8 Energy Resources in Germany

8.1 Petroleum in Germany

8.1.1 Petroleum Deposits and Production History

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

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

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

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

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

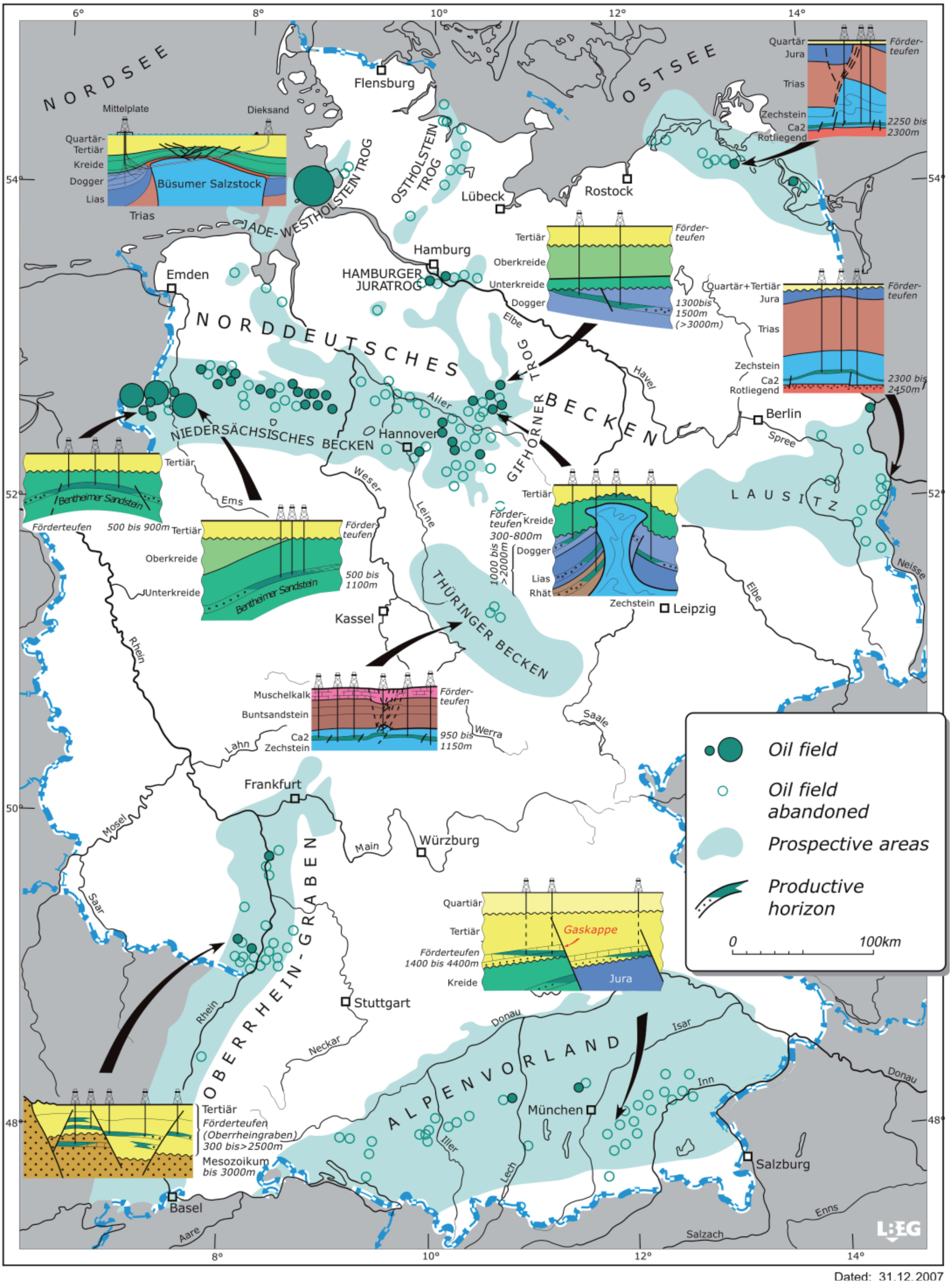


Figure 8.1: Prospective regions, oil fields and characteristic traps in Germany.

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

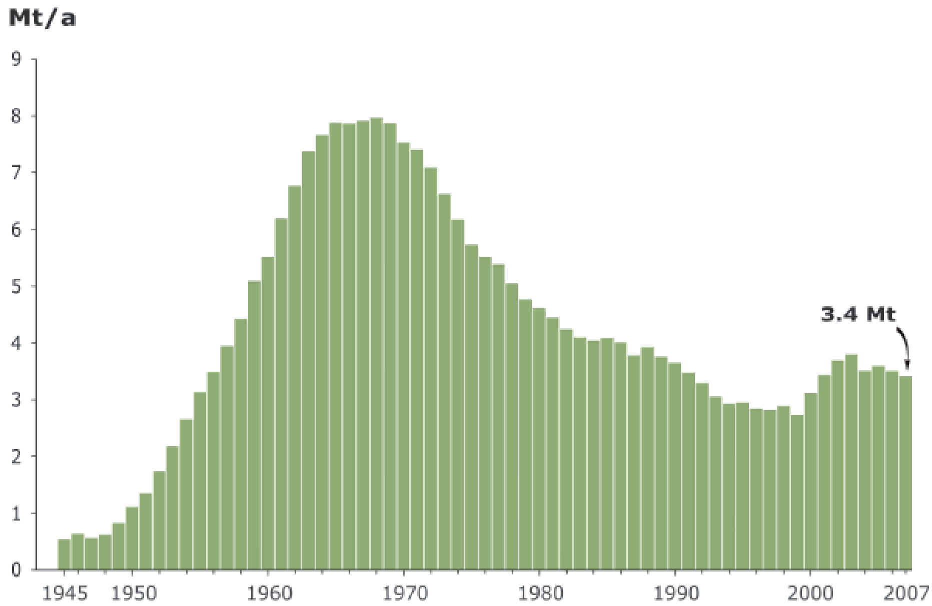


Figure 8.2: Oil production in Germany since 1945.

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

8.1.2 Petroleum Production and Consumption in 2007

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

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

8.1.3 Petroleum Reserves and Resources

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

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

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

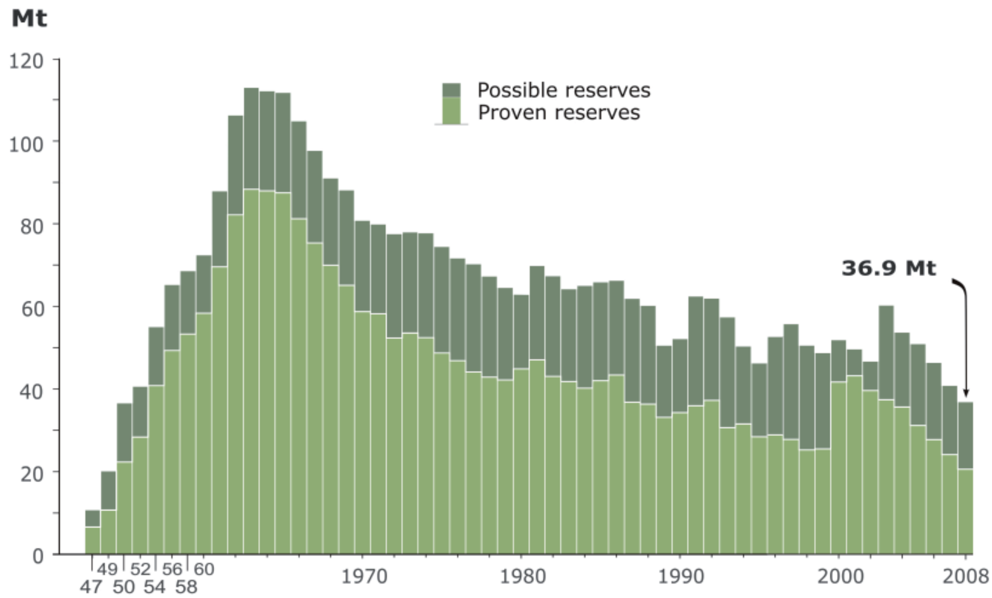


Figure 8.3: Petroleum reserves trend over time in Germany.

8.1.4 Germany's Supply with Petroleum

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

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

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

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

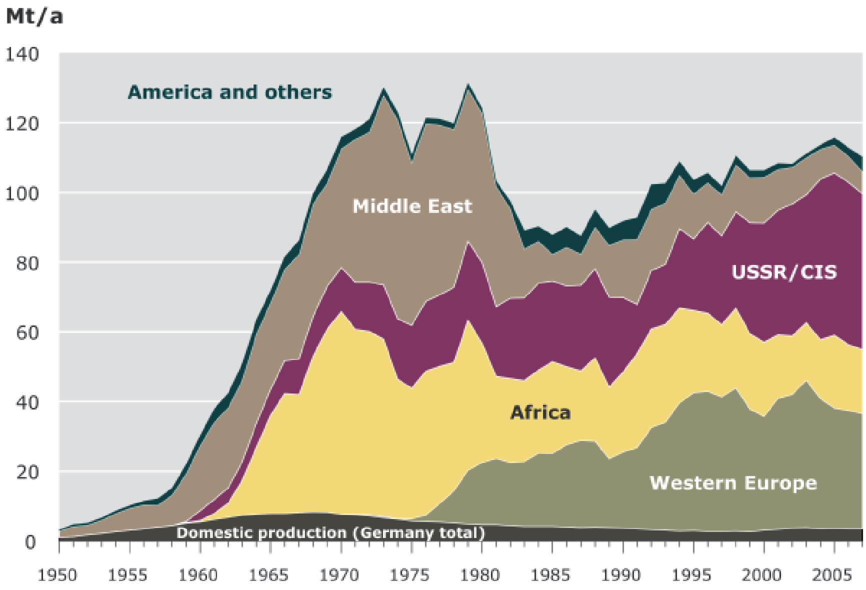


Figure 8.4: Crude oil supply in Germany between 1950 and 2007 and share of mineral oil in total primary energy supply (TPES).

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

8.1.5 Unconventional Oil

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

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

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

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

8.2 Natural Gas in Germany

8.2.1 Natural Gas Deposits and Production History

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

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

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

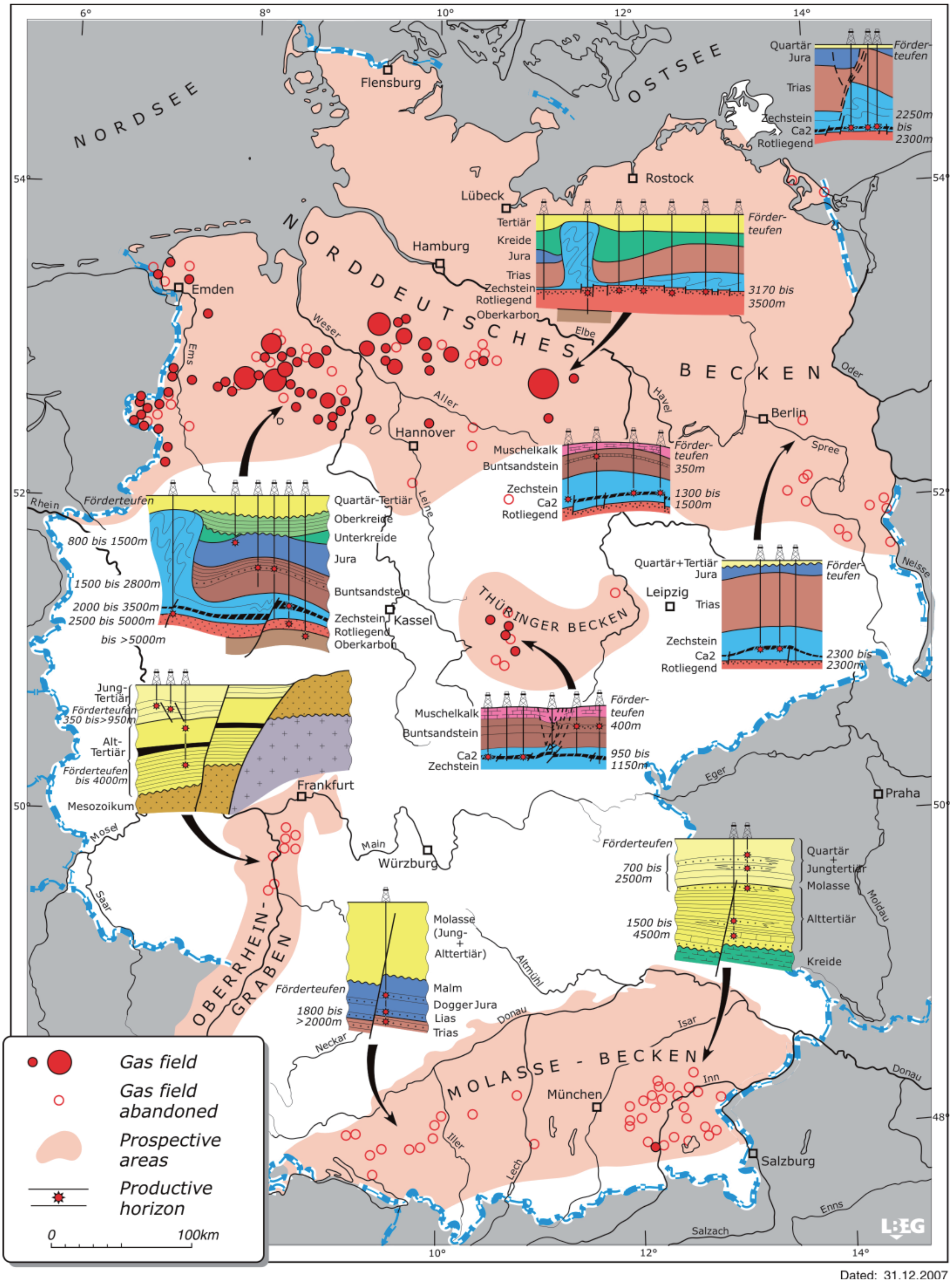


Figure 8.5: Prospective regions, gas fields and characteristic traps in Germany.

fundamental reference term. In other statistics, a calorific value of 11.5 kWh/m³ is used as reference value in connection with the average quality (calorific value) of North Sea gas.

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

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

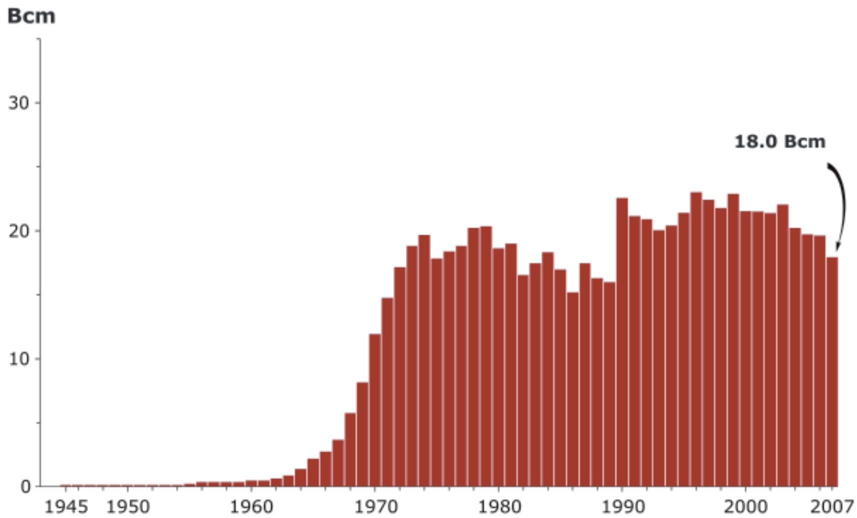


Figure 8.6: Natural gas production (raw gas) in Germany since 1945.

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

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

8.2.2 Natural Gas Production and Consumption in 2007

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

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

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

8.2.3 Natural Gas Reserves and Resources

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

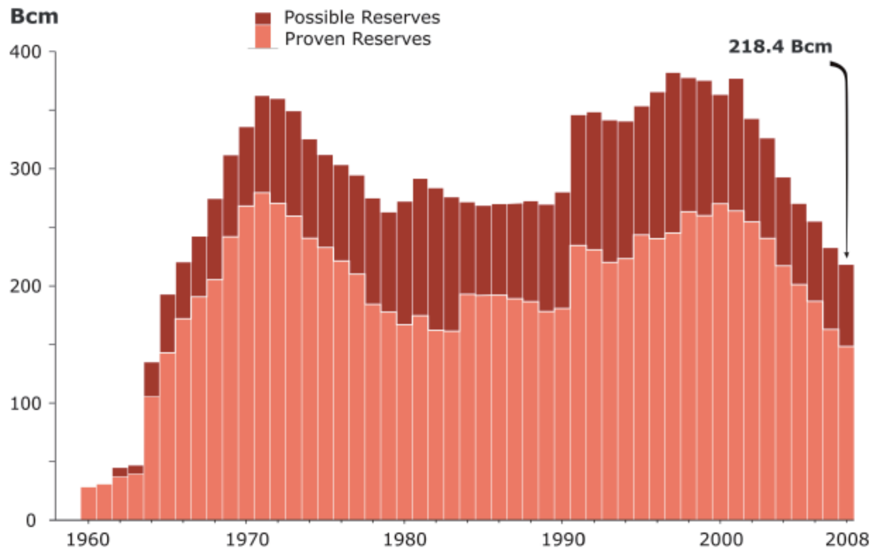


Figure 8.7: Natural gas (raw gas) reserves trend over time in Germany.

8.2.4 Germany's Supply with Natural Gas

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

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

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

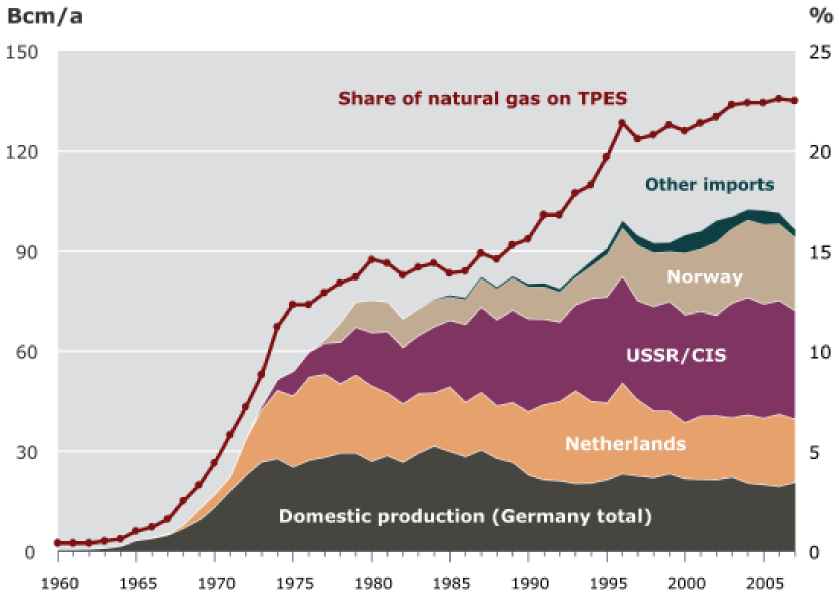


Figure 8.8: Supply of natural gas in Germany between 1960 and 2007 and share of natural gas in total primary energy supply (TPES).

8.2.5 Unconventional Natural Gas

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

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

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

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

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

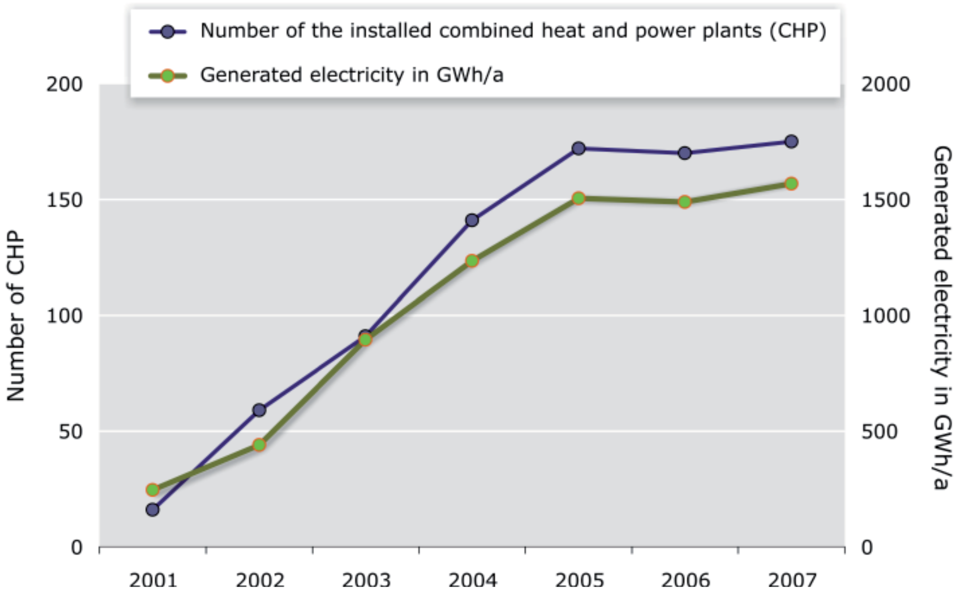


Figure 8.9: Trend in mine gas use in Germany between 2001 and 2007.

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

8.3 Coal in Germany

8.3.1 Coal Deposits and Production History

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

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

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

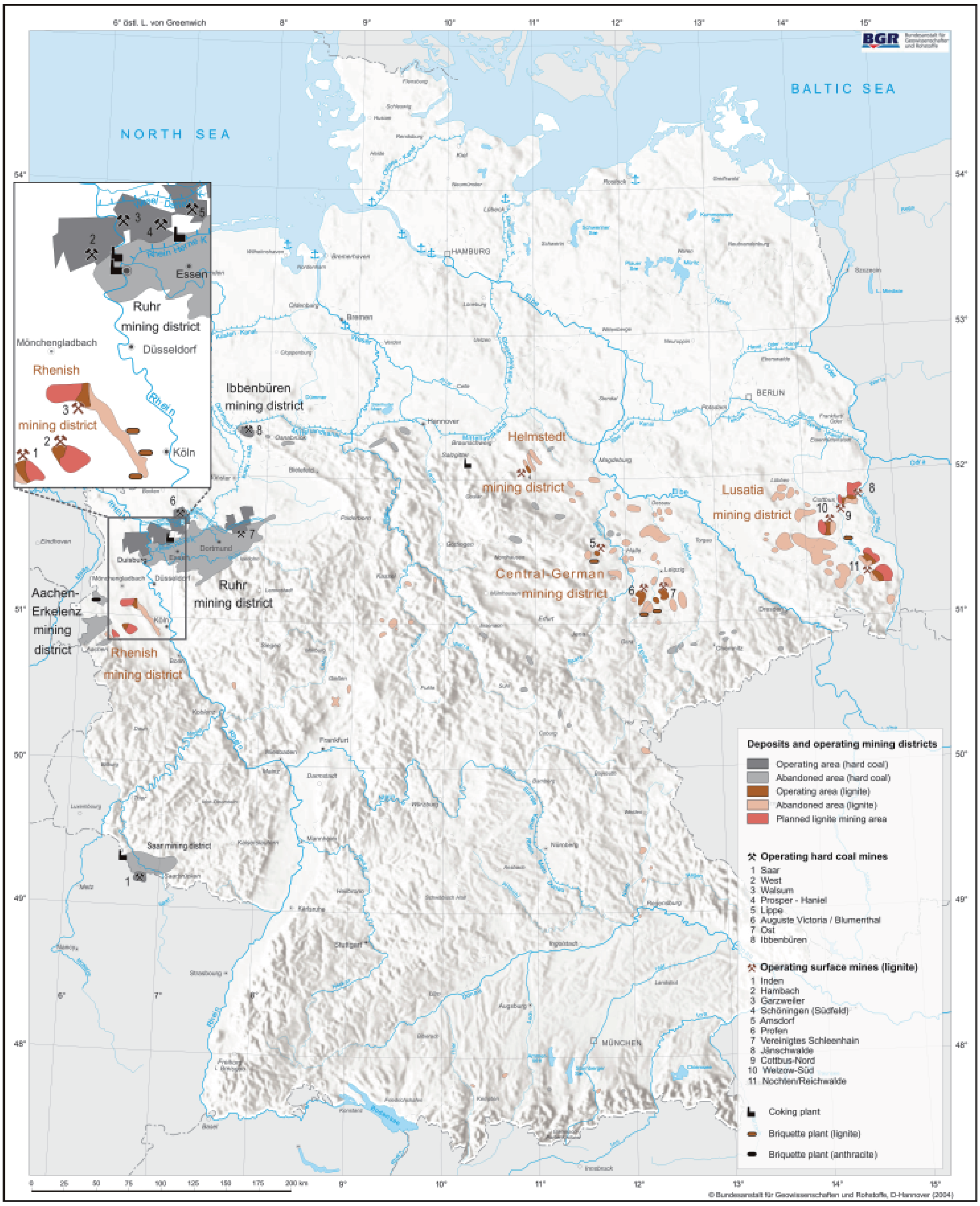


Figure 8.10: Hard coal and lignite deposits and mining districts in Germany (modified after Thielemann, 2005).

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

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

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

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

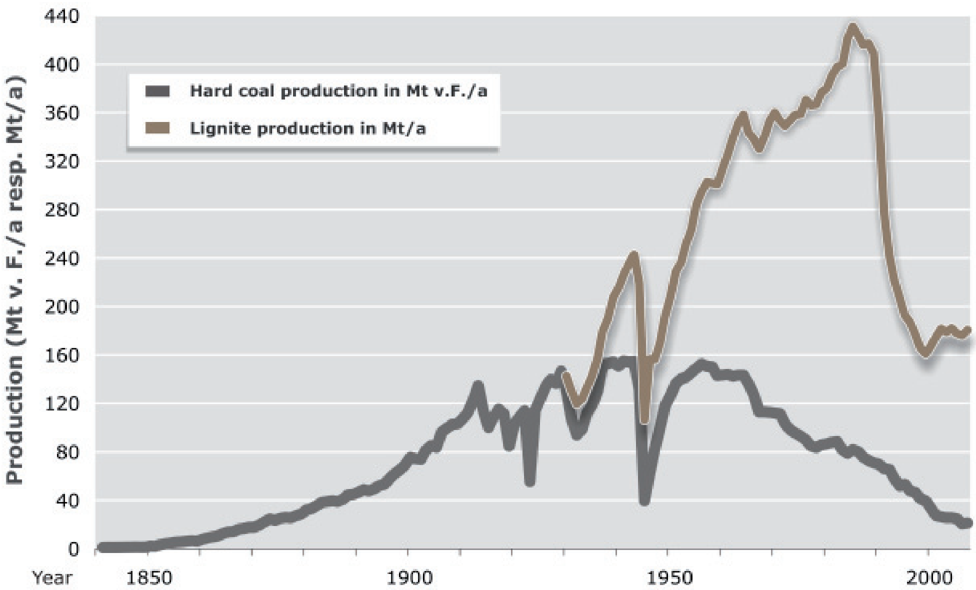


Figure 8.11: Trend in the German coal production between 1840 and 2007 (SdK - different volumes).

8.3.2 Coal Production and Consumption in 2007

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

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

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

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

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

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

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

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

2) incl. hard coal resources of the Münsterland area

8.3.3 Coal Reserves and Resources

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

8.3.4 Germany's Supply with Coal

While the consumed lignite in Germany comes almost entirely (99.9 %) from domestic production, currently already around two thirds of the consumed hard coal is imported. Due to decreasing domestic production (Fig. 8.11), the German hard coal imports continuously increased during the past years (Fig. 8.12). In 2007, German hard coal imports including the hard coal products like briquettes and coke amounted to 47.5 Mt. The imported hard coal came predominantly from Russia with 8.6 Mt, followed by Columbia with 6.9 Mt as well as Australia and South Africa with 6.5 Mt each (Fig. 8.12). The imports from Poland in the last year fell by around one third to 6.4 Mt (BGR, 2008; VDKI, 2008).

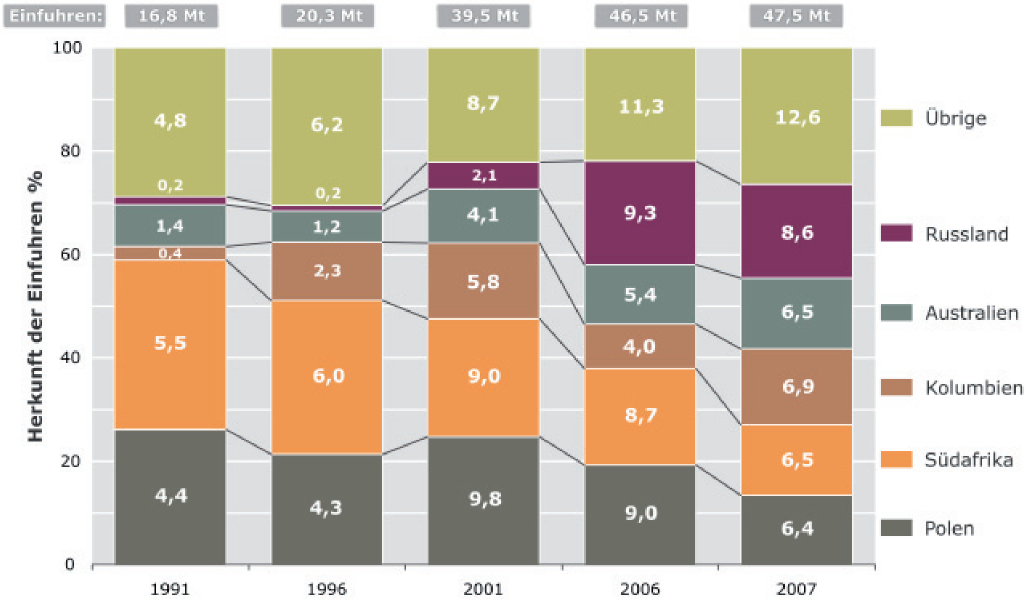


Figure 8.12: Development of German hard coal imports of selected years since 1991 (according to different annual reports of the VDKI).

8.4 Cross-Border Prices of Fossil Fuels

As a country which is heavily dependent on imports of fossil fuels, Germany pays large sums for their importation. While the expenses for fossil fuel imports amounted to about € 25 billion in 1999, they already reached € 43.4 billion in the year 2004 and increased to € 67.6 billion in the year 2007. This increase was to a large extent determined by price trends.

The Federal Office of Economics and Export Control (BAFA) specifies cross-border prices (Tables A 8-3 and A 8-4) for fossil fuels, which are average prices for long term and spot market contracts free German State borders. They are composed of the producer price, the cargo handling charges in the producer- and shipment country and the applicable transportation costs via pipeline, ship or rail to Germany. If the applicable fossil fuel is not transported directly to Germany, further costs must be taken into account. In this manner, the predominant part of coal imported by Germany arrives first in the ARA ports (Amsterdam, Rotterdam, Antwerp). Only afterwards the coal is transported by rail or barge to Germany (Fig. 8.13). Accordingly, there are additional transportation fees to the cross-border price. Petroleum reaches Germany partly by oil tanker and is transported to the refineries by pipeline from the German ports Wilhelmshaven, Hamburg and Rostock. A large part of the petroleum is transported by pipeline to Germany from foreign ports such as Trieste, Rotterdam and Lavena. Petroleum from Russia arrives in Schwedt via the Druzhba pipeline (Fig. 8.13). Natural gas is imported to Germany from Russia, Norway, the Netherlands and Denmark exclusively using pipelines.

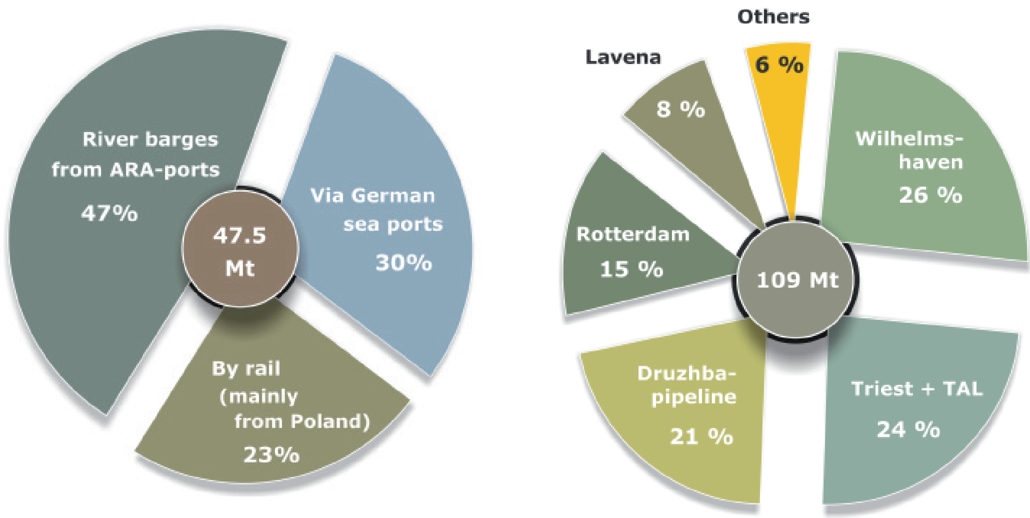


Figure 8.13: Routes of imported hard coal (in 2007) (left-hand side) and crude oil (in 2006) (right-hand side) to Germany (VDKI, 2008; MWV, 2007).

The average cross-border prices for steam coal from third countries outside the EU-27 amounted to € 112.48/tce in 2008, the price for crude oil was € 338.80/tce and for natural gas € 218.34/tce (Fig. 8.14). Therefore, the cross-border prices for crude oil in 2008 were three times as much and for natural gas nearly twice as much as those for steam coal of the same energy content. At the same time, the prices in 2008 for all three fossil fuels were at a record high never seen before.

The price increases during the last eleven years were different for each of the three fossil fuels. While the prices for imported steam coals increased by a maximum of 293 % (4th quarter 1998 to 3rd quarter 2008), the prices for imported natural gas rose by 507 % (April 1999 to November 2008) and crude oil by 854 % (December 1998 to July 2008). As a result of the global financial crisis from August 2008 onwards, a noticeable decrease began for crude oil and following that also for coal and natural gas.

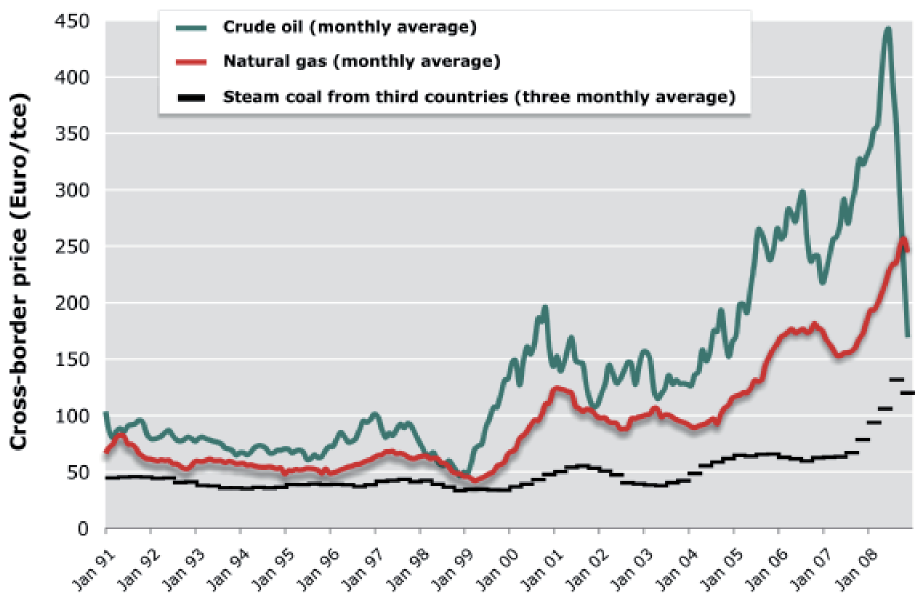


Figure 8.14: Comparison of German cross-border prices by fuel from January 1991 to December 2008 (BAFA, 2009; BMWi, 2009).

Over the period under review here from January 2002 until December 2008, the cross-border price for coking coal was on average 40 % higher than the price for steam coal (Fig. 8.15). This corresponds to the common price difference between steam and coking coal. From late summer 2007 until August 2008, the prices for imported steam coal doubled from € 67.05/tce to € 136.86/tce. The average cross-border price for coking coal increased from € 96.22/t in 2007 to € 132.62/t (+37.8 %) in 2008 (VDKI, 2003-2009). In November 2008, the prices for imported coking coal reached their maximum value of € 211.57/t.

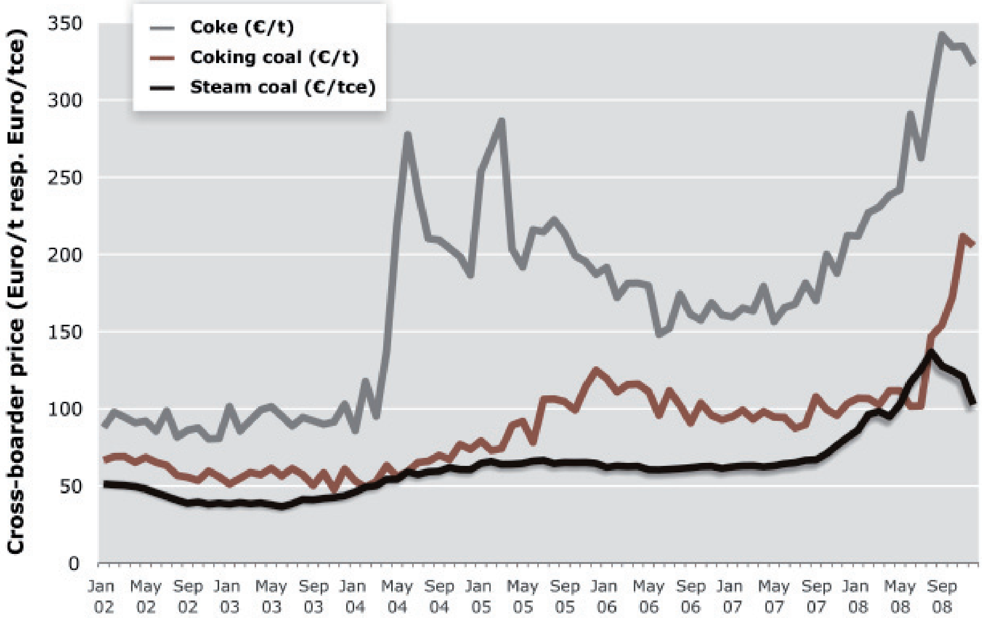


Figure 8.15: Trend for German cross-border prices for coke, coking coal and steam coal from January 2002 until December 2008 (VDKI, 2003-2009).

A major reason for these increases is the sharply increasing coal demand in Asia. Thereby coal became the fossil fuel with the highest year-on-year growth rates in consumption over the last five years. Due to investment in the extension of coalmines and infrastructure capacities, which was hesitant in relation to the large growth rates, various bottlenecks resulted and therefore prices rose. At the beginning of 2008, the situation came to a head due to external influences on the market: There were disruptions in the coal mining operations and in the railway transport of coal to the export ports in South Africa. The sudden onset of winter in the PR of China lead to production outages and temporarily prevented domestic coal transport which raised the danger of increased Chinese imports in view of a strained market situation on the world markets. In Australia, production in some mines had to be stopped as heavy rainfalls had flooded them. Since Australia is the most important coking coal exporter by far (Chapter 5), the events there had a dramatic impact on the worldwide coking coal price in 2008. Every spring, Japanese steel producers negotiate contract prices for a term of one year for coking coal with the Australian coking coal exporters, which then act as global benchmark prices. In the spring of 2008, this benchmark price for high-quality hard coking coal *(HCC)* rose from slightly under USD 100/t (fob) in the month of the previous year to around USD 300/t (McCloskey, 2003-2009).

The cross-border price for imported coke already increased markedly in the years 2004 and 2005 compared to the previous years (Fig. 8.15). Resulting from shortages on the world coke market dominated by the PR of China (Chapter 5), the prices rose sharply by more than 200 % to as much as € 277.47/t in only a few months. Thereafter, the price leveled off at between € 160 and 170/t from the start of 2006 until summer 2007. Since late summer of 2007, the cross-border prices for coke rose comparable to the developments described for cross-border prices for steam coal and coking coal and reached their nominal all-time high in September 2008 at € 342.13/t. The increase in coke demand worldwide due to the continual growth in pig iron production, fears as well as actual delays in the granting of Chinese coke export licenses and coking coal prices, which had sharply risen since 2008, were the main reasons for this price trend. The average cross-border price for coke increased by 60 % compared to the year 2007 to € 281.20/t in 2008 (VDKI, 2003-2009).

Along with sharply falling oil prices and the expanding global financial and economic crisis, the cross-border prices for coke, steam coal and coking coal decreased from summer 2008 onwards.

8.5 Nuclear Fuels in Germany

8.5.1 Uranium Deposits and Production History

Until the reunification, exploration and mining of uranium was carried out in both parts of Germany. In the German Democratic Republic, the Soviet joint-stock company SAG Wismut explored from 1946 to 1953. These activities were concentrated on known vein mineralization of silver, bismuth, cobalt, nickel and other metals in the Erzgebirge in Saxony and in the Vogtland area. Here, the main focus of uranium mining initially was on mines rich in cobalt and bismuth near Johanngeorgenstadt and Oberschlema. In this early phase, more than 100 000 miners were employed in exploration and mining. The rich uraninite and pitchblende ore from the hydrothermal vein deposits was concentrated by hand and transported to the former U.S.S.R. for further processing. Lower grade ore was processed locally in small plants.

In 1954, the SAG Wismut became the Soviet-German Joint-Stock Company (SDAG Wismut); equal shares were held by both governments. The entire uranium production, manually enriched, gravitative or chemical concentrates, was transported to the U.S.S.R. for further processing. The pricing of the final product was established between both national partners.

At the beginning of the 1950s, uranium mining in Eastern Thuringia began. The mines in Eastern Thuringia supplied around two thirds of the annual production of the SDAG Wismut.

From 1946 until 1990, a total of 231 000 tons of uranium was produced from the uranium fields in Thuringia and Saxony by the Wismut Company. The field in Thuringia in the Gera-Ronneburg area consisted of the sites Schmirchau, Paitzdorf, Beerwalde, Drosen and individual open-pit mines, and produced approximately 116 000 tons of uranium. In the Erzgebirge, approximately 90 000 tons of uranium were produced from the Niederschlema/Alberoda and Poehla deposits. Approximately 17 000 tons of uranium came from the Koenigstein deposit near Dresden. From the mid 1960s until the end of the 1980s, around 45 000 workers were employed by the SDAG Wismut. In 1990, there were still approximately

32 000 employees of the Wismut Company, of which 18 000 employees worked in the areas of uranium mining and uranium processing.

For the uranium exploration, a combination of on-ground and airborne methods was used particularly in the south of the former GDR. These activities covered a large area of approximately 55 000 km^2. The costs of these uranium exploration programs were approximately GDR marks 5.6 billion.

From 1960 onwards, the SDAG Wismut operated two processing plants. The Crossen plant near Zwickau in Saxony began ore processing in 1950. The ore was transported by road or rail from various mines in the Erzgebirge. The composition of the ores from the hydrothermal deposits required processing techniques using carbonate pressure solution. The plant had a maximum capacity of 2.5 Mt ore per annum. Crossen was finally closed on December 31, 1989. The second processing plant near Seelingstadt in Thuringia was put into operation in 1960 for the uranium deposits hosted by black shales in Ronneburg. The maximum capacity of the plant was 4.6 Mt of uranium ore per annum. The ore bound by silicate was extracted by acid solution until the end of 1989. Ores rich in carbonate could by treated using carbonate pressure solution.

The uranium exploration in the Federal Republic of Germany started in the Hercynian crystalline massifs in the Black Forest, Odenwald, Frankenwald, Fichtelgebirge, Upper Palatinate, Bayerischer Wald, Harz, in Paleozoic sediments of the Rheinisches Schiefergebirge, in Permian volcanic rocks and continental sediments of the Saar-Nahe region as well as other areas with suitable sedimentary formations. In the course of this work, survey photographs and detailed examinations in prospective areas were made using hydro-geochemical studies, radiation measurements, field work, drilling and aerogeophysical surveys. Based on these investigations, three deposits of economic interest were identified: The hydrothermal deposit near Menzenschwand in the Southern Black Forest, the sedimentary deposit Muellenbach in the Northern Black Forest and the Großschloppen deposit in the Fichtelgebirge. This uranium exploration was abandoned in 1988. Until then, approximately 24 800 boreholes with an overall length of 354 500 m were sunk. The exploration costs amounted to around USD 111 million.

In West Germany, a processing plant existed in Ellweiler, Baden-Wuerttemberg, which was operated by the Gewerkschaft Brunhilde from 1960 onwards. The plant primarily acted as a testing plant for different ore types and had a capacity of only 125 tons per annum. It was closed on May 31, 1989, after a total production of approximately 700 tons of uranium.

8.5.2 Uranium Production and Consumption 2007

German demand for natural uranium as fuel can be calculated at approximately 3300 tons per year. In 2007, 3191 tons Unat were imported. There is no domestic commercial uranium production. Since 1990, there have been no exploration activities in Germany, either. Different German mining companies continued their exploration activities overseas, especially in Canada, until 1997. Since 1998, there is no commercial German uranium industry any more. Since 1991, uranium is only produced in the course of remediation activities in the area of former deposits and production centers of the Wismut GmbH (Fig. 8.16). Between 1991 and 2008 this amounted to 2471 tons of uranium.

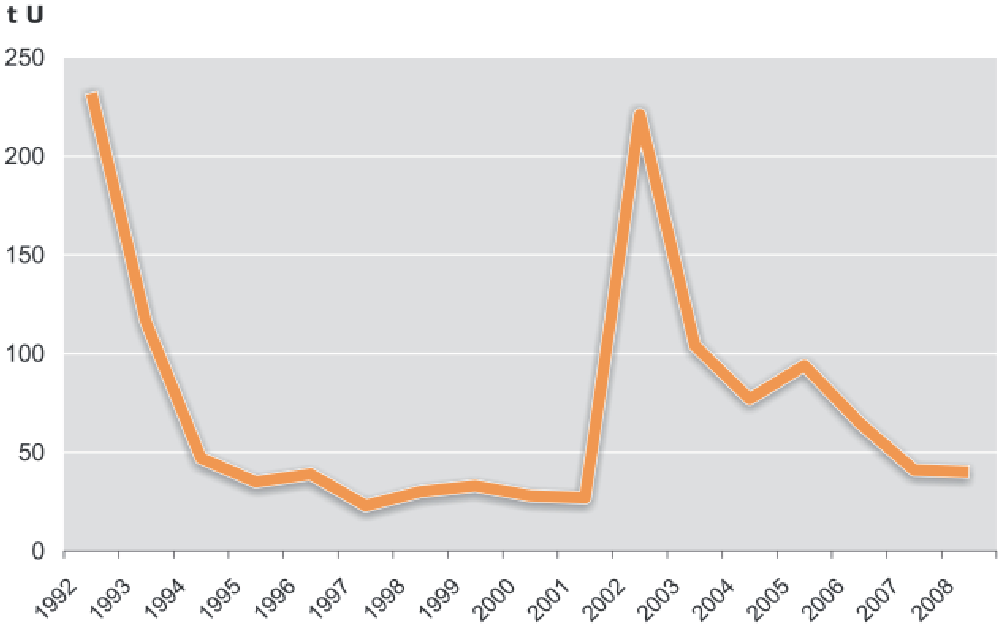


Figure 8.16: Trends in uranium volumes between 1992 and 2008 from the remedial action taken by the Wismut Gmbh (in tons of natural uranium).

As a consequence of high commodity prices on the international markets, the remaining uranium resources in Germany have, however, become the focus of foreign exploration companies. Several requests of national consultants as well as Canadian and Scandinavian companies for the Großschloppen deposit in the Fichtelgebirge have been received. Up to now, there were no reports or plans regarding exploration projects and boreholes. Preparations for the exploration of tungsten and tin in the Poehla mine in the Erzgebirge, which also contains uranium, have started.

8.5.3 Uranium Reserves and Resources

German uranium reserves and resources were last evaluated in 1993. In total, identified uranium reserves which are minable in the price category < 130 US$/kg uranium amount to about 7,000 tons. The known conventional reserves and resources mainly occur in closed mines of the East German mining areas, which have been renaturalized, and remediated since 1991. The future exploitation and availability is uncertain and is subject to political and economical framework conditions. Germany, in addition, has speculative uranium resources of 74 000 tons of uranium with mining costs exceeding 130 US$/kg of uranium.

8.5.4 Germany's Supply with Nuclear Fuels

With the amendment to the Atomic Energy Act in the year 2002, which represents the implementation of the agreement between the Federal government and energy supply companies dated June 14, 2000, the phasing out policy from the nuclear energy program for the peaceful use of nuclear energy in Germany has been regulated by law. Based on an average operating term of 32 years, a cut-off electricity limit has been fixed for each nuclear power plant. Once this has been reached, the appropriate nuclear power plant must be taken off the national grid. In accordance with this, it is envisaged that the last nuclear power plant in Germany will by switched off around 2022. The future uranium requirements in Germany will be reduced accordingly.

German demand for natural uranium is limited to the fuel supply of German nuclear power plants. In 2008, the installed base was 17 nuclear power plants with a gross output of 20 339 MW_e. The contribution of nuclear energy towards primary energy consumption in 2007 had a share of 11.1 % with 52.3 Mtce. With a share of 22 %, nuclear energy was in third position after brown coal (25 %) and hard coal (23 %) in the context of public energy supply and in second position for base load power supply with a share of 45 %. Owing to a slight overall increase in gross power generation, nuclear energy output reached 141 TWh. This was possible because plant utilization remained at a high level. Net power generation was 133 TWh.

The demand for natural uranium in fuel amounted to 3332 tons. It was covered by imports and from stocks. The volume of natural uranium needed for fuel production of 3191 tons U_{nat} was almost exclusively obtained via long-term contracts with producers in France, Canada, the USA and the United Kingdom.

8.5.5 Remediation of Uranium Mines

The closure and remediation activities of the former production sites of the SDAG Wismut were in their 17th year in 2007. The work is carried out on behalf of the German Federal Ministry of Economics and Technology (BMWi) by the Wismut GmbH. Of the € 6.4 billion made available for the major project in 1991, € 5.1 billion had been spent by the end of 2008, which amounted to 80 %. Until the end of 2008, the budget had been mainly spent on the landfill remediation in the Ronneburg area, the backfilling of the open-cast mine Lichtenberg, the flooding of the underground mining pits and the tailings remediation of the Crossen and Seelingstädt processing plants. Approximately 99 % of the underground backfilling work has been completed. Beside the activities in the areas of landfill remediation and site rehabilitation as well as the filling up of industrial tailings ponds, the remaining focal points will be the treatment of contaminated water from the pit flooding and the industrial tailings ponds. A particular challenge is posed by the driving of a hydraulic connecting gallery, the WISMUT-Stolln, with an overall length of around 2900 m from the pit fields in Dresden-Gittersee to the Elbestolln. It is envisaged that this work will be completed in 2011.

8.6 Geothermal Energy in Germany

8.6.1 Geothermal Energy Resources

In Germany, there are no hot steam resources from active volcanoes that can be used directly and with limited effort for the generation of geothermal power. Germany has, however, hot water reservoirs. Their thermal energy can be used for heating purposes and, with an appropriately high temperature, even for geothermal power generation. While heat generation, in particular from geothermal energy near the surface, is already well-established, geothermal power generation in Germany is still in its infancy. At the end of 2003, a demonstration project in Neustadt-Glewe produced electricity from geothermal energy for the first time in Germany. Current research efforts and pilot projects urge an increase in the use of geothermal energy in Germany.

8.6.2 Near-Surface Geothermal Energy

The use of geothermal energy from the ground near the surface for direct use (heating and production of domestic hot water) in Germany is economically viable in many cases. Experience with this technology exists since the 1970s. The development risk is low and the costs for the construction of small plants are manageable. For these reasons, the use of decentralized heat pump heaters in small dwelling units is suitable for the substitution of fossil energy sources.

According to Kaltschmitt & Wiese (1997), around 360 MJ per m^2 and year can be extracted in Germany from the soil layers near the surface. The technically realistic potential for development (Chapter 7) is considerably smaller, since the heat generated must be extracted in the immediate vicinity of the building to be heated and restrictions for land use have to be taken into account. The usable surface area is therefore reduced to approximately 7 ‰ of the total surface area of Germany; the reasonably exploitable energy amount is reduced to 940 PJ/a (Kaltschmitt & Wiese, 1997).
The number and output of small heat pump units installed currently in Germany can only be estimated since there is no central registration system. As of late, sales figures for heat pumps are published by the Bundesverband für Wärmepumpen e.V. (BWP, 2007) (Fig. 8.17), showing evidence that they have doubled for 2006 compared to the previous year. These sales figures do not, however, make any predictions with regards to the replacement of older plants using new technologies. Conservative estimations put the number of small plants for Germany in 2006 at 65 000 with a total output of 740 to 810 MW_{th} (Schellschmidt et. al., 2007). The installed output of these heating systems typically amounts to between 8 and 15 kW_{th}.

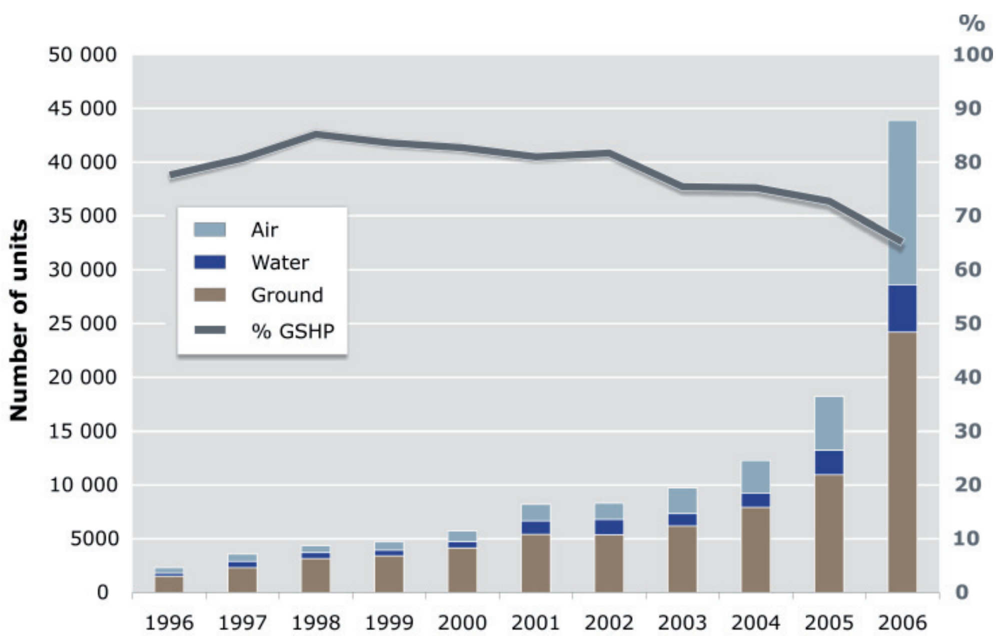


Figure 8.17: Sales statistics for geothermal heat pumps in Germany between 1996 and 2006 (BWP, 2007).

8.6.3 Hydrothermal Resources

Hydrothermal resources of high temperature are mainly limited to areas with recent volcanism where ascending igneous magma bodies intensely heat the rocks in situ at comparatively shallow depths. There are no active volcanoes in Germany; therefore, underground temperatures that do not differ far from the normal geothermal gradient are mainly encountered there. If one excludes depths below 5000 m, in essence, only hydrothermal resources of low temperature (up to 150 °C) can be considered in Germany. These resources are found in areas where water bearing rocks are encountered in depths that can be considered for the use of geothermal energy. The most important of these areas are the Southern German Molasses Basin, the Upper Rhine Valley and the North-German Basin (Fig. 8.18).

Normal temperature gradients found in the North-German Basin down to a depth of 5000 m are generally approximately 30°C/km. Potential hydrothermal resources are water-bearing strata from the Lower Cretaceous, the Middle and Upper Jurassic, the Late Triassic, the Middle Bunter and the Rotliegend. In the South-German Molasses Basin, the hydraulically permeable Malm karst forms the most important geothermal resource. Its potential for geothermal heat generation was estimated at the end of the 1980s in a comprehensive research project (Frisch et al., 1992; Schulz & Jobmann, 1989). The estimated amount of geothermal energy that can be gained regionally has been confirmed through a number of drillings.

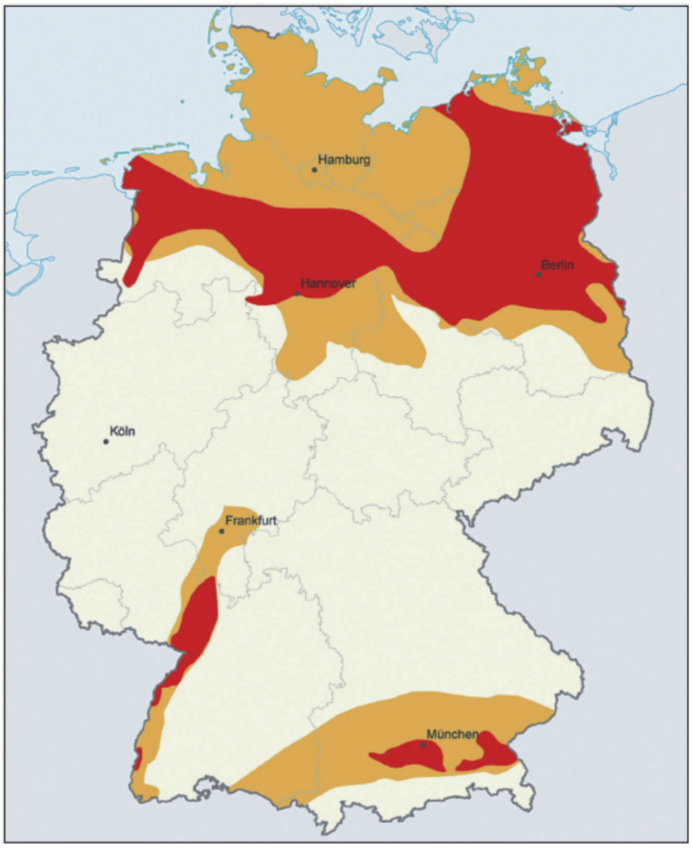


Figure 8.18: Hydrothermal resources in Germany (Schulz et al., 2007). Red areas highlight areas with temperatures above 100 °C, while yellow areas designate temperatures above 60 °C.

The areas with the highest temperature gradient are in the Upper Rhine Valley. In the southern part, the gradient can reach almost 110°C/km, in the northern part up to 44°C/km can still be encountered down to a depth of 3000 m. In the Upper Rhine Valley, the Upper Lacustrine Limestone, the Bunter and the crystalline basement can be considered as suitable aquifers and hydrothermal resources. Apart from the areas specified, other basin structures can also be considered in principle as possible hydrothermal deposits, such as the Sub-hercynian Basin, the Thuringian Basin and the South-German Basin.

According to table 8.3, the potentially usable energy content of the North-German Basin is the largest with 293 EJ, mainly due to its large surface area. Estimations are, however, subject to large uncertainties as the determination of the recoverable geothermal energy is largely dependent on hydraulic permeability and porosity in the target formations. Their distribution and due amount is generally not well known.

Table 8.3: Estimates for the maximum geothermal energy by regions (Hurter & Haenel, 2002) and for the maximum extractable geothermal energy for power generation (Jung et. al., 2002).

Region	mineable thermal energy (EJ)	extracable geothermable energ for power generation (EJ)
North-German basin	293	59
Molasses Basin	64	13
Upper Rhine Valley	156	18
total	*513* *approx. 16 300 GWa*	*90* *approx. 2 900 GWa*

Only part of the total amount of energy recoverable, detailed in Table 8.3, can be considered for power generation: Those areas where the temperature of the thermal waters exceeds a minimum value and where the residual temperature after use does not drop beneath a lower limit for technical reasons. Jung et al. (2002) include potentially water-bearing formations with temperatures above 100 °C and limit the residual temperature to 70 °C after power generation without further utilization of heat. For the selection of preferred development areas, the figures in Table 8.3 are not decisive, though. In this case it is very important in which areas the highest yields and thermal outputs for each drill hole pair can be achieved and how high the non-discovery risk for hydraulically favorable structures will be.

The currently largest geothermal power plant in Germany was put into operation in 2007 in Landau, Rheinland-Pfalz. Here, hot water with approx. 150 °C and a flow rates of 50 to 70 l/s is brought to the earth's surface via a borehole at a depth of around 3,300 m and cooled down in two stages (Fig. 8.19). In the first step, the temperature range between 150 and 70 °C is used in an ORC power plant to generate the electricity for around 6000 homes. The installed electrical output is 3 MW_e. The residual heat of the thermal water is then used for the district heating supply of approximately 200 to 300 homes in a second step, which corresponds to a residual heat between 3 and 6 MW_{th}.

The largest geothermal heating plant in Germany so far was put into operation in 2005 in Unterschleißheim near Munich. Here, hot thermal water with a temperature of 81 °C and a production rate of 90 l/s from a depth of around 1960 m is produced. The energy of the thermal water is used to supply residential areas and public buildings via a district heating network. The annual geothermal production is 28.25 GWh. Additional heat generation using natural gas and light fuel oil is required only during peak load times and the geothermal share of it is at least 61 %.

(diagram)

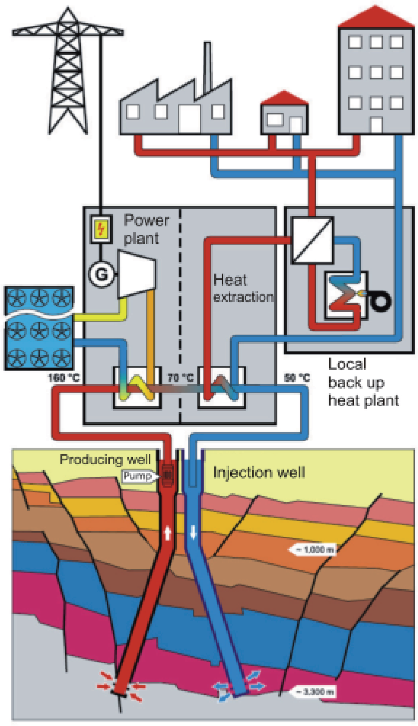


Figure 8.19: Geological situation and technical implementation of the largest geothermal power station in Germany, Landau (www.geox-gmbh.de).

8.6.4 Hot Dry Rock Resources

Hot dry rock deposits for geothermal energy comprise rocks where the temperature is high enough, but without additional treatment only insufficient amounts of hot water can be extracted (Chapter 7.2.4). Areas potentially usable for power generation using hot dry rock technology in Germany are the Central and Southern German crystalline area, the crystalline in the Upper Rhine Valley and the occurrence of Rotliegend volcanics in the North-German Basin (Fig. 8.20). Based on the assumption of optimum functioning and usability of the HDR technology, the maximum extractable thermal energy quantities detailed in Table 8.4 are

Tabelle 8.4: Maximum extractable thermal energy for power generation with optimum usability of HDR technology (JUNG et al., 2002).

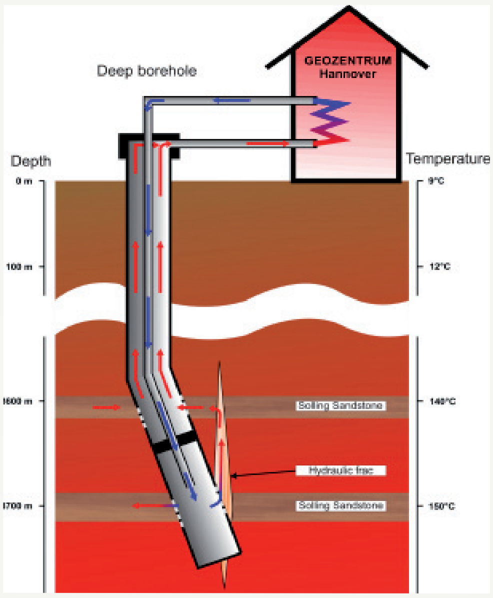
Region	usable energy for power
North-German basin	540 EJ
Upper Rhine Valley	480 EJ
Central and South German crystalline area	7 600 EJ
Total	8 620 EJ = approx. 274 000 GWa

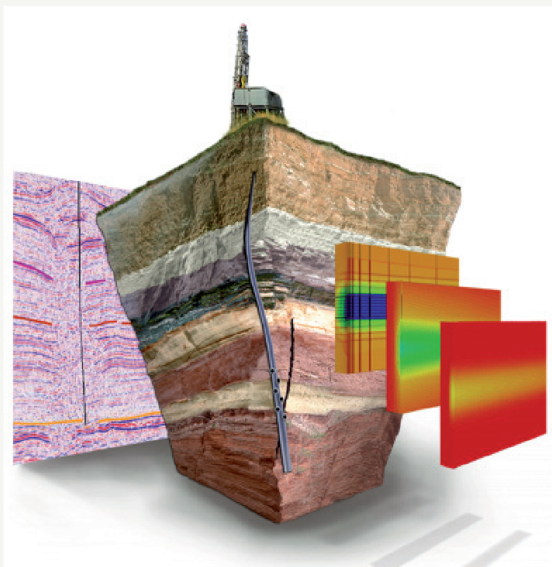
achieved. Jung et al. (2002) include crystalline rocks in the depth range between 3000 m and 7000 m and estimate a residual temperature of 70 °C for power generation without further utilization of heat. This way, they estimate the maximum extractable energy quantity for power generation with optimum usability of the HDR technology in Germany to be 8620 EJ (Table 8.4).

i 11

GeneSys – Heat Generation Using Single Borehole Method

The GeneSys project (Generated Geothermal Energy Systems) is carried out by the BGR and the Leibniz Institute for Applied Geophysics (LIAG) in Hanover in order to develop and implement innovative concepts for geothermal heat generation from large depths. Emphasis is on heat generation for medium-sized customers (a few Megawatts of thermal output), independent of location and even from sediment rocks with little permeability. The implementation of a single borehole method for the reduction of development costs is planned using the heat supply of office and laboratory buildings of the Geozentrum Hanover as an example. To this end, next to the Geozentrum a borehole up to the rocks of the Middle Bunter at a depth of approximately 3800 m is sunk. Based on the single borehole concept previously developed in a research project at the natural gas exploration well Horstberg Z1 water must then be made available at a temperature of approximately 130 °C with a mean flow rate of 25 m^3/h for use. The creation of large artificial fractures in the deep underground is the basis for water flow and geothermal energy extraction in low permeable sedimentary rock. This is done by breaking up the rock strata (*Frac*) by injecting water at high pressure. Good hydraulic conductivity of such artificially made fracs in the rock and its high storage capacity could be proven in Horstberg Z1 in a so-called cyclic test for heat recovery. Cold fresh water was injected into the crack and recovered as hot water after a certain delay. By repeating this process, cyclic energy recovery from the crack could be demonstrated in principle. In another process, the hydraulic communication between two sandstone strata created by the crack is used to realize water circulation. Drilling of the GeneSys well is planned to start in 2009.





Source: LIAG

Methods to assess the stored heat in low permeable rock are still under development. Only in 2008, electricity was produced from a hot dry rock system in the **pilot project in Soultz-sous-Fôrets** in Alsace. The extraction of geothermal energy from deep, dense rock formations by means of artificial crack generation had been investigated for 20 years in the European research project. To develop the reservoir, a borehole triplet consisting of a single injection and two production wells was sunk down to 5000 m in the granite (Fig. 8.21) and connected to a fissure system extending over several square kilometers by enormous injections of water. The artificial geothermal reservoir created this way enables circulation of water in a closed-loop circuit between several boreholes (Schindler et al., 2008). Following a successful circulation test in 2005, the trial operation for power generation started in summer 2008. The thermal output of 13 MW_{th} is converted to an electrical output of 2.1 MW_e by means of an ORC power station.

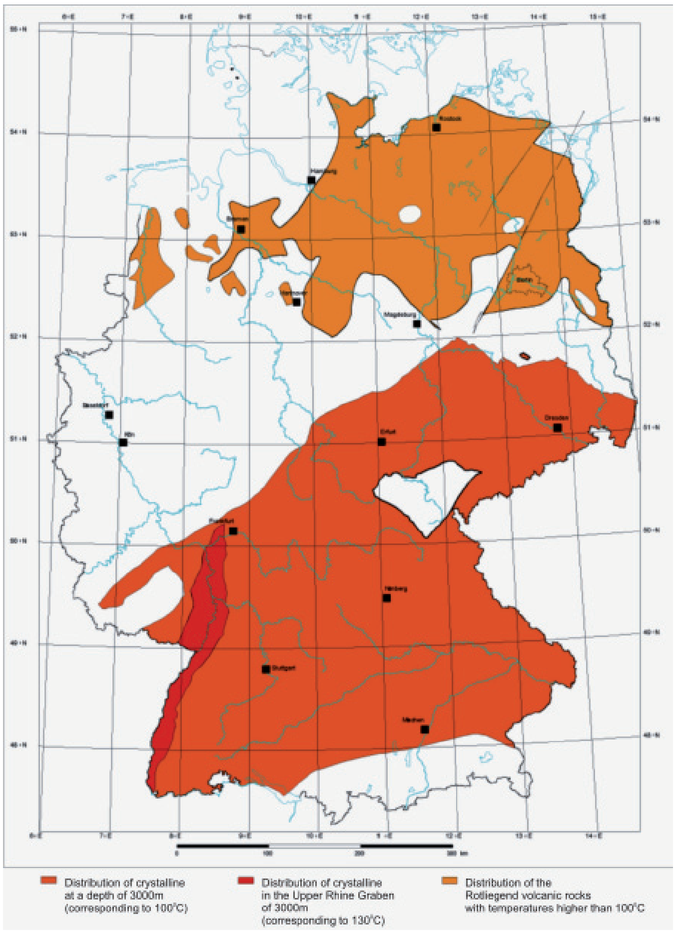


Figure 8.20: Occurrence of crystalline rocks in Germany which can be considered for geothermal power generation using the hot dry rock method (Jung et al., 2002).

Despite the achievements in the Soultz HDR project, current experience is not sufficient to ensure success of the hot dry rock technology at any desired location. Site conditions, especially rock properties, tectonic stresses, fissure grids and the existence of faults have significant influence on formation and properties of created or stimulated crack systems. Therefore, it is currently not certain if the hot dry rock method is usable at all locations in the crystalline areas and beyond and which proportion of the huge potential is actually usable.

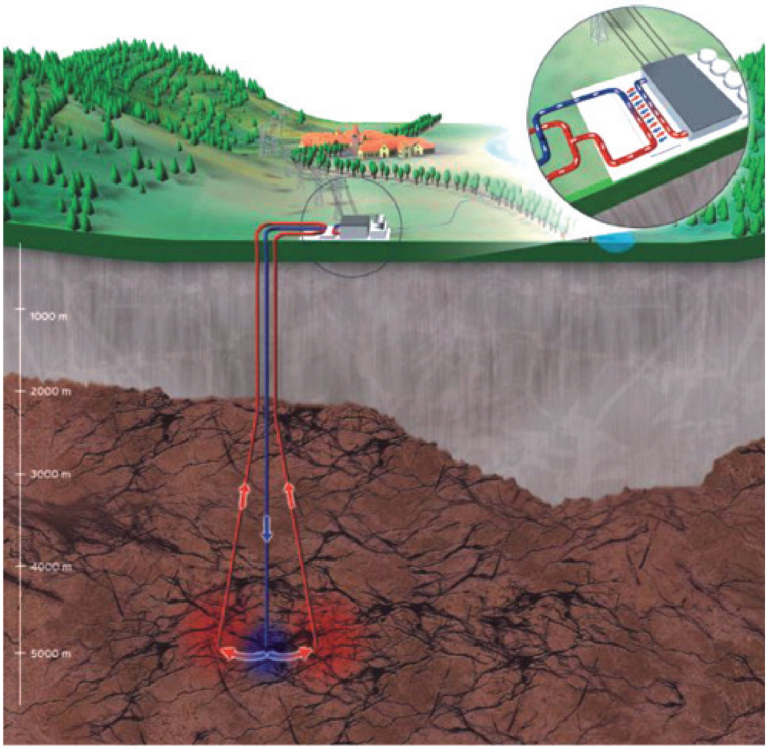


Figure 8.21: Geological situation and technical implementation of the hot dry rock project Soultz-sous-Fôrets. Source: GEIE „Exploitation Minière de la chaleur".

8.6.5 The Future of Geothermal Energy in Germany

The development of the utilization of geothermal energy in Germany has benefited significantly from law changes and measures of the integrated energy and climate package of the German Federal Government. In connection with the ecological tax reform, the Federal Government published a support program for *measures for the utilization of renewable energies*. In 2004, the Amendment of the Act on Renewable Energies (EEG) was adopted and modified in 2008. Thus, electricity from geothermal power stations up to 10 MW is paid at 16 ct/kWh and from plants larger than 10 MW at 10.5 ct/kWh. Additional payments result for plants that are put into operation before 2015, for the utilization of residual heat and the use of petrothermal technology for artificial crack generation.

The dramatic development of thermal utilization of geothermal energy has resulted in 30 geothermal installations larger than 100 kW_{th} (Fig. 8.22) with a total installed output of 104.6 MW_{th} being operated by 2004 in Germany (Schellschmidt et al., 2005). Further 15 projects are planned to be completed until 2010. This would mean a total of 231 MW_{th} installed, the electrical output from geothermal plants would then be 18 MW_e.

An overview of sites and details of the geothermal projects currently being planned or implemented provides the geothermal information system for Germany. This is developed by the Leibniz Institute for Applied Geophysics (LIAG) in the Geozentrum Hanover and can be researched using the Internet (www.geotis.de).

The research regarding deep geothermal energy in Germany is aimed mainly at reducing the costs for exploration and utilization of geothermal resources through technical innovation. Examples of research projects are the hot dry rock plant in Soultz-sous-Fôrets just put into operation and the GeneSys project that is to supply the offices and laboratories for around 1000 employees of the Geozentrum Hanover with heat from a geothermal plant using innovative single borehole technology (Info box 11).

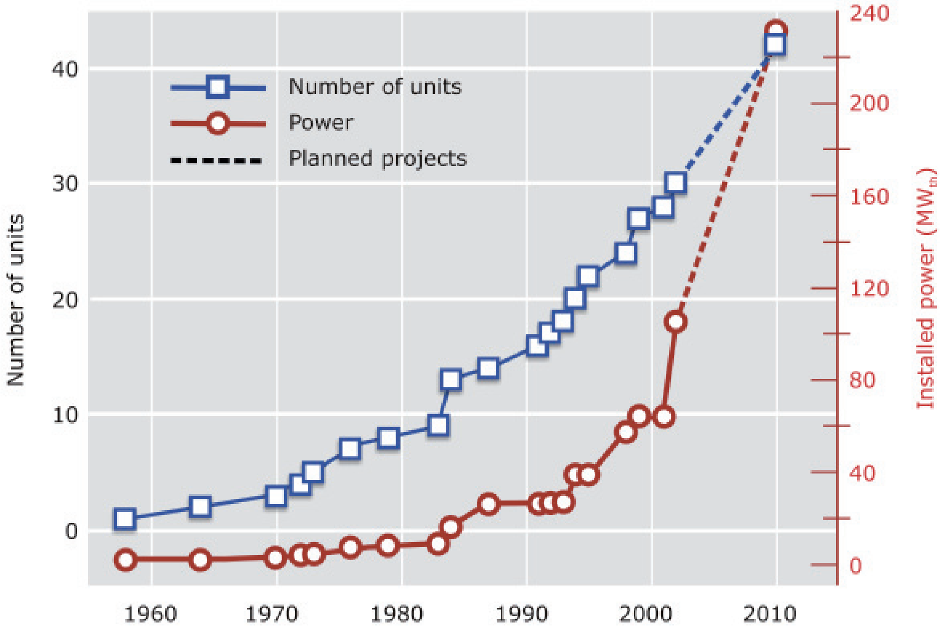


Figure 8.22: Geothermal installations with more than 100 kW_{th} and their output in Germany since 1955 as well as a scenario of the development until 2010 (Schellschmidt et al., 2005).

8.7 The Supply of Germany with Energy Resources

With the exception of brown coal, Germany is highly dependent on imports of energy resources. Germany receives nearly 90 % of its uranium from France, Canada, the United Kingdom and the US. For this reason and in view of a good stock of uranium, supply bottlenecks are not expected. The situation in the most important supplying countries regarding individual fossil energy resources like petroleum, natural gas and coal will be discussed in the following section. In this context, the trends in reserves and production as well as the estimated resources still available have been analyzed. In addition, further potential supplier countries will be discussed.

8.7.1 Petroleum Supplier Countries

We will take a closer look at the seven leading supplier countries, each having delivered more than 2.5 Mt of oil in 2007. Together they account for more than 83 % of all imports (Table A 8-1). The trends in reserves and production since 1960/1970 are shown in Figure 8.23, ranked according to the amount of petroleum supplied to Germany in 2007. It should be noted that separate reserves figures for Russia, Kazakhstan and Azerbaijan only exist since 1990. In addition, the resources figures at the end of 2007 are given.

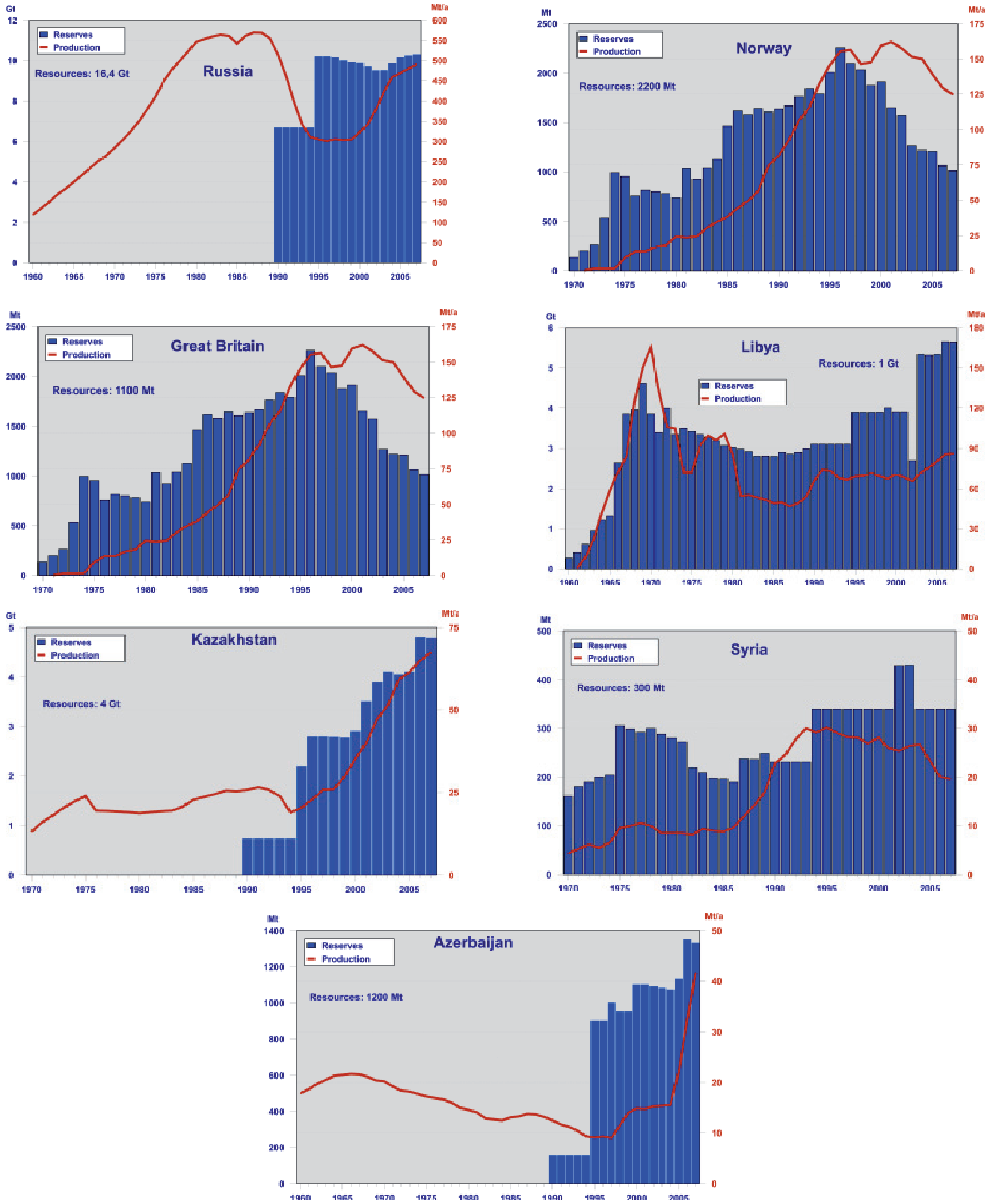


Figure 8.23: Trends in reserves and production as well as estimated resources at the end of 2007 for major crude oil supplying countries of Germany.

Based on the presented figures, the above countries can generally be grouped into two categories:

1. Countries with decreasing reserves and falling production. These include Norway, the United Kingdom and Syria, which will also face falling production in the future.
2. Countries with rising or constant reserves and rising production. These particularly include Kazakhstan and Azerbaijan, but also Libya and Russia.

In accordance with this grouping, the importance of these countries for future German petroleum imports will change. While the proportion of North Sea oil, which together with the Danish supplies currently reaches approximately 30 %, will decline, the share of countries such as Kazakhstan and Azerbaijan but also Libya will probably increase. The volume of Russian supplies, however, depends on other factors. A deciding factor is the further development of production, on the one hand, which has been decreasing slightly in 2008, and the development of exports to other regions, particularly to the Asian markets, on the other hand.

Because petroleum is a product traded worldwide, other suppliers could be of interest to Germany, too. In accordance with the amount of remaining potential (Fig. 3.3), the OPEC states on the Persian Gulf, Nigeria, Angola, Brazil and Venezuela are obvious candidates. This, however, would increase the OPEC share in German imports. The availability of energy resources on the world market depends on the global situation of supply and demand. In this respect, it seems important that German oil companies get involved in exploration and production abroad in order to help safeguarding supplies.

8.7.2 Natural Gas Supplier Countries

In the following, the three leading supplier countries Russia, Norway and The Netherlands will be looked at more closely. In 2007, they had a share of more than 96 % of the imported gas (Table A 8-2). The trends in reserves and production since 1950 are shown in Figure 8.24, ranked according to the amount of the natural gas volume supplied in 2007. In addition, the estimated size of resources at the end of 2007 is given.

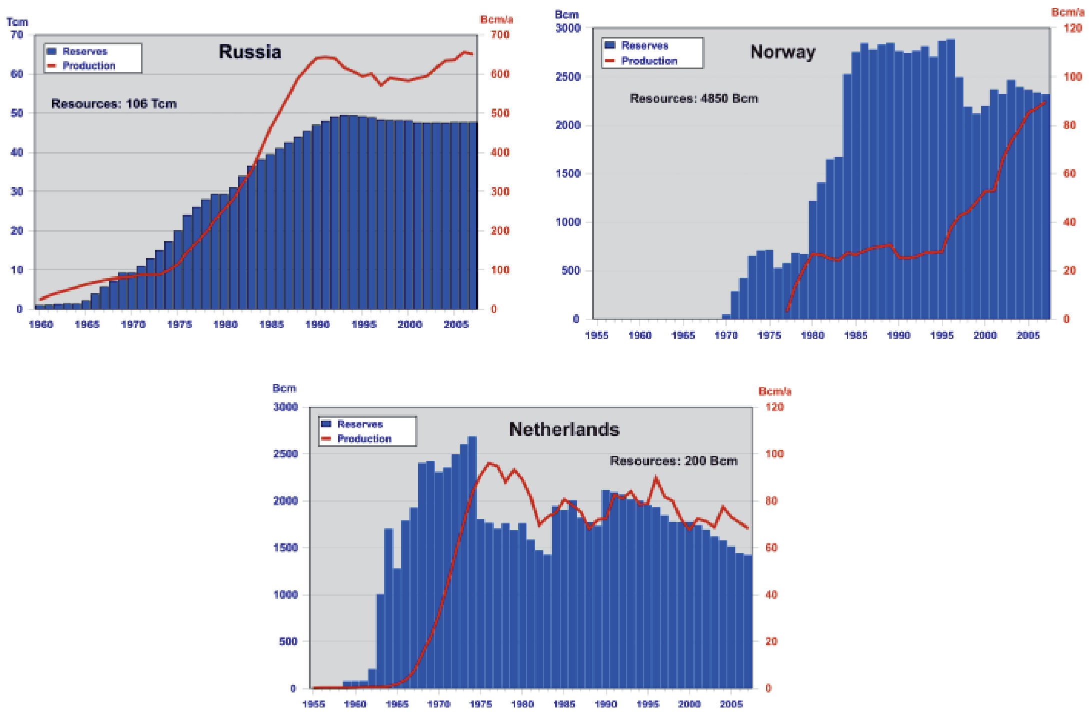


Figure 8.24: Trend in reserves and production as well as estimated resources at the end of 2007 for major natural gas supplying countries of Germany.

Based on these graphs, the supplying countries can be grouped into two categories for natural gas just like oil:

1. Countries with decreasing reserves and falling production. These include the Netherlands, who only have a low amount of resources.
2. Countries with constant reserves and rising production. These include Russia and Norway, which both still possess major resources. These two countries will keep playing an important part in supplying Germany with natural gas in the future. For Russia, it should be considered that the reserves not yet exploited in the Arctic regions, particularly the Jamal peninsula and the Shtokman field, must be developed in the near future to be able to meet long-term supply obligations (Bittkow & Rempel, 2009).

The following countries are rich in natural gas and can be considered to be potential supplier countries: the Middle East (Iran, Qatar, Iraq), North Africa (Algeria, Libya, Egypt), the Caspian region (Kazakhstan, Turkmenistan, Azerbaijan) and Nigeria. Appropriate diversification of natural gas imports, however, presupposes the creation of the required infrastructure. Apart from the construction of new or the extension of existing pipelines, the foundations for the import of liquefied petroleum gas have to be laid.

8.7.3 Coal Supplier Countries

Lignite coal used in Germany almost exclusively comes from domestic production (Chapter 8.3.4). In contrast to this, the declining domestic production of hard coal over the last few years has been balanced largely by rising hard coal imports. German hard coal imports 1990 only came to 11.7 Mt, but in 2007 they were already four times as high (47.5 Mt) and covered around two thirds of the German demand for hard coal. The five leading supplier countries for hard coal (Fig. 8.12), which are Russia, South Africa, Columbia, Australia and Poland, accounted for nearly 74 % of imports in 2007. Because of the continuous increase in Russian imports seen since the turn of the millennium, Russia has risen to the position of largest coal supplier for Germany in the years 2006 and 2007. Almost in parallel to this, the imports from Poland decreased, which is primarily due to the decrease in production there. All these countries have sufficient reserves for many decades to maintain current production. In addition, major resources have been reported for these countries.

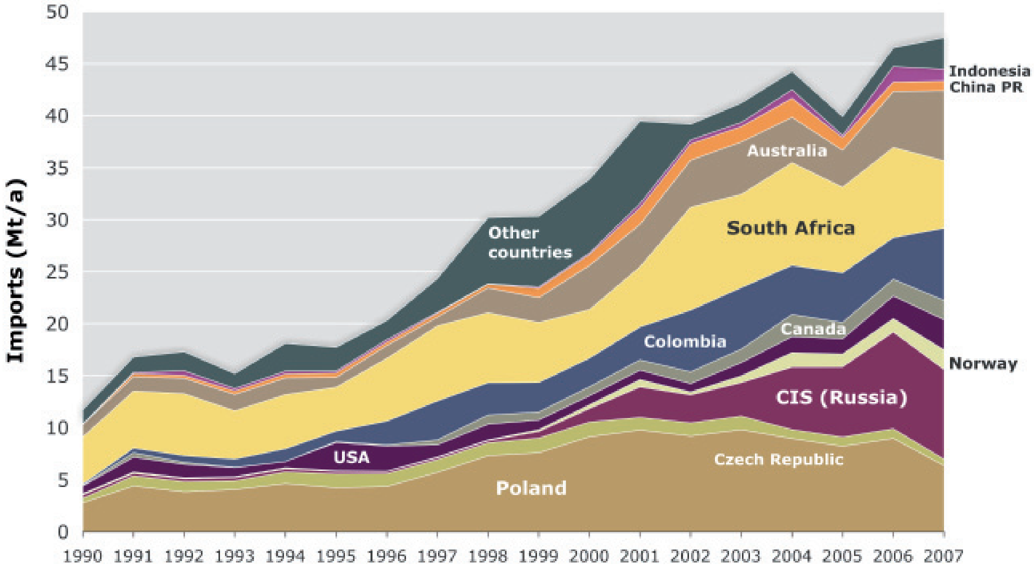


Figure 8.25: Trends in the import of hard coal and hard coal products such as coke and coal briquettes into Germany since 1991 (according to various annual reports by the VDKI).

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9 Availability of Energy Resources

9.1 The Dynamics of Exhausting Finite Resources

In the discussion about the finite nature of resources, in particular of energy resources, various terms such as reach, static reach, maximum production, peak oil or availability are supposed to provide statements or guidelines on the degree of depletion of the resources. The term reach, in particular, directly implies the question as to how long the resources will last. Generally, it is not defined whether "how long the resource will last" means the point in time up to which all demands for the resource can be met, or the last production before all deposits are exhausted, or any other scenario in-between these two extremes.

9.1.1 Static Reach

Static reach represents a certain specification of the term *reach. The static reach* is calculated as the ratio of the reserves and the current annual production. The result is a number of years, for example 40 years for oil, which indicates the point in time when oil from the currently known reserves would be exhausted, if production were to continue in a constant manner, i.e. statically, each year from now on, and the initial reserves would stay constant. However, because the quantity of oil production has varied each year to date, and the known quantity of producible oil has also changed every year, the *static reach* needed to be modified every year in an unpredictable way. In fact, for many resources, including oil, relatively constant *reserves-to-production ratios* have been observed over the years (Fig. 9.1). For example, between 1945 and now, the *static reach* for oil ranged between 20 and 45 years. For the past 20 years, this value has been fluctuating only between 40 to 45 years. This is due to the fact that the oil industry is continually exploring, discovering new deposits, and using technical means to expand the potential of deposits that are already in production. Therefore the term "static reach" should be understood rather as a situational report of the

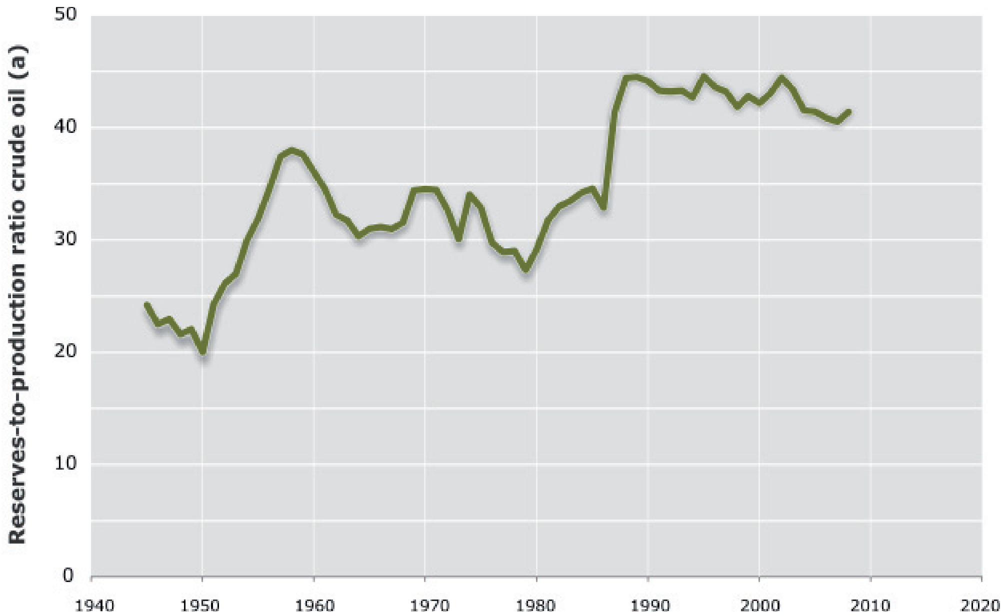


Figure 9.1: Static reach (= reserve to annual production ratio) of oil between 1945 and 2008.

industry that is extracting the respective resource. A sudden clear drop in that *static reach* could mean that in the aforementioned ratio the quantity of producible oil, i.e. the reserves and resources, vanish faster than required by demand. This could be interpreted as a sign that the industry's economic interest in developing new deposits is waning, or that the exploration and development is no longer in step with the required increase in production.

It follows from the situation described above that the *static reach* is not suitable to predict future developments with respect to the production of energy resources. Thus, there is no correlation between the name and the value of evidence of the *static reach*, and therefore, the use of *static reach* is mostly misleading. For this reason, the present study does not use the term *static reach* to characterize the availability of energy resources.

9.1.2 Peak Oil

Peak Oil is generally considered to be the all-time maximum of oil production, i.e. the maximum quantity of crude oil ever produced in a year. The model was initially developed to forecast oil production, but several authors now also use it for natural gas (peak gas) and even for coal (peak coal). The peak oil theory was derived from the assumptions of the Hubbert curve, which was developed by the American geologist Marion King Hubbert (1903—1989). According to Hubbert, the worldwide production of oil will initially increase steadily, and then decline irreversibly as soon as half of the oil has been produced. Because in this theory half of the oil will have been used at peak oil, this point is also called the depletion midpoint. The reason given for the correctness of the assumptions with respect to peak oil is that Hubbert's predictions about the course of oil production did in fact prove correct for the United States.

According to the peak oil theory, it is possible in the ideal case to predict the future course of the worldwide oil production, including that of peak oil, at an early time based on the production up to then and the finding history of the oil fields by adapting type curves. However, calculations, representations, definitions and compiled data of various peak oil models are not uniform, which results in a broad spectrum of potential production courses based on that theory (Fig. 9.2, 9.3). Although the initial peak oil discussion was primarily based on so-called Hubbert curves, recent forecasts also use approaches such as the backdating method, creaming curves, the hotelling model and probability models.

The scenarios of the potential development of oil production shown in Figs. 9.2 and 9.3 point at peak oil between 2007 and 2070. Some differences arise when taking unconventional oil into account. It is remarkable that there are strong fluctuations in the various models with respect to the total quantity of producible oil, i.e. the areas under the production curves in the relevant figures. This can be attributed to varying assumptions about the total potential (EUR). For better comparison, the representation of ASPO (2008) includes the production of NGL and oil from the arctic and deep-water regions, although according to Campbell, they are considered to be unconventional oil. It is obvious that the order of magnitude of the assumed EUR in itself is a significant uncertainty factor in the prognosis of future production developments. A combination of conventional and unconventional oil (Fig. 9.3) shows only a slight fluctuation of the peak oil, aside from the Odell curve (2000), which puts the maximum in 2070.

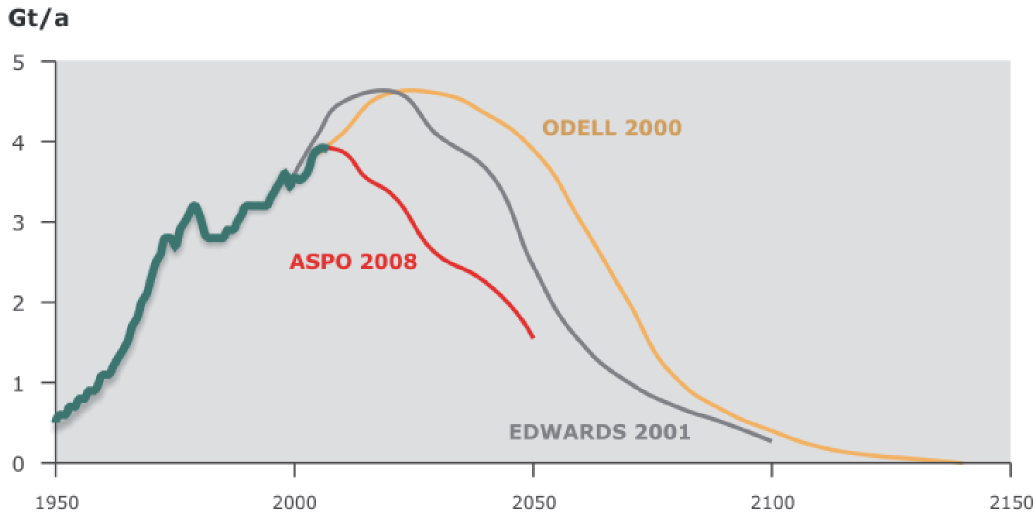


Figure 9.2: Examples of the prognosis of production courses with peak oil of conventional oil.

Contrary to the *peak oil* models, which have *per se* the objective of predicting the point in time of maximum oil production, demand scenarios, and the underlying growth prognoses, in general predict a steady increase of oil consumption into the distant future. However, these scenarios do not take the supply situation into account.

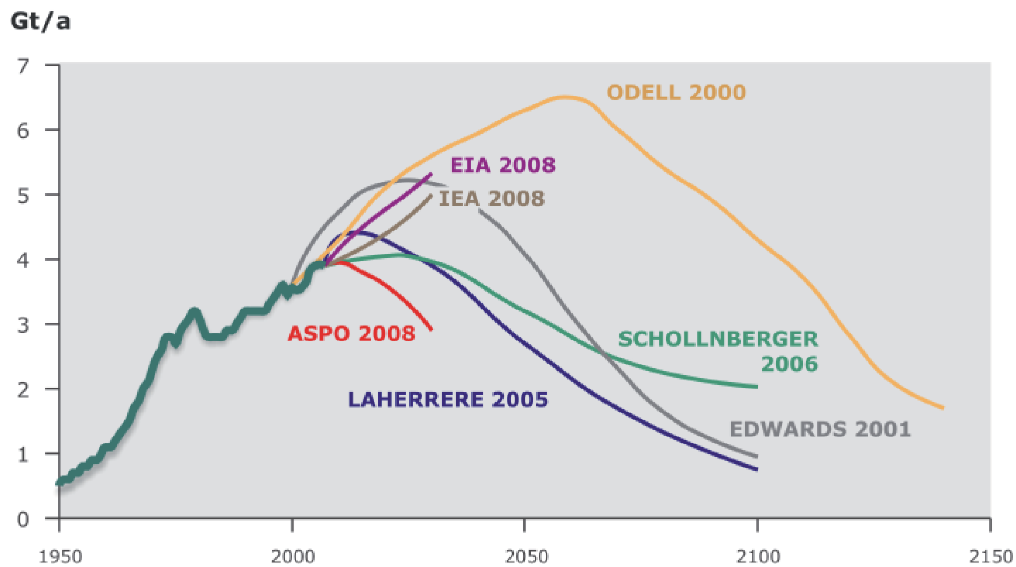


Figure 9.3: Examples for predicted production courses with peak oil of conventional and unconventional oil.

9.1.3 Availability

The production history of fossil fuels carriers to date shows that until now, geological availability was not the major factor affecting production. Rather, the increasing demand developed as a consequence of technological progress, macroeconomic and geopolitical processes, the high added value, and the respective investment climate. That demand, and the high profits were a steady incentive to find and develop new deposits. In the face of the limitation of fossil energy, this may change in the future, but in the past, the interplay of supply and demand was the driving force behind the development of new deposits and new locations, as well as for the abandonment of fields that were no longer profitable.

Therefore, the term *Reserve* is not only defined by geological criteria, but also by the requirement that production has to be profitable from an economic point of view (Chapter 2.4.2). Because of technical progress, and for lack of more economical alternatives, more and more deposits were categorized as profitable in the past, and thus contributed to an increase of the reserves. To what extent this development can continue largely depends on whether the economy and government accept the challenges related to a greater exploration and production effort in frontier areas. From this aspect, geological availability is not an independent variable, but can be considered only in the context of the economic environment.

The interaction of geological, political and economic factors, together with the technological development, can lead to unpredictable dynamics of the availability of energy resources. For example, phases with strong oil price increases represent additional burdens for oil-importing countries, with the side-effect that there is a greater desire for a careful use of oil. And as energy prices rise, there is also a greater willingness to explore and develop deposits that previously were not considered economical. A strong drop in oil prices, which initially appears lucrative for the consumer, leads to a strong loss of income for the companies that produce and export oil, and in the long term to a decline of their exploration activities. The resulting drop in the reserves can in time affect the future energy supply and price levels, boosting the prices because of a lack of supply.

An intermediate loss of income can lead to a decline of the respective economy of oil exporting countries that strongly depend on oil. For example, because 85 % of Nigeria's national income originate from the oil industry, it sank from USD 4.4 billion in October 2008 to about USD 2.09 billion in November 2008. After the Asia crisis and the decline of the demand for oil, as well as the disputes within OPEC, the OPEC countries suffered income losses of about USD 50 billion in 1998, which corresponds to one third of the planned revenue from the oil business. This experience was an important reason for the OPEC countries to make a greater effort of adhering to their self-imposed production discipline.

Historically, there have been repeated interferences that affected the availability of energy resources, for various reasons (Fattouh, 2007 b). Complementary interests of producers and consumers, governmental exertion of influence, as well as insecurities about the investment behavior due to economic, financial and political framework conditions have played an important role in this respect.

For example, the behavior of OPEC and IEA indicates **complementary interests** of producers and consumers. Having the option to establish production quotas gives OPEC an effective instrument for influencing the oil market. OPEC's goal is to produce enough crude oil to satisfy the demand at a uniformly high price. Excessive supply - as well as shortages - is unfavorable for trade. As protection against unexpected interruptions, the objective is to keep the production capacity always a few percentage points above the actual production (Fig. 9.4). The difference between capacity and production, called spare capacity, is considered a potential indicator for the risk of short-term supply bottlenecks and influences the spot price (Fattouh, 2007 a).

As a counterbalance to the OPEC cartel, the OECD countries founded the International Energy Agency (IEA) in 1974. IEA estimates the short- and long-term demand for fossil fuels. The oil producing countries also use these analyses, which are published in monthly Oil Market Reports and annual World Energy Outlooks (cf. IEA, 2008 a), as an indicator for investments. Because of the quick economic development in countries outside of the OECD, global demand has increased to an unexpected extent in recent years, causing the spare capacity to shrink. The low spare capacity is seen as one potential reason for the price increases in recent years until 2008 (Fig. 9.4).

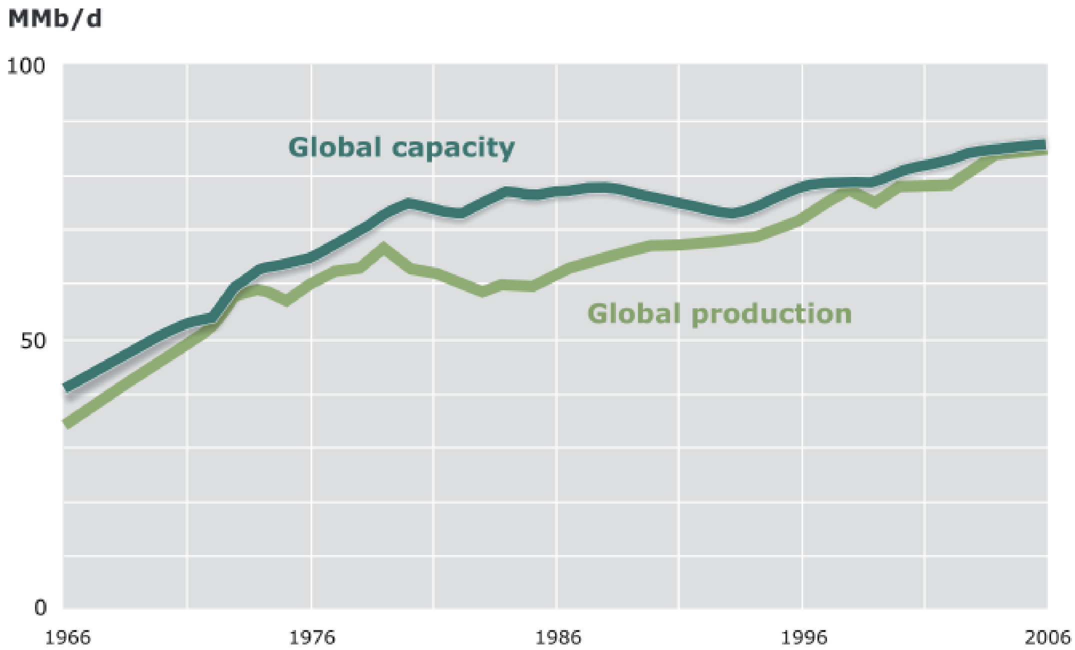


Figure 9.4: Worldwide production capacity and production between 1966 and 2006. The difference is called "spare capacity" (Kloppers & Yaeger, 2008).

Analog to the spare capacity on the production side, there is the national strategic reserve on the consumer side, which is intended to absorb unexpected supply bottlenecks. The national strategic reserve may be used only in case of physical interferences, but never to influence pricing. It is monitored by the IEA and can maintain the current supply of the OECD for about 52 days. In Germany, the German National Petroleum Stockpiling Agency [Erdölbevorratungsverband (EBV)] is responsible for maintaining a stock of oil and oil products in a range of at least 90 consumption days. All companies producing the respective products domestically or importing them to Germany are mandatory EBV members. Correspondingly, there are also buffer capacities for the gas market. However, these buffer capacities are not mandated by law, but rather compensate daily or seasonal fluctuations in supply and demand (Chapter 8.2.4) and therefore have been more of a business management tool so far than a political control.

The relation between the large international (IOC) and national oil and gas companies (NOC) (Info box 1) exemplifies an increasing **governmental influence** on the production of energy resources. Until the early seventies, the IOCs controlled the international oil market, and then this *era of the seven sisters* was replaced by the *OPEC era* (Fig. 9.15). Even today, in the *global market era*, the IOCs and the independents still wield considerable influence (Info box 1). The increasing influence of the NOCs raises the question if and to what extent an NOC must be considered a governmental institution, and how the political goals of governments affect corporate strategies. Combining national, social or military interests in the actions of NOCs may cause a drop in economic efficiency. Furthermore, in certain cases, NOC profits may not be applied to optimal corporate use. According to Jaffe (2007), the most of the NOCs lag behind the IOCs with respect to profitability because they subsidize oil products and do not work as efficiently as the IOCs. Because of the lack of profits, greater difficulties can be expected in the development of new deposits and the increase of production than it was the case in the past with IOCs.

The availability of energy resources may be further influenced by subsidies or legislation. For example, a few nations, such as China and India, but also OPEC countries, use subsidies to promote the consumption of fossil energy resources to stimulate their economy in a prominent place. According to IEA, the subsidies in the Asian region were approx. USD 100 billion in 2007. However, in view of the high oil prices, Asian governments had to cut the subsidies in mid-2008 (EID, 2008). Other countries try to curtail the use of individual energy resources with the help of legislation. They cite environmental protection, the reduction of CO_2 emissions, the desired independence from finite energy resources, as well as market advantages due to technical innovation, as some of the reasons. These developments are often accompanied by supporting measures to increase energy efficiency, the stimulation of the use of other energy resources, and the development and market introduction of environmentally safe, sustainable, regenerative forms of energy.

Investments are the central factor for discovering new deposits, developing technologies for the production efficiency of energy resources, and providing the infrastructure for the production, processing and transportation. It is known that investments lag behind energy prices time-wise. In the correlation between oil prices and investments in Fig. 9.5, it must be taken into account that when oil prices are high, the cost of exploration, for example the cost of deep-water drilling ships or prices for raw materials such as pipes, also rises. High prices for iron ore, steel and other raw materials are therefore the cause as well as the effect of high oil prices and oil products. The *IHS/CERA Upstream Capital Cost Index* (Yergin, 2008) shows that worldwide the cost of exploration and production almost doubled between 2005 and 2008. On the other hand, there is no obvious direct correlation between investments and oil production because a decade or more can pass between exploration, development and production from an oil field. This time is significantly longer in cases of exploration and development in frontier areas. Therefore, the judgment that a safe supply is guaranteed only if investments are made early and regardless of short-term economic developments, is all the more important.

This judgment is contradicted in some aspects by the situation in the energy markets. The fact that by far the greatest growth in the future oil and gas deposits is expected to be under the control of NOC in non-OECD countries leads to insecurities about whether future investments will be made at the right time, and to a sufficient extent. Furthermore, in times when oil prices are low, decisions to request and grant credit for investments are made rather hesitantly. Sufficient and timely investments can be made in particular when energy and financial markets are stable and predictable in the long run. Investments that are made too early can lead to an oversupply, price drops and losses. However, if there is

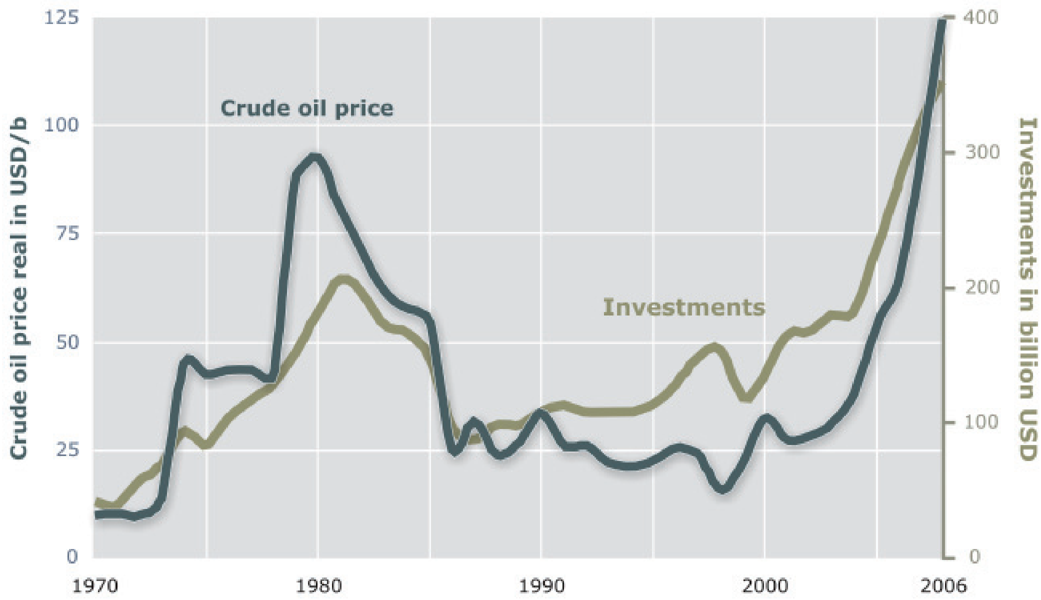


Figure 9.5: Comparison of the development of crude oil prices and investments in the oil sector since 1970 (NPC, 2008).

no prospecting, exploration and development of oil deposits in frontier areas, the result may be supply bottlenecks in the oil importing countries.

This implies that the term *availability of energy resources* has a different meaning at every point in the process chain, from the deposits up to the end usage. For example, a country with rich oil reserves will attribute a different meaning to availability than a company that produces oil, a refinery, or the driver of a car at the gas station. With respect to the entire process chain, the availability of energy resources may be influenced by geological conditions, the technical feasibility of the production, transport restrictions, the infrastructure situation, the political framework conditions, and specifics of the economic situation in the markets. The following discussion about the availability of the individual energy resources focuses specifically on the geological availability, and also discusses consequences on the remaining variables that influence availability.

9.2 Availability of Geothermal Energy

In recent decades, the development of geothermal power generation was limited largely to countries where high-temperature deposits could be exploited because of favorable geological conditions. Power generation from low-temperature hydrothermal deposits and impermeable rocks with the help of *Hot Dry Rock* (HDR) technology is still worldwide in the pilot phase, and a prognosis about its future development can be made only after the methods employed so far have proven effective. The significant influential variables for the development and prognosis of geothermal energy use are primarily the development of energy costs, especially for coal and natural gas, technical advancements in the development of geothermal energy, as well as political guidelines and funding measures for geothermal energy.

Between 1975 and 1980, the installed geothermal power strongly increased worldwide. From 1980 to 2005, the increase remained nearly constant at about 200 to 250 MW_e annually and continued until 2007 (Bertani, 2008). Extrapolating this trend to 2010 results in 11 GW_e, which corresponds approximately to the prognosis of the *International Geothermal Association* (IGA) (Fig. 9.6; IGC, 2007).

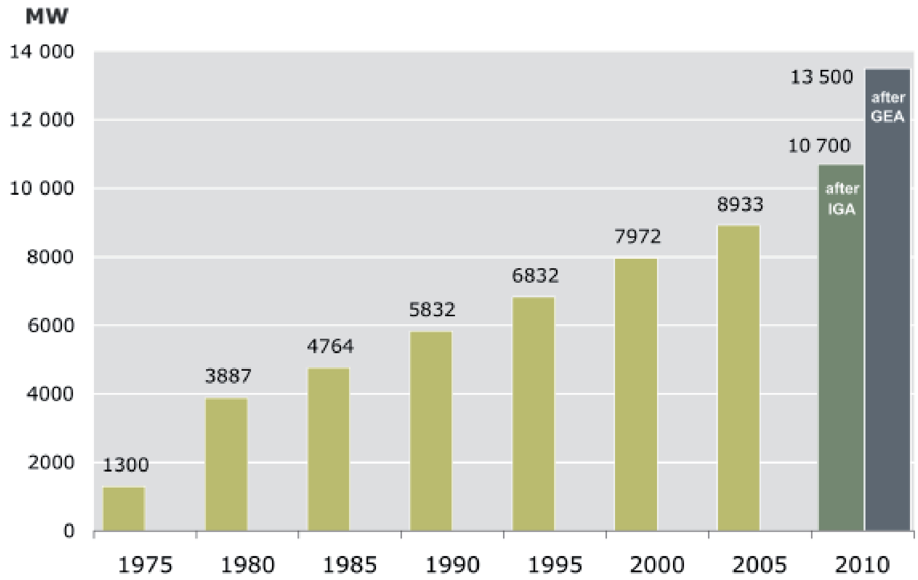


Figure 9.6: Development of power installed worldwide for electricity generation from geothermal energy between 1975 and 2005, as well as two prognoses for the year 2010 (data from Lud et al, 2005; Bertaini, 2005; Prognoses for the year 2010: International Geothermal Association (IGA); US Geothermal Energy Association (GEA); Gawell & Greenberg, 2007).

The cost of drilling and the quality of the reservoir significantly influence the economic efficiency of geothermal power generation. The higher the energy content of the reservoir, the less drilling is required for the same power plant performance. Binary power plant technology with the help of the *Organic Rankine Cycle* (ORC) and *Kalina* methods also plays a role in this context (Chapter 7.2.2). In many cases, the economic efficiency of a standard steam power plant can be increased significantly with a downstream binary power plant. The condensed liquid is normally injected back into the deposit at a high temperature after it has passed the steam turbine. This means that the residual energy of that liquid is not utilized. In an ORC- or Kalina facility, it would be possible to draw additional energy from the liquid without additional drilling costs. In many cases, this multi-stage utilization would be a very efficient option of generating additional energy and increasing efficiency, which can already be employed.

Another aspect that is currently discussed is the so-called crude oil co-production. Many oil wells that have existed for years also produce a significant amount of water with a temperature of up to 200 °C. The energy of these waters is currently not being used to generate electricity. On the contrary – the disposal of these waters often comes at a significant cost. After the oil has been separated from the water in separators, the energy can be used in ORC or Kalina plants without any additional development effort, and a resulting geothermal power of 1000 to 5000 MW_e is considered feasible (Forseo, 2008).

The further development of methods already existing such as using supercritical fluids, improving transmissivity in HDR doublettes, better and more cost-efficient drilling and power plant technology could push the rising rates of geothermal power production worldwide in the near future. Gawell & Greenberg (2007) as well as the World Energy Outlook (IEA, 2006) are assuming significant increases. The latter considers an annual geothermal power production of 185 TWh accomplishable by 2030. Gawell & Greenberg predict an installed power of 140 GW_e, resp. 1400 TWh annually by 2050 (Fig. 9.7). With the use of artificial geothermal systems (HDR or *Enhanced Geothermal System,* EGS), a geothermal capacity of considerably more than 150 GW_e is predicted by 2050 (Rybach, 2008).

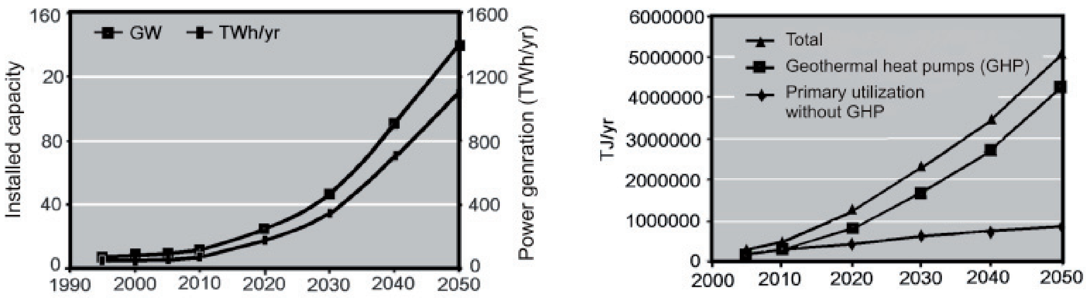


Figure 9.7: Prognoses on the development of geothermal power generation (left, Bertani, 2008) and direct thermal utilization (right, Friedleifsson et al, 2008).

Another aspect in the utilization of geothermal energy is the reduction of CO_2 emissions (Rybach, 2008). Geothermal processes work without combustion and thus cause little to no emission of greenhouse gases. The CO_2 emission of current geothermal power plants is around 120 g/kWh. It is expected that improved technology can reduce these emissions to about 10 g/kWh (Rybach, 2008). With an estimated geothermal power production of 1000 TWh/a by 2050, the emission of CO_2 could be reduced by several hundred million tons, depending on which fossil fuel source is substituted. Geothermal heating installations with heat pumps using electricity from fossil-fired power plants reduce CO_2-emissions by 50 % compared to oil burners. If the heat pump power is based on renewable sources such as hydropower, that reduction is 100 %. Because of the expected growth in direct usage, including geothermal heaters with heat pumps, geothermal energy could reduce emissions by more than 300 million tons CO_2 annually, according to Friedleifsson et al. (2008).

9.3 Availability of Uranium

Despite a sustained invigoration of the market, which made the mining of higher cost categories more economical, uranium reserves are defined conservatively and, for reasons of comparability, in quantities that can be economically mined up to USD 40/kg. In 2007, this was about 1.77 Mt of uranium in *reasonably assured resources* (RAR). A comparison between these uranium reserves and the current annual consumption of 0.041 Mt uranium shows that there is enough uranium available for several decades, even without using any secondary supply sources. In the past, the uranium reserves with mining costs up to USD 80/kg were taken into consideration when uranium prices were high, and in view of still higher prices, even the category minable up to USD 130/kg was taken into account. The

RAR of uranium, minable up to USD 80/kg, amount to 2.60 Mt, and those up to USD 130/kg amount to 3.34 Mt of uranium respectively, including the RAR at lower mining costs. With increased demand, and the higher prices that are most likely related to an increased demand, this would mean another significant extension of the life cycle of conventional uranium as energy resource.

The reserves of the category *"inferred resources"* (IR) can also be included into the availability analysis because they can be transformed into reserves with little effort. For example, it can be assumed that the large quantities of IR minable up to USD 40/kg of uranium will be developed before the RAR at extraction costs of more than USD 40/kg of uranium. All known reserves (RAR + IR) are listed in the following overview (Table 9.1).

Table 9.1: Known uranium reserves by extraction costs (IAEA/NEA, 2008).

Reserves/Resources	Reserve Category USD/kg U	Quantity (t U)
RAR	< 40	1 766 400
Inferred resources	< 40	1 203 600
RAR	40 – 80	831 600
Inferred resources	40 – 80	654 800
RAR	80 – 130	740 300
Inferred resources	80 – 130	272 200
Known resources minable up to USD 130/kg U		*5 468 900*

The known reserves of 5.4 Mt in conventional uranium deposits can be considered a workable quantity available for future supply. This is based on the assumption that extraction cost does not play a decisive role, and that these reserves do indeed reach circulation if there is appropriate demand, because the cost of uranium mining accounts for only 6 to 10 % of the power generation costs.

In 2007, there were about 2598 million tons of known reasonably assured uranium resources worldwide, which could be mined at costs of up to USD 80 per kg uranium. Currently, about 60 % of the world's uranium demand is covered by mining production; thus the currently known worldwide RAR would cover the demand for about 63 years, and with coverage of the entire demand of 64 615 t of uranium for only about 40 years. The additionally IR are 4456 million tons of uranium up to USD 80/kg and 5468 million tons of uranium up to USD 130/kg. Furthermore, there are resources totaling 7771 million tons of uranium. These figures represent the current status as of 2008 and do not take into account current and future exploration activity. Based on the existing figures, the calculated availability is more than 200 years.

For several years, the additional supply sources (Chapter 6.1.5) have attributed to the fact that less uranium is produced than is being consumed. It can be inferred that these supply sources will also play a major role in the future. According to an IAEA analysis (2001) on the availability of uranium until 2030 and beyond, it is estimated that until 2050, plutonium will be available as a mixed oxide (MOX) at up to 3600 tons of uranium annually, and up to 2500 tons of reprocessed uranium (REPU) will be available annually. Accordingly, they represent between 6 and 8 % of the respective annual demand.

The current stock of inventory could drop to zero by 2013. An important role is attributed to highly enriched uranium (HEU), which can cover about 15 % of the annual demand and, according to the current contractual situation, is available until the early 2020s. The re-enrichment of *Tails* is supposed to account for shares between 2 and 8 % until 2011. When viewed in five-year segments, the supply contribution of the additional sources could account for the following quantities (Table 9.2):

Table 9.2: Estimate of the available annual uranium quantities from additional sources until 2050.

Year	Uranium from additional sources
2007	23 336 t U
2010	22 500 t U
2015	17 500 t U
2020	18 000 t U
2025 to 2050	6 100 t U

According to the 2007 NEA and IAEA analysis, a *Low* and *High* scenario is created for the development of the uranium demand until 2030, which indicates that the cumulative uranium consumption from 2007 to 2030 may be 1.98 Mt respectively 2.35 Mt. According to the IAEA analysis, consumption is estimated at approx. 2.15 Mt uranium in the *middle scenario* between 2007 and 2030. The IAEA models, which are based on an older study, assume a cumulative consumption of 3.27 Mt uranium (*low*), 5.27 Mt *(middle)* and 7.45 Mt (*high)*.

Based on surveys of commercial facilities, the World Nuclear Association (2001) presented a projection of the uranium demand until 2020 in three scenarios (*lower, reference, upper*). The *lower* scenario expects a cumulative uranium demand of 1.16 Mt by 2020; this expectation is 1.3 Mt in the *reference* scenario and 1.5 Mt in the *upper* scenario.

It can be derived from the IAEA and WNA analyses that by 2030, up to 450 000 tons of uranium may be available from additional sources (inventory, HEU, MOX, REPU, re-enrichment). These quantities would not have to be produced during that period and, under optimal conditions, could be used to cover demand. Depending on the scenario, the total uranium demand from mining production would amount to 1.5 to 1.9 Mt between 2007 and 2030, which would be an average of approx. 65 000 to 82 000 tons annually. This is feasible, given the uranium reserves of 1.77 Mt. However, sufficient production facilities will have to be operated during that time, and new ones may have to be set up, if necessary. The situation of the current production facilities is as follows:

The analysis of production options submitted by NEA and IAEA in 2008 proceeds on the assumption of RAR + IR resources that can be mined up to USD 80/kg uranium. The facilities operated in 2007 have an annual gross capacity of about 54 370 tons of uranium. In view of the expansion of known deposits and the development of new production capacities, these capacities will increase to more than 95 630 tons of uranium annually by 2015. At approx. 80 % load, more than 76 500 tons of uranium would be available in 2015. Overall, 1.57 Mt of uranium could be produced between 2007 and 2030. When including the planned production sites, about 101 200 tons of uranium could be produced annually between 2007 and 2030. At 80 % load, this would lead to a producible quantity of almost 1.86 Mt of uranium.

These considerations show that even with a significant global expansion of nuclear energy, the supply from production and additional sources is guaranteed beyond 2030. In this context, it must be taken into account that the existing companies have developed only part of the reserves so far and that uranium resources of the higher cost categories and with a low exploration status, which may additionally increase the potential reserves, have not been included in these calculations.

Another factor that must be taken into account in the availability analysis is that the additional supply sources are not constant. In 2007, about 23 300 tons of uranium were available from these sources. This quantity will most likely drop to 17 500 tons annually by 2015. Their contribution will probably drop to less than 10 000 tons of uranium annually after 2030. The resulting quantities that would be theoretically required from production (Tab. 9.3) show that at 100 % capacity load the demand (high) can be met at high capacity until 2025. New deposits to be developed and potential additional sources must cover any difference that may develop in subsequent years. There is an IAEA model calculation for developments beyond 2030, which reaches to 2050. For 2040, a demand of 128 000 tons of uranium is estimated in the *middle demand case*. With the assumed increase in demand, uranium production would have to reach about 160 000 tons by 2050. Consequently, it is noted that given these assumptions, the demand in 2050 can be met adequately only if new production facilities are established based on the predicted and speculative resources. This requires significant exploration efforts to transform these uncertain quantities into reserves.

Table 9.3: Comparison between predicted uranium demand and assumed existing production capacities (t U/a) by 2030.

Year	Demand			Existing Capacities		
	Low	Medium	High	Low	Medium	High
2010	70 395	72 700	75 020	80 685	83 700	86 720
2015	76 870	81 600	86 385	95 630	106 500	117 420
2020	85 390	92 000	98 600	88 525	105 550	122 620
2025	90 935	100 700	110 510	83 840	100 950	118 060
2030	93 775	107 850	121 955	83 130	100 500	117 850

A large number of countries are turning to utilizing nuclear energy because of the clearly increasing energy demand, future energy security, and the climate development that is a worldwide topic of discussion.

9.4 Availability of Coal

Coal is the most abundantly available non-renewable energy resource worldwide. Even at a clearly increased demand, a limitation of the geological availability of hard coal or soft brown coal supply is not expected for decades. This becomes clear when comparing the figures of the worldwide demand of roughly 5.5 Gt of hard coal and 0.9 Gt of soft brown coal to the verified reserves in a quantity of 729 Gt of hard coal and 269 Gt of soft brown coal for 2007. Even if only a small part of the resources in the amount of 15 675 Gt of hard coal and 4076 Gt of soft brown coal is transferred to reserves, the geological availability of coal is still guaranteed over many more decades.

Contrary to soft brown coal, which is traded internationally only to a very limited extent, hard coal is traded worldwide and is therefore subject to the limitations of the world market. Between 2003 and 2008, the availability of hard coal was at times quite tight on the world market which is reflected in particular by the volatile coal prices (Fig. 5.22). This was attributed to the above average increase in consumption and the fact that capacity was not expanded accordingly with respect to production as well as transport infrastructure. These cyclical demand and price fluctuations are typical for all resource markets. They are relevant only for short-term considerations, but not for long-term availability.

The concerns about supply shortages in the world market related primarily to steam coal because this is where the strongest absolute growth was experienced. Most of all China, which currently produces and consumes about 45 % of all hard coal worldwide, doubled its hard coal demand in 2007 in comparison to 2000. India, which produces about 8 % of all hard coal is the third-largest hard coal producer and with a 9 % share the third-largest consumer, increased its consumption by almost 50 % during that time period. During that time period, hard coal consumption increased by about 49 % worldwide, or almost 15 % without taking China and India into account (IEA, 2008b). At the same time, primarily India and the People's Republic of China increased their imports in addition to local production and were for the first time among the five-largest hard coal importers in 2007. In addition, exporters important for the pacific coal markets, such as Indonesia, Vietnam, but also Russia announced with national energy strategies an increased coal demand for the future, which would lead to a reduction of the export capacities.

Because only 16 to 17 % of all hard coal produced worldwide is currently traded on the world market, the development of the Asian hard coal consumption and the related Asian imports and exports have a particular impact on the availability of hard coal in the world market. In 2007, Europe produced only about 41 % of its hard coal consumption. Against the background of a continually decreasing hard coal production in Europe and the related increase of export dependency, a shortage would have a particularly harsh effect on the European region. During the current financial and economic crisis (status of late 2008/early 2009), investments to increase the capacities have already been stopped and the first coal-mines have already been shut down because of the reduced demand for coal, so the supply situation on the world coal market is relaxed. This development could also reverse quickly if the economy recovers, resulting in increasing demand and rising prices. In view of the much smaller per capita consumption of hard coal in emerging and developing countries, in comparison to that of industrialized countries (Table 9.4) and in connection with an energy demand that will continue to rise in the future, primarily in the Asian region, an increase in worldwide coal consumption can be expected. It also remains open to what extent the future demand, in particular in Asia, can be met by local production.

Table 9.4: Per capita hard coal consumption of selected industrialized countries as well as threshold and developing countries in 2007.

	Industrialized Countries				Threshold and Developing Countries			
Country	**Germany**	**Great Britain**	**Japan**	**USA**	**India**	**Indonesia**	**Vietnam**	**China**
Per capita hard coal consumption (tons/person)	0.8	1.4	1.4	3.1	0.4	0.1	0.4	1.9

9.5 Availability of Natural Gas

The estimated total global conventional natural gas potential for 2007 was 509 trillion m³. Of these approx. 182 trillion m³ are reserves and 239 trillion m³ are resources, approx. 86.8 trillion m³ of natural gas have been produced (Fig. 9.8). Even with the expected significant growth rates in the consumption of natural gas, no limitation in the availability of natural gas is expected in the coming decades from a geological perspective.

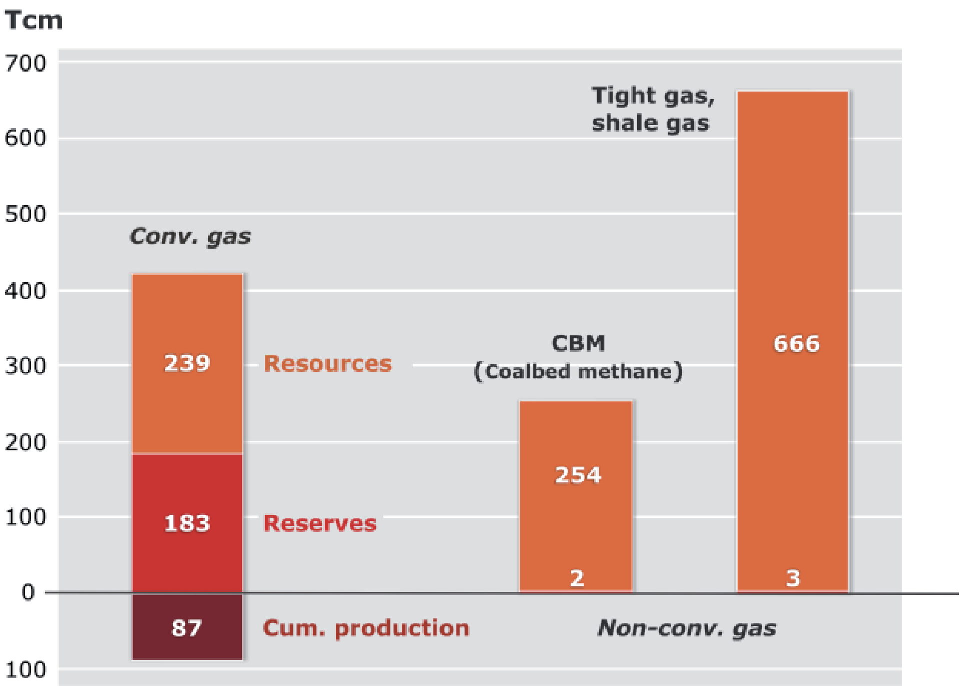


Figure 9.8: Worldwide total potential of conventional natural gas with reserves, resources and cumulative production as well as coal bed gas and natural gas from dense rock in 2007.

Despite current developments in the LNG market, the global trade of natural gas by sea will continue to play only a secondary role in comparison to pipeline transport (Chapter 4.2.6). Insofar, supplying regional natural gas markets with insufficient domestic resources may become a problem in the future. Although the European market is in a comfortable situation because it is located in close proximity to large production regions (Chapter 4.2.8), the North American market, for example, may experience shortages.

It is difficult to gauge how the development of non-conventional natural gas will advance. However, the production of CBM and natural gas from tight rocks has started worldwide, including Germany, and is progressing. It remains to be seen whether its share in the total worldwide production will meet the current level of about one third in the United States. Proof of efficient utilization of the huge natural gas potential in gas hydrate from a technical, economic and ecological perspective is still lacking. The years to come will demonstrate to what extent natural gas from gas hydrate can be utilized as an energy resource. Further innovation is also needed for the economic production of natural gas from aquifers. These could either be based on a desired continued use of the infrastructure of the hydrocarbon industry already existing, or on the other hand on technical combinations with geothermal facilities.

Because the cumulative natural gas production until now represented only a comparatively small proportion of the actual total potential (Fig. 9.8), it can be assumed that the information on the actual natural gas resources – in particular compared to oil – is still undervalued. This makes any prognosis of future production developments difficult because the exact knowledge of the total potential is the most important starting variable for such models. A compilation of various published prognoses on the course of natural gas production, which is shown in Fig. 9.9, shows the great differences in the assumptions about the producible quantities, perceptible in the enfolded areas under the production trends. Most of the scenarios relate to conventional natural gas and expect a maximum of the worldwide total production after 2025, in part even 2050 or later.

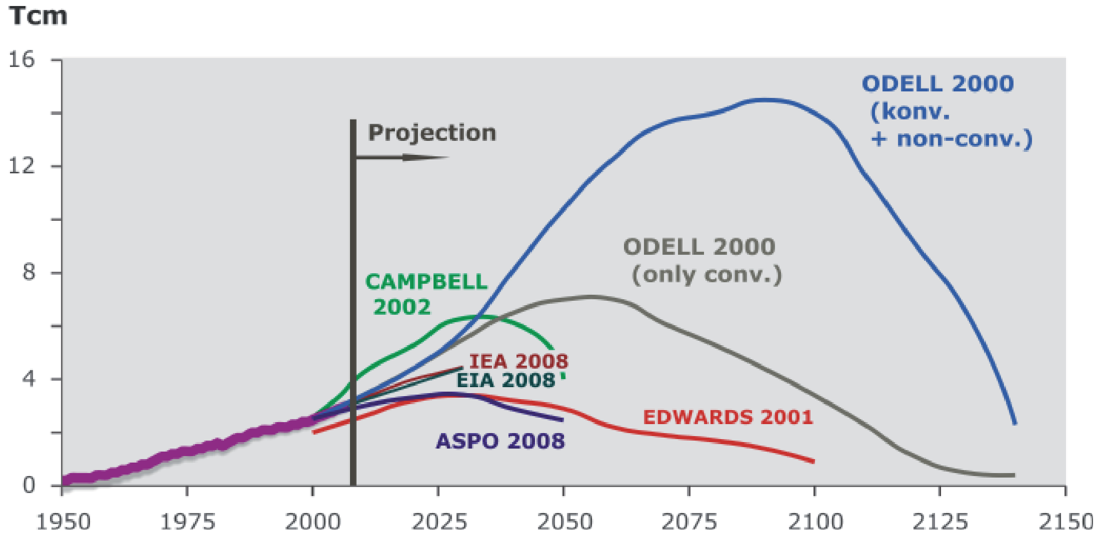


Figure 9.9: Development of natural gas production between 1950 and 2007, and a few published scenarios until 2150.

Edwards' scenario (2001) appears to be based on estimates of the total potential and the growth potential of the production that are too low (Fig. 9.9). Campbell's scenario (2002) shows relatively high production values until 2030, which can be attributed to the fact that this scenario was based on a reduction of oil production from 2005 on, with natural gas as the replacement. After 2030, Campbell's scenario (2002) shows a sharp drop in production. The ASPO scenario appears to be conservative although it incorporates the use of unconventional natural gas. Odell (2000), on the other hand, who also includes the use of unconventional natural gas, including a significant natural gas production from gas hydrate starting in 2025, draws a very optimistic picture of production development.

In summary, the aspects of the future availability of natural gas, as derived from the supply data, are as follows:

From a geological perspective, natural gas is available in sufficient quantities to cover the estimated demand for decades. A moderately increasing demand can also be covered for most natural gas markets with additional deliveries. Possible future bottlenecks, for example in the North American natural gas market, would have to be compensated with LNG deliveries from other markets. The specific transport costs, which are clearly higher compared to oil and coal, and the partly great distances between producers and consumers may influence the price of natural gas significantly. In the future, the transport of natural gas will continue to proceed largely via pipelines, even if a disproportional increase of the LNG transport and the establishment of a spot market for natural gas are likely. The IEA (2004) estimates the LNG share in the global natural gas trade to exceed 50 % for 2030. The growing LNG capacities will contribute to a relaxation of the natural gas market because even natural gas deposits far away from infrastructure can be developed for the world market in this way. The increasing activities for the production of synthetic fuels from natural gas (*gas to liquid,* GTL) could take away volumes from the natural gas market in the future. Overall, creating the necessary new capacities for the production and transportation of natural gas requires long-term financial commitments as well as close cooperation between producers and consumers.

9.6 Availability of Oil

9.6.1 Geological Availability of Oil

The current annual consumption of oil corresponds to approximately the quantity formed in the earth crust in about 500 000 to 1 000 000 years. This comparison emphasizes the finality of the oil resources and thus raises the question how long our economy can depend on the demand-oriented annual increase in the oil production. There are various and in part strongly diverging opinions in this respect. Some predict the end of the oil era in only a few years, while others predict that oil availability will last for several centuries. In any case, the period called the age of oil, which describes the beginning of the use of this resource until the time when the mass use of oil will have been replaced by other energies, will be just an episode in the history of mankind.

Oil is the energy resource that has been exhausted to the greatest extent. Of the known total potential of conventional oil in the amount of 400 Gt; 151 Gt, e.g. almost 38 %, have already been produced to date (Fig. 9.10). Given the fact that there are verified reserves of 157 Gt, this means that 49 % of the initial reserves (Fig. 2.5) have already been extracted from the deposits. Relative to these currently known initial reserves of 308 Gt, the *depletion midpoint*, where half of the known supply has been used up, would be reached in a few years, even without any increase of production (Chapter 9.1.2). When the conventional oil resources are included as well, this point could be reached in ten to twenty years. At an annual increase in production by one to two percent, which is within the scope of the IEA reference scenario (IEA, 2007), about half of the remaining oil would have been produced within the next 20 to 25 years, and a large part of the known reserves would be exhausted. Several authors have discussed production prognoses. Different production scenarios are usually the result of a different valuation of the available total oil potential, and of different model approaches (Fig. 9.2, 9.3). The BGR study includes an independent projection of the future oil production based on BGR data (Chapter 9.6.3).

In addition to the unpredictable dynamics of the development of demand and changes in the world oil market, various geological and geotechnical factors determine the development of future production. For example, in addition to the total potential of producible oil and its regional distribution (Chapter 3.2.1), the distribution of the deposits, and here in particular the remaining and still undiscovered large oil fields, the so-called *giants, super-giants* and *mega-giants*, play a particularly important part. For one, the discovery of large new fields has decreased steadily in recent years. The quantity of oil reserves discovered in

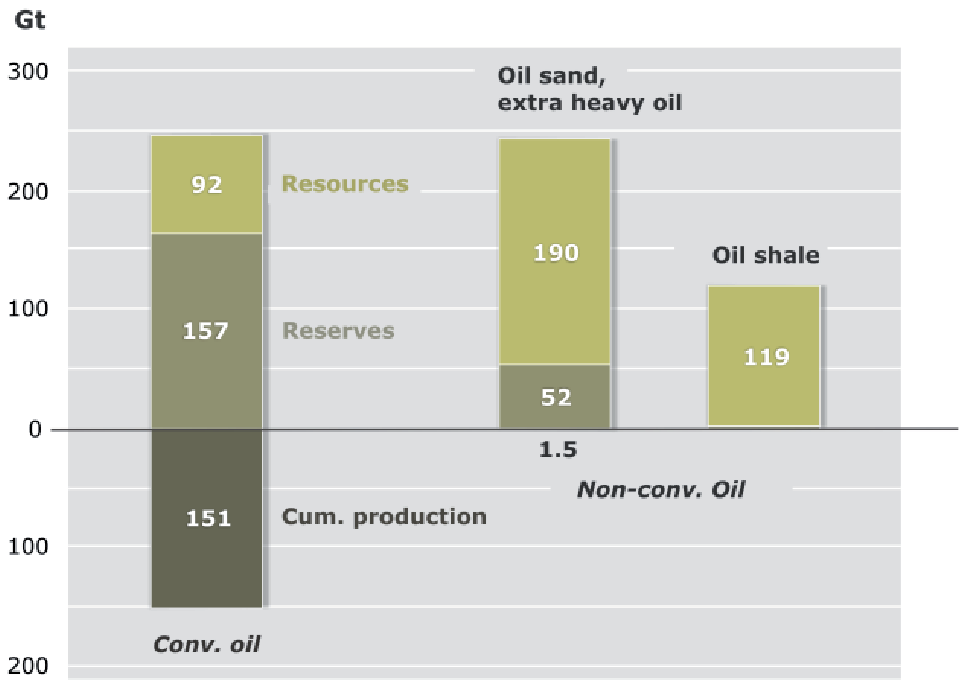


Figure 9.10: Worldwide total potential of conventional oil with reserves, resources and cumulative production as well as oil sands, heavy oil and shale oil for 2007.

giants during the past ten years only corresponds to about the current worldwide annual oil production. Furthermore, as the largest fields are increasingly being exhausted, the burden of oil supply will be focused on the few large fields. These large fields are mainly located in the most important production regions, i.e. the Middle East and Russia. All in all, about 70 % of the conventional oil reserves and also 70 % of the conventional natural gas reserves are located in those regions (Fig. 9.11). This regional concentration of the important reserves will presumable lead to a further progressive world polarization in producing and consuming countries (Chapter 3.2). Because of their strategic importance for the future world supply of energy resources and the political consequences arising from this, this region is called the *strategic ellipse*.

Other parameters that influence the development of the future worldwide production are the production schedules of large oil fields and important producing regions. Limitations can also be experienced as a result of a limited development of fields, for example for ecological reasons, or a limitation of the production quantity, for example in the scope of OPEC production rate quotas to stabilize the oil price.

In summary, the following statements concerning the geological availability of oil and their consequences can be made:

From a geological perspective, the remaining potential of conventional oil is sufficient to safeguard the supply for the next decade even at a moderate increase in oil consumption. The share of oil from the OPEC countries, in particular the Gulf region, which still has significant reserves to expand production capacities, is increasing. The share of unconventional oil will increase in the coming years if oil prices remain at a relatively high level, but will probably not exceed a share of 5 to 10 % of the total production by 2020.

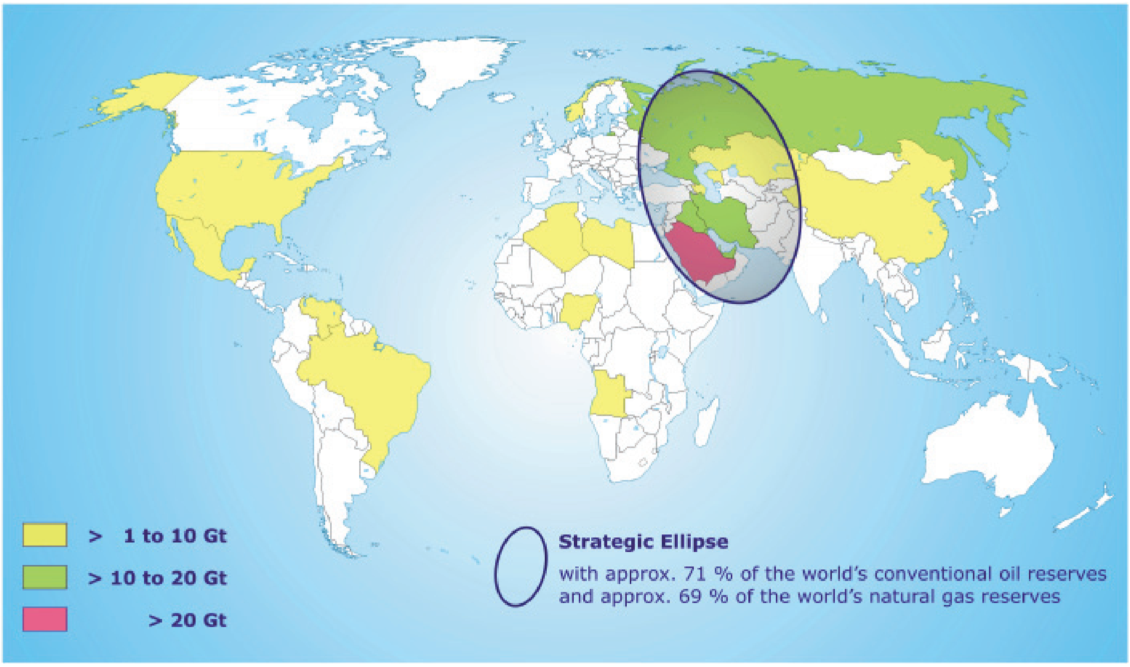


Figure 9.11: Worldwide distribution of countries with more than 1 Gt of conventional oil reserves, and location of the Strategic Ellipse where more than two thirds of the worldwide reserves of conventional oil and natural gas, respectively, are located.

There are many uncertainties which may additionally impact on the availability of oil. For example, the availability of oil may be reduced if OPEC revises their reserves which in a partly politically motivated step had been increased to secure the production quotas in the years 1986/88. On the other hand, the inherent uncertainties when assessing reserves could also contribute to an increased availability. Generally, the reserves figures do not include probable and possible reserves. Even if proven reserves were risk discounted, particularly those in the OPEC, the oil potential would be greater than indicated in this study. Past experience has shown that production prognoses based on the respective current production potential fell short of reality and usually had to be adjusted later. This is where *reserve growth* leads to an increase in the producible quantities beyond the reserves indicated today, in particular because of improved production technologies (Chapter 9.6.3).

Despite these options, it is obvious that in the near future oil production can no longer be increased arbitrarily. In view of the long time periods required for a reorientation in the energy sector, it is therefore necessary to look for alternatives to oil now, and to promote the development of new technologies to that effect.

9.6.2 Future Potential of Oil

In addition to the non-conventional oil resources, there are other options to improve the future oil supply situation. Besides expanding the utilization of technical measures for a more effective oil recovery from oil fields (EOR, Info box 2), a significant additional oil as well as natural gas potential is expected in Arctic frontier areas and in the deep-water areas of the continental margins. This is where oil exploration has started just recently.

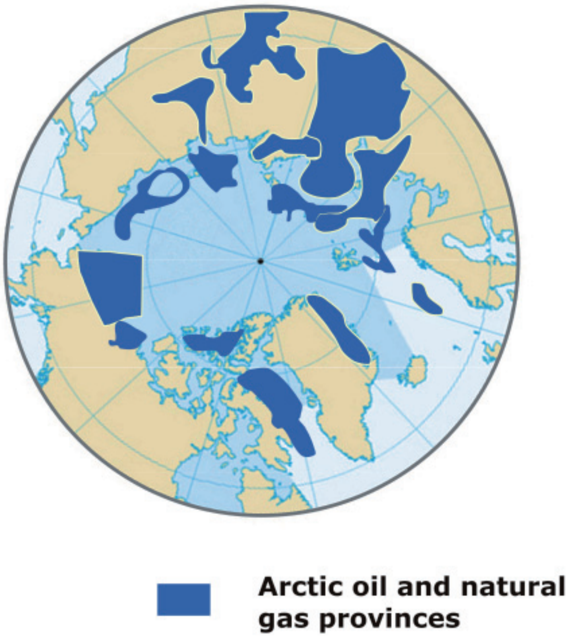
The prospecting and development of oil and natural gas fields in the deep-water area is progressing as quickly as the development of special deep-water technology allows. In this context, deep-water is generally considered the water depth where a normal drilling platform can no longer be used, e.g. about 500 meters. Water depths greater than 1500 meters are generally called *ultra deep water*. The formation of oil and natural gas deposits requires sufficient sediment thickness (greater than 2000 to 3000 meters). These thickness are generally obtained only directly at the continental margins. The large abyssal plains between the continents can be omitted.

However, at a few continental margins the geological conditions are excellent, and only the great water depth has prevented a more effective development of deposits so far. Of special significance are the Atlantic continental margins, with the deep-water areas off the Brazilian coast and at the conjugate Angolan shelf currently being the center of activities. From an oil-geological perspective, the conditions here are exceptionally favorable. An excellent oil host rock in a magnitude of more than 400 meters is located under an enormous salt layer. When the Atlantic first formed, special climatic conditions led to the formation of extended neritic zones, which allowed the deposit of the host rock as lacustrine black shale and the formation of huge carbonates as reservoir rocks. They were subsequently covered with a huge salt layer, which created a very effective sealing horizon for the oil generated afterwards.

In the Santos basin, the national Brazilian oil company Petrobras has already started developing very large fields. At a water depth of about 2000 meters, and under another 4000 meters of rock- and salt layers, the oil and natural gas supplies discovered there were estimated all in all 7 to 15 Gtoe. Because of the great depth and the challenge in deep water, a regular production is not expected until the next decade. However, an experimental production will probably start as early as 2009 in the Tupi field. The cost of development and subsequent production, with drilling ships, half-diving drilling platforms and production systems, is immense. For example, the cost of only one of the seven production systems is estimated to be USD 7 billion.

The deep-water discoveries became feasible and economically attractive only after significant scientific and technological developments. For example, specifically in recent years, the method for imaging geological structures in the underground was improved significantly (Info box 5). This led to a reduction in the drilling risks, the development of new exploration concepts, and a more effective recovery rate of individual fields. A breakthrough in the understanding of deep-water deposit systems was accompanied in particular by the development of the three-dimensional reflection seismics and wide-angle seismic and the resulting possibilities to render previously *non-transparent rock* formations such as salt rock transparent for acoustic methods. This data, in combination with multi-beam echo sounder data, offers deep insights into complex sedimentation systems typical for deep-water areas. Furthermore, drilling and production technologies adapted to the situation in the deep-water area, such as production installations on the ocean floor, *floating production, storage and offloading vessels (FPSO)* and special directional and horizontal drilling methods were and are being developed. In offshore fields, directional drilling is now the usual form of development. In view of the fast-paced technological advancements, the deep water and ultra-deep water regions will be able to supply a huge, still inestimable oil potential as well as natural gas potential in the future. However, because of the required technological effort, the production costs for energy resources from deep-water regions will definitely be higher than for most of the conventional deposits.

The Arctic is considered the most important frontier area for the exploration of oil and gas. The prospective sediment basins run in particular along the gigantic shelf areas of the polar sea and along the north shores of the North American and the Eurasian continent (Fig. 9.12). On the Eurasian landmass, a few onshore sediment basins are also counted among the arctic provinces. The West Siberian basin deserves particular attention; its northern part is known as the largest natural gas province worldwide, and its southern part has been Russia's most productive oil producing region for decades. Western Siberia is also Germany's main supplier of natural gas. About a third of the natural gas consumed in Germany comes from that region. The exploration of the arctic sediment basins in the European northern part of Russia – Kara Sea, Timan-Petschora basin and Barents Sea – has also made significant progress. In addition to the reserves already verified, a significant potential can be expected in particular for natural gas, but also for oil. For example, the giant Shtokman field in the northern Barents Sea will probably start production in a few years.



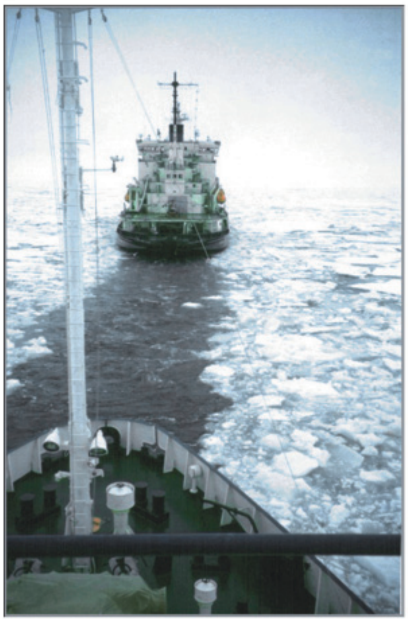


Figure 9.12: Left: Arctic gas and oil provinces (as per USGS data); right: research ship accompanied by icebreaker conducting seismic exploration of the Siberian Laptev Sea by the BGR.

The farther the prospective arctic regions are located from the huge consumer centers in Europe, Asia and North America, the less they have been explored. For example, far regions of the Siberian coast in the Asian north of Russia have been barely examined for oil from a geological aspect so far. In a first estimate of the presumable occurrence of oil and natural gas in the entire Arctic region north of the polar circle, the USGS (2008) specifically pointed out that the Arctic, in particular the offshore region, is largely unexplored from the aspect of hydrocarbon exploration. The estimates in the study are based largely on analogies to known, geologically comparable oil provinces, and have not been verified by concrete findings. Therefore, the degree of certainty of these statements is low. Furthermore, this assessment of the Arctic does not include any prognosis as to how many of the potentially existing resources can in fact be discovered and produced. Overall, the mean statistical prediction for the Arctic is about 12 Gt oil and 47 billion m^3 of natural gas. This corresponds to about 30 % of the natural gas resources and 13 % of the oil resources. Together with natural gas, it is assumed that there are economically substantial quantities of condensate (NGL) in the Arctic. The greatest part of the arctic oil and natural gas resources by far, e.g. 84 %, is assumed to be under the Arctic Ocean.

BGR is performing geological research work in various arctic regions. This research allows an independent assessment of individual provinces, which essentially corresponds to the USGS assessment for the western arctic region and the western Barents Sea. However, BGR data cast doubt on the USGS statement that the deep ocean basins of the Eurasian basin and the central arctic basin as well as the sunken continental fragment of the Lomonosov ridge are more promising rich yields than, for example, the continental shelves of the East Siberian Sea or the Chukchi Sea. With the deep water basins, only their outermost regions, e.g. the shelf regions, are potential hydrocarbon provinces. According to current data, the sediment coverage of the Lomonosov ridge is barely sufficient to form hydrocarbon. However, because of their geological structure, the Russian marginal seas, and in particular the East Siberian Sea, are indeed considered promising provinces.

Overall, however, it remains questionable to what extent and when the arctic oil and natural gas provinces, which lack infrastructure, and in particular those primarily considered as having natural gas potential, will start producing. The extreme environmental conditions, e.g. cold, pack ice and drift ice during most of the year, represent a tremendous challenge for the drilling, production, processing and transportation technology. Ice drifts, icebergs and the weather-conditioned freezing of technical facilities would require a great effort, or even make it impossible to use floating facilities, or facilities that are firmly mounted at the water surface. One way to avoid these problems would be to assemble production facilities on the ocean floor, as it is practiced on the Snøhvit field in the Norwegian Barents Sea. However, in large parts of the arctic shelf such installations are also at risk of being destroyed by icebergs. Because of the long distances to the consumer centers, transport infrastructure must be provided as well. With natural gas, this would most likely mean transport as LNG. Russia's planning also includes considerations of using the Northeast Passage to develop the arctic oil and natural gas fields. This ambition would be made easier by the potential receding of the polar ocean ice.

Much development work is needed to meet these technical challenges. Because of the high technological effort, the IEA estimates the production cost of arctic oil at up to USD 100 per barrel (IEA, 2008). Investments for the development of faraway arctic regions would therefore be made only if the price level for oil remains high over an extended period of time. However, if arctic oil is supposed to close a future supply gap, investments to that effect must be made well in advance.

9.6.3 The Future Development of Oil Production

Chapter 9.1.3 describes the relationship between the state of production and the known energy supply. It is found that the estimate of the total oil-potential is more certain, than the estimate of the remaining fossil energy sources. Under these conditions, it is possible to examine prospective developments of oil production using a mass balance of the resources, reserves and cumulative production.

This approach can circumvent two difficulties of previous oil production development models: By avoiding the peak oil premise, the model is not fixed primarily on a short-term production maximum. Furthermore, concentrating on supply-specific variables and the historic production schedule does not take into account direct economic variables such as the development of global demand. Thus, the resulting projection will be independent of the development of the global economy, but it can also be interpreted in the light of the expected economic developments.

The principal plan of action is a continuous transformation of resources into reserves, and the production of oil from the reserves on a corresponding annual basis. In doing so, reserves and resources are based on the data of the present study. The respective transitions are neither forced nor fixed, but rather result from taking parameters into consideration, which have characterized the oil production system and the supply dynamics in the past decades. For example, the ratio between known supply and current annual production (Chapter 9.1.1) of conventional oil without condensate, which is known as *static reach*, has been fixed at 38 years for the projection, according to the known development of this parameter (Fig. 9.1). From a geo-scientific perspective, a ratio of 38 years indicates that the production schedule is at an optimum if 1/38th of the available minable reserves are produced annually. The projection defines the value as the optimal production ratio from the current point of view taking into account technical and economical aspects. This limits the projection to the current framework conditions in an open global market where oil companies can develop and then produce the reserves required to meet the demand. Other parameters defined in this sense are the transition from resources to reserves and reserve growth.

The process of reserve growth describes the observation that reserves of developed deposits grow during the course of the production history. The reason for this is the reassessment of the deposits, which either categorizes more oil in the reservoirs as extractable or locates new oil reserves for production in the deposit, based on better and more efficient exploration and production technology. This process becomes apparent in a comparison of the course of annual global oil production and the new reserves reported by new discoveries of deposits. Fig. 9.13 shows the discoveries of new fields between 1945 and 1994 and their backdated annual initial reserves (Robelius, 2007). The reserve growth and other revisions were backdated to the year the deposit was discovered. Only the reserves from new discoveries were attributed to the current year. Whereas annual production increases to date, with brief interruptions, reports of new discoveries have been decreasing since the 1960s. A comparison of this timeline and the annual production, which is also shown in Fig. 9.13, suggests that since the 1980s, more oil has been consumed than has been discovered. In fact, though, the reserves have also grown to date.

This apparent contradiction is resolved in the comparison of cumulative reserve figures backdated to various years (Fig. 9.14), which makes clear that in the reassessment, oil discoveries even from less than recent years are being corrected upward annually. If one wants to analyze the development of the initial reserves according to this differentiated method, a new curve would have to be added to the family of curves in Fig. 9.14 for each annual revision. The USGS (2000) stated a total value of 46.1 Gt oil for the future expected reserve growth. Until 2003, half of this had already been realized with 23 Gt (Klett el al., (2005).

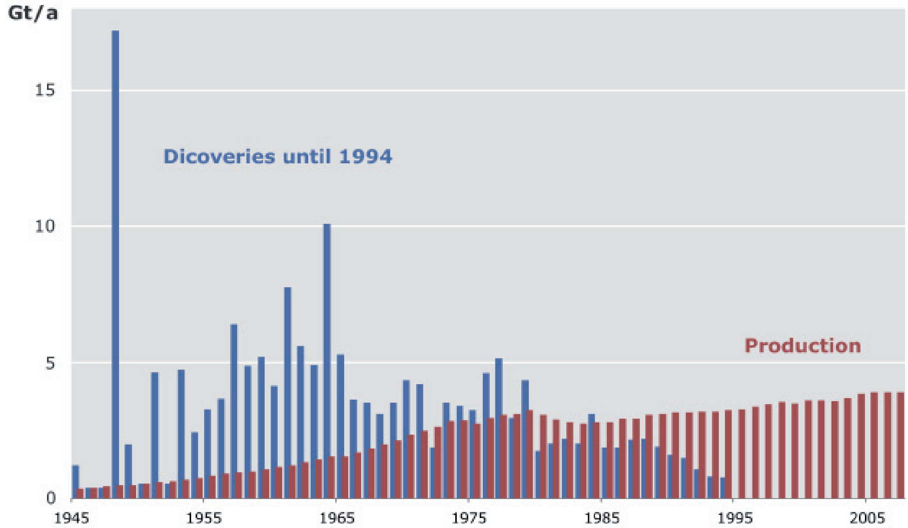


Figure 9.13: Annual production and reserves of new oil discoveries, backdated to the year the fields were discovered (BGR data base; Robelius, 2007).

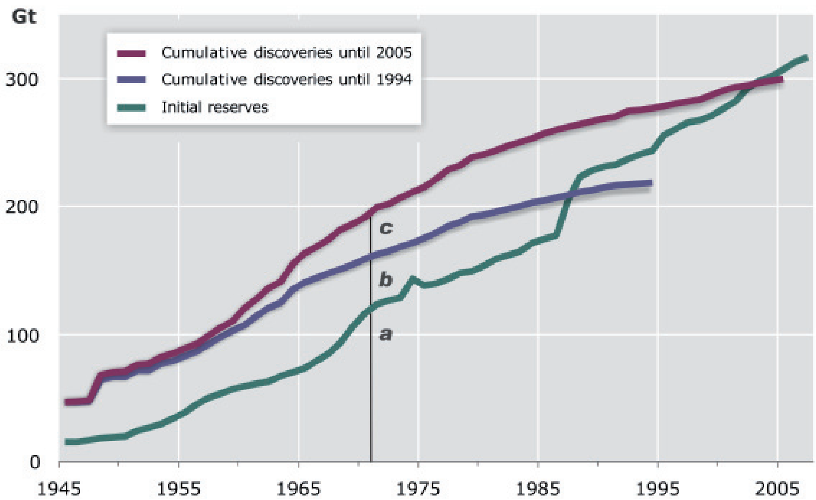


Figure 9.14: Comparison of the initial cumulated reserve figures for oil up to 2007 (green) and the backdated reserve figures as known in 2005 (red) and 1994 (blue); data from (Robelius, 2007). Example: In 1971, the initial reserves were 123 Gt (a). By 1994, this estimate was corrected to 163 Gt because of the reserve growth of the deposits discovered before 1971 (b); in 1995, these deposits were again revised to 200 Gt (c).

Thus, reserve figures are always only snapshots that by definition change over time. This means that by themselves, they are not suitable to establish prognoses for future production. This is where the total potential must be applied as the ultimate producible quantity. The partial quantities of the total potential – reserves, resources and cumulative production – develop dynamically over the life cycle of the oil energy resource.

Based on the chosen approach, the following projection can indicate how production may develop when adhering to previous dynamics, but not what it will ultimately indeed look like. This limitation is important as in the past the oil market has repeatedly been subject to drastic changes that could not even have been foreseen with the help of this projection. These changes are obvious from the historical oil production schedule. Three ages can be distinguished: The age of international oil companies and an accelerated increase in production, the OPEC age during times of oil crises and repeated drops in global production, and the current age of globalization with a nearly linear increase (Fig. 9.15). Each of these ages is subject to specific framework conditions; the changes in these conditions cannot be captured in the projection. The projection is based on laws derivable from the current globalization age.

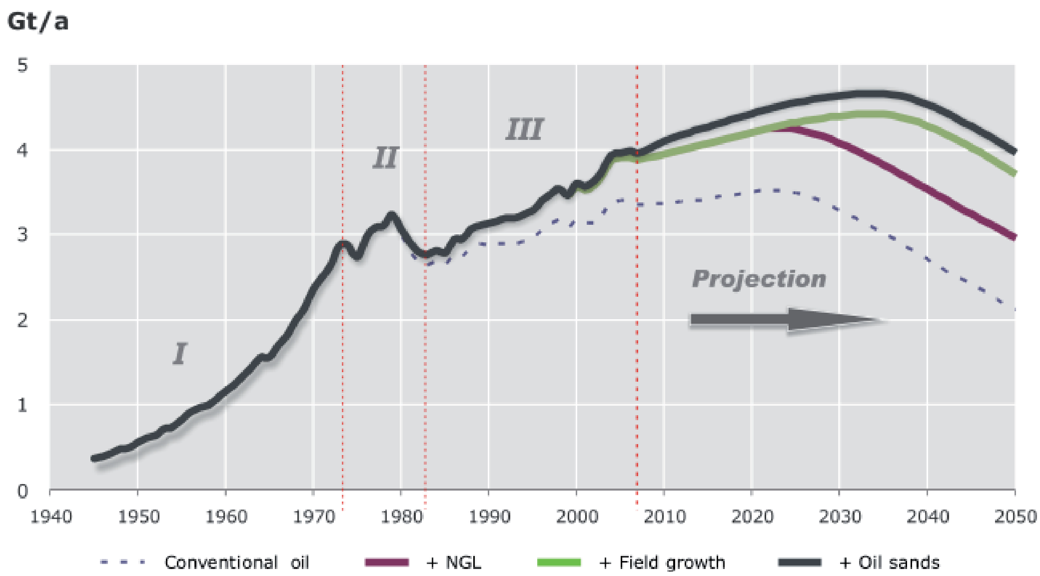


Figure 9.15: Historic development of oil production and projected production schedule for conventional oil with and without condensate (NGL) and with condensate and oil sands, taking into account reserve growth (field growth). Shown ages of historical oil production: Age of international oil companies (I); OPEC age (II); age of globalization (III).

Overall, the projection essentially confirms the previous statement based on the current supply data, e.g. that for conventional oil, a production maximum can be expected by 2020 (BGR 2008). After that, an increase of production is not possible from the currently known supply beyond 2023 under the given framework conditions (Fig. 1.3). Taking into account reserve growth, a growing share of condensate in oil production resulting from the expected increase of natural gas production, and the development of the production of oil from oil sands and heavy oils (Chapter 3.3), the picture changes: The reserve growth moves maximum oil production into the years between 2030 and 2035 (Fig. 9.15). This means that the reserve growth has the potential of increasing oil production by ten to fifteen more years.

The influence of the increase of condensate production and oil production from oil sands, on the other hand, has barely any influence on the projected timeline of maximum oil production. However, the potential growth rates of oil production according to the projection are increased significantly by condensate (NGL) and the use of oil sand. Without condensate and oil sands, the projection only reaches maximum annual production rates of about 3.6 Gt. Condensate already accounts for more than 500 Mt of the annual oil production. This share will increase even further with the expected growth of natural gas production. According to the projection, a share of 800 Mt of condensate in the annual oil production is possible by 2030. With the expected increase in condensate production, maximum oil production could be increased to about 4.4 Gt. When additionally taking oil from oil sand into account, the projection reaches a maximum production of about 4.7 Gt (Fig. 9.15).

The projection does not allow any statement on the development of oil prices because oil prices essentially depend on economic developments and less on the supply situation. As described above, the results of the projection are also subject to the provisions that arise from the defined framework conditions. Actual development of oil production may already deviate clearly from the projected course in the next few years if the lesser increase in demand resulting from the global economic crisis becomes noticeable. Furthermore, the projection assumes that the progress made in technological developments will be able to master the more difficult problems in exploration and production of oil. Likewise, the conditions for making the necessary investments in research, development, production and infrastructure in a timely manner must be met. If significant drops are experienced in that area compared to previous years, the projected production schedule for oil will not be realized.

Overall, the projection results in a maximum possible oil production schedule as it might develop at realistic assumptions from the current perspective. All conceivable changes in the oil market indicated above would mean that the projection falls short.

9.7 Energy Resources 2030, 2050

The data on the supply and availability situation of energy resources provided in this study and the projection for future oil production (Chapter 9.6.3) allow a few statements about trends for the coming decades, which have been summarized below for the horizons 2030 and 2050.

2030

If energy prices remain at a sufficiently high level, the use of **geothermal energy** will probably have multiplied by 2030. The result of current pilot projects on the wider use of deep geothermal energy, for example with single borehole methods and HDR technology, will be an important factor in the development of geothermal energy.

For the **nuclear fuel**, no bottlenecks are expected with respect to geological availability until 2030. Political decisions about if and to which extent nuclear energy may contribute to the energy supply in future will have a far greater influence than the geological availability of the fuel. With an expansion in the worldwide use of nuclear energy, new reactor types will make more efficient use of the nuclear fuel by 2030. Thorium might also start being used in that case.

For **coal**, the IEA reference scenario (IEA, 2008) assumes an annual increase in demand of 2% on average, from approx. 5 billion tons of coal equivalent units in 2007 to 7 to 7.3 billion tons of coal equivalent units in 2030. These growth rates would not lead to any limitations in geological availability for either soft brown coal or hard coal in the coming decades. It is apparent that the results of the current pilot projects on CCS (Information Box 7) will have an influence on the future use of coal. If the price level for oil is sufficiently high in the coming years, it is also likely that a few large-scale projects on coal hydrogenation (Info Box 8) will be implemented. Then coal would be used as a substitute for oil, although to a low extent from a global perspective.

For **natural gas**, there are also no obvious bottlenecks until 2030, even with increased demand. It remains to be seen how the concentration of the natural gas reserves in the *strategic ellipse* will lead to noticeable consequences as early as 2030. Until then, the results of the current research and development programs, which are focused on a production of natural gas from the huge offshore deposits of gas hydrate, will be an important milestone for the development of the natural gas production until 2030. If this work is successful and energy prices are high enough to permit the necessary investments to develop this resource, natural gas production from gas hydrate could already have started by 2030.

Whether **oil** production can be increased until 2030 at the rates of the past 20 years depends on a number of factors that are not based on geological availability. According to the results of the projections in the present study, such an increase is possible until 2030 with an optimal utilization of the supply, including unconventional deposits, under current market conditions. The resulting maximum annual oil production for 2030 is about 4.6 Gt. However, this projection must be categorized as optimistic because many influential factors could cause the development described in the projection to fall short. With a look at 2030, it is therefore likely that even despite the measures for the substitution of oil, which are already underway, there will be a noticeable physical shortage. An annual production in 2030 that is higher than the annual production shown in the prognosis would be possible, for example, if the oil industry were to make drastic and disproportionate increases in the reserve base in the coming decades. This would require enormous investments in projects that are currently not foreseeable.

2050

Statements founded on the availability of geothermal energy, nuclear fuels, coal and natural gas for 2050 beyond the statements made for 2030 are not possible on the basis of the supply data on hand and the predictable developments.

However, for **oil**, there is no possibility of an increase by 2050 (Fig. 9.15), according to current knowledge. What is possible and likely is a peak demand clearly before 2050 for the substitution of oil. This means that the main burden of the current load of the world's energy supply must be redistributed from oil to other energy carriers. In this new energy mix, economically sensible regenerative energies should play an important role. Most likely, oil will be produced nevertheless far beyond the year 2050 for specific applications and in particular for the chemical industry.

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A

AAPG	American Association of Petroleum Geologists
af	ash-free
Anticline	rocklayers folded in the shape of an arch, slopes moving downwards on all sides.
°API	unit of measure for the gravity of liquid hydrocarbons, low grades correspond to heavy oil (American Petroleum Institute).
Aquifer	an underground zone of permeable rock saturated with water under pressure.
Aquifer gas	natural gas dissolved in formation water
assoc. gas	associated natural gas; natural gas occurring in connection with oil accumulations in the same reservoir. This gas may be dissolved in the oil under reservoir conditions (solution gas) or may form a cap of free gas above the oil in the reservoir (gas cap gas).
Authigenic	name for rocks whose components originated at the site (e.g. from magma).

B

Biogenic	produced by living organisms
BSR	Bottom Simulating Reflector. Seismic reflector indicating the lower edge of the stability zone of the gas hydrate
BTL	biomass to liquid. Synthetic fuel produced from biomass.
Btu	British thermal unit. The amount of heat required to rise the temperature of one pound of water by one degree Fahrenheit. (1 million Btu = about 28 m^3 of natural gas) → *cf. Units of measurement*

C

CBM	coalbed methane. Natural gas (methane) found in coal seams.
C/H	carbon to hydrogen ratio.
cif	cost, insurance, freight. Usual transportation clause in the overseas trade, when the seller bears the costs of the delivery, the insurance and the freight up to the port of destination in addition to the fob-clause (s. below).

CIS	Commonwealth of Independent States. → *cf. groups of countries*
Clean gas	natural gas with a standardized heat value of 9.7692 kWh/Nm³ (valid in Germany: Reingas).
Coalification	conversion of organic raw material due to an increase in temperature in the course of geological periods.
Condensate	mixture of light hydrocarbons that are gaseous under reservoir conditions and liquid under conditions at the surface (condensed), which are produced together with natural gas (density: > 45°API or < 0.80 g/cm³).
Continental shelf	zone, adjacent to the shoreline of a continent, that extends from the lower water line to the continental slope (app. 200 m water depth).
Continental slope	the marine areas adjacent to the shelf with water depths down to more than 2000 m (in some cases).
Conventional oil	crude oil capable of flowing, >20°API.
CTL	coal to liquid. Production of synthetic fuel from syngas using Fischer-Tropsch process.
Cumulative production	amount of fuels produced since the start of production

D

depletion mid-point	time at which half of the estimated ultimate recovery (EUR) has been produced.
Depletion rate	rate of reduction of initial reserves (percentage thereof).
Discordance	angled or irregular adjoining rock layers; e.g. reservoir rock can be cut by an impermeable layer.
DOE	Department of Energy of the USA.
Downstream	activities beyond the wellhead such as treatment, transportation, processing, supply.
Dry gas	natural gas containing few or no hydrocarbons other than methane.

E

EAR	estimated additional resources; deposits, which are not reserves. Nomenclature of the NEA/IAEA-task force "Uranium, Resources, Production, and Demand". → *cf. Uranium*

Efficiency is the ratio of power output to power input. Is used in the area of energy conversion and energy transmission, respectively.

Enriched uranium uranium, for which the percentage rate of the fissionable isotope U-235 has been increased above the percentage of 0.7205 % in the natural uranium. Nuclear reactors use degrees of enrichment between 3 % and 4 % U-235.

Enthalpy state variable of ideal gases, [J]; measure of the technical work, which a given amount of gas can perform; J depends on the temperature and pressure.

EOR enhanced oil recovery; process for improving the natural degree of oil recovery of a petroleum deposit, secondary and tertiary production processes.

EU European Union (EU-27).
→ *cf. Economic policy divisions*

EUR estimated ultimate recovery. The sum of cumulative production, reserves and resources. see: *BGR Definition of Reserves and Resources*

Exploration the search for reservoirs of a natural resource in the earth's crust, including prospecting, geophysical and geological surveys and drilling of wildcats.

Extraction costs costs of the mining extraction and treatment up to the finished product (yellow cake).
→ *cf. Uranium*

F

Field growth increase/growth of the reserves in an oil or gas field due to increased recoverability, e.g. new drilling results.

fob free on board. The price of a product actually charged when loaded onto a ship at the port of loading. From this point onwards, the purchaser is responsible for the goods.

FPSO floating production, storage and offloading units. FPSO's are vessels for exploiting offshore oil fields.

Frac artificially created crack starting at a borehole, for increasing permeability and thus stimulating production.

Frontier area area, in which little exploration work has been conducted up to now for instance for climatic or logistic-geographic reasons.

FRS financial reporting system. System of the EIA, comprising about 30 US-based oil companies, which provide data of their global operations.

G

Gas hydrate solid compounds formed under certain pressure and temperature conditions (even above 0 °C) from water and methane.

GECF Gas Exporting Countries Forum. Association of fifteen countries exporting natural gas (cf. Info box 4).

Giant, Supergiant Megagiant categories of hydrocarbon fields according to their size; with reserves greater than 500, 5000 and 50 000 Mb (68, 680, 6800 Mt) respectively for petroleum and greater than 3, 30 and 300 tcf (85, 850, 8500 Bcm) respectively for natural gas.

Ground water that part of the underground water, which is located in the water-saturated (waterlogged) zone. It is separated from the capillary fringe by the phreatic surface. The phreatic zone reaches down into the crust areas, in which virtually no connected network of fissures and pores exists any more.

GTL gas to liquid. Production of synthetic fuel from natural gas using different processes, amongst others Fischer-Tropsch.

H

Hard coal anthracite, bituminous coal and hard brown coal; calorific value >6,500 kJ/kg.

Hydrocarbons (HC) chemical compounds of carbon and hydrogen, in which small amounts of other elements (e.g. sulfur, nitrogen, oxygen, metals) can be bonded chemically. Hydrocarbons exist as solids, liquids or gases, which are petroleum, condensate and natural gas.

higher-order HC: HC with more than one carbon atom.

HDR-process Hot-Dry-Rock process. In rocks with very low hydraulic permeability and temperatures of > app. 150 °C, flow-paths in hydraulically generated cracks between deep boreholes are produced, which serve as heat exchangers. Heat energy is extracted from the circulating water.

Heat capacity measure for the heat storage capacity of a material; [J/(K • kg)]; symbol: c.

Heat flow amount of heat that flows per unit of time through an area of one square meter in the earth's crust; [J/s • m²] = [W/m²]; symbol: q.

Heat flow density amount of heat flowing through an area of 1 m² per second, [W/m²]; (0.001 W/m² = 1 mW/m²); symbol: q

Heat pump technical system, which draws heat from a heat store of low temperature and moves it to a heat store of higher temperature.

HEU	highly enriched uranium (> 90 % U-235), mainly used for military purposes.
High temperature deposit	geothermal deposit with a temperature > app. 150 °C.
hydrostatic	corresponding to the pressure of the head of water above
Hydrothermal high enthalpy deposit	vapor or hot water occurrences with a temperature > 150 °C. → *cf. Geothermal energy*
Hydrothermal low enthalpy deposit	hot or warm water deposits with a temperature < 150 °C. → *cf. Geothermal energy*

I

IAEA	International Atomic Energy Agency; UN-authority based in: Vienna (= Internationale Atomenergie Organisation, IAEO). → *cf. Economic policy divisions and uranium*
IEA	International Energy Agency; intergovernmental organization established by the OECD, based in Paris.
IGU	International Gas Union.
In place	total amount of a fuel accumulated in a deposit.
In-situ	at the site. Located in the reservoir; but also designation of a response or of a process at the place of origin, also used as a synonym for *in place*.
IOC	International Oil Companies, e.g. supermajors: Chevron Corp., ExxonMobil Corp., BP plc, Royal Dutch plc, Total.
IOR	improved oil recovery. Process for improving the recovery rate of a petroleum deposit (more comprehensive than EOR), comprises amongst others additional stimulation measures, reservoir management, cost reduction.

J

J	Joule. Unit of measurement for Energy. → *cf. Unit of measurement*

K

Kalina-process	mechanical power generation by evaporation of an ammonia-water mix. → *cf. Geothermal energy*

kcal	Kilocalories → *cf. Unit of measurement*
kJ	Kilojoule → *cf. Unit of measurement*

L

lb	Pound (1 lb = 453.59 g).
Licence	permission provided to a company for exploration and/or production purposes for a certain time.
Licence area	area provided to a corporation for exploration and/or production purposes for a certain time.
Lignite	brown coal; calorific value < 16,500 kJ/kg
lithostatic	corresponding to the pressure of the rock layers located above.
LNG	liquefied natural gas. Natural gas that has been liquefied for transport; 1 t of LNG contains about 1400 Nm^3 natural gas, 1 m^3 of LNG weighs about 0.42 t).
Low temperature deposit	geothermal deposit with a temperature of < app. 150 °C.
LPG	liquefied petroleum gas. Propane, butane or a mixture of both which has been liquefied by reducing the temperature, increasing the pressure (< 25 bar) or a combination of both.

M

Methane	simplest hydrocarbon, first member in the alkane series (CH_4).
Migration	underground process in the course of the generation of hydrocarbons, during which petroleum and natural gas migrate from the source rock to the reservoir rock.
Mineral oil	petroleum and petroleum products manufactured in refineries.
MOX	mixed oxide; enriched uranium oxide with plutonium oxide; used as nuclear fuel.
MW_e	electrical power in MW.
MW_{th}	thermal power in MW.

N

NAFTA	North American Free Trade Association. → *cf. Economic policy divisions*

Natural gas	gas produced from an underground reservoir. Mixture of gaseous hydrocarbons; may also contain varying amounts of other gases. **conventional:** free natural gas and associated gas. **unconventional:** natural gas in shale beds, tight reservoirs, coalbed methane, aquifer gas and gas hydrates.
Natural uranium (U_{nat})	uranium with natural isotopic composition, a mixture of U-238 (99.2739 %), U-235 (0.7205 %) and U-234 (0.0056 %).
NEA	Nuclear Energy Agency; linked with OECD, based in: Paris. → *cf. Uranium*
NGL	natural gas liquids; those hydrocarbons, which are gaseous under reservoir conditions and are extracted in liquid form when produced. Typically ethane, propane, butane and pentane will be the predominant components (no common definition available).
NOC	National Oil Companies; largely state-owned oil companies, e.g. Saudi Aramco, Petrobras, China National Petroleum Company.

O

OECD	Organization for Economic Cooperation and Development based in: Paris. → *cf. Economic policy divisions*
OGJ	Oil & Gas Journal (periodical).
OPEC	Organization of Petroleum Exporting Countries; based in: Vienna. → *cf. Economic policy divisions*
ORC plant	Organic-Rankine-Cycle plant/system; power generators, whose turbines are powered by (organic) substances with low boiling temperature.

P

Permeability	the capability of a rock to allow the flow of liquids or gases in the presence of a pressure difference. Unit of measure: Darcy [D] and Millidarcy [mD], respectively [$m^2 = 10^{12}$ Darcy]; symbol: k.
Plutonium	fission product of the nuclear chain reaction; made from U-238, by neutron capture Pu-239 is formed.
Porosity	the ratio of the pore volume to the total volume of a solid rock in the formation; unit: percent [%].

Potential **technical potential:** amount of heat of a geothermal type of deposit in a certain area extractible per year in consideration of all technical restrictions.
→ *cf. Geothermal energy*

theoretical potential: amount of heat of a geothermal type of deposit in a certain area available per year.
→ *cf. Geothermal energy*

Pour point temperature, at which a liquid (in this case: petroleum) reaches a viscosity that just prevents it from flowing.

Primary energy, use of direct usage of the geothermal energy (e.g. for heating purposes, i.e. no conversion into electrical energy).

Primary energy consumption refers to the amount of energy required in total for the supply of a national economy.

PSC production sharing contract or agreement (PSA); contract between a country and an oil/gas company, which divides the produced amount of petroleum or natural gas according to a certain ratio.

R

RAR reasonably assured resources; in the lowest cost class: reserves, otherwise resources (cf. EAR).
→ *cf. Uranium*

Raw gas untreated natural gas produced from a reservoir.

Recovery efficiency the recoverable amount of original hydrocarbons in place in a reservoir, expressed as a percentage of total HC in place.

Recycled uranium uranium that was not consumed after employment in the nuclear reactor; return to fuel elements.

Remaining potential sum of reserves and resources. see: *BGR Definition of Reserves and Resources*

Reserves proved amounts of an energy resource in a deposit, at today's prices economically extractible, using the current state-of the art technology. Original reserves: cumulative production plus remaining reserves. see: *BGR Definition of Reserves and Resources*

reserve growth (or field growth) increase in reserves in an oil or gas field resulting from the use of enhanced production methods and improved knowledge of the deposit.

R/P ratio reserves to production ratio: ratio of reserves and last year's production.

Reservoir rock porous and permeable rock (e.g. sandstone, limestone), in the pore space of which liquids (petroleum, water) or gases (natural gas) are present.

Resources proved amounts of an energy resource in a deposit that cannot be recovered at current prices with current technology but might be recoverable in the future, as well as quantities that are geologically possible but not yet proven. see: BGR Definition of Reserves and Resources

Royalties are the best-known and most frequent dues in the extractive industry. Royalties are usually levied as percentage rate of the market value of the produced crude oil or natural gas.

S

scf standard cubic foot/feet.

Source rock rock with high proportion of organic material from which curde oil and/or natural gas can be generated.

SPE Society of Petroleum Engineers.

Spot market a regional market (e.g. for Northern Europe: Rotterdam), where mineral oil products and crude oil are traded on a short-term basis.

Stimulation improvement of the production characteristics of a borehole by technical measures.

Surface fees a state can demand payment of the so-called surface fees proportional the surface of a petroleum field. There are surface fees for exploration areas (exploration surface fees) and for production areas (exploitation surface fees).

swing producer producer of a natural resource, who can compensate fluctuations in demands due to its large production capacity.

T

tce tons of coal equivalent (~29.308 GJ = 7 Gcal).

Temperature degree Kelvin (absolute temperature), [K];
T [K] = T [°C] + 273.2; symbol: T.

toe ton(s) of oil equivalent (app. 1.428 tce).

TPES total primary energy supply; equivalent to total primary energy demand. This represents domestic demand only and, except for world energy demand, excludes international marine bunkers.

Transmissibility measure for the hydraulic permeability of a layer of rocks;
1 $m^3 \cong$ 1012 Darcy m; symbol : T.

U

UAE United Arab Emirates.
→ *cf. Groups of countries*

Unconventional oil Oil not capable of flowing in the deposit. API degree < 10°, very heavy oil, crude oil of oil sand (bitumen, asphalt), or shale oil from oil shale.

UN-ECE United Nations Economic Commission for Europe, based in: Geneva.

upstream searching for and recovering and production of hydrocarbons up to the wellhead: exploration, development, production.

upgrading improvement in quality, increase of the API-Grade (extraction of unconventional petroleum).

USGS United States Geological Survey.

V

Vertical temperature gradient change of the temperature with depth; [K/m] or [°C/m]; symbol: dT/dz.

W

waf water and ash free.

WEC World Energy Council; based in; London
also used for: World Energy Conference

WGC World Gas Conference

WPC World Petroleum Congress

Regional Definitions and Country Groupings

Regional division of the countries of the world

Europe

Albania, Andorra, Belgium, Bosnia-Herzegovina, Bulgaria, Cyprus, Czech Republic, Denmark, Germany, Estonia, Faroe Islands (Denmark), Finland, France, Gibraltar (GB), Greece, Great Britain, Hungary, Ireland, Iceland, Isle of Man (GB), Italy, Channel Islands (GB), Croatia, Latvia, Liechtenstein, Lithuania, Luxemburg, Malta, Macedonia, Monaco, Montenegro, Netherlands, Norway, Austria, Poland, Portugal, Romania, San Marino, Sweden, Switzerland, Serbia, Slovakia, Slovenia, Spain, Turkey, Vatican City

CIS (Commonwealth of Independent States; 12 countries)

Armenia, Azerbaijan, Georgian Republic, Kazakhstan, Kyrgyzstan, Moldova, Russia (Russian Federation), Tadzhikistan, Turkmenistan, Ukraine, Uzbekistan, Belarus

Africa

Algeria, Angola (incl. Cabinda), Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, Central African Republic, Chad, Comoros, Congo (Democratic Republic, formerly Zaire), Congo (Republic), Côte d´Ivoire (Ivory Coast), Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Mayotte/Maore, Morocco, Mozambique, Namibia, Niger, Nigeria, Rwanda, Sao Tome & Principe, Senegal, Seychelles, Sierra Leone, Somalia, St. Helena (GB), South Africa, Sudan, Swaziland, Tanzania, Togo, Tunisia, Uganda, Western Sahara (Democratic Arab Republic), Zambia, Zimbabwe

Middle East

Bahrain, Iraq, Iran, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, United Arab Emirates, Yemen

Regional Definitions and Country Groupings

Regional division of the countries of the world - continued

Austral-Asia

Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia, China (Republic; also: Taiwan), China PR (People's Republic), India, Indonesia, Japan, Korea (Democratic People's Republic; also: North Korea), Korea (Republic; also: South Korea), Laos, Malaysia, Maldives Islands, Mongolia, Myanmar, Nepal, New Caledonia, Pakistan, Papua New Guinea, Philippines, Singapore, Sri Lanka, Thailand, Vietnam

Australia, Belau (of Palau Ils. (USA), Cook Islands (New Zealand), Fiji, French Polynesia, Guam (USA), Kiribati (Gilbert Islands), Marshall Islands, Micronesia, Nauru, New Caledonia, New Zealand, Norfolk Island (Australia), Northern Marianas, Palau, Pacific Islands (USA), Pitcairn Island (GB), Ryukyu Islands, Solomon Islands, Samoa (Western Samoa), Samoa (USA), Tokelau Islands (New Zealand), Tonga, Tuvalu (Ellice Island), Vanuatu (New Hebrides), Wallis & Futuna (France)

North America

Canada, Greenland, Mexico, USA

Central and South America (Latin America without Mexico)

Anguilla, Antigua & Barbuda, Argentine, Bahamas, Barbados, Belize, Bermudas, Bolivia, Brazil, Caiman Islands, Chile, Costa Rica, Dominica, Dominican Republic, Ecuador, El Salvador, Falkland Islands (GB), French Guyana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Colombia, Cuba, Martinique, Montserrat, Nicaragua, Netherlands Antilles, Panama, Paraguay, Peru, Puerto Rico (USA), St. Kitts & Nevis, St. Lucia, St. Pierre & Miquelon, St. Vincent & the Grenadines, Suriname, Trinidad & Tobago, Turks & Caicos Islands, Uruguay, Venezuela, Virgin Islands (GB), Virgin Islands (USA)

Regional Definitions and Country Groupings

Economic groupings

European Union (EU-27)

Austria, Belgium, Bulgaria[2], Cyprus[1], Czech Republic[1], Denmark, Estonia[1] , Finland, France, Germany, Greece, Great Britain, Hungary[1], Ireland, Italy, Latvia[1], Lithuania[1], Luxemburg, Malta[1], Netherlands, Poland[1], Portugal, Romania[2], Sweden, Slovakia[1], Slovenia[1], Spain

IAEA (International Atomic Energy Agency; 129 countries)

Afghanistan, Albania, Algeria, Angola, Argentine, Armenia, Australia, Austria, Bangladesh, Belgium, Benin, Bolivia, Bosnia-Herzegovina, Brazil, Bulgaria, Burkina Faso, Byelorussia, Cambodia, Cameroon, Canada, Chile, China, Colombia, Congo, Costa Rica, Croatia, Cuba, Cyprus, Czech Republic, Denmark, Dominican Republic, Egypt, Ethiopia, Germany, Ecuador, El Salvador, Estonia, Finland, France, Gabon, Georgian Republic, Ghana, Great Britain, Greece, Guatemala, Haiti, Hungary, India, Indonesia, Iran, Iraq, Ireland, Island, Israel, Italy, Ivory Coast, Jamaica, Japan, Jordan, Kazakhstan, Kenya, Kuwait, Latvia, Lebanon, Liberia, Libya, Liechtenstein, Lithuania, Luxemburg, Macedonia, Madagascar, Malaysia, Mali, Malta, Marshall Islands, Mauritius, Morocco, Mexico, Moldova, Monaco, Mongolia, Myanmar, Namibia, Netherlands, New Zealand, Nicaragua, Niger, Nigeria, Norway, Pakistan, Panama, Paraguay, Peru, Philippines, Poland, Portugal, Qatar, Romania, Russia, Saudi Arabia, Senegal, Sierra Leone, Singapore, Slovakia, Slovenia, Spain, Sri Lanka, South Africa, South Korea, Sudan, Sweden, Switzerland, Syria, Tanzania, Thailand, Turkey, Tunisia, Uganda, Ukraine, Uruguay, USA, Uzbekistan, United Arab Emirates (UAE), Venezuela, Vietnam, Yemen, Yugoslavia (Serbia), Zambia, Zimbabwe

NAFTA (North American Free Trade Association, 1994)

Canada, Mexico, USA

OECD (Organization for Economic Cooperation and Development, 1949; 30 countries)

Australia (1971), Austria (1996), Belgium (1949), Canada (1960), Czech Republic (1995), Denmark (1949), Germany (1949), Great Britain (1964), Greece (1964), Finland (1969), France (1964), Hungary (1996), Iceland (1964), Ireland (1964), Italy (1964), Japan (1964), Luxemburg (1964), Mexico (1994), Netherlands (1996), New Zealand (1973), Norway (1996), Poland (1996), Portugal (1959), Slovakia (2000), South Korea (1996), Spain (1959), Sweden (1959), Switzerland (1959), Turkey (1996), USA (1960)

OPEC (Organization of the Petroleum Exporting Countries)

Algeria, Angola (since January 1st, 2007), Ecuador (since January 1st, 2007), Gabon (until June 10th, 1996), Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates (UAE), Venezuela

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1 member since 2004
2 member since 2007

Natural Gas Markets

European Gas Market

Europe, Russia (west of the Yennisey river), other European countries of the CIS, Algeria, Egypt, Libya, Morocco, Tunisia, Western Sahara (Democratic Arab Republic)

Asian Gas Market

Australasia, Russia (east of the Yennisey river)

Transition Zone European/Asian Market

Middle East, Central Asian countries of the CIS (Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan, Uzbekistan, Kyrgyzstan)

North American Gas Market

North America

Latin American Gas Market

Argentine, Bolivia, Brazil, Chile, Paraguay, Peru, Uruguay

Units of measurement

b, bbl	barrel	1 bbl = 158.984 Liter
Btu	British thermal unit	1 Btu = 1060 Joule
		1000 Btu = ca. 1 cf natural gas
boe	barrel(s) of oil equivalent	
bopd, b/d	Barrel(s) oil per day	
cal	calorie	1 cal = 4.1868 J
kcal	kilo calorie	1 kcal = 10^3 cal
bcf	billion cubic feet	(= billion cf) 10^9 cf
cf, cuft	cubic feet	1 cf = 0.02832 m^3
cf/d	cubic feet/day	1 cf/d corresponds to app. 10 m^3/year
(m)mcf	million cubic feet	(= million cubic feet) at times one „m" means 1000 und two „m" mean million
tcf	trillion cubic feet	(= trillion cubic feet) = 10^{12} cuft
D	Darcy	unit for the specification of the permeability of a rock (1 mD (milli Darcy) = 0.001 D)
J	Joule	1 J = 0.2388 cal = 1Ws
kJ	Kilojoule	1 kJ = 10^3 J
MJ	Megajoule	1 MJ = 10^6 J
GJ	Gigajoule	1GJ = 10^9 J = 278 kWh = 0.0341 t SKE
TJ	Terajoule	1 TJ = 10^{12} J = 278 x 10^3 kWh = 34.1 t SKE
PJ	Petajoule	1 PJ = 10^{15} J = 278 x10^6 kWh = $34.1 \cdot 10^3$ t SKE
EJ	Exajoule	1 EJ = 10^{18} J = 278 x 10^9 kWh = $34.1 \cdot 10^6$ t SKE
m^3	cubic meters	
Nm^3	standard cubic meters	amount of gas in 1 m^3 at 0°C and 1013 mbar [also abb. m^3(Vn)]
Mcm	million cubic meters	= 10^6 m^3
Bcm	billion cubic meters	= 10^9 m^3
Tcm	trillion cubic meters	= 10^{12} m^3
W	Watt	
kW	Kilowatt	1 kW = 10^3 W
MW	Megawatt	1 MW = 10^6 W
GW	Gigawatt	1 GW = 10^9 W
kWh	Kilowatt-hour	1 kWh = 3.6 x 10^6 J
MWh	Megawatt-hour	1 MWh = 3.6 x 10^9 J
GWh	Gigawatt-hour	1 GWh = 3.6 x 10^{12} J
MWa	Megawatt-year	1 MWa = 3.15 x 10^{13} J

Units of measurement - continued

Pa·s	**Pascal-seconds**	= $kg \cdot m^{-1} \cdot s^{-1}$ specification of the viscosity of a liquid; e. g. water has a viscosity of 1 mPa·s at 20°C
ppm	**parts per million**	$=10^{-6}$ = 0.0001 %
t	**ton**	1 t = 10^3 kg
t/a	**metric ton(s) per year**	
tce	**tons of coal equivalent**	
kt	**Kiloton**	1 kt = 10^3 t
Mt	**Megaton**	1 Mt = 10^6 t
Gt	**Gigaton**	1 Gt = 10^9 t
Tt	**Teraton**	1 Tt = 10^{12} t

Conversion factors[1]

1 t petroleum	1 toe = 7,35 bbl = 1,428 t SKE = 1101 m³ natural gas = 41,8 x 10^9 J
1 t LNG	1380 m³ natural gas = 1,06 toe = 1,52 t SKE = 44,4 x 10^9 J
1000 Nm³ natural gas	35 315 cf = 0,9082 toe = 1,297 t SKE = 0,735 t LNG = 38 x 10^9 J
1 tce	0,70 toe = 770,7 m³ natural gas = 29,3 x 10^9 J
1 EJ (10^{18} J)	34,1 Mio. t SKE = 23,9 Mio. toe = 26,3 Mrd. m³ natural gas = 278 Mrd. kWh
1 t Uranium (nat.)	14 000 bis 23 000 t SKE; different values depending on the utilization factor
1 kg Uranium (nat.)	2,6 lb U_3O_8

1 As natural products, fossil energy resources are subject to variations; the specific energy contents represent average values, which may deviate significantly in some cases.
For natural gas the conversion factors have been adapted to international standards, which are significant higher than the values used for Germany. This allows a better world-wide comparison of natural gas with other energy resources. As conversion factor for natural gas 38 MJ per m³ was used according to „Energie Daten 2003" by German BMWi (p. 52). According to IEA „Natural Gas Information 2006" (p. XXIX/XXX) heat values of natural gas varying from 33,32 MJ/m³ (Netherlands) to 43,717 MJ/m³ (Tunisia). Values for Germany of 33.337 MJ/m³ range at the lower end. Heat value of natural gas produced by the 'Top Ten' countries in 2006 averages 38.3 MJ/m³. Other conversion factors range between 37.68 MJ/m³ (BP 2007) and 41.4 MJ/m³ (E.ON Ruhrgas). Thus the value of 38 MJ/m³ is on the safe side.

Geological Timechart

Era	System	Series	General	Time (Ma)
Cenozoic	Quaternary	Holocene (Recent)		
		Pleistocene		2,6
	Tertiary – Neogene	Pliocene	Piacenzian	
			Zanclean	
		Miocene	Messinian	
			Tortonian	
			Serravallian	
			Langhian	
			Burdigalian	
			Aquitanian	24
	Tertiary – Paleogene	Oligocene	Chattian	
			Rupelian	
		Eocene	Priabonian	
			Bartonian	
			Lutetian	
			Ypresian	
		Paleocene	Thanetian	
			Danian	65
Mesozoic	Cretaceous	Upper	Maastrichtian	
			Campanian	
			Santonian	
			Coniacian	
			Turonian	
			Cenomanian	
		Lower	Albian	
			Aptian	
			Barrêmian	
			Hauterivian	
			Valanginian	
			Berriasian	142
	Jurassic	Upper (Malm)	Tithonian	
			Kimmeridgian	
			Oxfordian	
		Middle (Dogger)	Callovian	
			Bathonian	
			Bajocian	
			Aalenian	
		Lower (Lias)	Toarcian	
			Pliensbachian	
			Sinémurian	
			Hettangian	200
	Triassic	Upper	Rhaetian	
			Norian	
			Carnian	
		Middle	Ladinian	
			Anisian	
		Lower	Olenekian	
			Induan	251
Paleozoic	Permian	Upper	Tatarian/Kaz.	
			Kunjurian/Art.	
		Lower	Sakmarian/Ass.	296
	Carboniferous	Pennsylvanian	Stephanian	
			Westphalian	
			Namurian	
		Mississippian	Visean	
			Tournaisian	358
	Devonian	Upper	Famennian	
			Frasnian	
		Middle	Givetian	
			Eifelian	
		Lower	Emsian	
			Pragian	
			Lochkovian	418
	Silurian	Upper	Pridolian	
			Ludlovian	
		Lower	Wenlockian	
			Llandoverian	443
	Ordovician	Upper	Ashgillian	
			Cradocian	
		Middle	Llandeilian	
			Llanvirnian	
		Lower	Arenigian	
			Tremadocian	495
	Cambrian	Upper		
		Middle		
		Lower		545
Pre-cambrian	Proterozoic	Early		
		Late		
	Archaen	Archaen		>3800

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