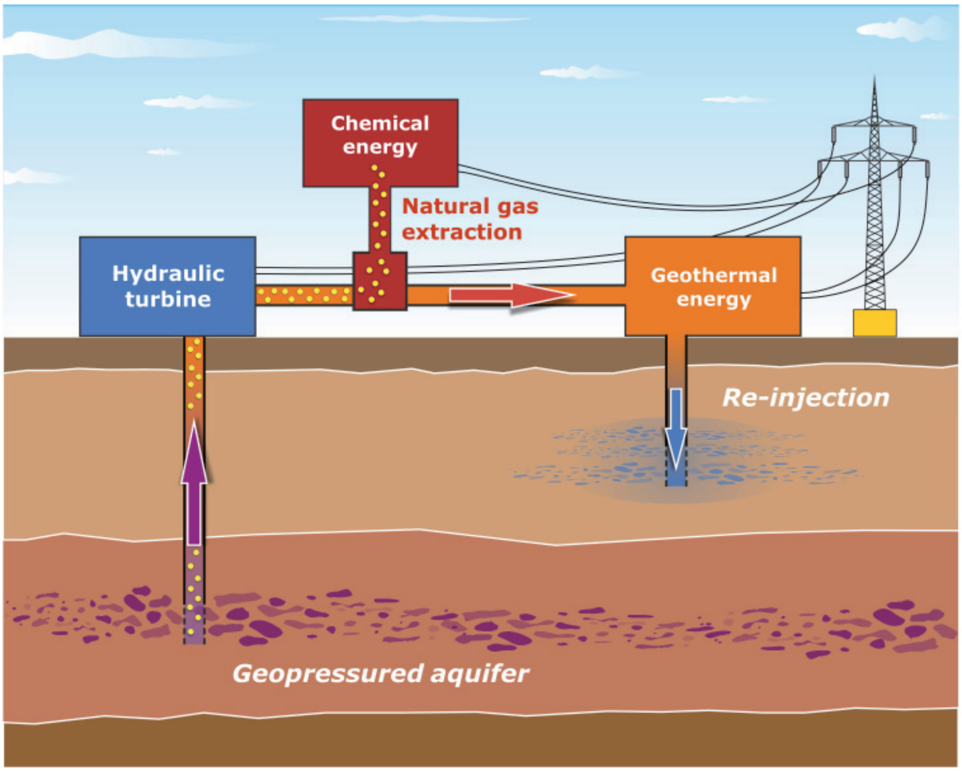


Figure 4.25: Schematic chart of a hybrid power plant for the use of three energies extractible from geopressured-geothermal aquifers: hydraulic energy, geothermal energy and chemical energy (Aquifer Gas).

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 m³ 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).

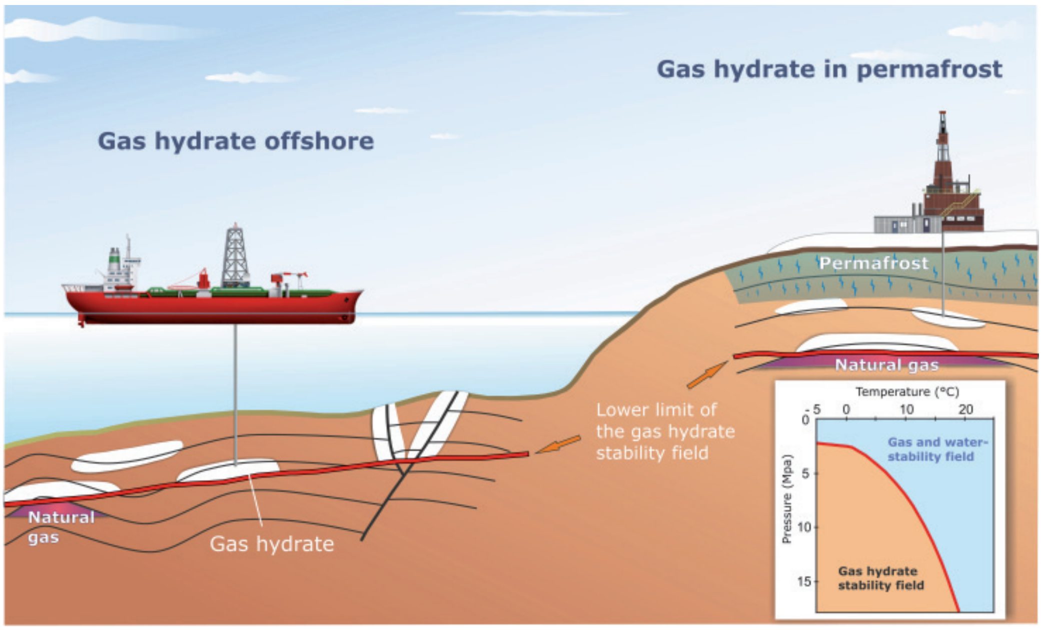


Figure 4.26: Occurrences of gas hydrate: offshore (on the left) and in permafrost areas (on the right). Small diagram: gas hydrate is stable at low temperatures and high pressure.

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).

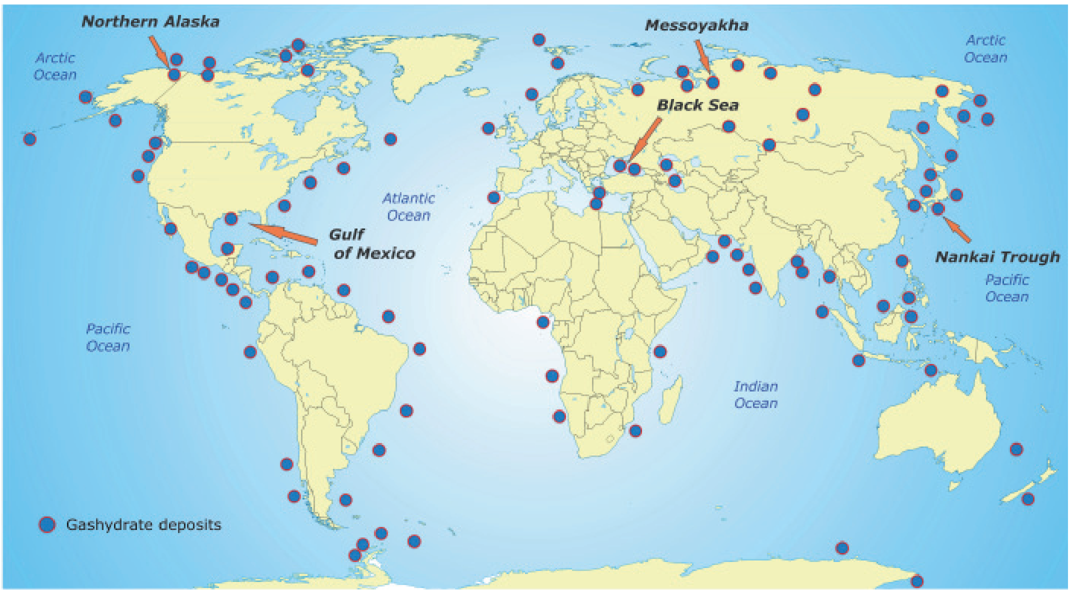


Figure 4.27: Proof of gas hydrate globally naming occurrences mentioned in the text.

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.

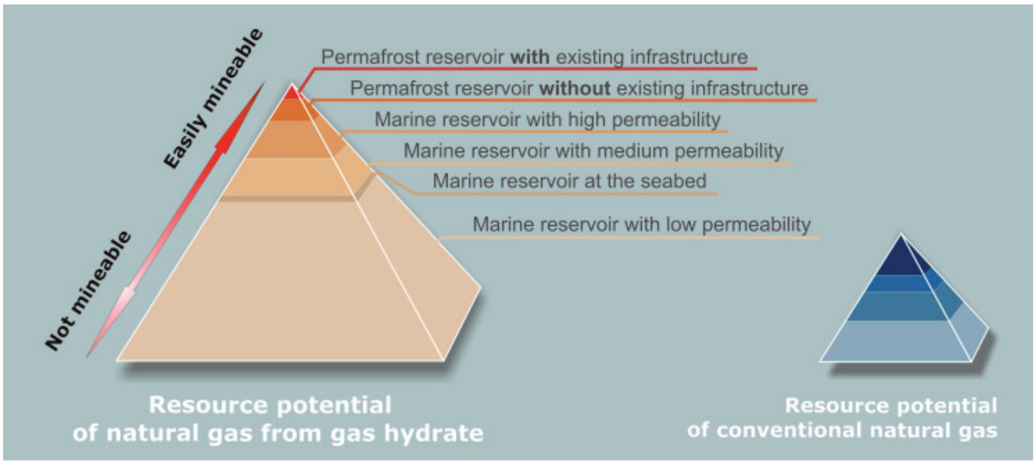


Figure 4.28: Resource pyramid: total natural gas potential in gas hydrate and conventional natural gas (modified in accordance to Boswell & Collett, 2006).

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.

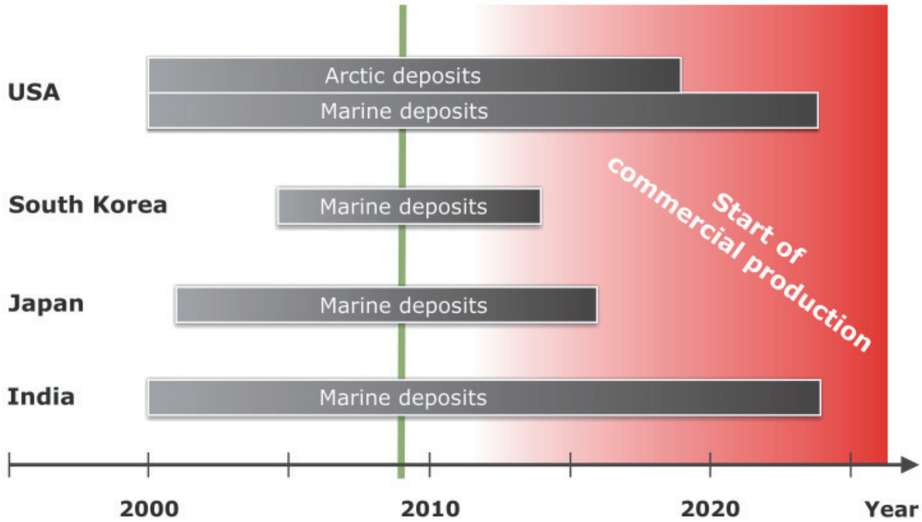


Figure 4.29: Terms of important national programs aimed at an economic extraction of natural gas from gas hydrate.

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).

i 6

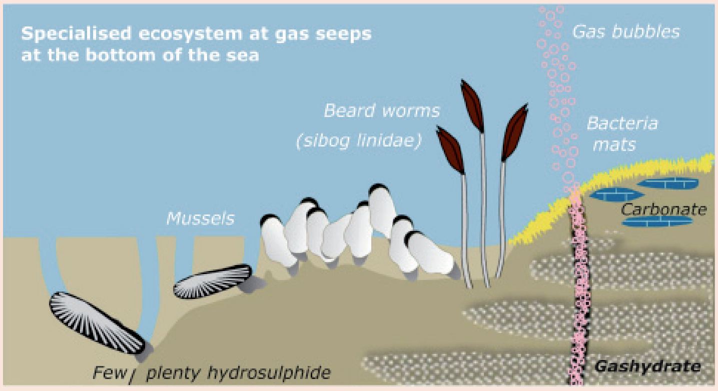
Possible Environmental Effects on the Use of Gas Hydrate

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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