# Fossil and Nuclear Fuels – the Supply Outlook

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# ***EXECUTIVE SUMMARY***

### Scope

Since 1998 when the oil geologists Colin Campbell and Jean Laherrère published a widely discussed survey article “The End of Cheap Oil” in the journal “Scientific American”, the concept of peak oil and the present state of oil depletion are part of any serious analysis of the future oil supply potential. However, recently various publications suggest that oil is still abundantly available and that there is little need to worry about the future oil supply potential.

As in previous years, the International Energy Agency (IEA) in its latest World Energy Outlook 2012 (WEO 2012) projects a rising global oil demand and supply in the coming decades. The IEA explicitely asserts that for the forseeable future – to 2035 and beyond – no geological or technical restrictions will prevent a continually growing oil supply. The media were echoing this report by emphasising the likelihood of a global oil and gas supply glut triggered by new production technologies in the USA, while ignoring possible geological supply restrictions.

In contrast to the projections put forward by the IEA, in 2008 the Energy Watch Group (EWG) had published a report on the future world oil supply, presenting a scenario projecting a significant decline of global oil supply in the coming decades up to 2030. It is the intention of this new report to update these findings by analysing the developments which took place in the last five years and thereby to arrive at an enhanced understanding of the conditions determining present and future oil supply.

In addition, it is the intention of this study to broaden the perspective of the original study by embedding the oil scenario into a global scenario for all fossil and nuclear fuels by including natural gas and by updating the EWG coal supply scenario of 2006 and the EWG uranium supply scenario of 2007.

In a nutshell, this report gives a short overview on the future availability of fossil and nuclear fuels with an emphasis on critical issues.

### Oil

- Empirical data shows that world oil production has not increased anymore but has entered a plateau since about 2005. The production of conventional oil is already in slight decline since about 2008. The peaking of conventional oil is now also accepted by the International Energy Agency. Present and future efforts by the oil industry are directed at upholding this plateau as long as possible while at the same time having to struggle with the growing decline of production in ageing fields. It is becoming increasingly more difficult to compensate this reduction by developing new fields which are getting harder to find, smaller, and are of poorer quality.

- Recent increases of unconventional oil and gas production in the USA are due to a number of specific conditions, such as a highly developed oil and gas industry and infrastructure, sizeable unconventional oil and gas resources in prospective areas with very low population densities, certain financial incentives for publicly listed companies, and exemptions for the oil and gas industry from environmental restrictions (Energy Policy Act 2005). But most important were the high oil and gas prices reached in 2006. This has led to the fast development of the few hot spots of shale gas and light tight oil while the decline of the conventional oil and gas production is continuing to progress.

- The scenario projections in the WEO 2012 by the International Energy Agency stating that around 2020-2025 unconventional oil and gas production will make the USA independent from imports rest (1) on the assumption that demand declines considerably and (2) on the speculation that huge possible resources will be transformed into proven reserves and then be put into production. In particular the latter is by no means ensured. There is a high probability that light tight oil production in the USA will peak between 2015 and 2017, followed by a steep decline. Light tight oil production will likely turn out to be a bubble, lasting only for about 10 years.

- New field developments in “frontier areas” are disappointing and lagging far behind the hopes raised five to ten years ago:

  The *Caspian region* (Kazakhstan, Azerbaijan) is currently producing 3 Mb/day, much less than the expectations raised by the US-EIA in 2000. At that time it was thought that production in the Caspian region might rival the Middle East countries by 2015-2020. The most promising new development since 2000, Azeri-Chirac-Gunashli, has already passed peak and the whole region is now in decline. Only the expensive and delayed development of Kashagan might bring about a production increase in that region.

  Oil production in deep water areas in the *Gulf of Mexico, West of Africa,* and *East of Brazil* is far behind forecasts from ten years ago for each of the areas. The Gulf of Mexico has already passed peak production; the same is true for Angola. Stagnating oil production in Brazil is standing at 2 Mb/day at the end of 2012. This is far behind Petrobras’ original time schedule and poses huge financial problems for the state company. In contrast to earlier expectations, gasoline imports to Brazil grew over the last years.

  Tar Sands in *Canada* and Extra Heavy Oil in *Venezuela* have increased global reserves by several hundred Gigabarrels. However, production growth from these resources is far behind the goals published five years ago. Synthetic crude oil and bitumen production in Canada amounts to 1.8 Mb/day, while projections in 2007 suggested a production level of about double that (3.5 Mb/day). Extra heavy oil production in Venezuela still stays at 600 kb/day – similar to the year 2000.

*Saudi Arabia*, ten years ago still seen as the most important future oil producer which would raise its production to 12-14 Mb/day and maintain that rate until 2033, struggles with steep decline rates of up to 8 per cent in aging fields. Though Saudi Arabia is reporting huge oil reserves lasting for many decades, empirical evidence casts doubts on the reliability of these data.

- The decline of the European oil production was already predicted in 2001 by ASPO. Production is now below 3 Mb/day, a 60 per cent decline from the peak in 2000, and close to the predicted number by ASPO. In 2004, when the ongoing decline should have been obvious to every neutral observer, the International Energy Agency still predicted a production rate of 4.8 Mb/day for 2010.

- On the other hand, some other regions showed higher production than anticipated several years ago:

  *China* still increased its production to 4 Mb/day in 2011, while EWG and IEA expected a decline to between 3.3-3.5 Mb/day. Declining production of aging fields was more than offset by new offshore developments.

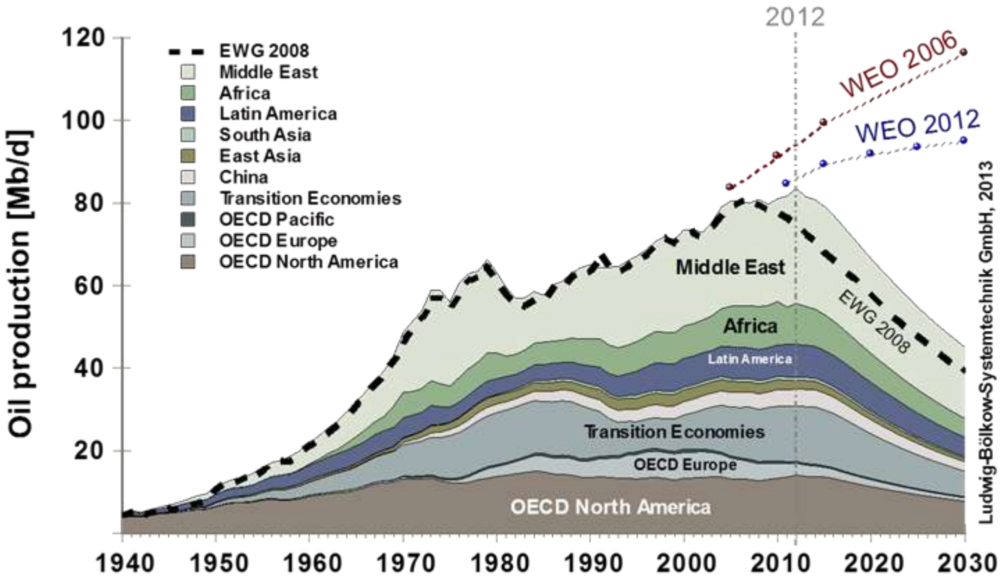
  In 2008, the EWG expected the peak of *Russian production* around 2010. Now it seems that the production plateau is coming to an end and 2012 is probably the peak year.

  Major *Middle East* producers still increased their production to a joint volume of 25.8 Mb in 2011 which is close to the 26.5 Mb/day projected in the WEO 2002.

- Most important, the development of light tight oil resources in the USA reversed the decline of the US production which has been rising again since 2010 as a result. This production increase in the US was not expected and has fuelled speculations that the USA will become the world leading oil producer by 2020 with 11.1 Mb/day. This would require a doubling of present crude production.

- According to our analysis, it is quite likely that in 2030 world oil production will have declined by 40 percent compared to 2012. The figure below shows the updated scenario of world oil production 1940 - 2030.

- The oil consumption in OECD countries has already passed peak – in favour of non-OECD countries which could still increase their consumption, while total world oil demand stayed almost flat.




*World oil production according to the present study; the comparison to some other studies is also given*

**Natural Gas**

This report also contains scenario projections for the future supply of natural gas. These are performed in similar depth as the projections of future oil supply. Important findings are:

- Conventional gas production is in decline in Europe and North America which together hold almost 35 per cent of world gas production.

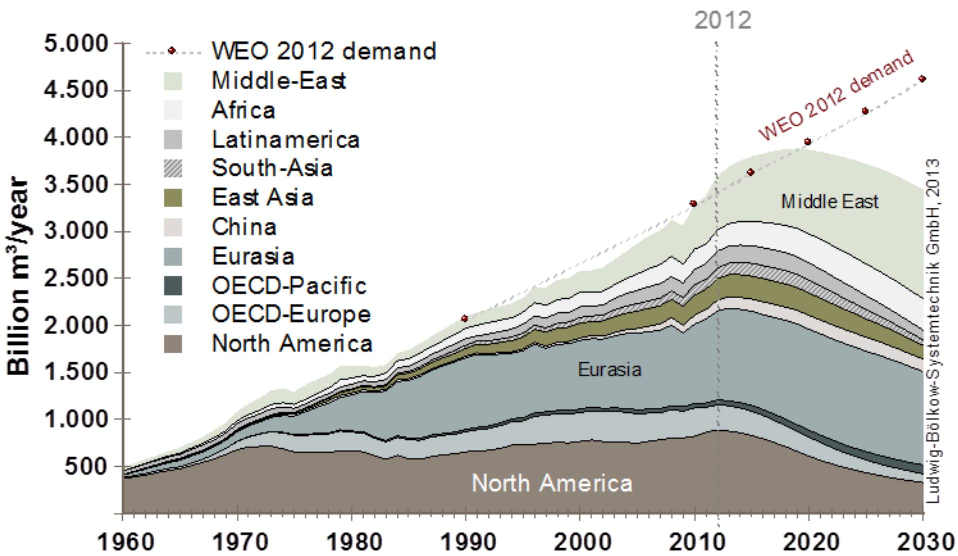
- Unconventional gas production, predominantly shale gas production, has increased US production in the last years since the exemption of the gas industry from environmental regulations of the Safe Drinking Water Act (SDWA). Now shale gas has a U.S. market share of 30 percent.

- Shale gas production in the USA is unlikely to see a significant further expansion. Due to the particular production dynamics of shale gas it will decline as soon as new wells are not being developed any more at an adequate rate. The decline of shale gas production from 2015 onward will add to the decline of conventional gas production. In 2030 gas production in the US probably will be far below present production levels.

- Gas production in Europe has been in decline since the turn of the century and will continue to follow that trend. Shale gas production will not play a role comparable to the one in U.S., since geological, geographical, and industrial conditions are much less favourable. In order to keep gas consumption in Europe flat or rising, imports will need to increase by at least additionally 200 billion m³/yr.

- Russia, the second largest natural gas producer closely behind the U.S., faces a struggle between declining production from ageing fields and new expensive and time consuming developments in Northern Siberia and offshore. Russian gas production reached a first peak in 1989 when the largest fields passed peak production. Gazprom production never reached that level again. Ageing fields force Russia to speed up the development of new fields. The developments of Shtokmanskoye in the Barents Sea and of other fields in Yamal are delayed. If the gas fields in the Yamal Peninsula would be developed in time, they would have produced 310-360 bcm in 2030 according to Gazprom. But even this will not be sufficient to compensate for the decline of ageing current fields.
- Domestic consumption in Russia and growing demand from Asia will put increasing pressure on volumes available for export from Eurasia to Europe in the coming years.
- The Middle Eastern countries Iran and Qatar are expected to feed the rising demand for liquefied natural gas over the next decades. Though these countries have large reserves, it is highly probable that reported reserves are exaggerated.

The following figure shows the gas supply scenario projections until 2030.

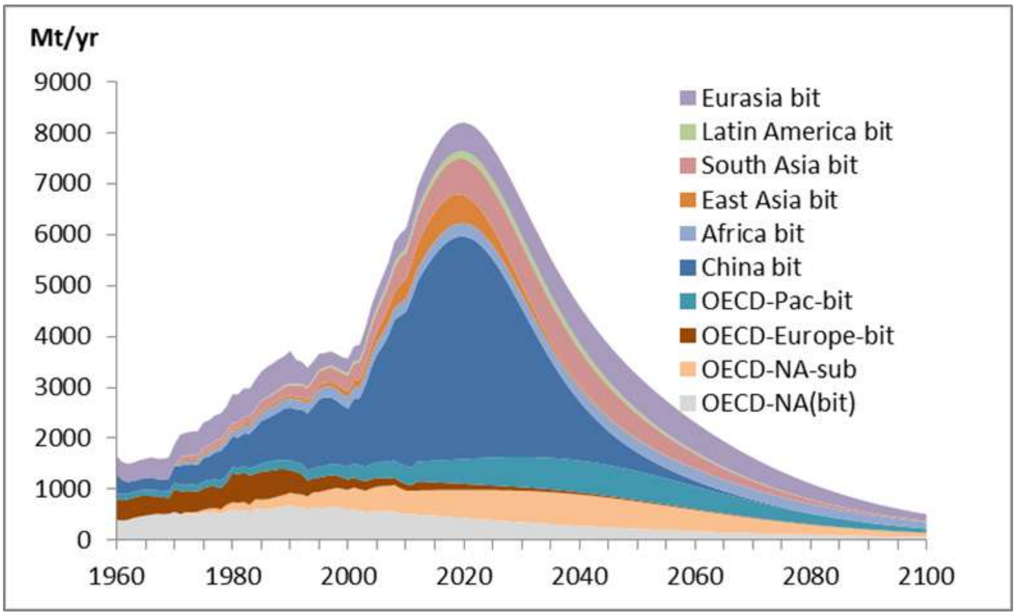



*World supply of natural gas according to the present study; the projection of the WEO 2012 by the International Energy Agency is also shown*

## Coal

Coal still is widely regarded to be an abundant resource. However, internationally coal is only available from few countries having large export capacities. This signals a supply risk that is actually greater than it seems at first glance:

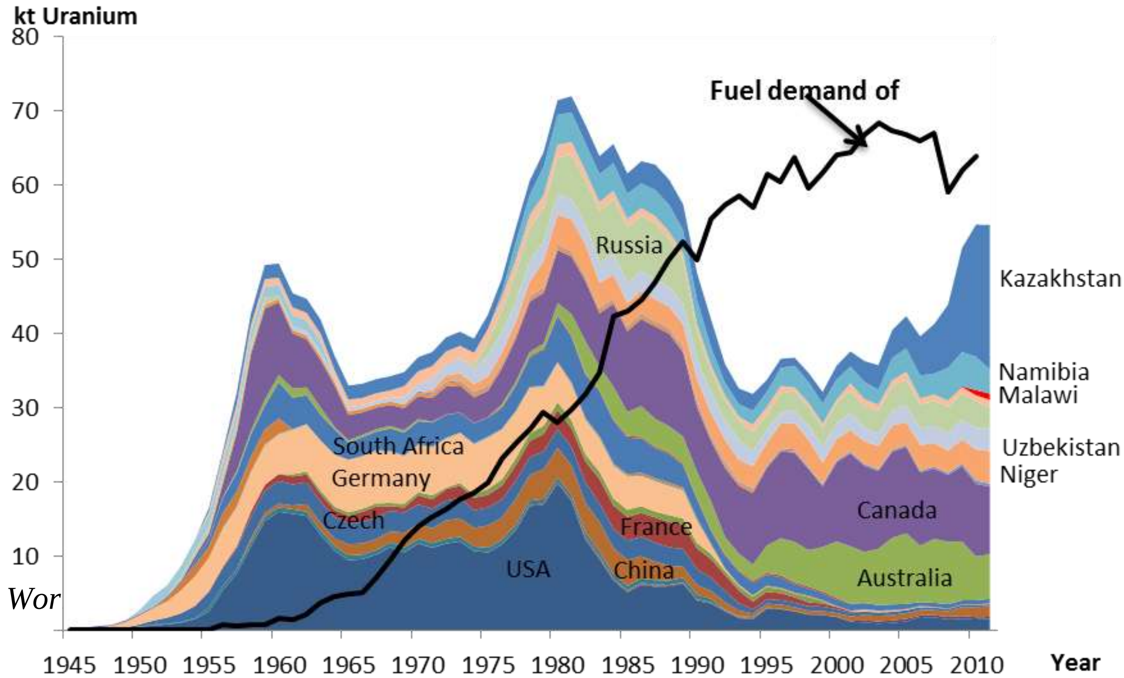
- The USA has passed peak production of bituminous coal 25 years ago.
- China is reporting the second largest reserves; notwithstanding, it switched within a few years from being one of the largest coal exporters to being the largest coal importer comparable in volume to Japan.
- India is among the largest reserve holders, but also its coal imports are rising, due to the low quality of domestic coal reserves which contain up to 70 percent of ash.
- Only about 10-15 per cent of world coal production is sea-traded. Trade volumes more than doubled over the last decade. This rising demand predominantly was supplied by two nations: Australia, the world's largest exporter of coking coal for steel production, and Indonesia, the world's largest exporter of steam coal for power generation.
- Future world coal trade volumes will predominantly depend on these two nations.
- The quality of mined coal will gradually decrease.
- Coal production is expected to peak within the next decade.




*World coal production according to the updated scenario*

## Uranium

World uranium production has already peaked around 1980. The recent increase of production is driven by mining extensions in Kazakhastan. The size of reported remaining resources would be sufficient to fuel the present number of nuclear reactors for several decades. However, the ore concentration of new mining projects in Africa has declined to below 0.02 per cent, which in turn raises the necessary effort for mining including the energy needed. As a consequence, most new projects are in delay while the production from old mines is declining. Therefore, according to our analysis, the risk of a uranium supply gap for nuclear reactors within the present decade is high.



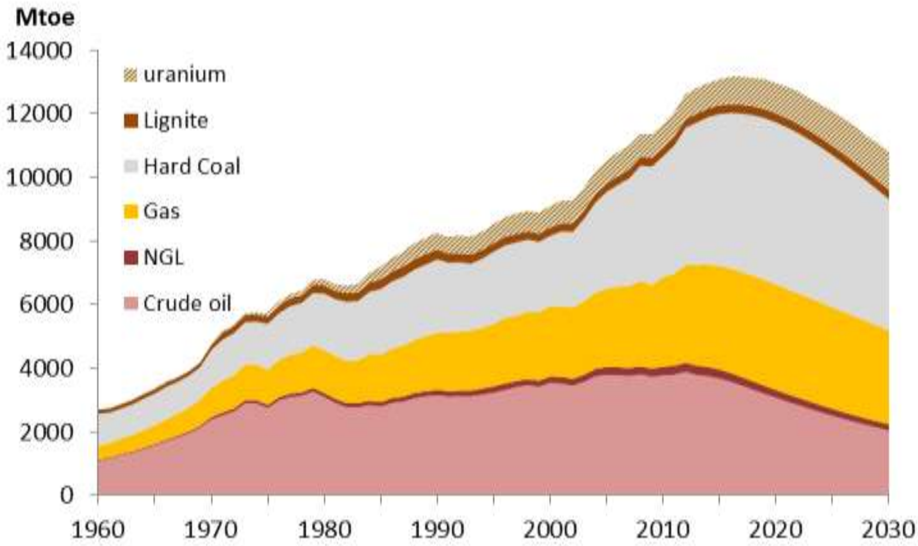

## Conclusion

The figure below shows the supply scenario for all fossil and nuclear fuels. Fuel supply for all fuels is measured in energy units (1Mtoe = 1 million tons of oil equivalent).

According to our study, coal and gas production will reach their respective production peaks around 2020. The combined peak of all fossil fuels will occur a few years earlier than the peaking of coal and gas and will almost coincide with the beginning decline of oil production.

Therefore, the decline of oil production – which is expected to start soon – will lead to a rising energy gap which will become too large to be filled by natural gas and/or coal. Substituting oil by other fossil fuels will also not be possible in case gas and coal production would continue to grow at the present rate. Moreover, a further rise of gas and coal production soon will deplete these resources in a way similar to oil.

The energy contribution of nuclear fuels is too low in order to have any significant influence at global level, though this might be different for some countries. Moreover, like with fossil fuels, easy and cheap to develop mines are also being depleted in uranium production and production effort and cost will continuously increase as a consequence.




*Scenario of world supply of fossil fuels and uranium*

Total world fossil fuel supply is close to peak, driven by the peak of oil production. Declining oil production in the coming years will create a rising gap which other fossil fuels will be unable to compensate for.

# ***FOSSIL AND NUCLEAR FUELS – THE SUPPLY OUTLOOK***

# ***INTRODUCTION***

Five and six years ago, on behalf of the Energy Watch Group the authors already prepared studies on the supply outlook for oil (EWG 2008), coal (EWG 2007) and for uranium and nuclear power (2006). It is the intention of this report to update the data and findings of these studies and additionally to include for the first time a supply outlook for natural gas. In this update we will analyse how far the world has progressed on the road towards depletion of fossil and nuclear fuels.

Since November 2012, when the International Energy Agency published its World Energy Outlook 2012 (WEO 2012), the media are hyping scenarios of plentiful supplies of oil and gas in the coming decades, supposedly reversing the trend of rising energy prices. "Peak oil is dead" is the mantra of the day. This optimism is by no means justified by a sober analysis of the empirical data. Even the WEO 2012, apart from its misleading Executive Summary, has in the full report many detailed data and caveats pointing to different conclusions and, most relevant, the numbers of the New Policies Scenario do not support that hype.

However, in the public perception the promise of cheap and abundant fossil energy prevails. According to media reports, it seems as if the fundamentals of oil- and gas supply have changed completely over the last years, brought about by the 'energy revolution' of producing hitherto inaccessible reserves of unconventional oil and gas by means of 'fracking'.

Though it is impossible to predict future developments exactly, important trends which will have an influence are certainly identifiable. Since about 2005 the global production of conventional oil has reached a plateau. The peaking of oil and other fossil fuels will be a disruptive change from a world accustomed to "each year a bit more energy" to a world with "each year a bit less energy at higher prices". This will mark the end of business as usual. Since the world is now facing the imminent decline of the oil supply anytime in the near future, the exact timing is not the main issue – rather, the steepness of decline.

The aim of this study is to identify the probable supply restrictions and to raise the awareness of the general public and of politicians. The earlier the imminent challenges are addressed, the higher is the chance that the transition can be shaped in order to minimise the pain.

The study is covers in individual chapters the fossil fuels oil, natural gas, coal and the nuclear fuel uranium. The focus is put on updated detailed analysis of key producing regions. Supply scenarios for other regions are taken almost unchanged from the previous reports in cases when there were no new developments or the share of global production is negligible, not affecting the basic trends.

In a final chapter an aggregate supply scenario is presented which comprises all fossil and nuclear fuels. However, it must be emphasised that each fuel has its specific properties and therefore a simple substitution of one fuel by another fuels is not possible. For instance, a declining oil supply for transport cannot simply be substituted by the fuels produced via the liquefaction of coal. There are numerous challenges that have to be overcome: e.g. conversion plant technology, low conversion efficiencies, huge investments requirements, water requirements, securing coal supply.

The IEA and the media are concentrating on the supposed energy revolution in the USA and the possibility of this being a model for the rest of the world. For this purpose comprehensive analyses of the supply outlook for natural gas, oil and coal were carried out and can be found in the Annex of this report. This should lead to a better understanding of the US energy supply situation – its potentials and **its** limits.

## ***METHODOLOGY***

The scope and structure of these projections is similar to those put forward in the periodic World Energy Outlooks by the International Energy Agency (IEA). However, in this report no assumptions or projections regarding prices are made. The report concentrates on supply scenarios for each world region and their major countries. The results are aggregated for ten world regions. The definition of these regions follows the definition used by the International Energy Agency in 2008:

- OECD North America, including Canada, Mexico and the USA.
- OECD Europe, including Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, The Netherlands, Norway, Poland, Slovak Republic, Spain, Sweden, Switzerland, Turkey, and the UK.
- OECD Pacific, including
  – OECD Oceania with Australia, and New Zealand,
  – OECD Asia with Japan and Korea.
- Transition Economies, including Albania, Armenia, Azerbaijan, Belarus, Bosnia-Herzegovina, Bulgaria, Croatia, Estonia, Yugoslavia, Macedonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Romania, Russia, Slovenia, Tajikistan, Turkmenistan, Ukraine, Uzbekistan, Cyprus, and Malta.
- China, including China and Hong Kong.
- East Asia, including Afghanistan, Bhutan, Brunei, Chinese Taipei, Fiji, Polynesia, Indonesia, Kiribati, The Democratic Republic of Korea, Malaysia, Maldives, Myanmar, New Caledonia, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Island, Thailand, Vietnam, and Vanuatu.
- South Asia, including Bangladesh, India, Nepal, Pakistan, and Sri Lanka.
- Latin America, including Antigua and Barbuda, Argentina, Bahamas, Barbados, Belize, Bermuda, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Dominic. Republic, Ecuador, El Salvador, French Guyana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, St. Kitts-Nevis-Antigua, Saint Lucia, St. Vincent Grenadines and Suriname, Trinidad and Tobago, Uruguay, and Venezuela.

- Middle East, including Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, the United Arab Emirates, Yemen, and the neutral zone between Saudi Arabia, and Iraq.
- Africa, including Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, the Central African Republic, Chad, Congo, the Democratic Republic of Congo, Côte d'Ivoire, Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Morocco, Mozambique, Niger, Nigeria, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, Sudan, Swaziland, the United Republic of Tanzania, Togo, Tunisia, Uganda, Zambia, and Zimbabwe.

However, for many regions the scenario results presented in this paper are very different to the scenarios presented by the IEA in their periodic editions of the World Energy Outlook (WEO). The IEA projects a continuing growth of oil supply and as a consequence a continuation of business as usual for decades to come is deemed possible.

The report is divided into different chapters individually covering the four fuels oil, natural gas, coal, and uranium.

The analysis in this paper is an update of the 2008 scenario calculations which were based on data up to 2006. The actual development from 2006 to 2012 is compared with the projections of 2008 and adjustments and revisions are made where necessary. However, it is the intention to stick to the original approach. Therefore, the basic methodological approach is similar to that of the 2008 report: The projections do not primarily rely on data of proved reserves (1P reserves) which are difficult to assess and verify and in the past have frequently turned out to be unreliable. The history of proved plus probable discoveries (2P reserves) is a better indicator though also here the individual data are of varying quality. Rather, this analysis is based primarily on production data which can be observed more easily and are also more reliable. Historical discovery and production patterns allow for projecting future discoveries and – where peak production is close or has already been reached – future production patterns.

The detailed analysis in 2008 was based on an industry database for past production data and partly also for reserve data for certain regions. As reserve data vary widely and as there is no audited reference, the authors had in some cases made their own reserve estimates based on various sources and own assessments. Generally, future production in regions which are already in decline can be predicted fairly accurately relying solely on past production data.

The projections are based also on published development plans of new fields, on the observation of industry behaviour and on "soft" indicators.

The present report restricts a more detailed analysis to a few key regions, mainly the USA and Middle East.

# ***OIL***

## ***Introduction***

This chapter is concerned with the supply outlook for oil. The first subchapter focusses on empirically observable trends which are responsible for the peaking of oil production, and in addition gives a short survey of conflicting interpretations. The intention is to provide the empirical facts on which the reader can base his own conclusions.

This is followed by the updated scenario projections for each country, summarised for each world region. For regions where new empirical data and new insights were forthcoming in recent years, modifications and changes with respect to the scenario projections from 2008 are made and discussed. However, to put our findings in a nutshell, in contrast to the public perception in the media, the general long-term and medium-term view on future oil supply has not changed. There are no new facts which would require a fundamental change of views. In detail, however, some assessments of short and medium-term trends had to be modified according to developments which not expected five years ago. This holds in particular for the domestic oil and gas production in the USA which due to an enormous drilling activity for tight oil reversed the long-term declining trend, resulting in a rising production for a few years. This is discussed in some detail in this chapter and in more detail in the Annex on US fossil fuel production.

A further subchapter discusses some of the most diverging assessments between the updated EWG scenario projections and the New Policies Scenario in the WEO 2012 as the reference proposed by the International Energy Agency. This subchapter also includes a short comparison with Colin Campbell's recent update of his projections for world oil production.

## ***The present state of the world oil supply***

### *Key indicators*

The upper part of Figure 1 shows the monthly oil price development since 1960. Some important dates are:

- 1973: The first oil price shock in 1973 resulted in a permanent increase of oil prices by a factor of three to four.
- 1980: The second oil price shock in the aftermath of the Iranian revolution resulted in an oil price spike by another factor of three to four. The development of new fields and rising production capacity from non-OPEC regions which surpassed demand, then reduced oil prices by a factor of two, yet being still far above the pre-1973 level.

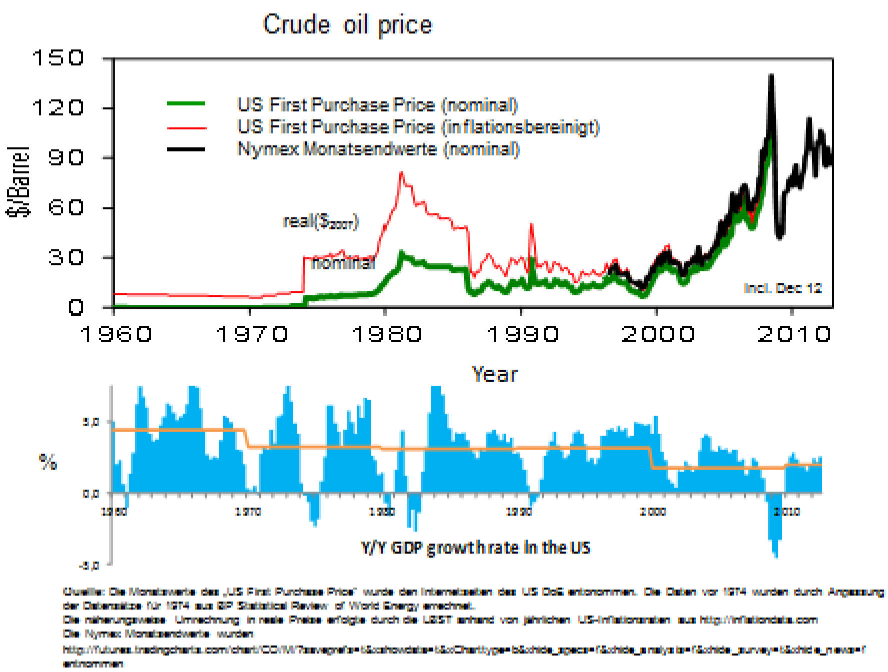
- The Iraq war in 1991 resulted in a one year price spike.
- Starting from about 2000 onwards oil prices rose exponentially until July 2008 when economic disruptions reduced demand and oil prices. After the short price drop in 2008 the oil price soon recovered and started to rise again.

Without going into details, it is nevertheless obvious that the strong and steady price increase since 2000 has a new quality.

The lower part of Figure 1 shows the year over year changes of the GDP in the USA since 1960. Almost every oil price spike was followed by a recession phase, e.g. in 1974, 1979, 1991 and finally, 2008. Moreover, the ten year average of the GDP growth rate shown in Figure 28 declines with each decade since 1960. Though further analysis is needed to interpret this correlation, at this point it is at least noteworthy.

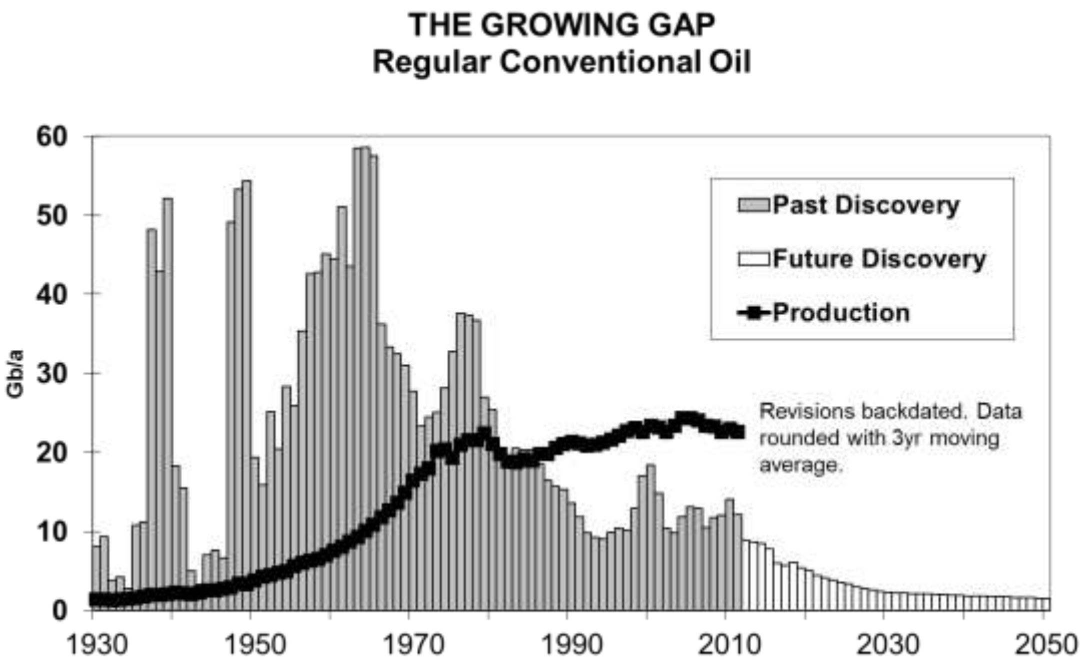
Another remarkable coincidence is the fact that the USA experienced almost no economic growth in 1970 which is the year when the oil production in the USA reached its peak. Just one year later the decoupling of the US dollar from the gold standard was performed. Some sources argue with good reasons that there is a link between these aspects as rising oil imports could be expected which in turn would export lots of US dollars (Ganser 2012).

**Figure 1: Development of crude oil price (top) and inflation adjusted year over year GDP growth rate in the US with 10 year averages (bottom). (Source: Nymex 2013; US-GDP 2013): Bureau of economic analysis; US, see at http://www.bea.gov/national/index.htm#gdp )**



Two times in the recent history oil prices rose permanently after an oil price spike: After 1973 and since 2000. Both events initiated the development of new oil reserves which became accessible only at considerably higher costs. But only developments of already known discoveries were triggered by the higher oil price, not the discoveries themselves, as was already described in (EWG 2008) and shown in Figure 2 in an updated version of the Depletion Atlas by Colin Campbell (Campbell 2013). The 1973 price shock was followed by the development of oil reserves producible only at higher costs in Alaska, the North Sea and other regions outside OPEC.

**Figure 2: Historical discovery pattern of conventional oil fields and projection until 2040. (Campbell 2012)**




Though development of the oil fields in the deep-water had begun already around 1980, its contribution to world oil production started to grow only much later, namely around 2000 (Gulf of Mexico, Brazil, West Africa). Also around 2000, unconventional oil production of tar sands in Alberta started to pick up speed after a few decades of small scale operations. After 2005, in the US the production of light tight oil from impermeable rock formations started to rise.

Rising prices were a necessary prerequisite for these developments as the production costs of these unconventional resources are much higher than for conventional oil - this is the simple reason why conventional oil was produced first.

Figure 3 shows the oil price development and the production of crude oil between 1994 and 2010. This graph shows a strong correlation between rising oil price and rising production until 2004, whereas later the data were almost not correlated. In other words: After 2004 big price fluctuations up to 100 USD had almost no influence on the global supply. This can be interpreted as a strong indicator for the fact that world oil production can no longer follow financial incentives.

A more detailed analysis by Sexton (2012) reveals the strong correlation between gasoline prices and the housing crises which was triggered first in California when people were forced to choose between spending part of their income for a rising gasoline bill or for the repayment of loans. A macroeconomic analysis on price elasticity by Hamilton (2009) gives clear evidence of the fact that the recession in 2008 was triggered by high energy prices.

**Figure 3: World crude oil production and oil price (Zerta 2011)**

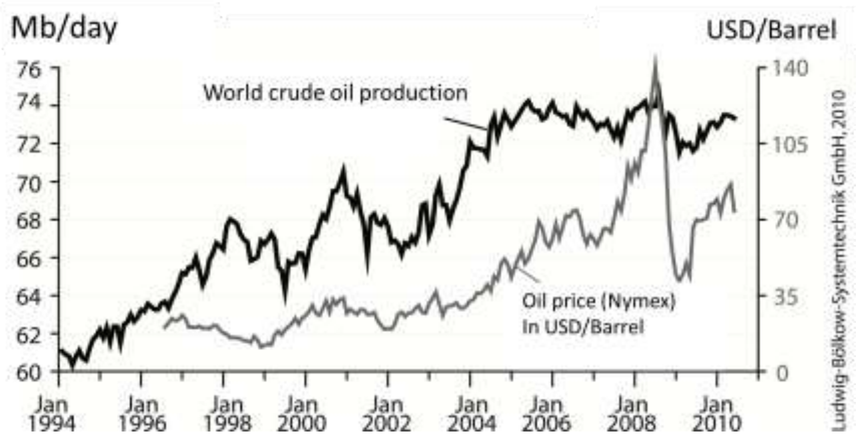
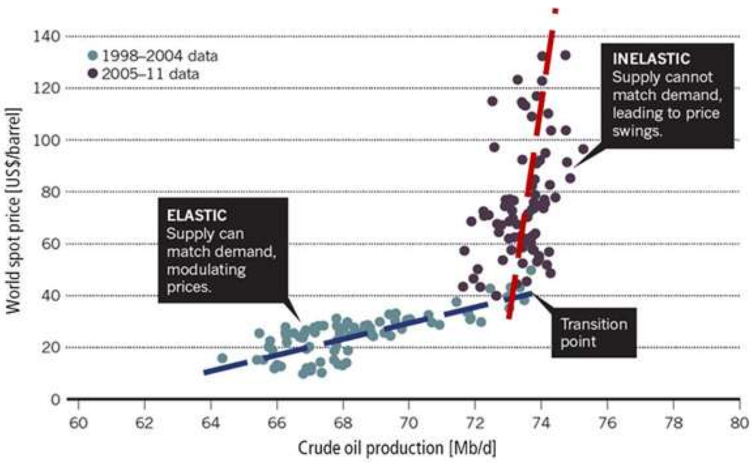


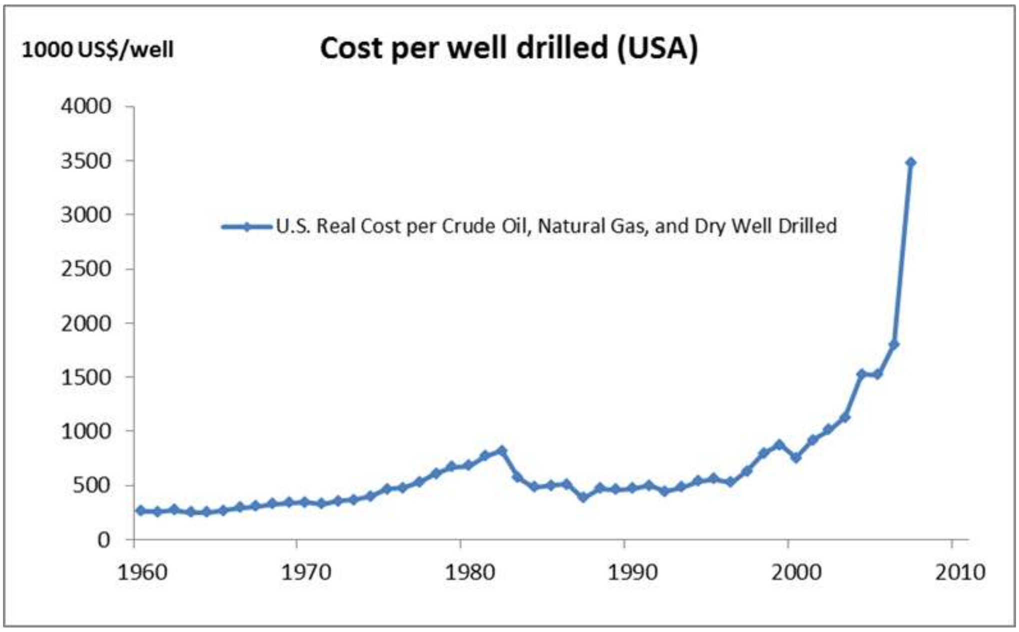

Figure 4 shows the different correlation patterns of 1998 – 2004, where oil supply and oil price show a highly elastic correlation and of 2005 – 2011 where oil supply and oil price show a highly inelastic correlation.

**Figure 4: Oil spot price vs. global production –different behaviour from 2005 on [Murray 2012]**



Also production costs rose since 2000 and skyrocketed since about 2005. Figure 5, for example, shows rising well development cost in the USA since 1960. (Data source US-EIA 2012a)

**Figure 5: Cost per well drilled in USA (source: EIA); against 2000 the cost are three to four times higher in 2007.**

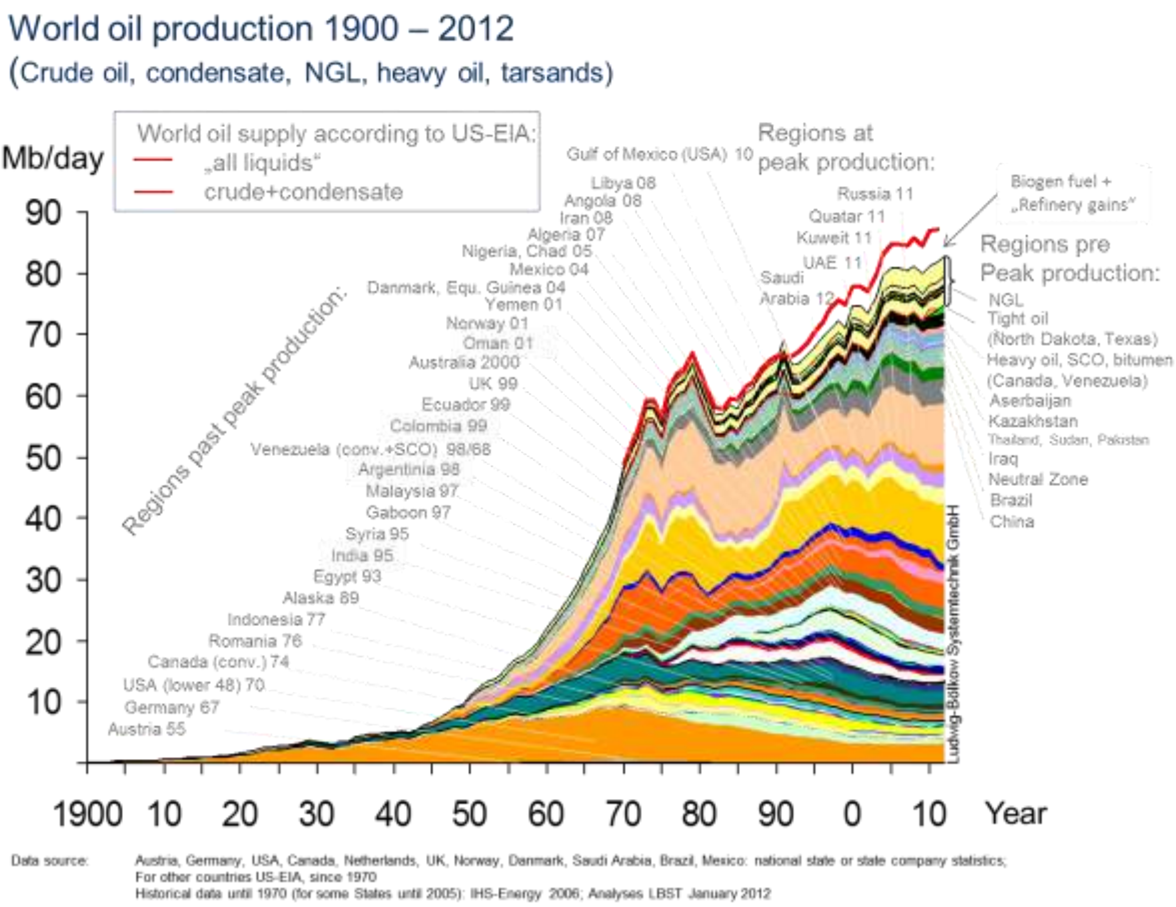



Another link to the GDP growth rate in Figure 1 might be constructed by the year over year growth rate of the world oil production. Until 1970 the annual growth rate amounted to between 5 to 8 percent. It peaked in 1973 at 8.9 percent and in 1976 with 8.2 percent. Then within 3 years the growth rate declined by 15 percent. During the late 1980ies and 1990ies the growth rate averaged at 1.5% percent. According to BP Statistics, since 2005 the average growth rate declined to 0.5 percent.

Figure 6 shows the oil production history between 1900 and 2011. It shows the production of the individual countries of crude oil & condensate and in addition natural gas liquids. For Venezuela and Alberta the production of heavy oil and tar sands is shown.

This detailed view reveals that crude oil production stayed flat or is in slight decline since 2004. The contribution from tar sands and heavy oil in Canada and Venezuela increased only slightly over the last years. Finally, the share of natural gas liquids is given explicitly by the light yellow areas. Though these data are primarily based on US-EIA statistics in cases when no original data from country or state agencies are available, the total shows a rising gap to the production volume of "all liquids", also published by US-EIA. This gap is filled by the addition of biofuels such as ethanol and by so called "refinery gains". Both are not originating from fossil oil sources, but come either from biomass or in case of refinery gains are just a volumetric increase from fuel upgrading in refineries by hydro treating or other petrochemical processes with feedstock from natural gas, not constituting a gain in energy content.

**Figure 6: World oil supply from individual countries**




The figure gives some insight into the regional development of oil production. The production of individual countries and regions is arranged according to the year of their peak production.

Production peaked early in Austria, Germany and USA. By the way, the peak production in the USA also marks the end of high growth rates of world production and the beginning of the second phase of oil production with considerably lower growth rates. Oil production in the US, Venezuela and Canada in this figure is split into the contribution from conventional oil & condensate, and unconventional oil including heavy oil and tar sands, offshore oil in the Gulf of Mexico and light tight oil production in the USA (explicitly in North Dakota and district 1 and 2 in Texas). Since oil production in the USA is discussed in the latest WEO 2012, speaking of the potential for becoming the world's top producer, in this report the US situation is discussed in more detail in a separate chapter in the Annex.

It is important to note that the production decline in the USA continues according to the expected trend when unconventional oil from North Dakota and district 1 and 2 in Texas are excluded. In line with the rationale of this figure, the new contribution from North Dakota and district 1 and 2 in Texas are reported in a separate area as being a new frontier region for the production of unconventional oil which therefore needs separate reporting. The production growth of these two regions contributed to a production increase of world oil production in 2012. But the most important country for this increase was Saudi Arabia, if it would have produced at the same level as 2011; total world production would have been declining in 2012. A further important contribution comes from natural gas liquids (NGL). These are counted as oil while physically they are a by-product from natural gas production. Furthermore, the metric in barrels conceals the fact that the energy content of NGLs is only about 60 to 70 percent of that of crude oil.

Figure 7 and

Figure 8 show the development of oil production and oil consumption of various important world regions. From Figure 35 it becomes obvious that since 2008 the oil consumption of OECD countries declined by about 10 percent while the consumption in non-OECD countries rose, apparently not influenced by the high oil price and the economic crisis in 2008 and 2009.

**Figure 7: Total oil consumption of OECD and non-OECD and of Middle East, China and USA. The total oil consumption in OECD countries has already peaked. The still rising thirst of non-OECD countries puts pressure on total oil supply.**

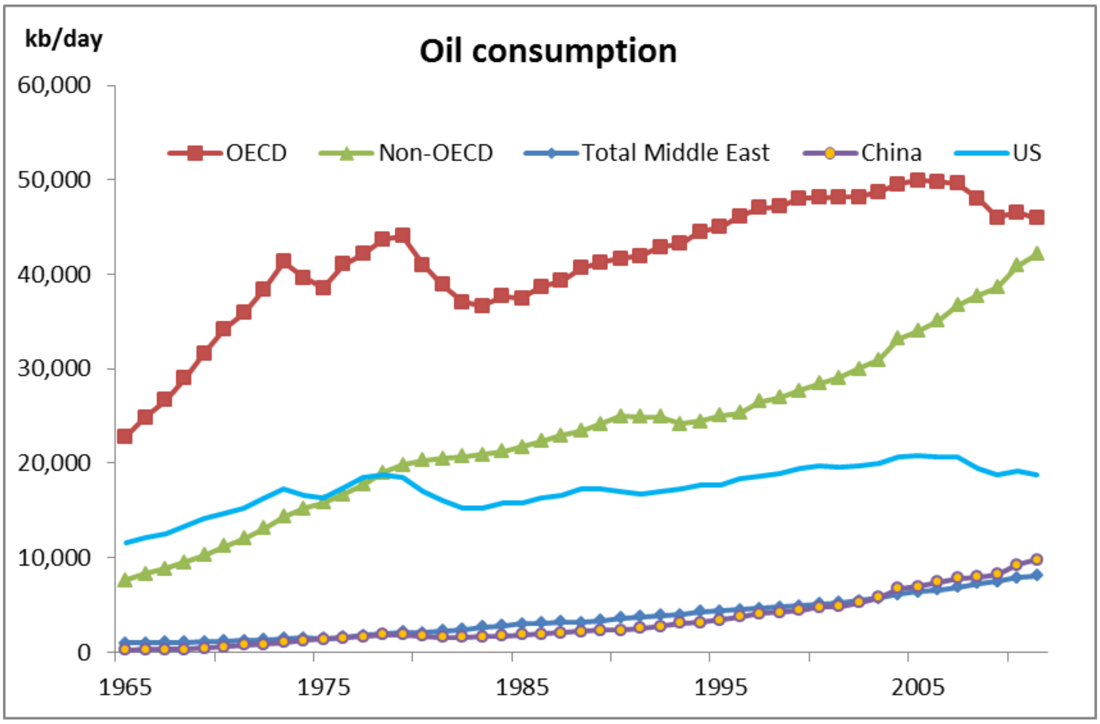
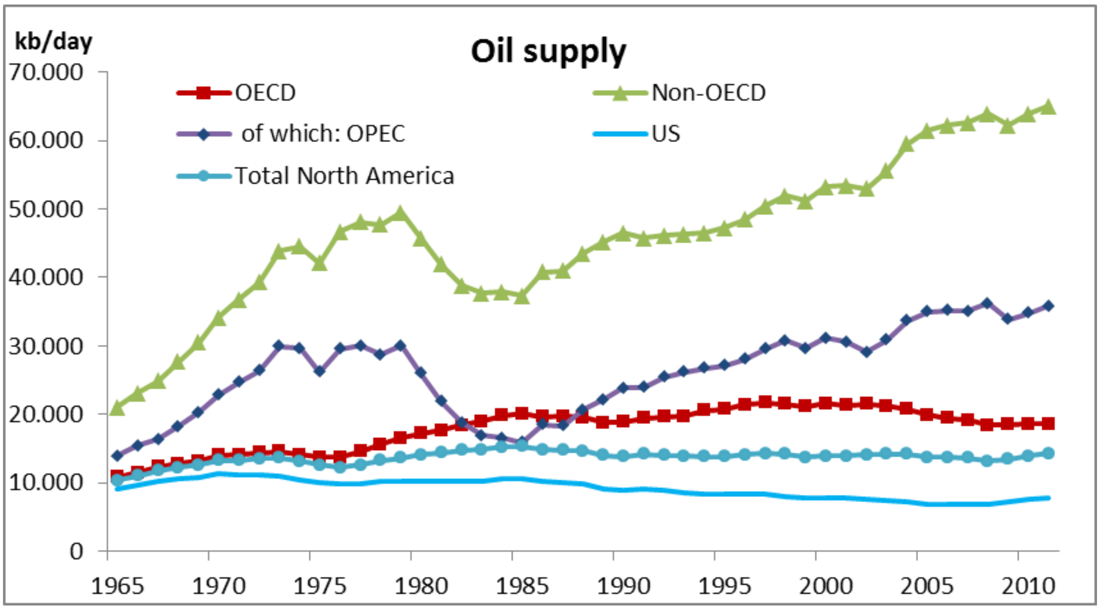


**Figure 8: Total oil production in OECD and non-OECD countries and in OPEC countries, Total North America and USA (Source: BP Statistical Review of World Energy 2012)**

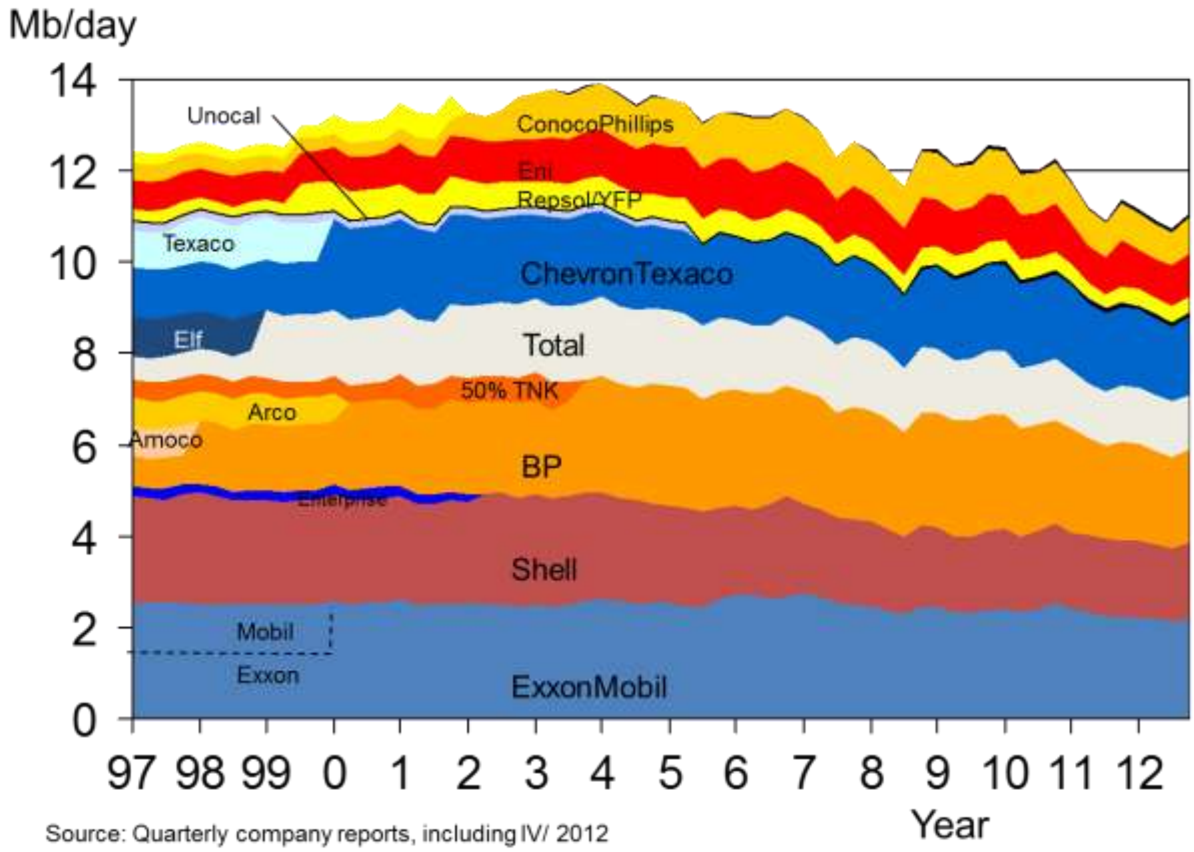



### *Company Statistics*

Figure 9 shows the aggregated production of major western oil companies. Their share of world oil production in 2004 when they experienced peak production was around 17 percent. In 2011 this share declined to 12 per cent. This is due to a production decline of almost 30 percent in a time when oil prices more than tripled. Obviously, these oil majors were not able to increase their production volumes. At end 2012 their combined oil production was 15 per cent below their 1997 production rate.

Various mergers between oil companies took place in the years 1997 to 2000. Some observers were interpreting these mergers as the cheapest way to increase production and reserves at a time when new discoveries became rare and cost intensive. For example Goldman Sachs:“The great merger mania is nothing more than a scaling down of a dying industry in recognition of the fact that 90 per cent of the world’s oil already has been found.” (Goldman Sachs 2000). However all measures taken by the industry could not stop the decline of production. This is mostly not reckognised by market observers because despite rising production expenses higher oil prices resulted in larger margins.

**Figure 9: Oil production of major western oil companies. The combined output of the formerly 17 companies declines since 2004 with an average rate of 2-3 percent per year.**




The higher oil prices resulted in higher earnings. But they were also needed by the companies as the expenses for production and exploration (E&P) increased substantially. Figure 10 shows these expenses for the three majors ExxonMobil, BP and Shell. Their combined effort rose by a factor of four since 2000, which corresponds to an annual increase of 15 percent. The figure also shows that most of the investment was put into the development of new wells. The absolute amount invested in exploration in 2012 was not larger than in 1998.

**Figure 10: Development of expenses for exploration (yellow area) and production (red area) of the three companies ExxonMobil, BP and Shell according to their quarterly reports.**

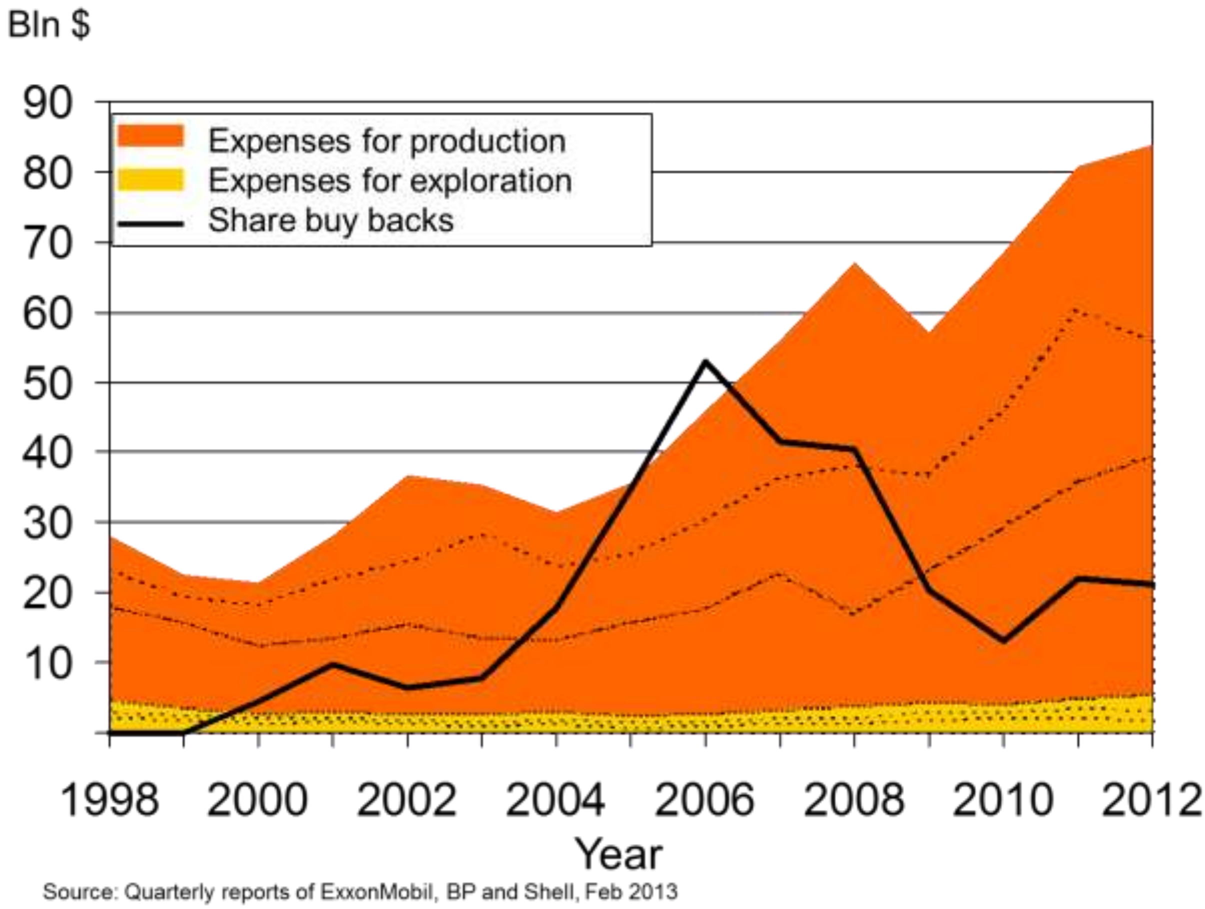



Figure 11 shows that earnings before taxes also increased over time. Once the production decline of the oil majors cannot anymore be compensated by rising oil prices, they will soon run into financial problems: They will either have to explain and justify to shareholders the stagnating or declining earnings and/or will have to reduce expenses for E&P which in turn would result in steeper decline rates.

**Figure 11: Earnings before taxes of the leading western oil companies ExxonMobil, BP and Shell. Due to rising oil prices the earnings increased despite declining oil production and rising expenses for exploration and production.**

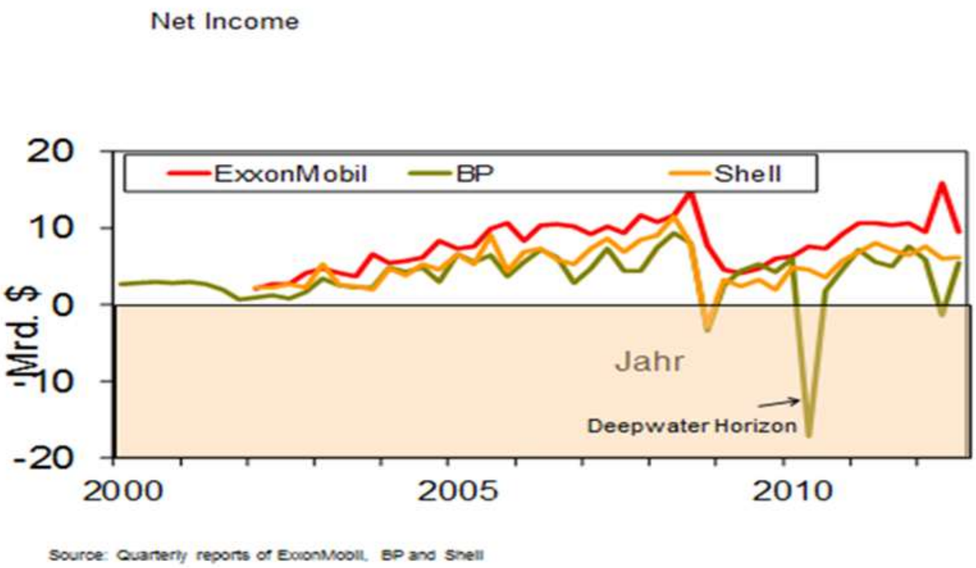
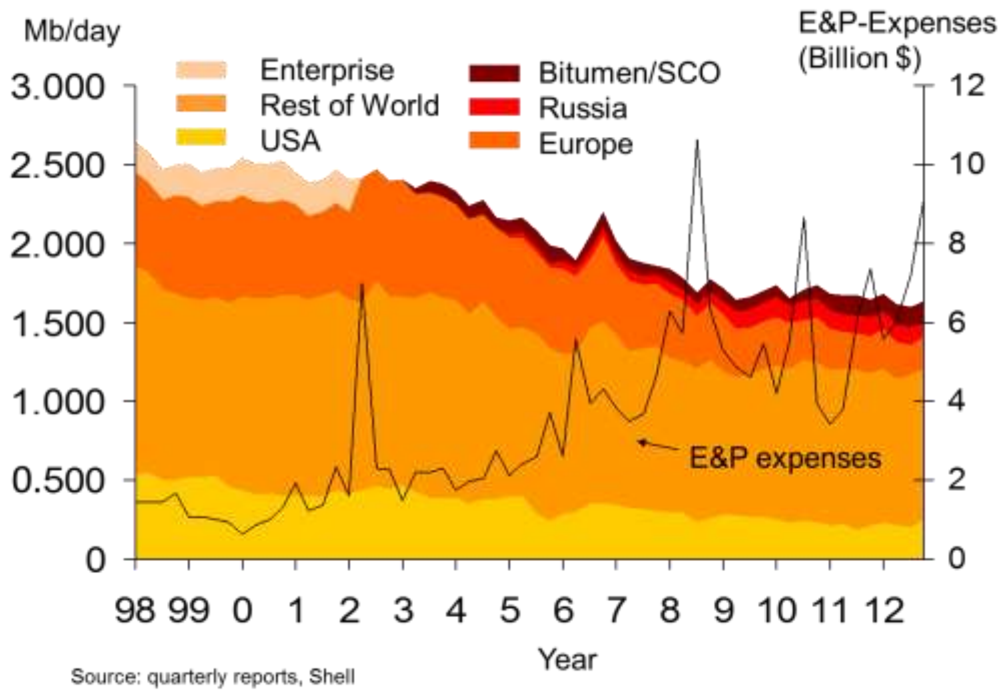



Figure 12, Figure 13 and Figure 14 show more detailed statistics for Shell, BP and ExxonMobil. Shell experienced by far the largest production decline of almost 40 per cent since 2003. The decline started just a year after they had bought the company Enterprise for about 5 billion USD. The year 2004 also marks the time when Shell was found guilty of having overstated its reserves. This resulted in the resignation of the CEO Sir Philip Watts, the payment of 17 million pounds fine and of 450 million USD to shareholders. (quoting).

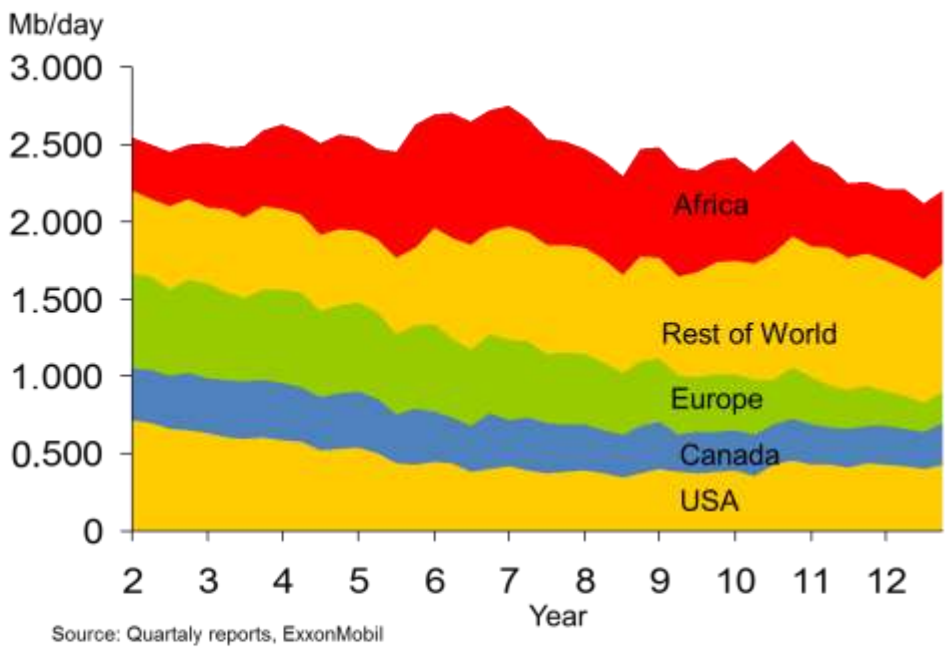
The figure also reveals that the engagement in Canadian bitumen development and upgrading could not reverse the production decline, though it was very expensive. Probably Shell was buying reserves rather than short term production potential.

**Figure 12: Shell – Quarterly oil production data and expenses for exploration and production since 1998. Though the expenses for E&P increased fivefold the production declined by more than 30 percent since 2000.**



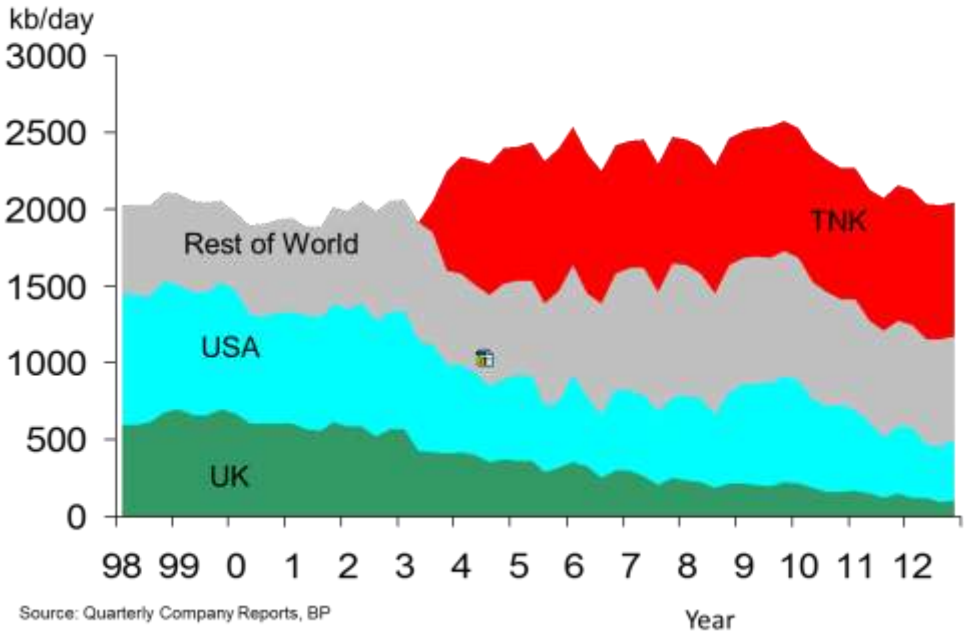

The production decline of ExxonMobil was less dramatic with only 20 per cent. Though the decline started only in 2007, it resulted in a steeper annual decline rate of four percent.

**Figure 13: ExxonMobil – Quarterly oil production data since 1998.**



The final example shows oil production data of BP. BP could even slightly increase its production volume until 2010, partly attributable to the investment into the Russian giant TNK. This acquisition was also responsible for the production increase in 2004. But notably BP shows the steepest annual decline rate since 2010 with almost 10 per cent.

**Figure 14: BP - Quarterly oil production data since 2002.**




## *EWG – scenario update*

The EWG scenario from 2008 (EWG 2008) is used as baseline and scenario calculations are updated were new information is believed to provide a better base for projecting possible future developments. In the first two subchapters only the development in some key countries are discussed: first countries where production was lagging behind expectations in the last years, and second, countries still regarded as being promising candidates for an increasing future oil production. The third subchapter aggregates regional production profiles to a global oil production scenario until 2030.

### *Key supply countries*

*Saudi Arabia:*

For a long time Saudi Arabia was believed to act as a swing producer and to provide additional oil barrels whenever they were needed. Still in the WEO 2004 it was expected that “Saudi Arabia will undoubtedly account for a major share of the increase in Middle East production” (WEO 2004, p. 111). This production increase of Middle East was believed to rise from 19 Mb/d in 2002 to 37.4 Mb/d in 2020 and then to 51.8 Mb/d in 2030. In WEO

2010, Saudi oil production in 2030 was expected to be much smaller with 14.6 Mb/d while total Middle East production was also revised downward to 34.1 Mb/d.

The latest WEO 2012 for the first time acknowledges that Saudi Arabia probably won't increase its production any further: 11.4 Mb/d are expected in 2030 while 2011 production amounted to 11.1 Mb/d.

Though 265 Gb of reserves are reported which remained almost unchanged over the last two decades, the reserve situation of Saudi Aramco is not as comfortable as these numbers might suggest. These numbers are highly questionable. Constant remaining reserves over twenty years of production would require that in total 75 Gb should have been added to the reserves in order to compensate for the cumulative production of 75 Gb from reserves. However, there were no discoveries during that period which could have been added to reserves. Therefore, a major uncertainty about the future of Saudi Arabia's oil production is the uncertainty of reserves estimates.

Figure 15 gives a short summary of the reserve situation. According to Jack Zagar, a petroleum engineer who spent many years developing production plans for Saudi oil fields, the total oil in place which has been found up to 2005 amounts to 582 Gb (Zagar 2005). In the figure, the historical discovery pattern based on data from IHS-Energy (IHS 2006) is adapted to that number while separating discoveries onshore (dark brown area) and offshore (blue area). These numbers are extrapolated until 2012 by the authors. The broken red line in the figure shows the estimated ultimate recovery (URR) under the assumption that on average 45 percent of the original oil in place can be extracted. This would result in an estimated URR of 264 Gb of which 134 Gb have already been produced at end 2012. The cumulative production between 1938 and 2012 is shown by the full red (onshore) and blue (offshore + onshore) lines. According to this analysis, reserves of 130 Gb are still available for future production.

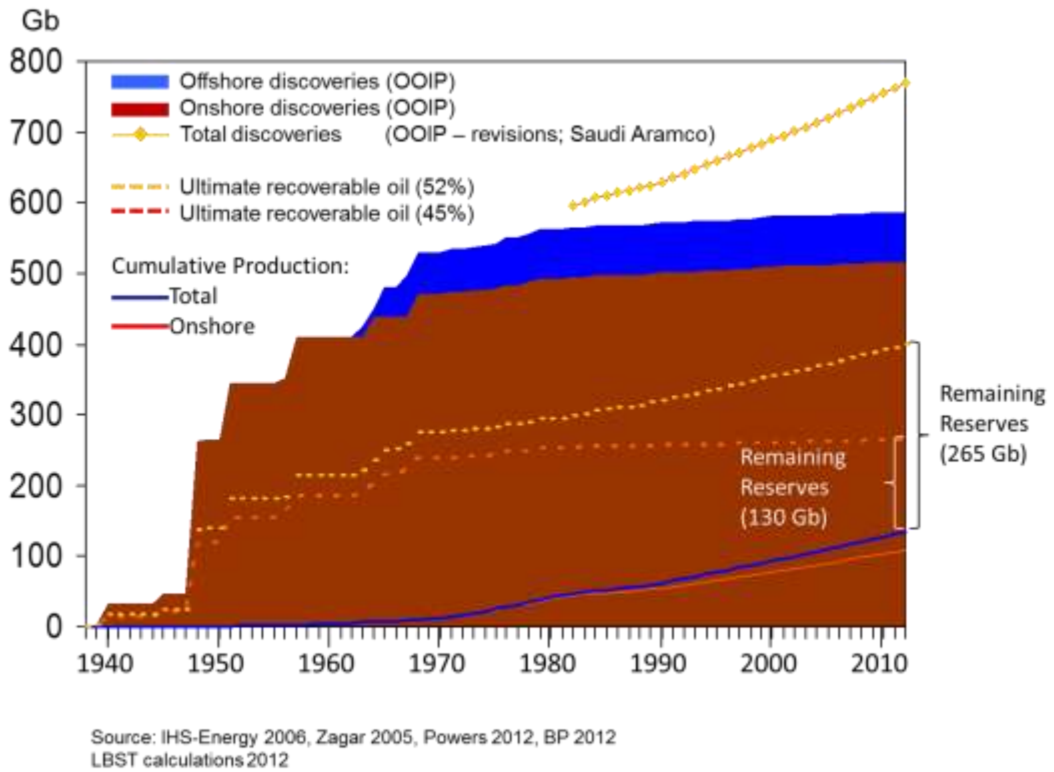
On the other hand, Saudi Aramco every year reports almost constant reserve numbers of 265 Gb even though 3 to 4 Gb are produced annually. As no new discoveries are known which could justify these reserve revisions, obviously these numbers must be interpreted differently:

A possible explanation are different assumptions regarding the recovery factor. In case that 52 percent instead of 45 percent of the original oil in place can be extracted, the URR would increase correspondingly. This is assumption is represented with the yellow broken line. It shows that in 1980 the ultimate recoverable oil had amounted to about 293 Gb. The annual revision of the proven oil reserves without new discoveries would mean, that the recovery factor would have increased from 52 percent in 1980 to 68 per cent in 2012.

The other possible interpretation would be that the estimates for the original oil in place were wrong in the early years and were later continuously upward revised each year in the way as shown by the line with the yellow diamonds. In that case the recovery rate of 52 percent would be constant over time, but the oil in place estimates would have been revised upward each year, up to 770 Gb in 2012.

A third interpretation could be that the estimate for the original oil in place already in 1980 amounted close to 770 Gb and that the recovery factor at that time was assumed to be 35 percent. If so, the recovery factor each year was continually revised upwards from 35 percent in 1980 to 52 percent in 2012. But the problem remains that these huge "oil in place"-numbers cannot be attributed to the individual oil fields which are known for a long time and are fairly well analysed by international petroleum engineers.

**Figure 15: Cumulative oil discoveries in Saudi Arabia, cumulative reserves and cumulative production**




Based on this figure it also could be argued – which often is done in the blogs – that the Saudi reserve number of 265 Gb does not specify the remaining reserve but the ultimate recoverable oil from which the produced oil has to be subtracted. This would also answer the question why this reserve figure each year is kept constant.

Following the numbers of Saudi Aramco, the reserves at end 2012 are 265 Gb. Louis W. Powers, also a reservoir engineer who worked for a long time in the industry, and for two years as Saudi Aramco's chief petroleum engineer, regards the 265 Gb of remaining reserves as being reliable (Powers 2012). Following Jack Zagar's analysis, the remaining reserves at end 2012 are 130 Gb of oil when his number of 157 Gb for end 2005 is extrapolated to 2012 (Zagar 2005).

Based on the analysis given above and various indications on production declines from aging fields we take 130 Gb as being a more realistic number for Saudi Aramco’s recoverable oil reserves at end 2012.

Saudi Aramco stated in 2004 that the natural decline rate of aging fields in Saudi Arabia amounts to around 8 percent per year, but that the decline rate is reduced to 2 percent by infill drilling. But this will work only for a limited time. Therefore, eventually the decline of the big aging fields has to be compensated by developing new fields in a timely manner. However, the last remaining large onshore discovery, Manifa, will start production late in 2013 or 2014. If no further significant new fields come on stream in the next years, Saudi Arabia’s oil production is expected to decline significantly.

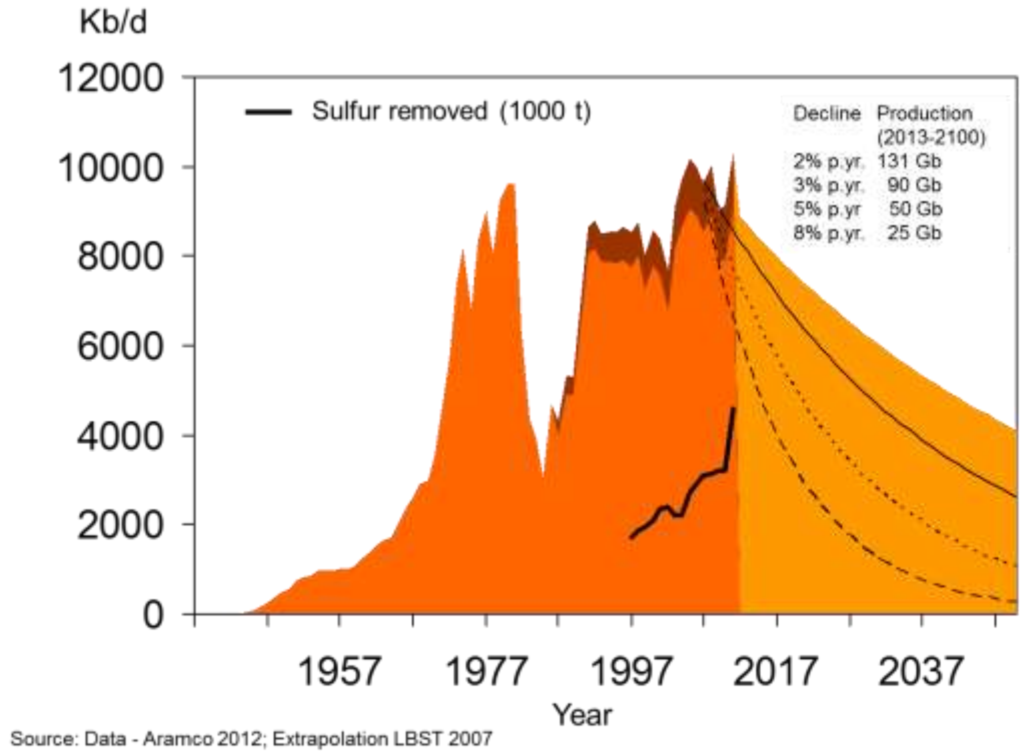
The huge exploration efforts undertaken by Saudi Aramco, notably the offshore exploration in the Red Sea, are indicators of a situation where new discoveries are needed to replace produced volumes. [Khawaia 2012]. The latest increase of production from January 2009 until July 2012 was based on several workovers in elder known fields, among them the fields Khurais [Burn 2012], Shaybah and Nuayyim (Powers 2012). Other not yet developed large discoveries are missing. Therefore, some observers expect Saudi Arabia’s output to already decline in 2013 by 4.5 per cent [Carey 2013].

Figure 16 shows the historical oil production in Saudi Arabia and our scenario calculations until 2050. The black line shows the amount of recovered sulphur. Since 1997, on average the sulphur content of the oil more than doubled – another indicator that the time of “easy to produce oil” has gone.

The scenario calculations with a varying decline rate of 2, 3, 5 and 8 percent were already performed in the EWG 2008 study (EWG 2008). The cumulative production between 2013 and 2050 would require remaining reserves of at least 131 Gb, 90 Gb, 50 Gb and 25 Gb. In total these developments would require an estimated ultimate recovery of at least 265 Gb, 225 Gb, 185 Gb, and 160 Gb.

Despite the observed production increase in 2011/12 we believe that a 2 percent average decline rate over the next decades is a moderate decline scenario. Because it is deemed unlikely that the 8 percent decline rate of the old fields can be adequately compensated in the longer term. If we adapt our scenario decline rate by taking the production of 10.2 Mb/d in 2012 as starting point, the future decline rate must grow to at least 3 to 4 percent per year. Otherwise the cumulative production between 2013 and 2100 would exceed the remaining reserves.

**Figure 16: Oil production in Saudi Arabia and Scenario calculations**




*Iran and Iraq*

Both countries together have larger reported reserves than Saudi Arabia according to public domain statistics. But their production lags far behind this potential. Like for Saudi Arabia, these reserve numbers are highly questionable.

According to the WEO 2004, the Iranian Ministry of Petroleum in November 2003 set a production target of 5 Mb/d for 2010 and 8 Mb/d for 2020. Based on these targets, the WEO 2004 argued that “Iranian production could double by 2030”. (WEO 2004, p. 113) The future output from Iraq was seen as being highly uncertain at that time.

But in the WEO 2010 this view was already modified: Iran’s output was seen at 5.1 Mb/day in 2030 and Iraq’s output at 6.1 Mb/d, rising further to 7 Mb/d in 2035.

In the WEO 2011, these projections were only slightly modified: Iran’s production in 2030 was downward revised to 4.5 Mb/d and Iraq’s output upward to 6.8 Mb/d in 2030 (7.7 Mb/d in 2035). The WEO 2012 goes a step further: Iran’s output in 2030 is downward revised again to 4 Mb/d in 2030, Iraq’s output upward revised to 7.5 Mb/d in 2030 and 8.3 Mb/d in 2035, expected to become by far the second largest OPEC producer behind Saudi Arabia.

At present problems in Iraq and Iran are still huge, producing fields are mature and new developments are slow. Iran’s target of 5 Mb/d in 2010 was missed with 4.1 Mb/d (US-EIA) which all the same was the largest annual output in the last decades. In 2012 Iran’s production declined to 3.4 Mb/d.

Iraq reached a production volume of 3 Mb/d so far. In recent months, Western companies have reduced their engagement in Iraqi oil fields.

To sum up: the EWG scenario assumes that OPEC output is now at peak and will decline by 2 per cent annually in the coming two decades.

*Russia, Kazakhstan and Azerbaijan*

Oil production in Russia is at peak. In the WEO 2004, Russian output was expected to rise from 10.4 Mb/d in 2010 to 10.8 Mb/d in 2030. In the WEO 2012, it is acknowledged that Russia is now at peak production. Output in 2030 is expected to decline to 9.3 Mb/d. For the updated EWG scenario, this decline is seen as too moderate. The decline rate assumed for Russia is 2 to 3 percent annually.

Both, Azerbaijan and Kazakhstan were believed to possess huge oil fields. In 2000, total output from the Caspian region was seen in 2000 to rival Saudi Arabia as the world's largest oil producer by 2015. But these hopes have been disappointed to a large extent. Today, the largest giant field in Azerbaijan on which many hopes rested, Azeri in the Caspian offshore, has passed peak production and until 2020 will decline to negligible production volume. Additional large fields which could compensate for this decline are not known. The WEO 2012 states that the output of Azerbaijan will fall to or below 1 Mb/d.

But another hope is still alive, resting on the huge oil fields in Kazakhstan. Although future production has been downward revised by IEA, the WEO 2012 expects Kazakhstan oil production to reach 3.4 Mb/d in 2030. This is mainly based on the development of the offshore field Kashagan. The field was discovered in 2000, though Russian geologists knew of its existence already in the Former Soviet Union, but were unable at that time to meet the technological challenges. Yet, up to now the development of Kashagan has been a nightmare for its owners. The highest field pressure ever measured in an oil field challenges existing production technologies and requires completely new constructions and materials. High sulphur content in the oil combined with hydrogen makes the work dangerous, as any blow out could have fatal consequences for the workers. Added to this are unfriendly environmental conditions (Shallow water or swampy land – depending on weather and wind conditions). Altogether these circumstances retard the development of the field. First oil was expected to flow in 2005. Today, in 2013, the development is even further behind time schedule and first oil is expected to flow in 2014 or 2015.

According to our assessment, there is no reason why oil production from Kazakhstan should substantially increase. The EWG scenario expects a slight increase of total production until 2015 and a slight decline thereafter.

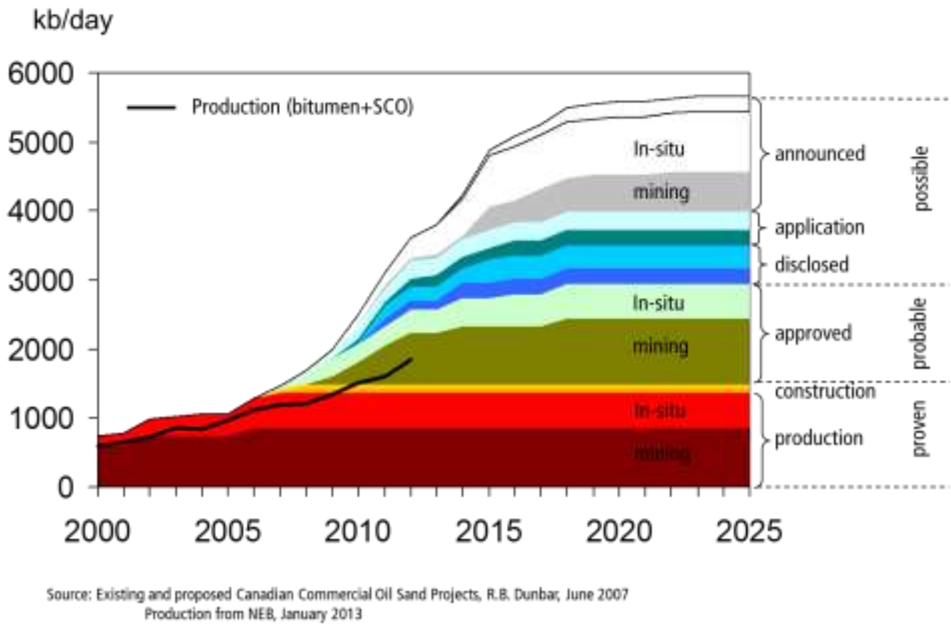
*Tar sands in Alberta, Canada*

Ten years ago, unconventional oil – tar sands in Alberta and extra heavy oil in Venezuela – was discussed as being the future of oil. Addressing this topic, the oil major ExxonMobil devoted a title story in its 2003 publication “Oildorado”, where the cover showed bitumen mining in Alberta, Canada. However, in the last years this hope has been disappointed more and more.

Even oil prices around 100 $/bbl are too low to foster new projects. Moreover, in November 2011the majority shareholder of Syncrude delayed expansion plans to beyond 2020 due to exploding costs (Healing 2011). As discussed above, Shell is in delay with its expansion plans as well (see Figure 12 above). But also limited transport capacities for export of syncrude to the US beyond the destination of Cushing, together with an oversupply of oil in Cushing, lead to depressed prices and are a further reason for the delay of new tar sand developments in Canada.

Figure 17 shows the projected production capacity of all mining and in-situ tar sand projects which were known in 2007 (Dunbar 2007). These projects are separated into mining projects and in-situ projects. The graph distinguishes also the level of realisation at the time of publication in 2007. The grouping “production” and under construction” can be interpreted as proven reserve, as the later operation of these projects is almost ensured. At that time approved projects had a high probablity of becoming realized and are classified as “probable”. Additionally, the future of projects which were in the status of “disclosure”, “application” or “announced” was relative uncertain and they were classified as possible projects. The dark line in the figure gives the actual production rate of bitumen and synthetic crude oil from 2000 until 2012. From the figure it is obvious that only half of all the projects listed in 2007 and 70 per cent of proven and probable projects has been realised so far, lagging far behind the time schedule.

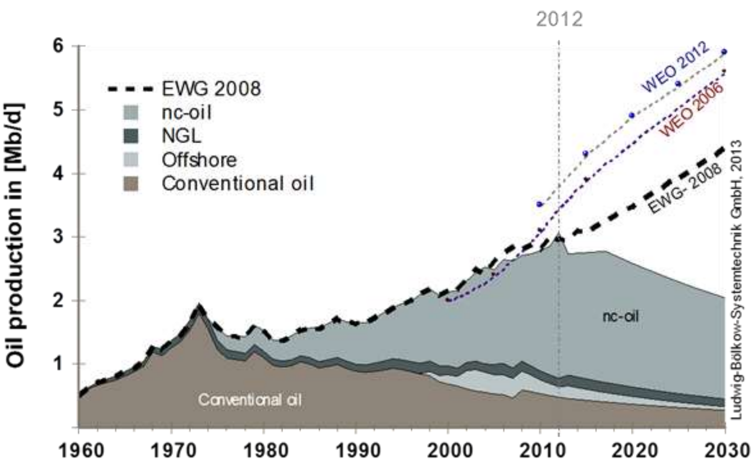
**Figure 17: Mining and in-situ tar sand projects production capacity until 2025**




For the reasons discussed above, the updated EWG-scenario considerably reduces the production from tar sands until 2030.

Figure 18 shows the updated scenario calculations for Canadian oil production until 2030. Also shown are the EWG-scenario 2008 and the scenarios in the WEO 2006 and WEO 2012 by the International Energy Agency.

**Figure 18: Oil production in Canada until 2030**




*USA*

Commercial US oil production began 150 years ago. Discoveries peaked about 70 years ago. Production in the lower 48 states peaked in 1970 at 11 Mb/day. Since then production is in decline. When oil prices increased the more challenging oil region in Alaska was developed though the huge oil fields were already discovered before. Alaska passed peak production in 1989.

Already 60 years ago, oil in the shallow offshore waters was discovered and developed. Offshore exploration in the deep sea started around 1980, first offshore Brazil and in the Gulf of Mexico. But all these new frontiers could not reverse the production decline of crude & condensate from 11Mb/day in 1970 to 5 Mb/day in 2007. Additionally, natural gas liquids (NGL) amounted up to 2 Mb/day.

The US oil consumption could steadily grow until 2005 enabled by rising imports. However, 2005 was a turning point for oil imports. Due to rising fuel costs, the demand declined. At the same time domestic oil production reversed its long downward trend and increased over the years 2008 – 2012.

Domestic oil production in the US was growing in the deep-water area of the Gulf of Mexico. In 2000 the US Energy Information Administration’s position was that Gulf of Mexico oil production would be boosted to 2 – 3 Mb/day around 2010 and that oil production in the Gulf of Mexico would rise to 2 – 3 Mb/day, a level that could be maintained for the next 10 to 20 years.

However, in actual fact production in the Gulf of Mexico only shortly reached a peak of 1.5 Mb/day around 2008, when the largest discovery (Thunderhorse and its satellite Thunderhorse North) was developed. But production from these fields declined much faster than expected: Between 2008 and 2012 oil production from Thunderhorse declined by as much as 90 per cent.

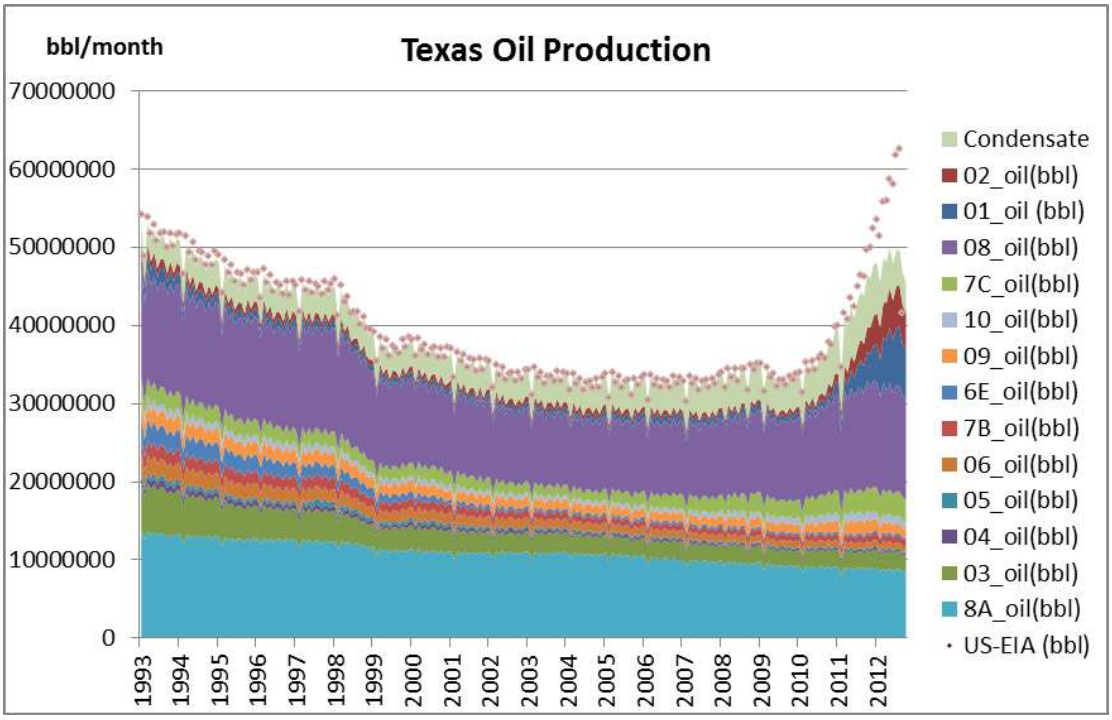
At present another frontier area is praised as having the potential to boost US oil production to new high levels making the US number one oil producer ahead of Saudi Arabia: light tight oil.

Though light tight oil is found in many areas, only in very few areas the conditions are favourable enough to allow for significant production increases. Actually only a few counties in Texas and in North Dakota could greatly increase their production. A more detailed analysis of the regional production patterns in the USA is provided in the last chapter. Therefore in the following only a comprehensive summary is given.

Figure 19 shows the oil production in Texas according to different statistics. The coloured areas show the contribution from individual regions inside Texas as reported by the Texas Railroad Commission (TRRC). Texas is divided into 13 districts, each of them is further subdivided into 20 counties on average. The upper grey area shows the contribution of condensate which is counted separately in the statistics by the regional supervising authority, the TRRC. The small dots show data for total oil production of Texas including condensates published by the US-Energy Information Administration (US-EIA). From the figure it is obvious that these two statistics match almost exactly until 2010, but start to increasingly deviate from each other as time progresses. Especially in the last two years the US-EIA data grew enormously to 63 Mb/month (2.1 Mb/day) while the detailed regional monthly statistics by TRRC show a much smaller production increase to 50 Mb/month (~1.7 Mb/day). Obviously these two statistics differ considerably for the last year.

The figure also shows that the production increase is restricted to almost only two districts: District 1 and District 2.

**Figure 19: Regional disaggregation of Texas oil production since 1993**




Though there were some increases in other districts, by far the largest increase is concentrated in these two regions. Predominantly this increase is due to the development of light tight oil assets by means of hydraulic fracturing. However, as the statistics for Texas do not distinguish between unconventional tight oil wells and conventional oil wells, the analysis is based on a geographical distinction. In other districts the net balance of declining mature wells and rising new (tight oil) wells is almost balanced or even negative.

A more detailed analysis given in the Annex exhibits that even within the productive districts the locations of productive new wells are restricted to only a few counties: in total to about 10 counties out of more than 200 oil producing counties in Texas.

Figure 20 shows the total US oil production of individual regions. In this figure, regions with rising oil production are shown separately. Beside the two mentioned districts in Texas (yellow area in the figure) only oil production in North Dakota (dark brown area) rose within the last four years. The aggregate total of all other regions follows the long-term declining trend. Even the offshore region in the Gulf of Mexico experienced the steepest declines in 2011 and 2012.

The total for all regions in the US does not match the aggregated total (blue line) when for Texas the data from Figure 48 (TRRC) are used instead of US-EIA data. But US-EIA statistics are the source for all other data. The white area marks the growing gap between these two data sets. Taking the more accurate regional TRRC data for Texas results in a much more moderate production increase than the aggregated US-EIA numbers suggest.

These data indicate that the US production increase since 2008 is only half as large as suggested by the aggregated US-EIA data. For this figure, production data for Texas are divided into the contribution from District 1& 2 and the rest of Texas.

The monthly data include data up to October 2012. Therefore annual averages for 2012 are calculated by extrapolating the production in the first ten months to the whole year.

**Figure 20: Regional disaggregation of US oil production; still promising regions are shown separately**

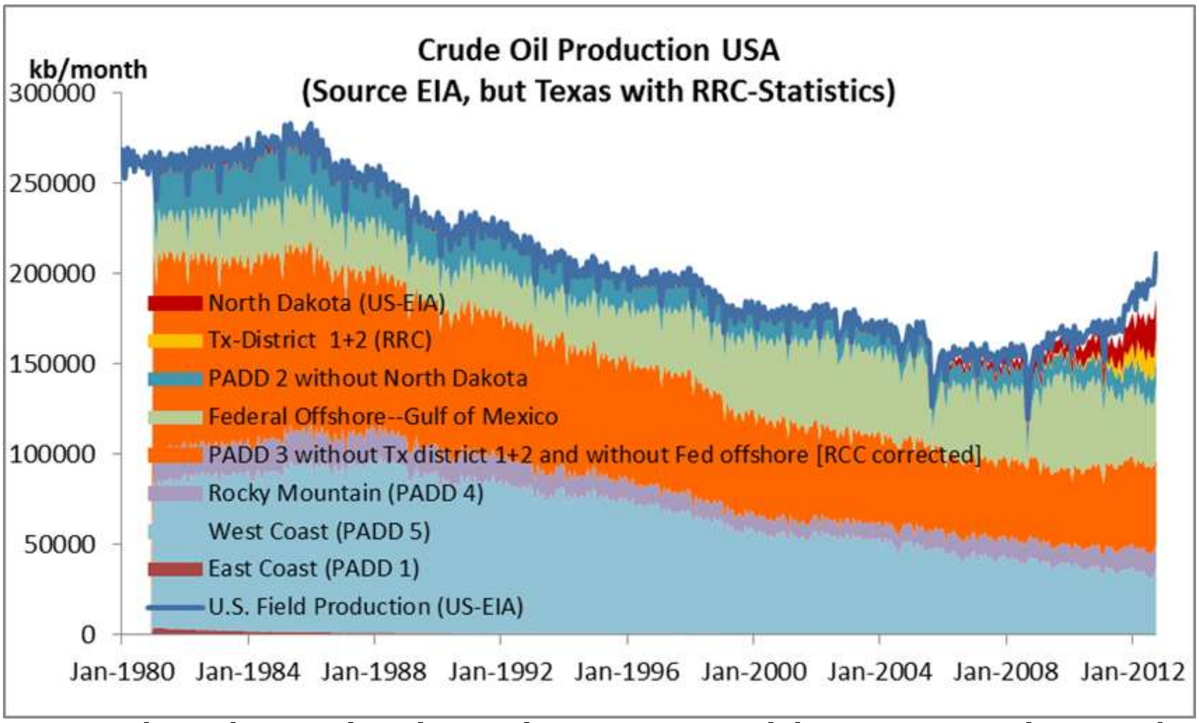


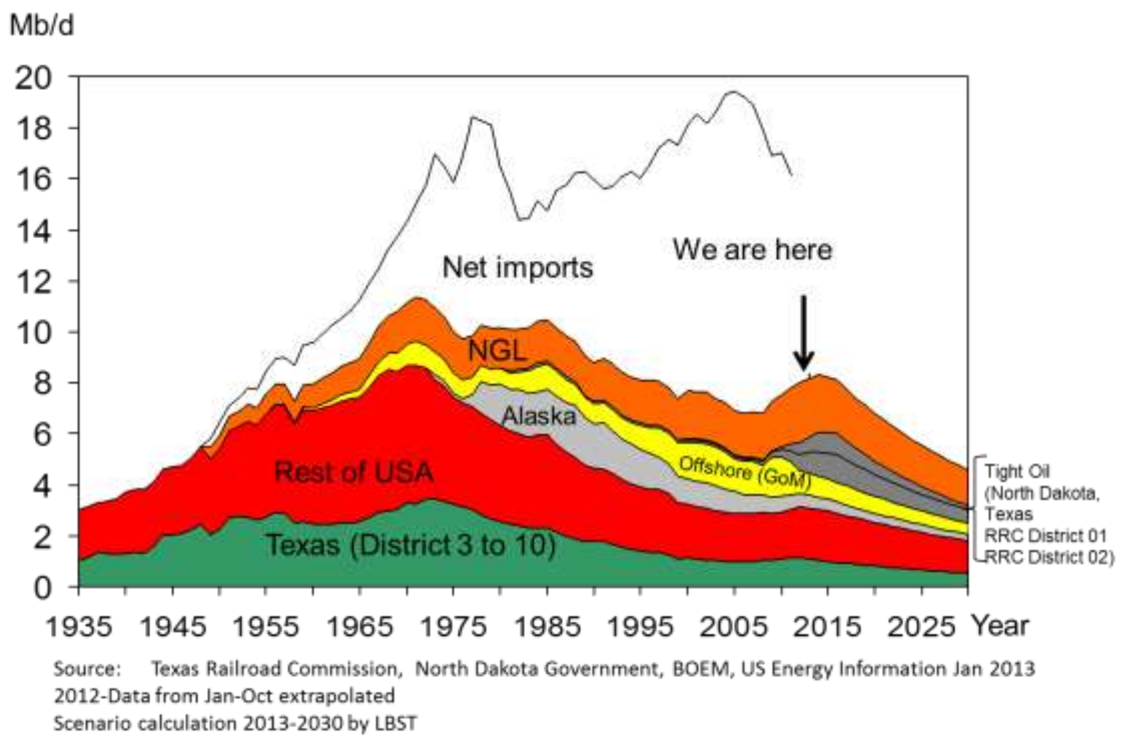

Figure 21 shows the annual production data since 1935 and the projection until 2030. When the production of North Dakota and District 1 & 2 in Texas is excluded, the aggregated production of the rest of the USA (other districts in Texas, all other lower 46 states, offshore production in the Gulf of Mexico, Alaska) follows its long-term declining production trend.

The two grey areas give the results of the scenario calculations for North Dakota and District 1 & 2 in Texas. Situated in these two regions are by far the largest and most promising geological trends containing light tight oil, namely Bakken (North Dakota) and Eagle Ford (Texas). Future production of light tight oil in these regions is claimed to have the potential of reversing the US domestic oil production upwards for at least 10 to 20 years. However, more detailed analyses cast doubts on these expectations. The dynamics of the high decline rates of producing wells requires the continuous drilling of many new wells just to compensate for the decline of the base production. Lead times for the development of new wells and accessible land area determine the development speed. Therefore, the aggregate production profile depends on these two parameters. Based on scenario calculations, it is highly probable that the rising production from Bakken (North Dakota) and Eagle Ford (Texas) will reach peak within the next two to three years and decline thereafter.

More details on these scenarios are given in the Annex which focusses on US fossil energy production. As a result, the expectation is that total US production soon will return to its long-term declining trend. In 2030 the production probably is much lower than today. The contribution from natural gas liquids is added in the figure on top of crude oil and condensate production. In addition, net oil imports are added in the figure (white area). The total equals the total domestic oil demand of the USA.

Total US oil demand declined since 2005 at an unprecedented decline rate and has now reached a level last seen in the 1980s. Hamilton (2009) shows that high oil prices caused this demand destruction which culminated up to now in the 2009 recession. When the present trend continues, total demand might be reduced by 50 per cent in 2030 compared with its 2005 level when it reached an all-time high.

**Figure 21: US oil production since 1935 and forecast until 2030 and accounting for light tight oil production**

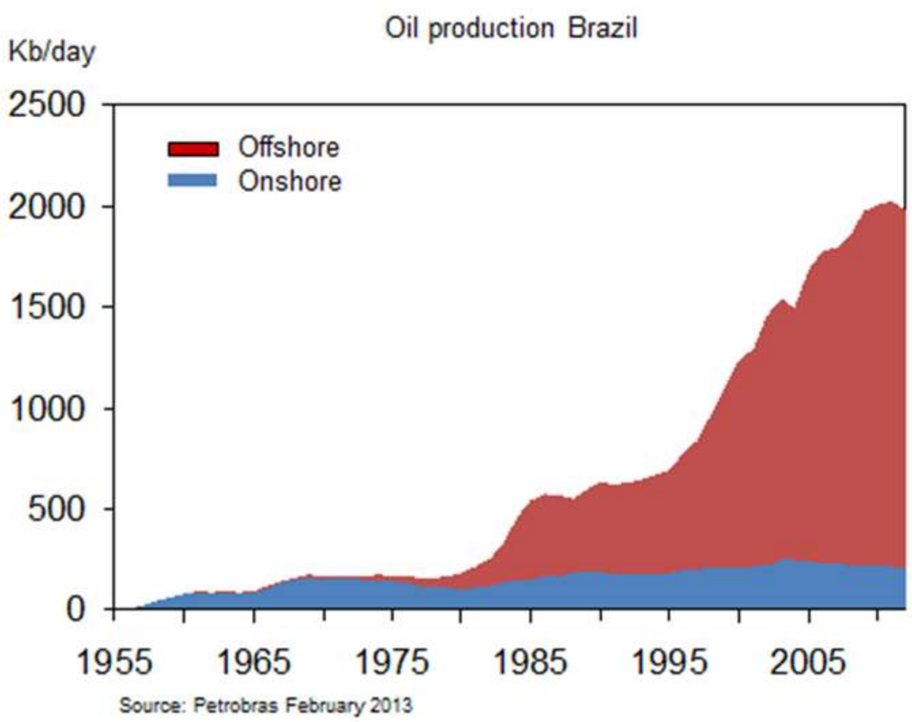


*Brazil*

Deepwater technology was developed more than thirty years ago to access the oil fields offshore Brazil since there are not many onshore oil fields in Brazil. The production rose to a plateau which lasted from 1985 to 1995. Then, new technology allowed the access to ultra-deep waters of the Campos and Santos Basins 50 – 150 km off the coast line.

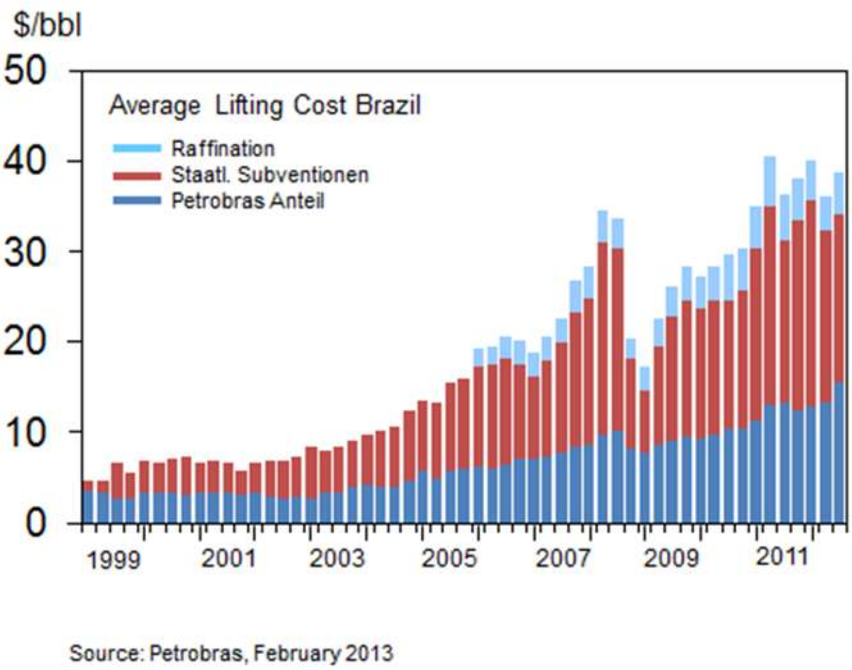
In total more than 40 fields have been discovered offshore, most of them are already producing. The frontier area at present is in the pre-salt layers up to 250 km off the coast line and several thousand meters below the sea floor. In the last years, technical problems mounted and so did development costs bringing Petrobras to its financial limits. Cumulative production at end 2012 amounted to 13.6 Gb of which 10 Gb were produced offshore. At end 2012 proven reserves in Brazil are reported at 10.5 Gb (Petrobras 2013).

**Figure 22: Oil production in Brazil (Petrobras 2013)**




The development of the deepwater fields is technologically and financially challenging. In 2012, the company Petrobras had unexpected high expenses for exploration and production (42 billion USD), its net debt rose continously from 48.8 billion USD in 2008 to 147.8 billion USD at end 2012. ("This result, 36 percent below 2011 net income, was the result of growing oil product imports at higher prices, the depreciation of the Real, which impacts both our financial result and operating costs, and the increase in non-recurring expenses such as dry hole expense. Contributing to the lower income was the daily production of oil in Brazil, which although within our target range, was 2 percent lower than 2011." Petrobras 2013). Figure 23 shows the rise of average lifting cost over time: Within one decade these increased five to six times. This rise is predominantly due to rising marginal lifting costs of new developments.

**Figure 23: Quarterly average lifting cost of Petrobras (data source: Petrobras 2013)**




Despite these problems the IEA sets ever larger hopes on Brazil's future production capacity: In the WEO 2004 total Brazil production in 2030 was expected to reach 4 Mb/d, in the WEO 2010 and WEO 2011 this expectation was raised to 5.2 Mb/d and being kept stable even until 2035. The latest WEO 2012 now projects 5.5 Mb/d in 2030 and even 5.7 Mb/d in 2035. But the reality of the last few years looks quite different, production rose only marginally and even declined in 2012, while oil imports had to be increased. Instead of supplying the world with oil, Brazil remains a net importer with rising imports. The EWG update does not change the production forecast for Brazil against the 2008 scenario, expecting a rise to 4 Mb/d in 2020 followed by a decline. (downward to 3 Mb/d)

### *The new EWG scenario – Regional summaries*

Figure 24 shows the world oil supply according to the EWG scenario 2013. The supply from different world regions is shown explicitly. Each region's production is shown in an individual figure (Figure 25 to Figure 35). The production of individual countries in a region is also shown.

Figure 24 also shows the world supply scenarios put forward by the International Energy Agency in 2006 (WEO 2006) and in 2012 (WEO 2012). These scenarios more or less extrapolate the business as usual trend of the past decades completely ignoring the risk of imminent peak production. Peak oil would be nothing less than a disruptive change – instead of each year a bit more oil a future with each year a bit less oil.

The thick broken line gives the result from the first EWG-scenario in 2008. At that time it was assumed that world oil production has peaked in 2006 and will then start to decline. Actually, in 2005 world oil production has entered a plateau which delays the following decline period. With each year, in which oil production stays on that high level, the probability rises that the eventual decline is beginning.

**Figure 24: World oil supply according to EWG scenario 2013**

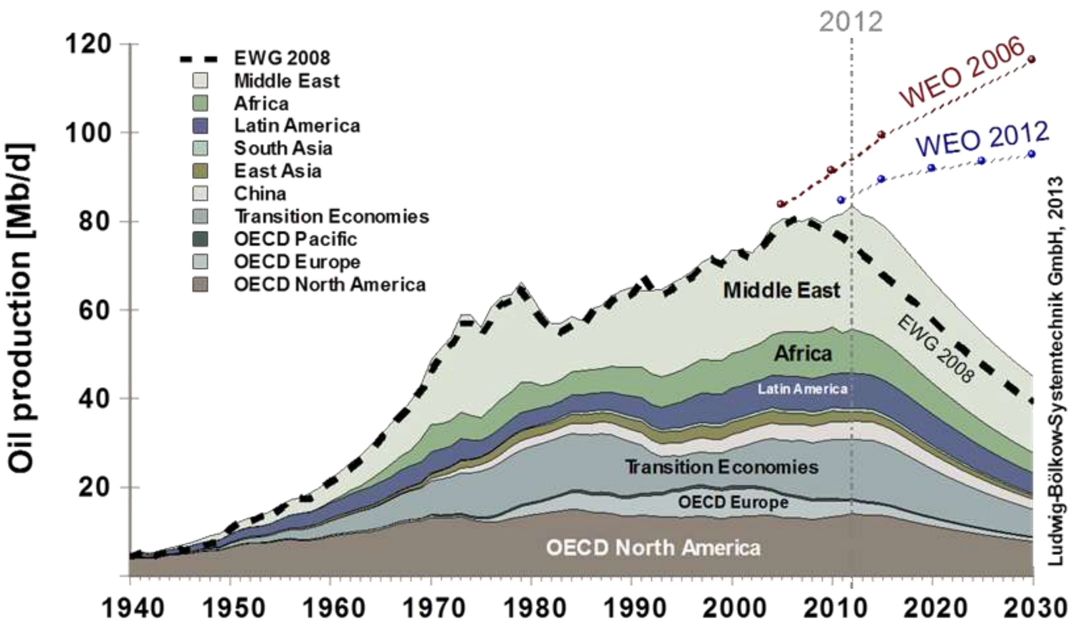



Figure 24 also displays minor differences between historical production data of EWG 2008 and the updated scenario. This difference is due to the choice of different data sets. In 2006 the industry data base IHS was used for all countries. In the update public domain production data are used in order to make the analyses more transparent. Government data are used for the following countries: UK, Norway, Denmark, Germany, Saudi Arabia (Aramco), Brazil (Petrobras), Mexico (Pemex), and USA (US-EIA, as well as Texas Railroad Commission and other regional authorities).

Another aspect to be noted is that all data are published in volumetric or weight units (Barrel or litres or Tons). But the energetic content of the volume or weight differs for different types of hydrocarbons. For instance, natural gas liquids contain about 25-30 per cent less energy per volume than crude oil. Also the energy content of different oil types and qualities varies from region to region (heavy oil, sweet oil, bitumen etc.).

Figure 25 provides a country by country assessment of world oil production between 1900 and 2050. Listed is the oil production of all producing countries, as well as the production of NGLs, and the production of unconventional oil in Canada, Venezuela and light tight oil in the USA. Since many producing countries have already passed peak, countries in the graph are ordered by the date of peak production. This presentation demonstrates that the rising decline from ever more countries must be compensated by ever few countries. These countries must increase their annual production permanently, to compensate for the decline in other regions.

**Figure 25: Country by country assessment of world oil production**

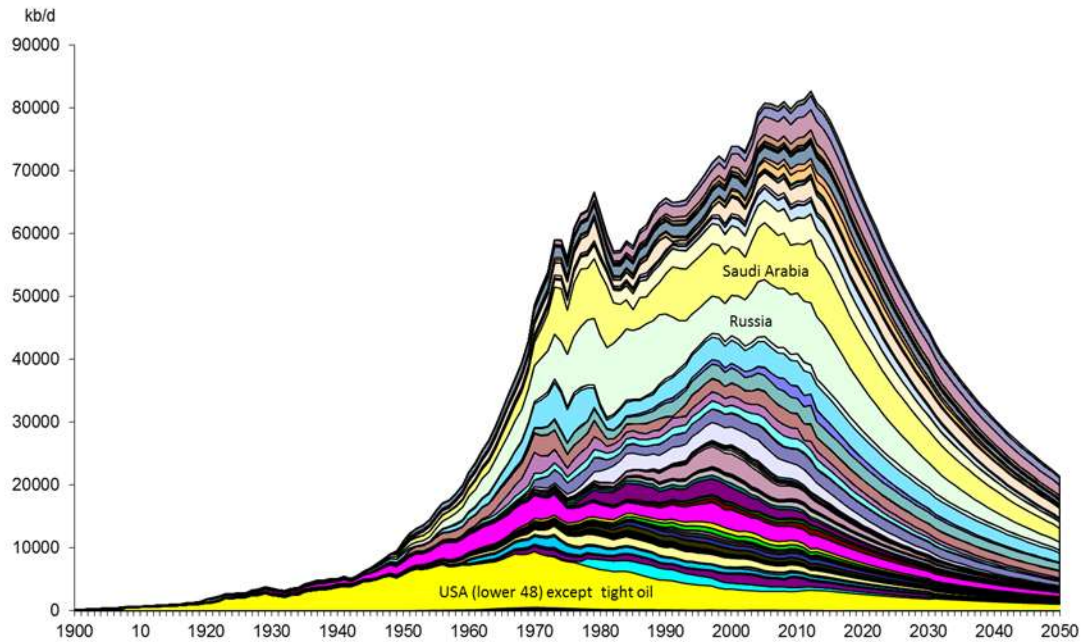



Figure 26 shows the total oil production in OECD North America. The contribution from Canada and USA were already discussed in more detail.

**Figure 26: Oil production in OECD North America**

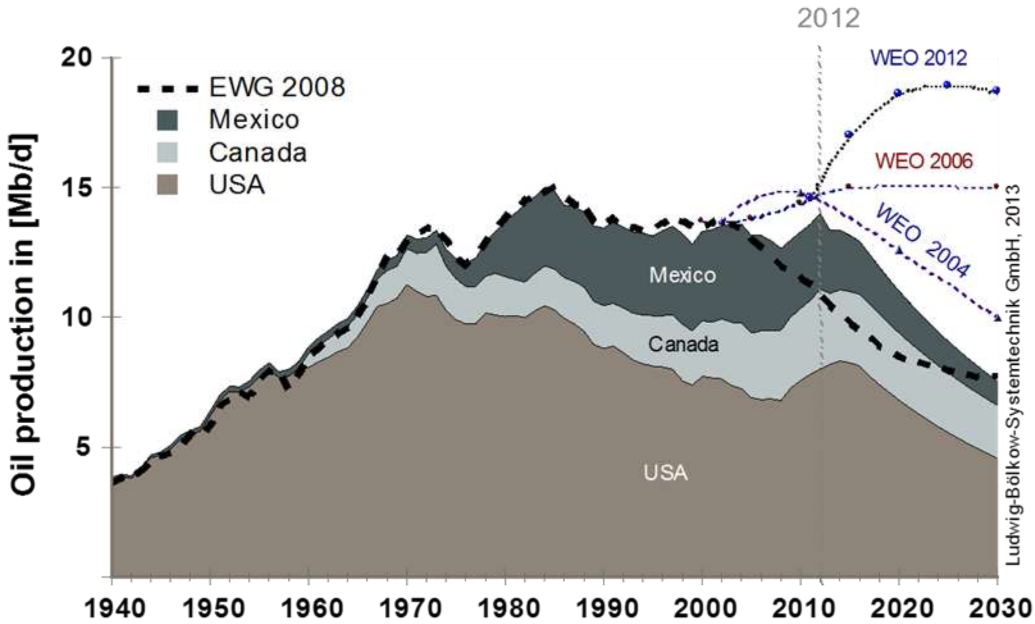



Figure 27 covers the oil production in Middle East countries which are dominated by the largest OPEC producers. Saudi Arabia, Iraq and Iran were already discussed above; data for other countries are the same as in the EWG-scenario 2008.

**Figure 27: Oil production in Middle East**

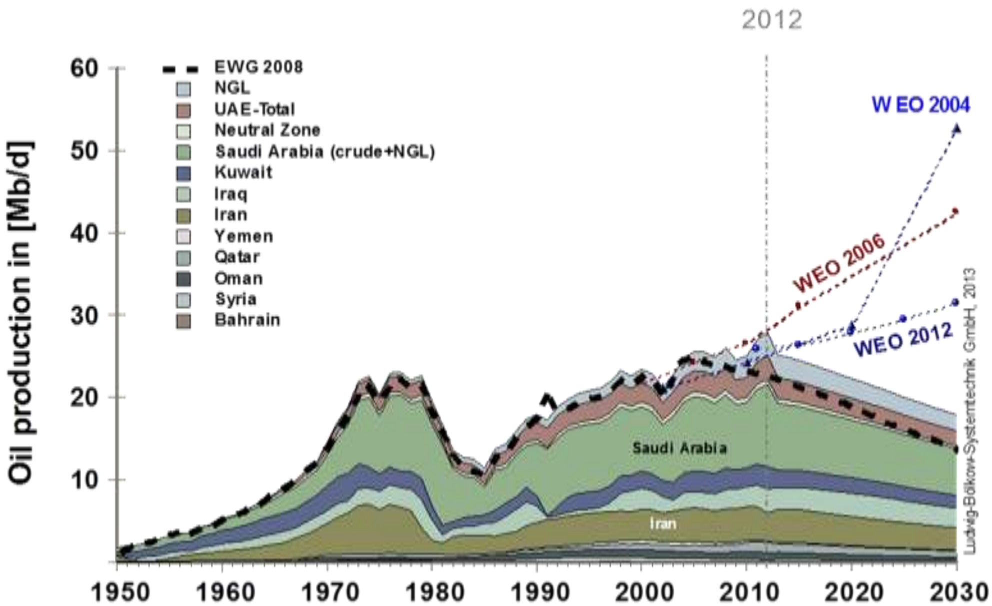



Figure 28 shows the oil production in the former Transition Economies. Oil production was lower than the expectation in 2008 and probably has now reached peak. Possible production increases in Kazakhstan are more than offset by the expected decline in Russia and Azerbaijan.

**Figure 28: Oil production in Eastern Europe and Eurasia (former Transition Economies)**

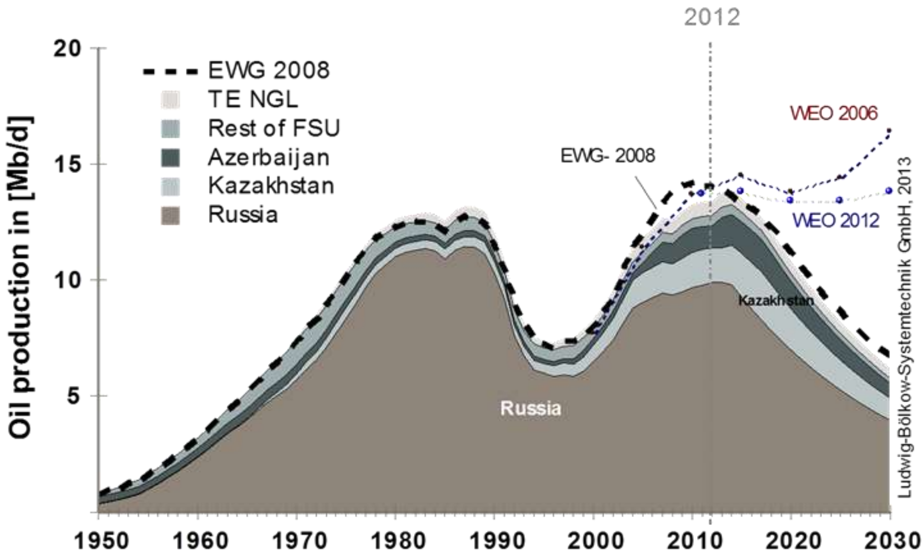



Figure 29 shows the oil production in Europe. All countries are in steep decline.

**Figure 29: Oil production in OECD Europe**

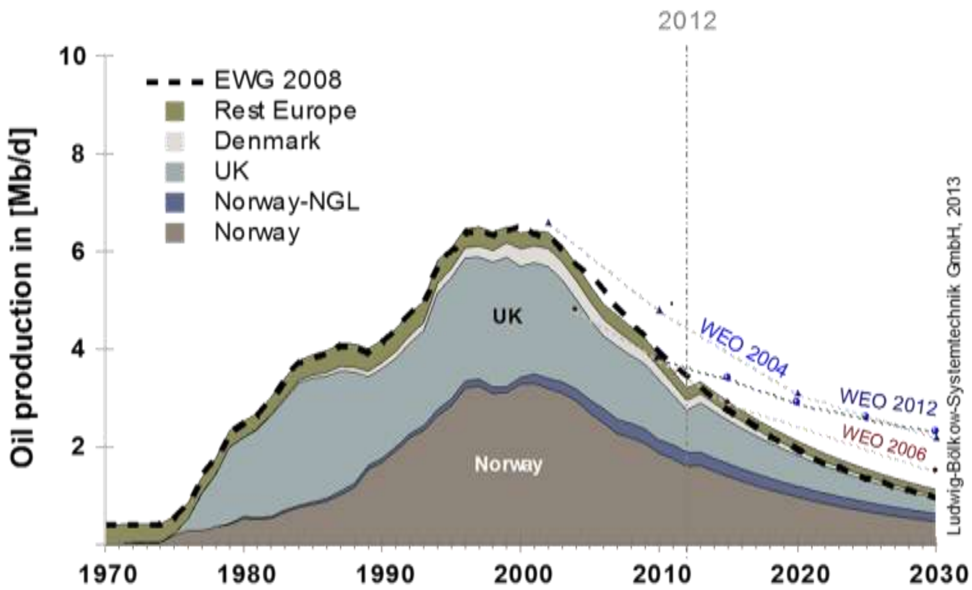



Figure 30 shows oil production in Africa. All countries are expected to have peaked. Production in 2030 will be reduced by 50 per cent. This view is in contrast to WEO 2012 which still expects a rising production, followed by a production plateau until 2030.

**Figure 30: Oil production in Africa**

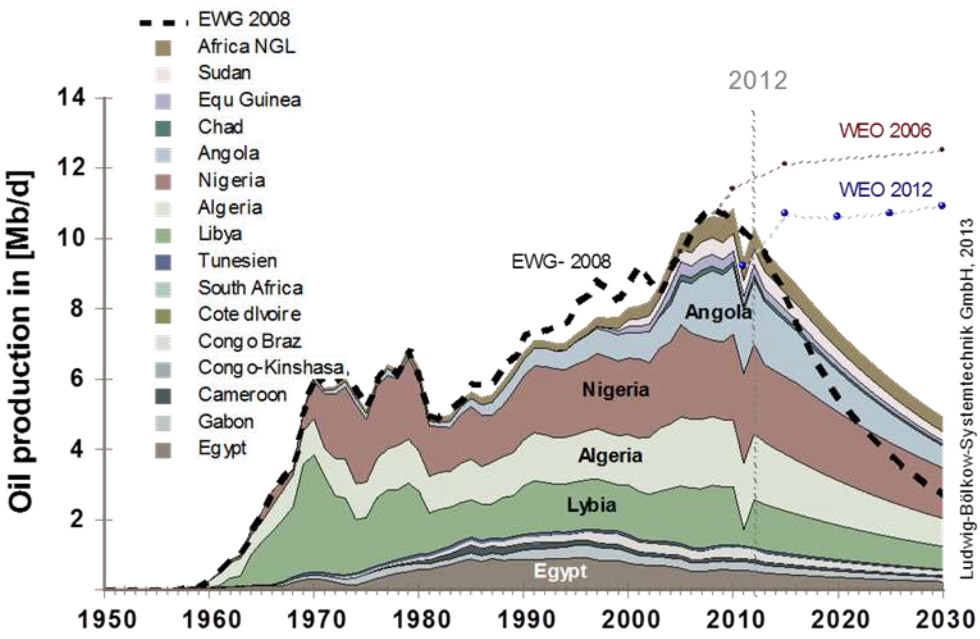



Figure 31 shows the production in Latin America. Colombia's oil production has increased over the last years. Also for Latin America the updated study has a completely different view on the future oil production than the IEA.

**Figure 31: Oil production in Latin America**

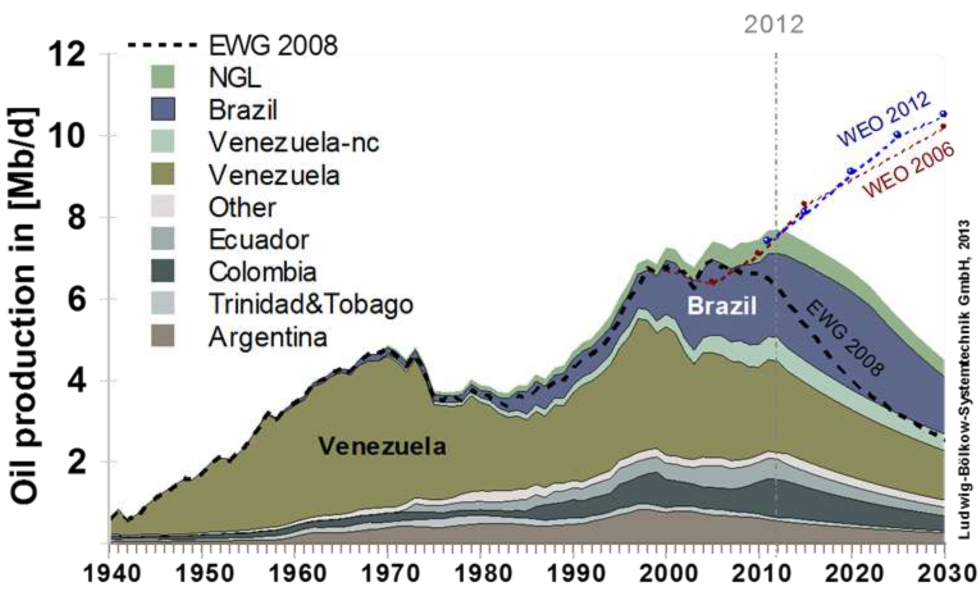



Figure 32 shows the oil production in East Asia. All countries have passed peak production and are declining.

**Figure 32: Oil production in East Asia**

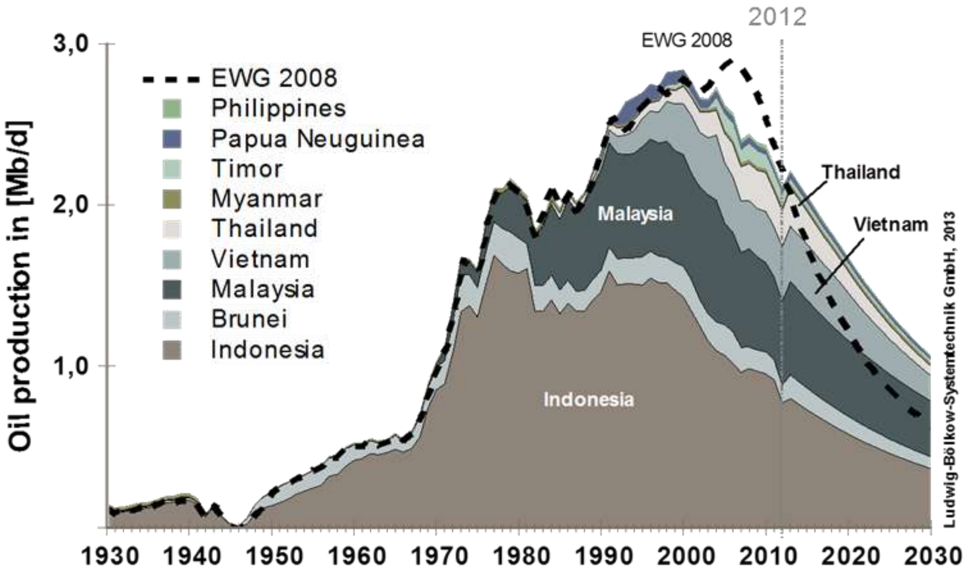



Figure 33 shows the oil production in China. The production increase over the last few years was unexpected. The updated EWG scenario stays by its old scenario projections forecasting a steep decline. Though this turned out to be too early the present judgement is that production will fall when the recently developed offshore fields become mature.

**Figure 33: Oil production in China**

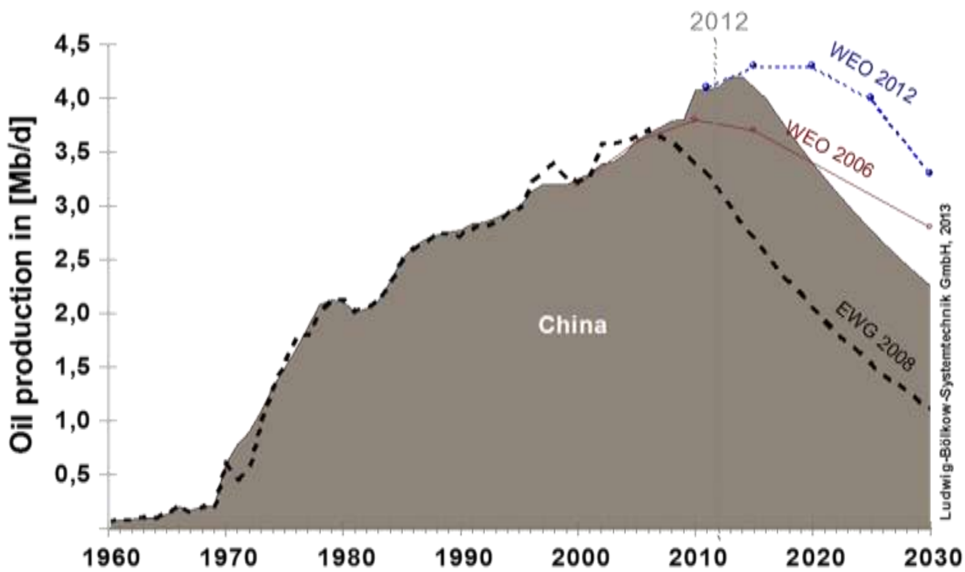



Figure 34 shows the oil production of India and Pakistan. The production increase is somewhat smaller than expected in 2008, but lasts longer. It is expected that the rising production soon will start to decline.

**Figure 34: Oil production in South Asia**

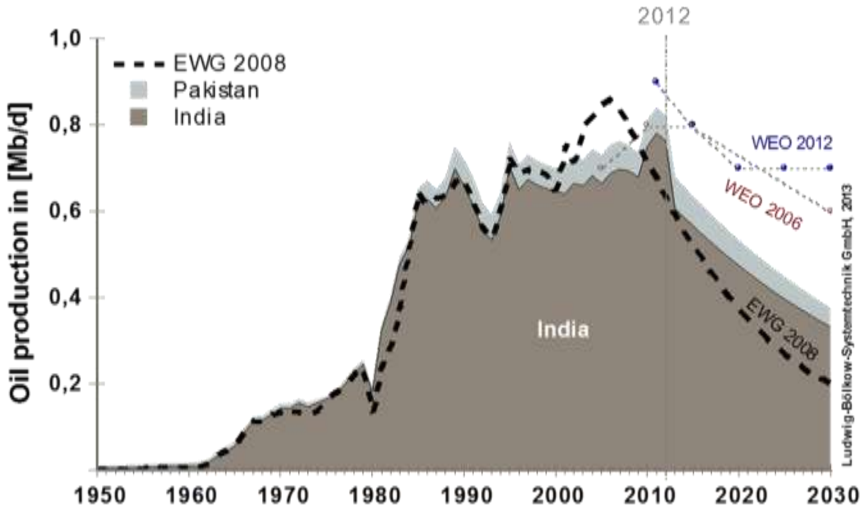
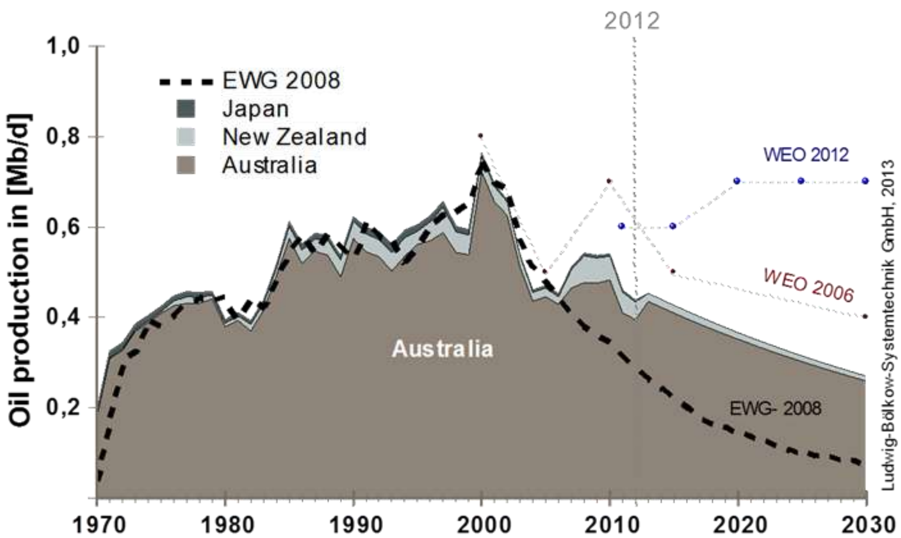



Figure 35 shows the oil production in Australia. Production peaked in 2000. The decline is partly offset by offshore field developments. However the scenario assumption is that the trend of decline will continue over the next two decades.

**Figure 35: Oil production in OECD Pacific**




## ***Comparison EWG 2013 vs. WEO 2012 and Campbell's Oil Depletion Model***

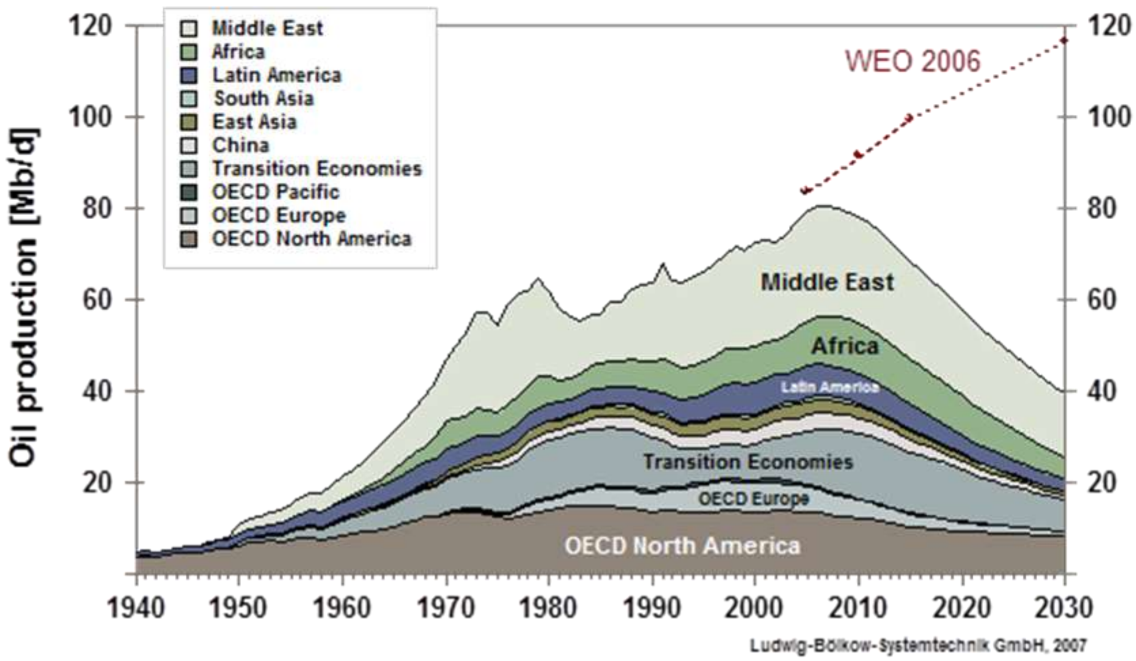
### ***EWG- oil scenario: the view in 2008***

In 2007, the Energy Watch Group published a world oil supply scenario and in 2008 a slightly revised scenario, which takes a critical view of future oil supply. The work was based on the expertise of a number of retired and still active oil experts analysing the peaking of conventional oil production. In short, individual countries were analysed with field by field production profiles, where these were available, and - based on detailed production profiles - projections were made by sketching future production from declining fields and taking into account published development plans for discovered but not yet producing fields and extrapolating from future field developments.

The following figures summarize the major results of that report. These figures are critically reviewed and updated in this report.

The main conclusion in 2008 was that peak oil production was reached. Production was expected to decline thereafter, falling to 39 Mb/day in 2030. Figure 36 shows world oil production since 1940 until 2006 according to the scenario. The production of individual regions is also given. In addition, the projection of the WEO 2006 is also included. Both scenarios show contradicting views.

**Figure 36: Oil production world summary (EWG 2008)**




In the 2008 report it was also analysed that the oil majors have reached their combined production peak in 2004 and now will start to decline. This statement still holds today while the production decline at present amounts to a 30 percent decline since 2004.

In this report the projections are compared with the empirical production data including 2011 and partly 2012 by extrapolating data from January to October data.

### *World Oil Atlas 2013*

The geologists Colin Campbell and Jean Laherrere with more than 50 year experience in hydrocarbon exploration analysed in 1995 the discovery, exploration and production patterns of oil and gas. Since then Colin Campbell updates his data and from time to time publishes regional updates. The summary figures in the latest publication in 2013 (Campbell 2013) are shown in Figure 37 and

Figure **38**. The trends of imminent peak of oil and gas production are in line with the findings of the present study.

**Figure 37: Regular conventional oil production by region according to Colin Campbell (Campbell 2013)**

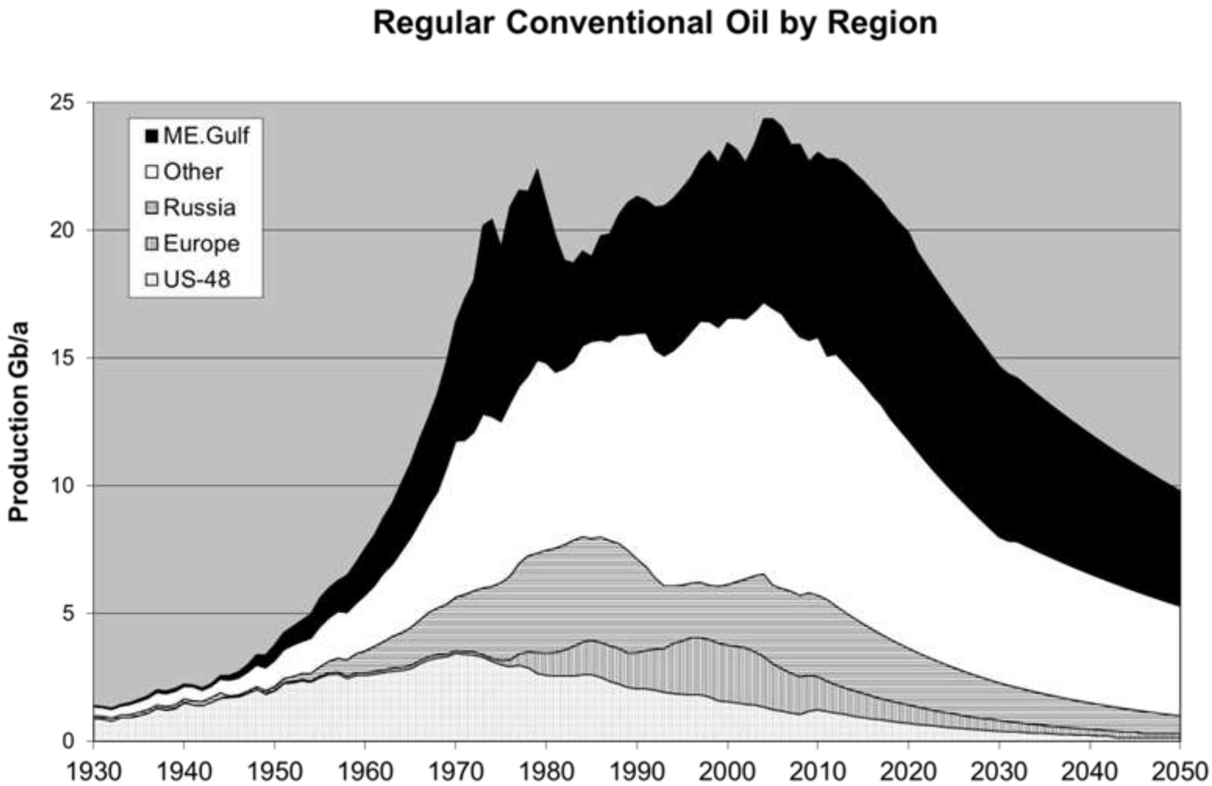
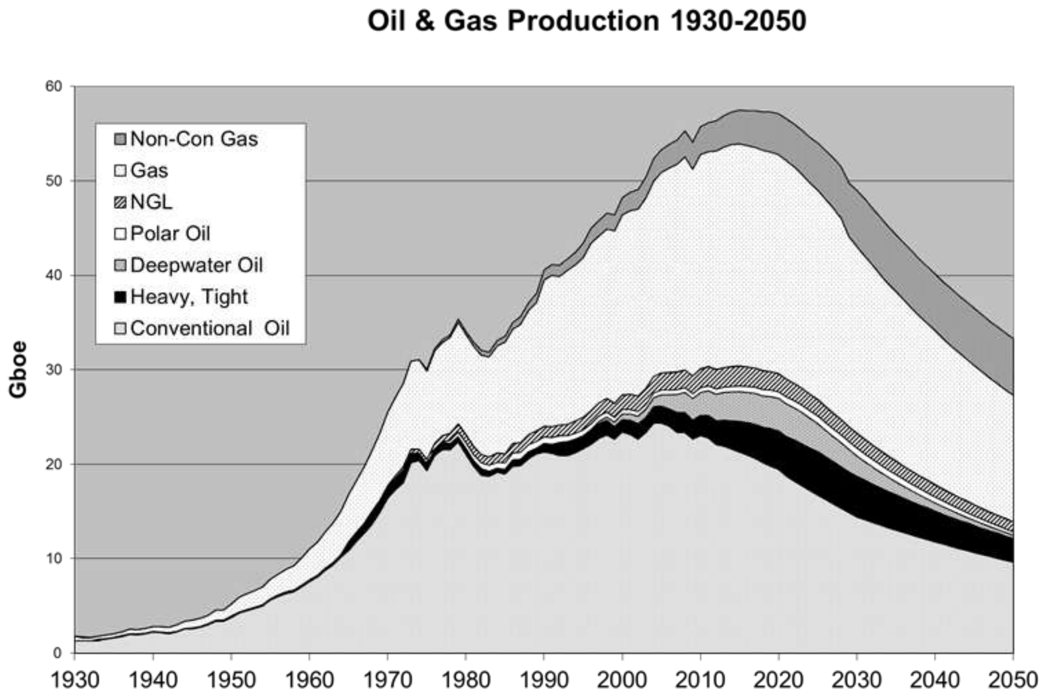


**Figure 38: Total oil and gas production according to Colin Campbell (Campbell 2013)**




### *World Energy Outlook 2012 –the world oil supply*

Each year in November the International Energy Agency publishes the World Energy Outlook which sketches various energy demand and supply scenarios for the next 20 to 25 years. The latest WEO 2012 calculates three oil demand scenarios which are shown in Figure 39. The upper line gives a business as usual scenario ("Current Policies") which more or less extrapolates the trend of the past 20 years. If this is going to happen, world oil demand would rise from currently 87 Mb/day to about 110 Mb/day in 2035. The "New Policies Scenario" sees a slightly more moderate demand increase to 100 Mb/day in 2035. Only the third scenario ("450 Scenario") shows a peak between 2015 and 2020 followed by a declining oil demand down to below 80 Mb/day in 2035. The rationale for this scenario are active political measures to keep carbon dioxide emissions generated by the burning of fossil fuels below a threshold value of 450 ppm atmospheric concentration – a level which is believed to keep the global temperature rise below 2 degrees Celsius until 2100.

**Figure 39: World oil demand according to WEO 2012. (WEO 2012)**

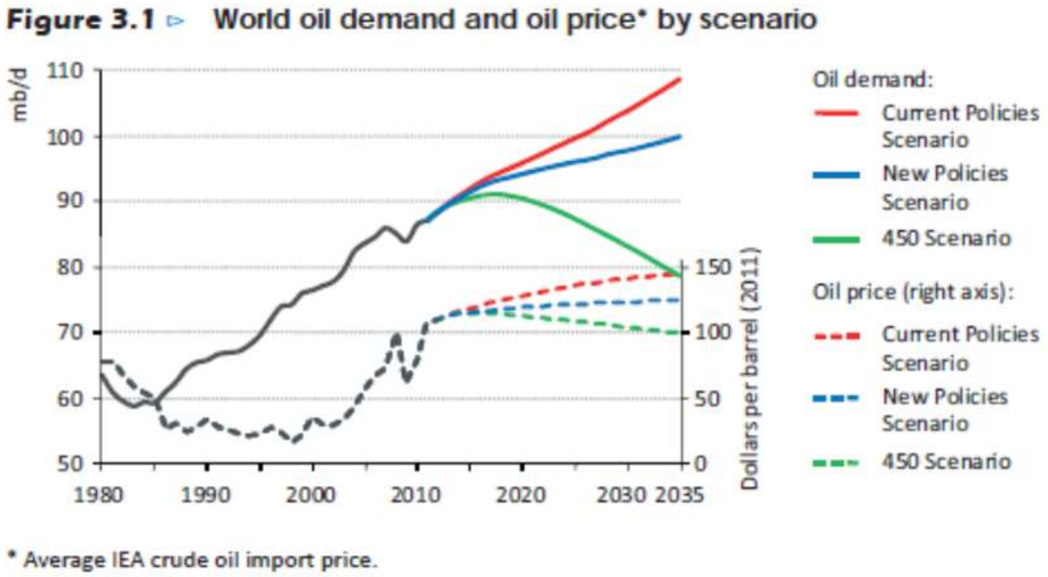



Figure 39 also shows the import price assumptions which correspond to the three scenarios. WEO 2012 assumes that oil demand drives the oil price. Therefore the “Current Policies Scenario” with highest oil demand also sees highest oil import prices. The other scenarios see declining oil import prices corresponding to declining demand.

Such a scenario ranking might be plausible when demand destruction is the driving force which is mirrored by the oil price. However, at least the reality of past decades followed a different logic: Only high oil prices did dampen demand or vice versa the oil price increased with rising demand until economic destruction (recession) led to a breakdown of demand and, as a consequence, of prices. This could be observed after the energy price crises of the 1970s as well as during the Iraq war in 1991, in the aftermath of 9/11 and lately in 2008, when the financial crises resulted in a worldwide recession depressing oil prices.

Figure 40 shows the varying price assumptions of the WEO from 1998 to 2012. This survey exhibits that the real price increase from 2000 onward was not foreseen by the IEA in 1998 and not in 2002. Even in 2005 the already realised increase was interpreted as being only temporary. For the first time in 2006, it was accepted that prices had reached a new permanent plateau. But this plateau had to be adjusted with each new report, following the real price records set year after year. The WEO 2008 for the first time accepted that further price increases might be probable. But the later reports in 2009, 2010, 2011 and 2012 started to reduce long-term oil price assumptions again, while accepting that between 2000 and 2010 fundamental changes had happened. The period between 2000 and 2010 is seen as a transition period where long-term oil prices are shifted from a low level around 20-30 $/bbl to a higher level above 100 $/bbl.

**Figure 40: Crude oil import price assumptions in various editions of the World Energy Outlook from 1998 to 2012 (data source: WEO 1998 – 2012)**

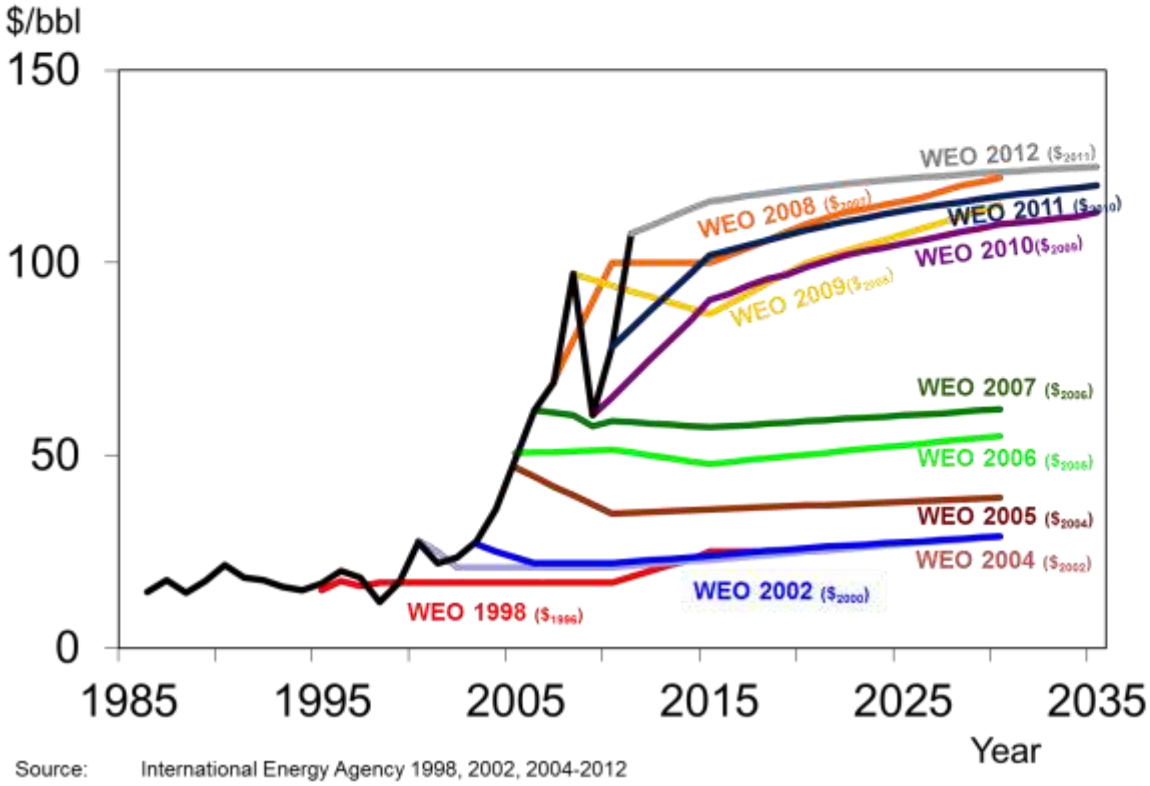
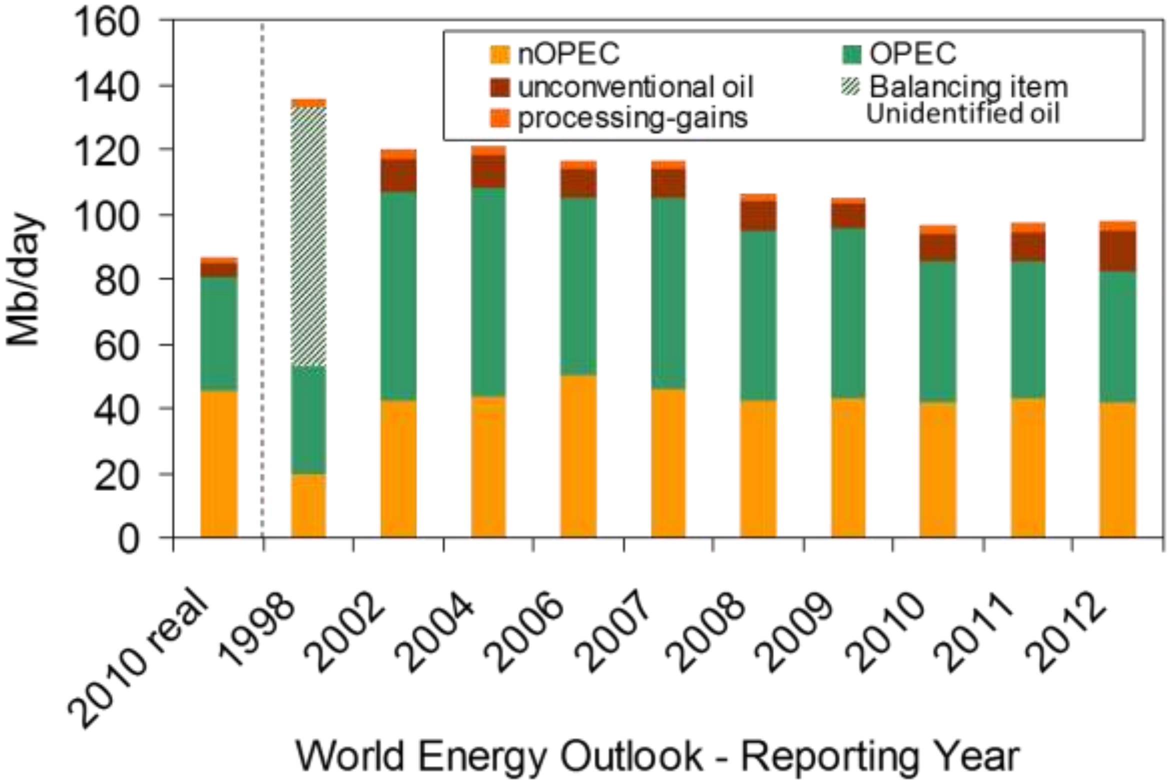



Figure 41 shows the total oil demand in 2030 and the supply shares of OPEC and non-OPEC countries and of unconventional oil. Basic assumptions for the next 20 years have changed considerably between 1998 and 2012. The outlook for 2030 in the WEO 1998 showed a mismatch between a supply from conventional sources of 80 Mb/day and a demand of 135 Mb/day, which had to be filled by so called “unidentified oil – yet to be found”.

**Figure 41: World oil supply in 2030 according to various editions of WEO from 1998 to 2012.**



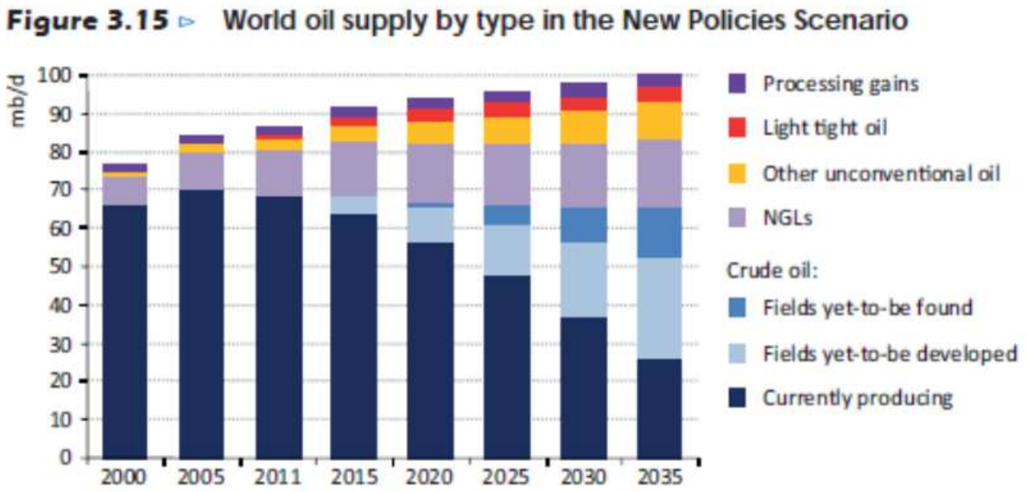

Similar to changing oil price assumption (see Figure 40) with each new report until 2010 the demand in 2030 was revised downward. Since then the demand expectations stay almost unchanged. The oil supply from non-OPEC countries in 2030 is seen stable at the same level as today, only the 2006 report shows an increase by more than 10 percent which was thought to be due to higher production in the USA (7.2 Mb/day against 4 Mb/day in the WEO 2004), Europe (2.2 Mb/day against 1.5 Mb/day) and developing countries (17.4 Mb/day against 14.8 Mb/day in 2004).

OPEC countries are expected to supply the largest share with the largest production capacity seen in Middle East OPEC countries. For instance, the Middle East OPEC contribution in WEO 2002 was seen at almost 51 Mb/day in 2030. This contribution was continuously revised downward, now standing at 31 Mb/day in WEO 2012. Though in former reports no further geographical disaggregation was published, the biggest share of OPEC production was expected to come from Saudi Arabia. Later reports downward revised this share continuously. The latest WEO 2012 expects Saudi Arabia to produce 11.4 Mb/day (incl. NGL) in 2030, which is close to the present production volume.

In 2004 for the first time and since 2008 regularly, the World Energy Outlook has more detailed data with regard to regions and types of oil.

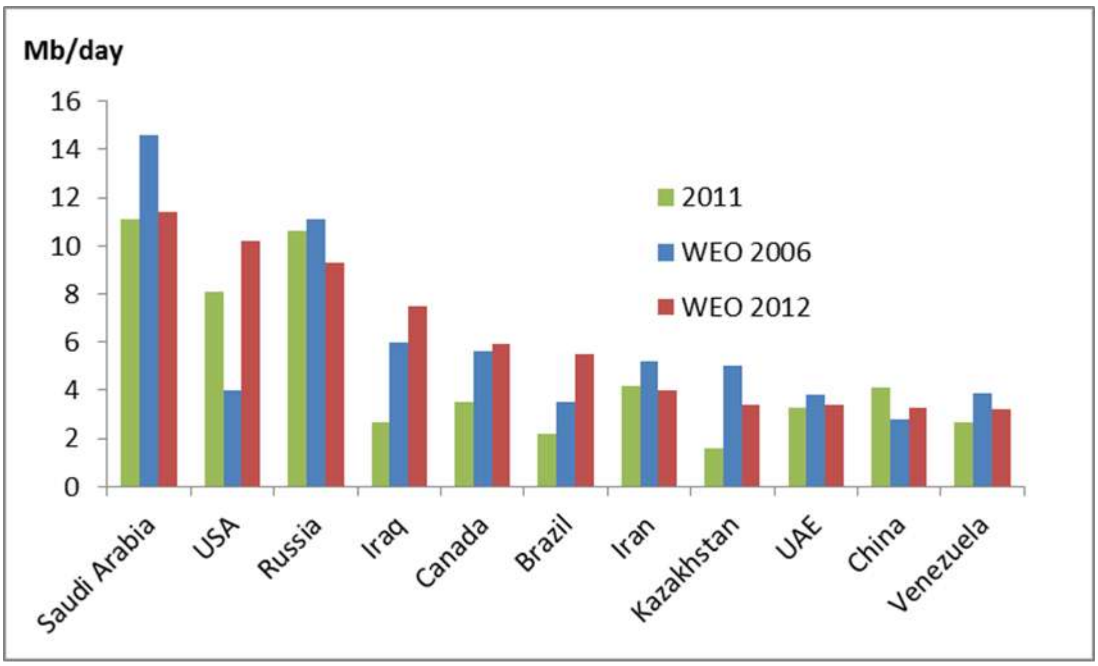
Projections of future production differentiate between production from currently producing fields, fields yet-to-be developed and fields yet-to-be found, unconventional oil (light tight oil and other), and NGLs. The pattern between 2000 and 2035 is shown in Figure 42.

**Figure 42: Disaggregation of world oil production 2000 – 2035 according to World Energy Outlook 2012 (WEO 2012)**




to the
s have
changed dramatically (e.g. regarding Saudi Arabia, USA, Brazil, Kazakhstan).

**Figure 43: Largest oil producers in 2011 (green left) and in 2030 according to WEO 2006 (middle, blue) and WEO 2012 (right, red)**



According to the WEO 2006, world oil production is expected to rise from 84.3 Mb/day in 2011 to 113.8 Mb/day in 2030, according to the WEO 2012 it is expected to rise to 95.1 Mb/day in 2030. In other words, while total world production in 2030 is downward revised by almost 20 percent, the production from the largest producers remains almost unchanged, thus increasing their share from 57 percent in the WEO 2006 to 70 percent in the WEO 2012.

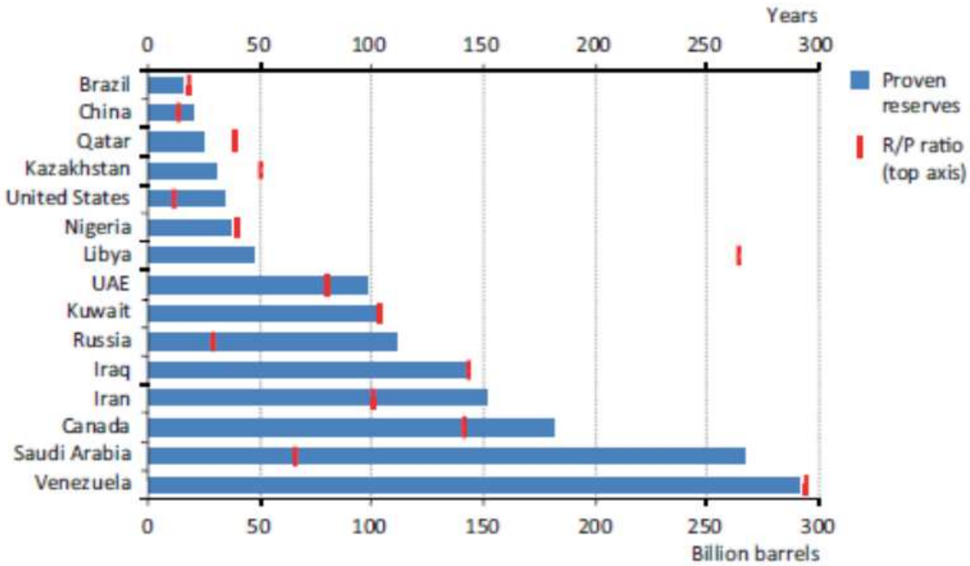
Prominent changes of assumptions between WEO 2012 and WEO 2006 are listed:

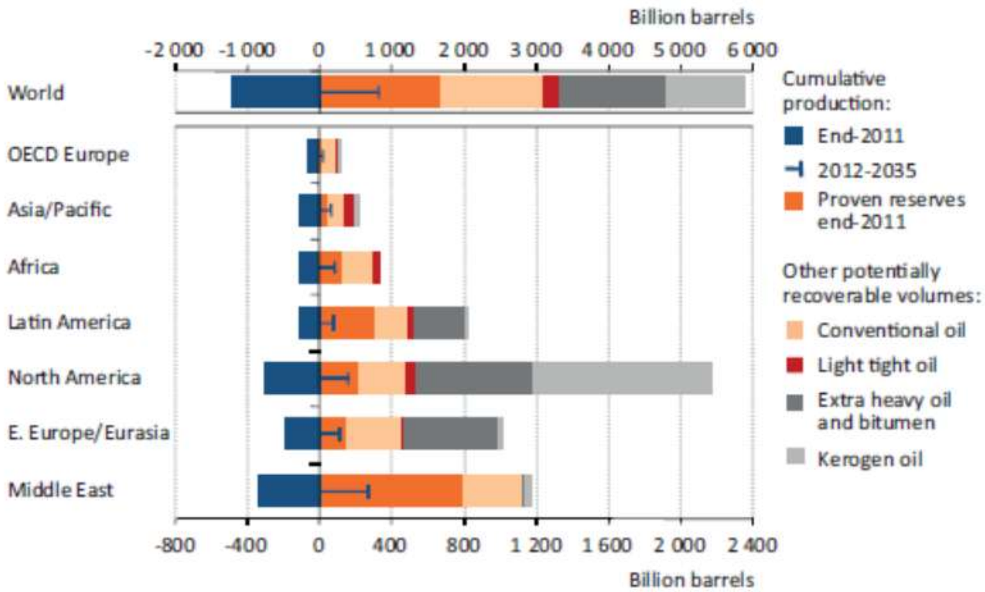
- The US oil production in 2030 is assessed completely different. In 2006 production was expected to decline by 50 percent, now it is expected to raise by 20 percent.
- The oil production in Saudi Arabia is seen in WEO 2012 at the same level as today. This is in contrast to all previous reports where Saudi Arabia was expected to raise production considerably until 2030.
- Production in Iraq, Canada and Brazil is expected to double until 2030 according to the WEO 2012 – far more than in any previous report.
- The production from Russia now is expected to decline until 2030.
- In 2012, future supply prospects of Kazakhstan are seen much less optimistic than in 2006 or any other previous report between 2006 and 2012.
- Total oil production from the 11 largest producers in 2030 has almost not changed in the reports between 2006 and 2012, inspite of the fact that the share of individual countries is completely different to previous reports.

The World Energy Outlook takes it for granted that the backbone of future production is a sufficiently huge reserve base. Figure 44 shows the proven reserves according to WEO 2012, and Figure 45 shows proven reserves and resources together with cumulative production and projected cumulative production over the period 2012-2030.

To show that there are no restrictions, total reserves are counted with 1,600 Gb and resources with about 6,000 Gb (see Figure 45), indicating that these resources are more than sufficient to cover the demand of any of the three scenarios in the WEO 2012.

**Figure 44: proven reserves according to WEO 2012 (WEO 2012)**




Venezuela, Saudi Arabia and Canada have by far the largest reserves with 296 Gb, 265 Gb and 175 Gb. USA have extremely low reserves with 31 Gb (data from BP 2012 and Figure 44). This ranking does not reflect the countries where the largest production increases are expected (Iraq: 4.8 Mb/day, Brazil: 3.3 Mb/day, Canada: 2.4 Mb/day, and USA: 2.1 Mb/day; see Figure 43).

According to the WEO 2012, the oil production in the USA in 2030 is seen very close to the production in Saudi Arabia, rising by 25 percent from 2011, while the production in Saudi Arabia is seen rising by only 3 per cent. However, reserves in Saudi Arabia are more than seven times larger than in the USA. Moreover, US oil production is expected to be larger than in Nigeria, Libya, UAE, Kuwait, Russia, Iraq, Iran, Canada and Venezuela – these are all countries which possess by far larger reserves than the USA.

Venezuela has by far the largest reserves, but its production in 2030 is seen at one third of the US-production according to WEO 2012 and still close to today's production.

The key behind these seeming inconsistencies is that reserves and even more so resources are of varying quality. Therefore, the reserve number by itself does not give any indication regarding the possible future production profile.

For instance, in Venezuela, Canada and USA the conventional reserves are almost depleted. Only the inclusion of unconventional reserves and resources from extra heavy oil, bitumen, shale oil and tight oil helps to increase reserve numbers of these countries. But even the inclusion of light tight oil in the USA does not increase its reserves considerably. Moreover, also unconventional oil plays are developed according to the same logic as conventional plays: for obvious economic and technical reasons, the easiest accessible resources will be produced first. Therefore, the same treadmill starts as with conventional prospects. Once the most profitable and most oil rich prospects are producing, to develop new assets is becoming increasingly more difficult. The result is a flattening of the production profile which surpasses its peak once the decline of old prospects can no longer be compensated by the fast development of new prospects. The scenario in the WEO 2012 according to which the USA will increase its oil production to become second largest producer worldwide within 15 years is a speculation on future developments. This is compounded by the fact that the reporting of oil reserves is highly questionable as has been stated already in WEO 2004: "The reliability and accuracy of reserve estimates is of growing concern for all who are involved in the oil industry."(WEO 2004) This is even more true today.

As is well known in the meantime, OPEC reserves have been upgraded in the late 1980s, in some cases by a factor of three, however only on paper, as there were no corresponding new discoveries.

In summary, detailed oil production scenarios rely only partly on reserve data. Other aspects such as the profile of historical production, decline patterns of producing fields and the potential to develop new but yet undeveloped discoveries in a timely manner are much more important.

It is a key message of this short analysis that huge reserves on paper do not imply that they will or can be turned into huge production volumes by 2030. Other factors are at least as important as reserve data.

# ***NATURAL GAS***

## ***Introduction***

In this chapter the historical production of natural gas is analysed and probable future developments are projected. The focus is on the USA, on Europe and on the future supply from Eurasia, predominantly the Russian Federation.

The first subchapter deals with an in depth analysis of natural gas production in the USA. Individual sections deal with historical data, scenario projections for coalbed methane, projections for shale gas production, and the updated aggregate US scenario projection. Detailed data concerning individual regions within the US are given as far as these are necessary to understand certain trends, additional details are provided in the Annex.

The situation in Europe is discussed in a separate subchapter. Again, in addition to historical trends in individual countries, the possible prospects for the production of unconventional gas are discussed. However, this time the discussion is shortened as many relevant aspects were already discussed in the chapter on shale gas production in the USA. This subchapter closes with a discussion of the future gas supply from Russia.

The third subchapter takes a global view including a separate section on historical LNG export and import capacities. It closes with short summaries on world gas production and gas production in individual regions including country by country production profiles.

## ***USA***

### ***Present Supply***

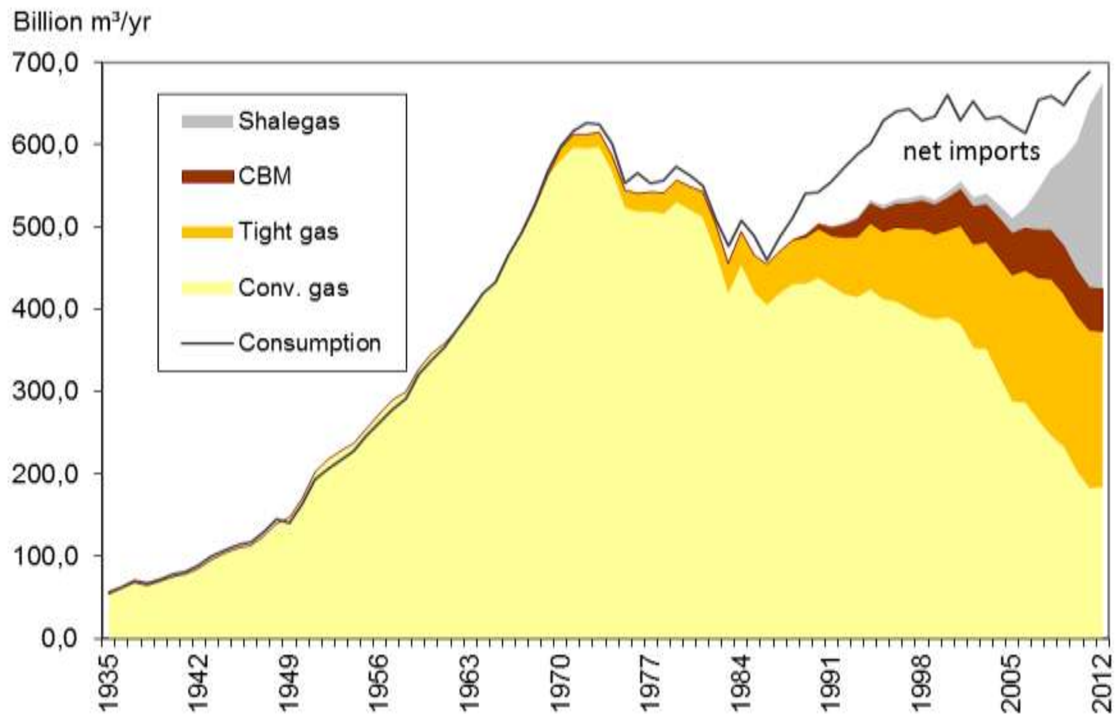
Figure 46 shows the natural gas production in the US and net gas imports according to US-EIA. Domestic gas production is disaggregated into conventional gas (including offshore production in the Gulf of Mexico), tight gas, coalbed methane and tight gas. The major difference between conventional and tight gas wells is the lower permeability of the rocks. To distinguish between these two types there is no distinct threshold, rather a smooth transition from high permeability to lower permeability rocks. As there is no clear threshold, thight gas wells are usually not separated from conventional gas wells. The present distinction is based on data from US-EIA.

Conventinional gas production is in decline since 1970. The increasing development of tight gas wells by hydraulic fracturing could not change that trend.

Coalbed methane (CBM) production is based on data from US-EIA.

Shale gas production increased significantly since 2005 when corresponding drilling activities were exempted from reporting to and supervision by the Environmental Protection Agency (EPA) according to the Energy Policy Act in 2005. Shale gas production grew within a few years from almost zero to a share of 30 percent of total gross production in 2012 which amounted to 810 billion m³.

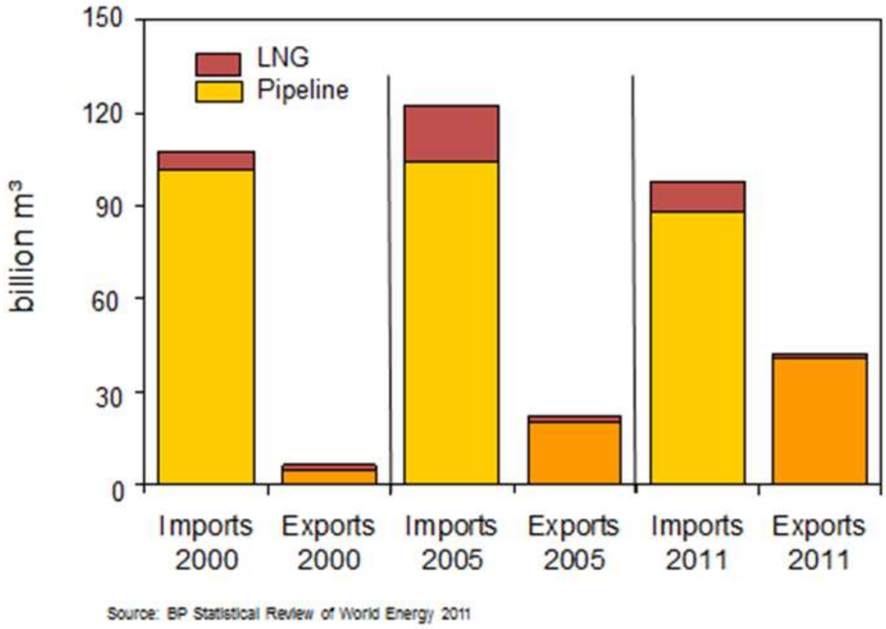
**Figure 46: Gas production in USA and net imports**




Out of the total gross production of 810 billion m³/yr in 2012 only 680 billion m³/yr are marketed asdry gas production. The difference is made up by losses, consumption for production, transport and purification, and the separation of natural gas liquids. The figure shows total dry gas production which – together with net gas imports – equals the US gas demand. Due to the rising shale gas production, net imports were reduced considerably in recent years.

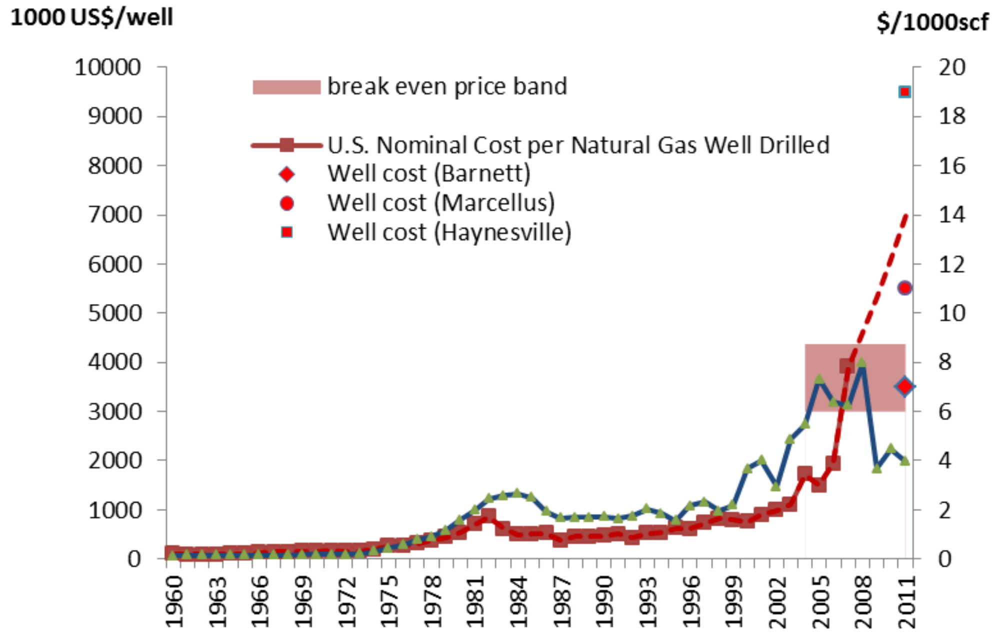
Figure 47 shows the development of gas imports and exports. The gas imports are slightly below 2000 numbers while LNG imports have a larger share. Since ten years, gas exports are rising as the gap between domestic demand and production has almost closed due to the fast rising shale gas production.

**Figure 47: US Natural Gas Imports and Exports**




Starting in 2000, natural gas prices began to rise continuously from around 2 USD/1000 scf (=0.07 USD/m³) to 8 USD/1000 scf (0.28 USD/m³) in 2008. The shale gas boom after 2005 led to a fast rising domestic production together which in 2008 met with a n economic downturn resulting in a collapse of gas prices. It is often claimed that the crunch of gas prices was a result of the development of shale gas. This is combined with the claim that gas production from gas shales is cheaper than conventional gas production. The first part of that claim is correct, but the second part is not. Figure 48 shows the gas price development (blue line) and the historical cost development of gas wells drilled (red line). Data from 1960 t o2007 are taken from US-EIA. The average well cost for 2011 (7 million USD) are estimate by the authors based on a range of costs from 3.5 million USD for Barnett, 5.5 million USD for the Marcellus shale and 9.5 million USD for Haynesville wells. (Source: Berman 2012, Baihly 2011)

**Figure 48: Cost of natural gas wells drilled and natural gas well head price (Source: US-EIA 2012, Berman 2012, Baihly 2011)**

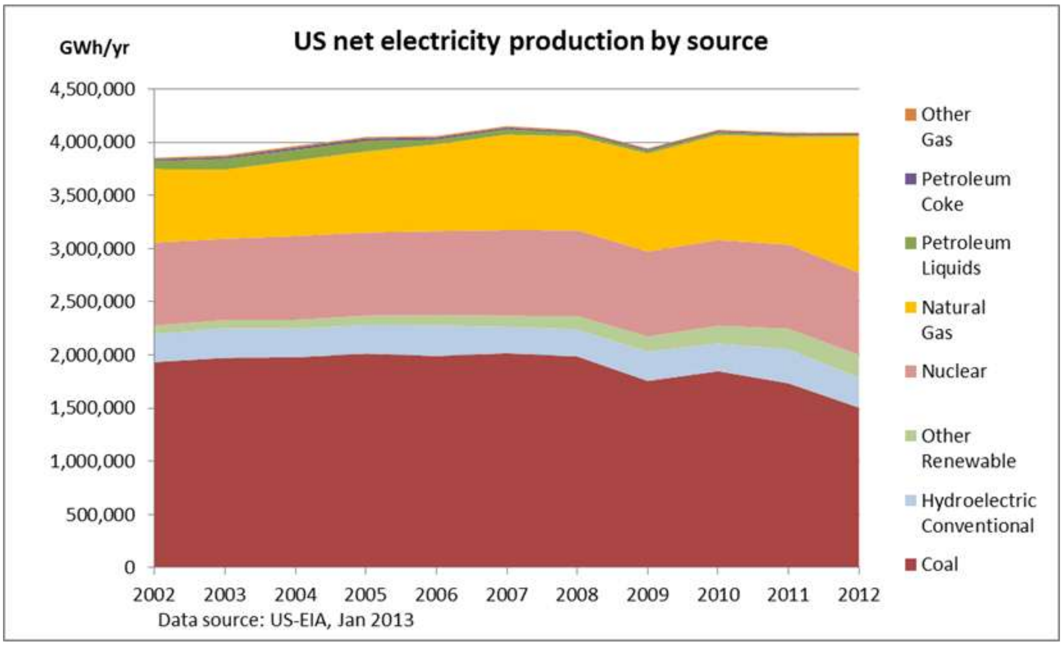



The economic viability of natural gas productiony depends to a high degree on the estimated ultimate recovery (EUR) of natural gas per well. Based on the projection, that the EUR in individual shale gas wells varies between 1.19 – 3 Bcf, the required break even gas price is calculated by Labyrinth Consulting Services at being between 5.06 to 8.75 USD/1000 scf (Berman 2012).

In power generation, the cheap US natural gas price resulted in a switch from coal to natural gas. However, while coal power plants are owned by electric utilities, gas turbines and combined cycle plants very often are owned by industry. Due to the much higher efficiency of gas power plants relative to old coal fired power plants, total fuel consumption (and CO2-emissions) for the electricity generation in the US declined while the electricity output remained almost constant.

Figure 49 shows the fuel switch for electricity production in more detail. On average, the conversion efficiency of US coal power plants declined between 2002 and 2011 from 22 percent to 21 percent while the average efficiency for gas power plants increased from 43 percent to 47 percent. For the calculation of efficiencies 1 million scf are converted into 283 MWh primary energy and 1 ton of coal is converted into 8.8 MWh primary energy.

**Figure 49: US net electricity production by fuel source (Source: US-EIA)**




Due to the low natural gas price, most shale gas producers are losing money. Therefore, it is very likely that the shale gas boom in the USA has reached its peak and that the excessive development of wells will slow down (Krauss 2012). Recent drilling statistics indicate that this slowdown has already started.

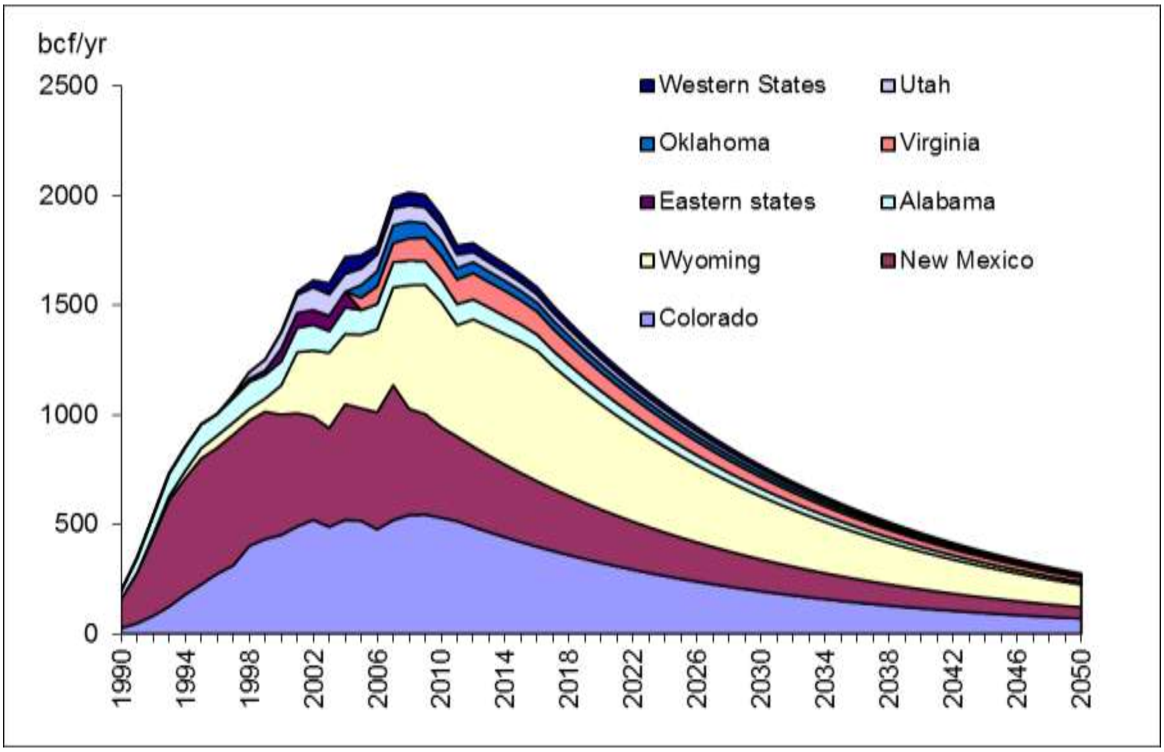
***CBM Scenario***

Methane in coal mining was always a threat because of the risk of explosions. Underground mining requires methane concentration in the air of the shafts being below a safety level of 1 percent. Because of its greenhouse warming potential, methane is degasified from not yet developed coal mines. The production technologies applied often use hydraulic fracturing similar to tight gas or shale gas developments. As the USA possess huge coal resources, the potential coalbed methane resource is large. However, total reserves in the US amount to 17,508 bcf (495 Mrd. m³). These reserves have grown continuously from below 5,000 bcf in 1990 to 21,874 bcf in 2007. Since then they already declined by 20 percent. Actually the production in the three states Colorado, New Mexico and Wyoming now supplies almost 80 per cent of US production which is in line with the respective reserve shares. Therefore, the potential of these three states will determine future coalbed methane productionin the US. Reserves in New Mexico have been downward revised by 33 percent since 2005, now amounting 3,532 bcf or 100 billion m³.

Figure 50 shows the historical production and scenario projections until 2050. Cumulative production in New Mexico between 1990 and 2010 adds up to 10,000 bcf or 283 billion m³ which is three times the size of proven reserves. The scenario assumes an annual decline rate of 5 percent. This sums up to a cumulative production of 6,700 bcf which is twice as large as proven reserves. New Mexico has already passed peak production in 2007. Colorado probably has passed peak production in 2009. Its future decline rate is also assumed at 5 per cent per year. Cumulative production between 1990 and 2012 was 7,700 bcf or 220 billion m³, cumulative production 2011-2050 is assumed at 8,960 bcf which is 40 per cent above the reserve. Wyoming is expected to reach peak production in 2015; cumulative production 1990-2010 amounts to 4,600 bcf or 130 billion m³, while cumulative production 2011- 2050 amounts to 12,700 bcf (360 billion m³) in spite of proven reserves of 2,683 bcf (76 billion m³).

The scenario projection 2011 – 2050 amounts to a total production of 35,600 bcf (1,000 billion m³) which is twice as much as proven reserves. Hence, coalbed methane production will not significantly influence total US gas production.

**Figure 50: Historical production of coal bed methane and scenario calculation until 2050**




### *Shale gas in the USA*

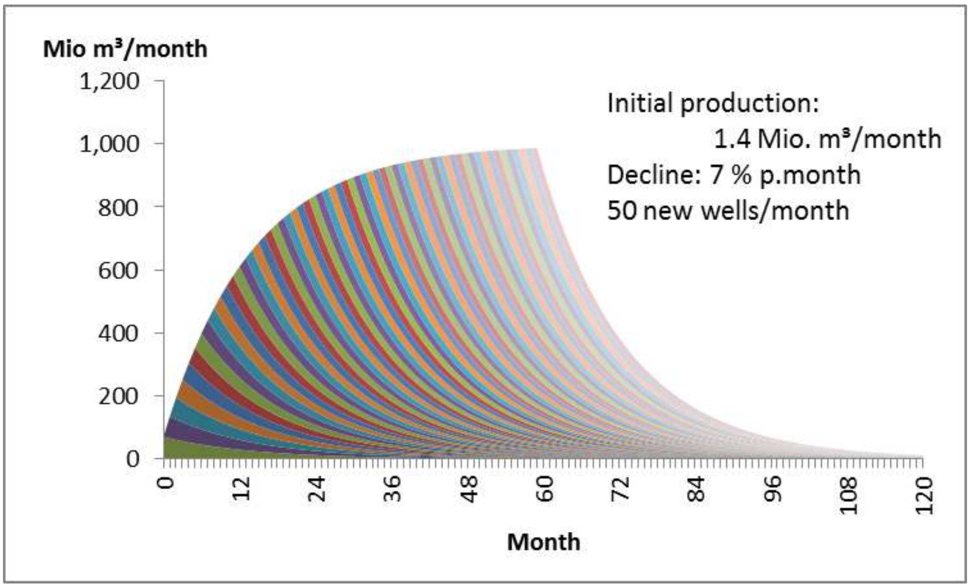
Declining conventional gas production in the USA since 2005 was over compensated by the fast development of shale gas assets. Figure 46 shows that production from shale gas exploded after 2005 when the Energy Policy Act in 2005 was set into force (EPA 2005) which in Sec. 322 excluded hydraulic fracturing operations from the regulations of the Safe Drinking Water Act (see SDWA 2005).

Shale gas is gas which is confined in small pores of source rocks (predominantly shales) with very low permeability. The permeability is about three orders of magnitude smaller than in conventional gas plays. To access this gas requires the fracturing of the rocks by the injection of water under very high pressure up to thousand bar. This injection opens cracks which make the gas accessible. In order not to close these cracks when the pressure is reduced propping agents are mixed to the injected water. In order to facilitate the injection process and to optimise the fracturing, hazardous and biocide chemicals are added to the injection fluid.

The gas flow of shale gas wells has a typical production characteristic which shows peak production with an initial production rate in the first days followed by a fast decline rate in the range of 5 to 10 per cent per month. Typical numbers depend on the permeability of the rocks, gas pressure, the pore volume of the rocks and the total organic matter. But a general trend has been learned from the various producing gas shales in the USA: The higher the initial production rate, the steeper is the decline in the following months.

Figure 51 shows a typical idealised aggregated production profile for a natural gas play which would result if each well has an initial production rate of 50 million scf (1.4 million m³/month) and a monthly decline rate of 7 per cent per month. A further assumption is that each month 50 new wells start production. The growth rate of the aggregate production, being very high in the first year, soon flattens as new wells have to compensate more and more the decline of elder wells. After about 5 years (60 months) fifty new wells per month are required in order to keep the production flat.

**Figure 51: Simulation of shale development with 50 new wells per month**




In reality, a shale gas basin is inhomogeneous with some hot spots rendering highest production volumes. These hot spots usually are developed first. Also the addition of new wells is not constant over time, but rises in the beginning and peters out when more wells have been drilled. With the progressive development of a basin, prospective well sites are becoming scarce and the addition of new wells faces more restrictions, e.g. well sites are coming closer to inhabited areas and closer to the boundaries of the shale.

Figure 52 shows the gas production profile of the Fayetteville Shale in Arkansas which covers about 85 per cent of total gas production in Arkansas. The black broken lines show the production decline of all fields connected at the beginning of the year. The decline of the base production in 2011 is missing in that figure. These decline profiles exhibit the steepening decline pattern of elder wells which must be compensated by the ever faster development of new wells. At end 2010 the average production of the 3,068 wells was 22,500 m³/well/day. This average declined to 17,600 m³/well/day by August 2012.  Based on these data it can be concluded that production in the Fayetteville shale is at or close to peak and probably will start to decline unless many more wells will be developed each month than in the past.

**Figure 52: Gas production from the Fayetteville Shale in Arkansas**

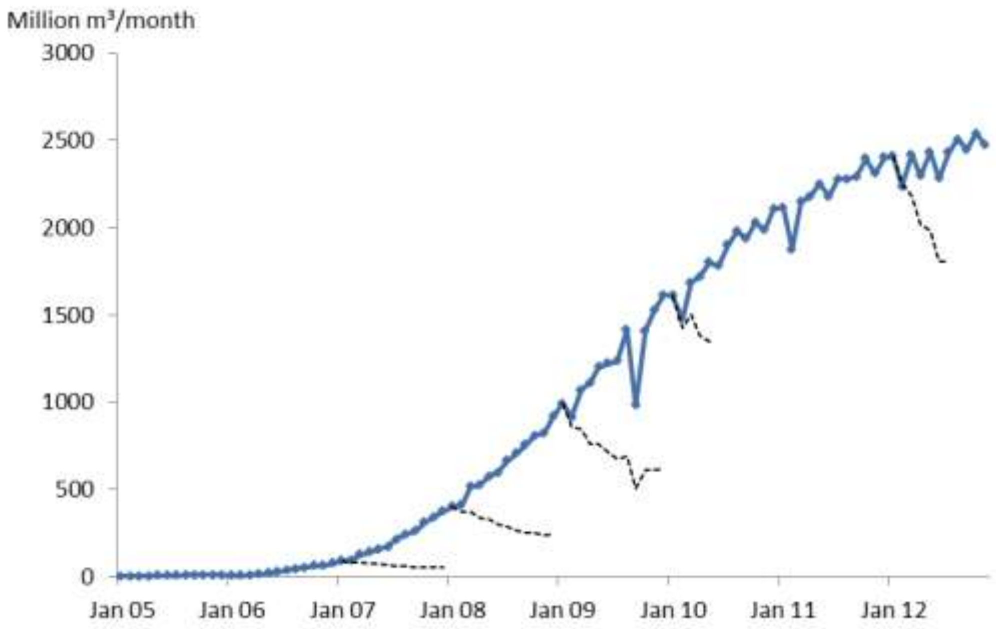
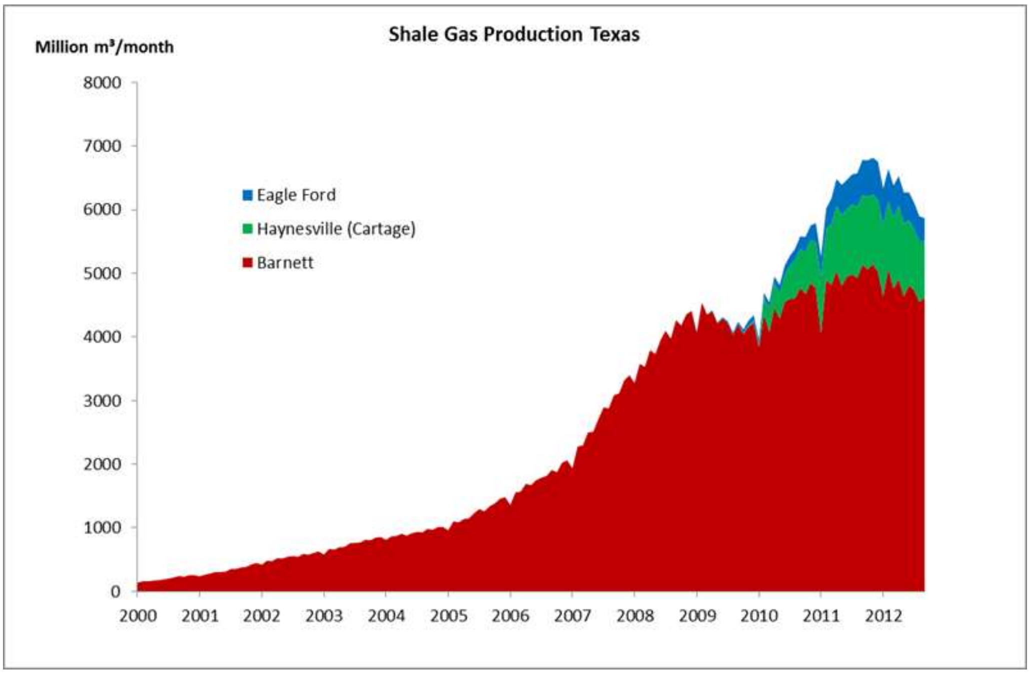



Figure 53 shows gas production in the three largest shale plays which cover more than 99 percent of total shale gas production in Texas. Though the production data for the last six months might still be revised upward as some companies have disclosure agreements to delay their reporting, production in the Barnett shale has peaked in the summer of 2011. The second largest share of shale gas production in Texas comes from the Texan part of the Haynesville shale. Also in the Haynesville shale production has already peaked. The remaining sizeable contribution to shale gas in Texas comes from Eagle Ford Shale where production has also peaked in autumns 2011. The gas production from the other shales (Bossier, Pregnant, Woodford, La Escondera, Oran, Phobie  and Toyah) is negligible contributing less than 0.1 per cent to Texas shale gas production. Besides, production in these plays has already peaked some years ago.

**Figure 53: Shale gas production in Texas until Nov 2012 (RRC)**




Even though the production data for the last few month are preliminary, Figure 54 shows an obvious discrepancy between statistics from the Texas state authority Texas Railroad Commission (TRRC) and federal state Energy Information Agency (US-EIA). Though both statistics match closely between 2000 and 2010, since early 2011 the discrepancy between reported data increases: TRRC statistics report a steep decline of Texas gas production since summer 2011, whereas US-EIA statistics still report flat or slightly rising production until October 2012. Thus, US-EIA reports a 30 percent larger gas production than TRRC. In the figure conventional and shale gas production are shown explicitly. This reveals that conventional gas production is in decline since 2009. This decline was masked for some time by the rising shale gas production. But the declines of conventional and shale gas production add up. This causes the steep decline pattern that can be observed since about one year.

This pattern can be generalized. Conventional gas production is declining everywhere in the US. This decline was masked for a few years by the fast development of promising shale gas plays. However, as soon as new shale gas wells cannot be developed any longer in time and at high rate of several thousand wells per month – the decline of shale gas will exacerbate the decline of conventional gas production.

**Figure 54: Total gas production in Texas; Reporting discrepancies between Texas Railroad Commission and US-Energy Information Administration**

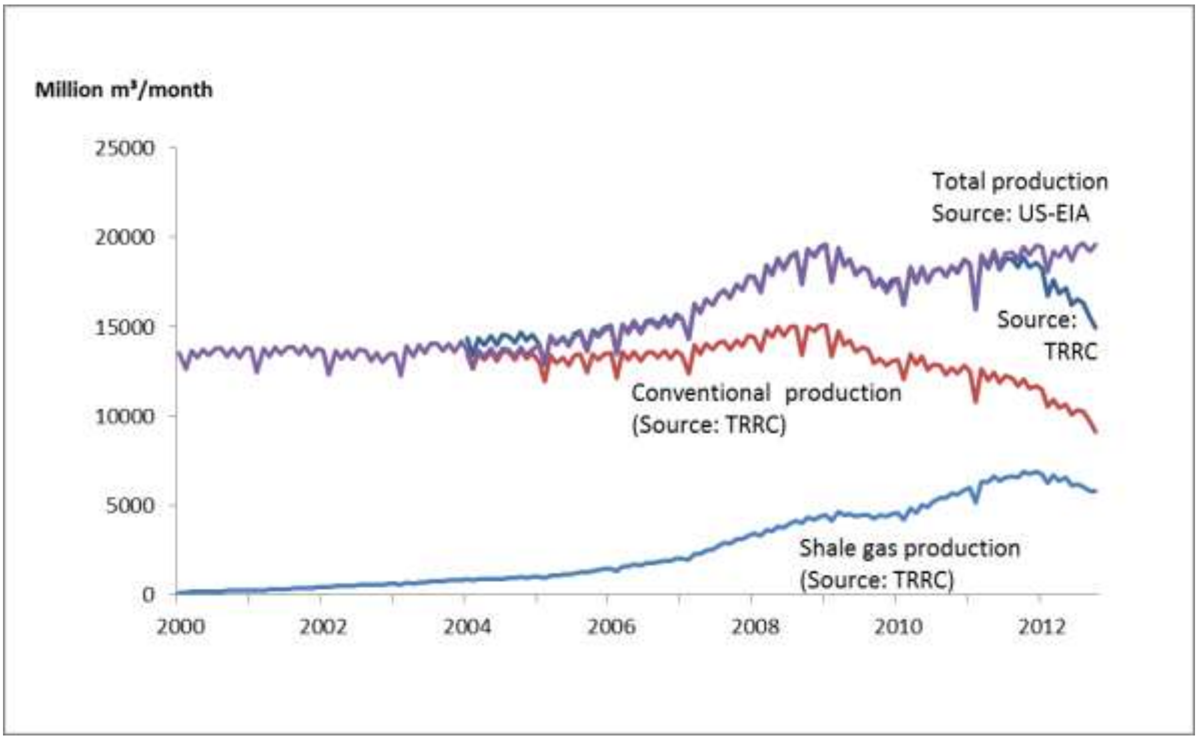



Figure 55 shows the gas production in Lousiana, another important gas producer in the USA. Conventional onshore production is in decline since 1970. This was compensated since 1985 by the development of offshore gas production in the Gulf of Mexico. However, since 2000 gas production in the Gulf of Mexico declined at an unprecedented rate by almost 80 per cent within ten years. Since 2009 this decline was offset by the fast rising production in northern Louisiana where the greater part of the Haynesville shale is located. However, recently even the gas production from the Haynesville shale could no longer offset the steep decline of the offshore production.

**Figure 55: Gas production in Louisiana, including the Haynesville shale and offshore production in the Gulf of Mexico**

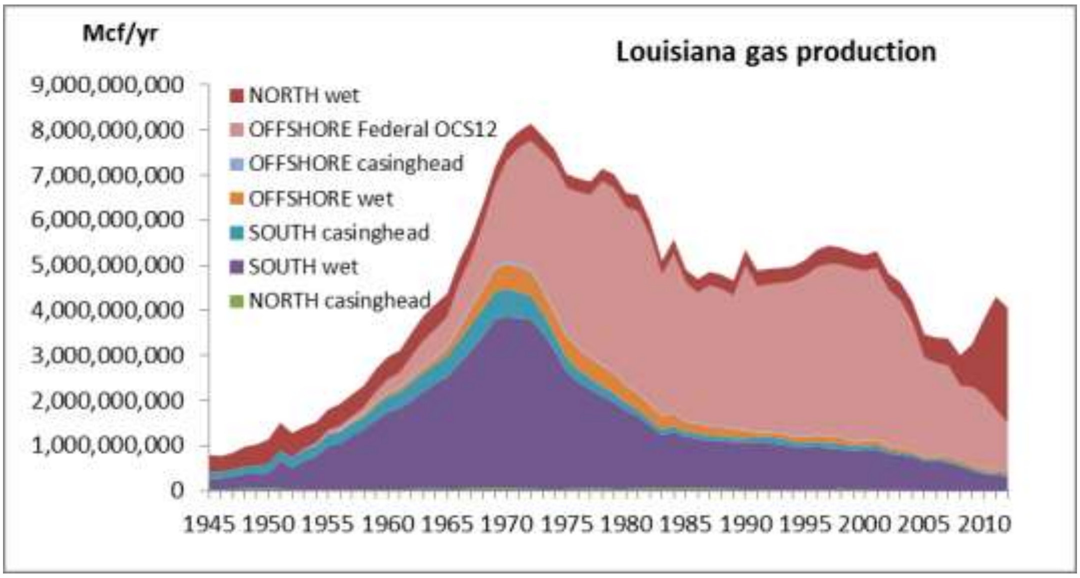
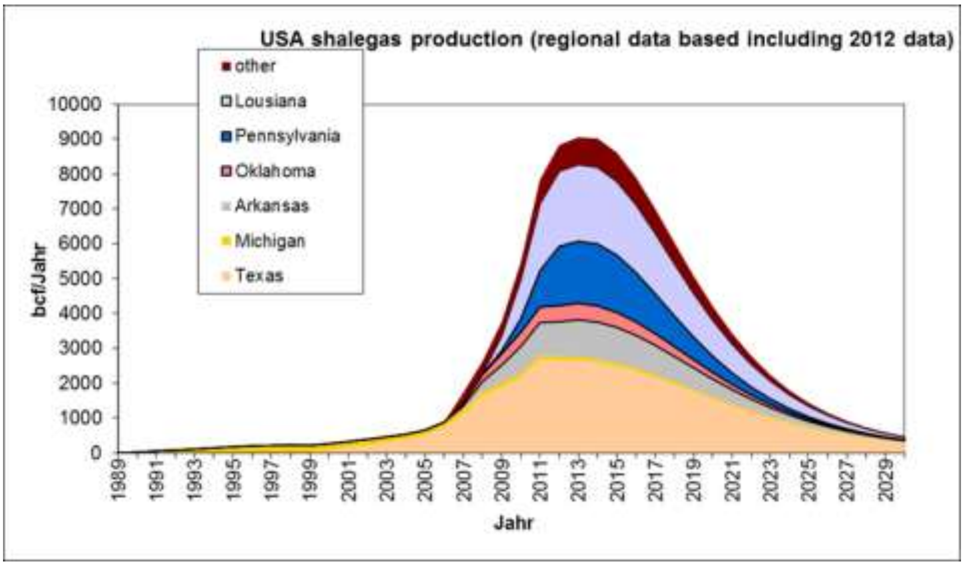



Figure 56 shows the scenario projections for the shale gas production in each federal state. Production in Texas is peaking, followed by a slight decline which in coming years will accelerate. Further production increases are expected to come from the Marcellus shale in Pennsylvania and Oklahoma. This production growth might offset the decline in Texas and other states for a few years.

**Figure 56: Scenario calculation for shale gas development in USA until 2030.**



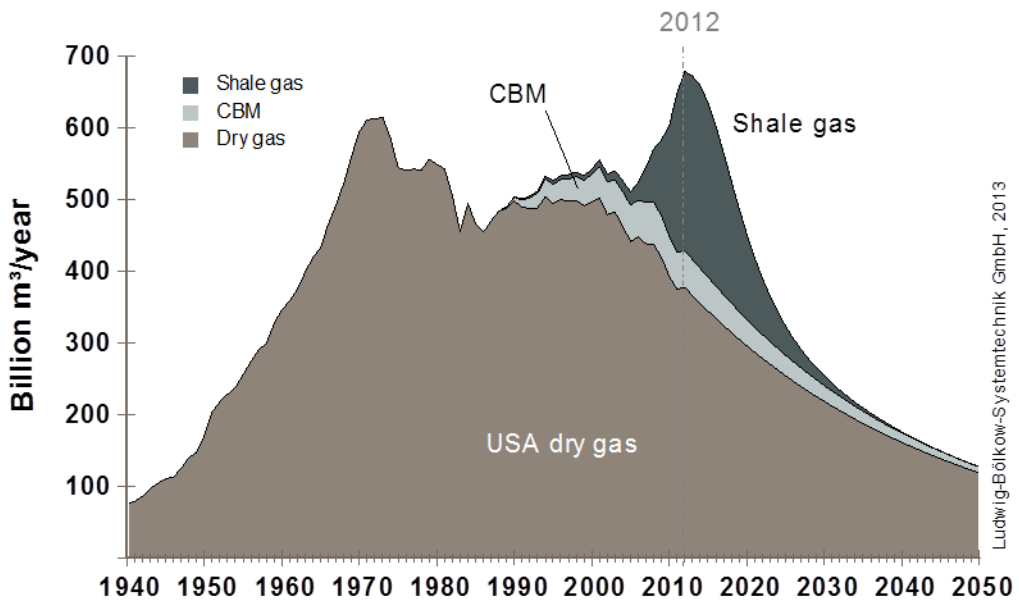

These projections are based on the analysis of the decline rates of the large shales and account for remaining reserves. For instance, cumulative production 2011 – 2050 amounts to 2,600 billion m³ while US Shale gas reserves are 2,700 billion m³. Almost 93 percent of the remaining reserves are located in Texas, Louisiana, Arkansas, Pennsylvania and Oklahoma.

Texas alone holds about 40 percent of those reserves. According to this analysis, Texas shale gas production has already peaked and is likely to decline according to Figure 79.

### *LBST natural gas scenario for the USA*

By aggregating the detailed analyses for the different producing regions, one arrives at a scenario for the production of natural gas in the USA until 2050 as shown in Figure 57. Conventional gas production including the offshore production in the Gulf of Mexico is already in steep decline, despite remaining large reserves. Since 2005, this decline was more than compensated by the accelerating production of shale gas. The growth of the shale gas production is slowing and will in only a few years no longer be able to offset the decline of the conventional production. This might result in a steep decline of total gas production from about 2015 onwards. The decline rate probably will be much steeper than from conventional production alone, due to the above explained characteristics of shale gas production. This will probably lead to a decline rate not seen before. It is therefore possible that domestic US gas production might decline by 50 percent or even more within the next twenty years.

**Figure 57: US gas production scenario until 2050**




## Europe

### *Conventional gas production*

Conventional gas production in Europe peaked around 2000 and is in decline since then despite Norway which still has the potential to increase production.

Production of the small producers Germany, Italy, Poland and Romania is shown in Figure 58. Their combined output is in decline already since 1990. The scenario expects that production will continue this decline until 2030. A possible future shale gas production eventually might modify that decline not earlier than 2015 onward. Shale gas is discussed later in a separate section.

**Figure 58: Gas production in Germany, Italy, Poland and Romania (Source IHS 2006, BP 2012, LBEG 2013)**

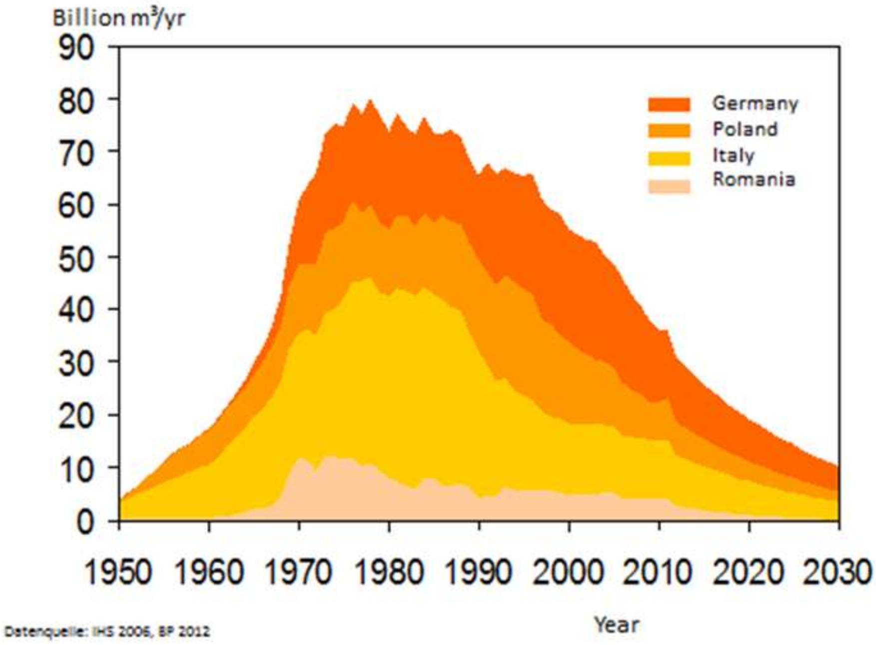
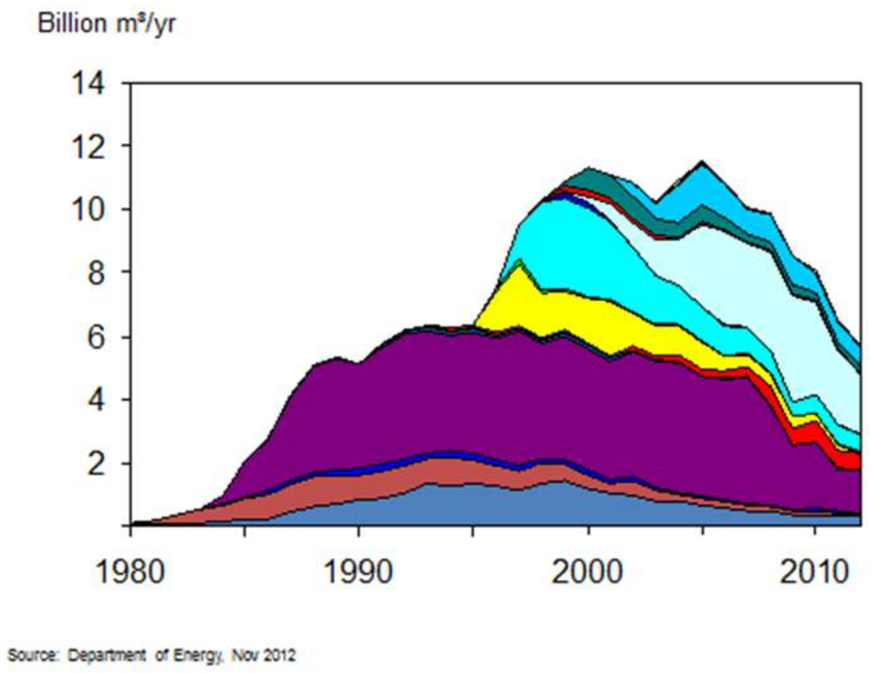



Figure 59 shows the gas production of Denmark, being the smallest European offshore producer. The largest field "Dan" was developed early on. It produced at an almost constant rate from 1988 until 2007 when output started to decline. This field was managed in a sustainable way by adapting the production rate to a level far below a possible maximum, thereby feeding the pipeline for twenty years. Fields which were developed later were producing at maximum level. This resulted in a short lived high output which soon was followed by a decline. With several such fields the total output could be kept at a plateau from 2000 until 2005. Since 2005 the production declined by 50 percent at an average decline rate of almost 10 per cent per year.

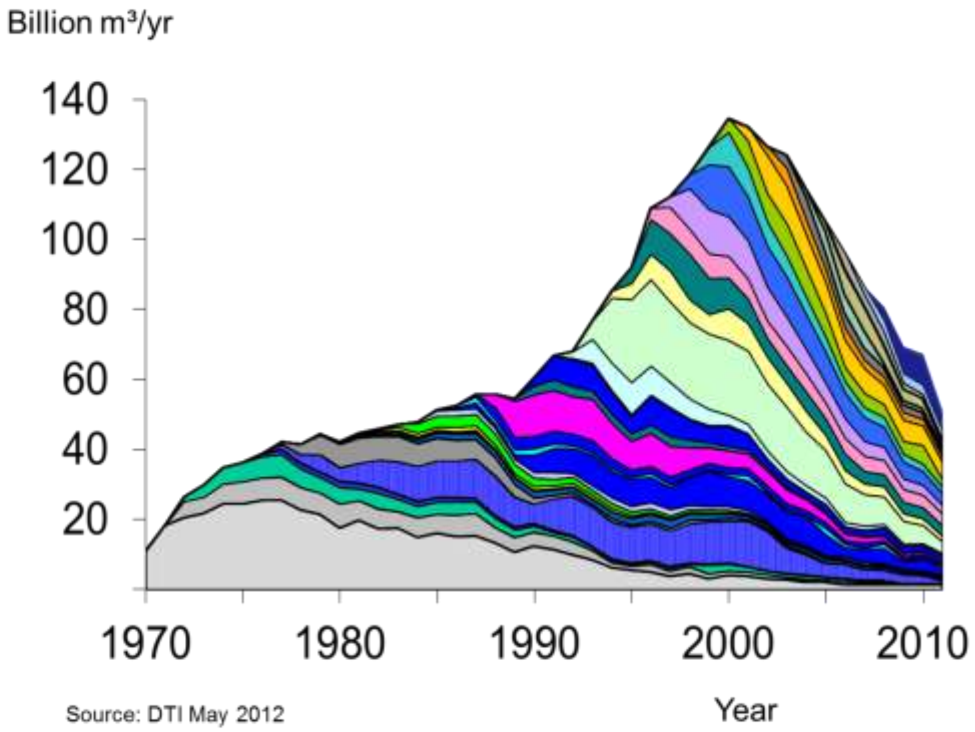
**Figure 59: Gas production in Denmark (Source: Department of Energy 2012)**




Gas production in the UK was increased rapidly from 1990 onwards. The policy was to develop these fields fast and to thereby increase the share of electricity generation from natural gas by substituting coal. This was meant to reduce greenhouse gas emissions. However, in parallel to the course of the domestic oil production, the UK gas production peaked in 2000. The following decline was unprecedented, arriving at 60 percent within 12 years which is an annual decline rate of almost 7 per cent.

Figure 60 shows the gas production in the UK where each area corresponds to the production from all fields developed in that year. The decline after 2000 follows almost exactly the decline of the base production, only marginally offset by the development of new fields. All fields developed within the last ten years helped to reduce the decline from 75 to 62 per cent.

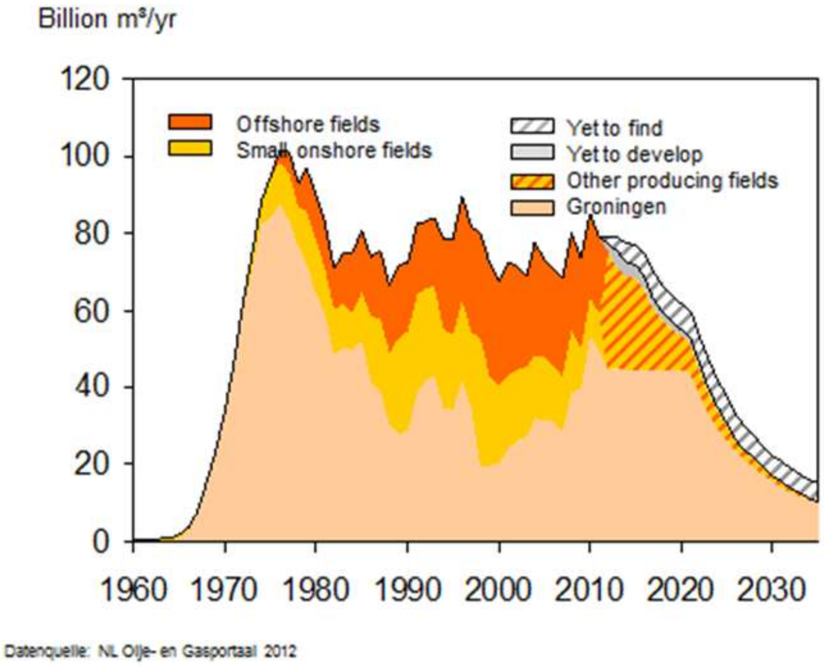
**Figure 60: Gas production in the UK; each area corresponds to the combined production of all fields developed in one year**




European natural gas production was closely linked to the development of the large gas field near Groningen in the Netherlands. This field was discovered in 1959 and was then developed fast. It reached peak production already in 1976. At that time, the government proposed a small field initiative aimed at developing the smaller fields in order to save the remaining reserves of Groningen for later times. In the following decades total gas production in the Netherlands was kept between 70 to 80 billion m³/yr. But as the output of the small fields is declining, since 2000 production of the Groningen field had to be steadily increased to compensate for this decline.

Figure 61 shows historical gas production in the Netherlands and a forecast published by the Netherlands government (Olje en Gasportal 2012). According to that figure, output from Groningen might be kept at a constant level until 2020 when its production will start to decline for geological reasons, with a rate of 5 percent per year. Small fields are in decline since 1990 and offshore production peaked around 2000. These fields will decline further to a negligible production level in 2030. Not yet developed discoveries are by far too small to compensate for that decline. Even the expected discoveries yet to be made will influence this trend only marginally. It must be expected that gas production in the Netherlands will soon start to decline. As a consequence, exports from the country will shrink drastically if the decline cannot be compensated by fast growing imports from outside Europe – either LNG with new terminals, or via pipeline from North Africa or Eurasia (Russia, Caspean Sea or Middle East).

**Figure 61: Gas production in the Netherlands**




Norway is the only European country which still has the potential to increase its gas production. Figure 62 shows a field by field analysis of the gas production in Norway. Production increased since 1995 when the largest gas field, Troll, began to produce. Actually, Troll accounts for almost one third of the Norwegian gas production. Other large fields are Ormen-Lange, Asgard and Kvitjeborn. However, the impact of Troll is so large that its future production capacity determines when Norway's gas production will start to decline. New discoveries are rare. The known discoveries contained about 3,700 billion m³ of natural gas originally recoverable of which at the end of 2012 still 2,060 billion m³ were available. At a constant production rate, this gives a reserve-to-production ratio (R/P-ratio) of 18 years. However, the remaining reserves are unequally distributed over the individual fields. Troll contains half of these reserves, having a R/P-ratio of 30 years. It is already depleted by 30 per cent. The other large fields Ormen-Lange, Asgard and Kvitjieborn have a R/P-ratio of between 7 to 10 years. All remaining fields have a combined R/P-ratio of 11 years.

The scenario projection until 2050 accounts for the production history and the remaining reserves of each individual field. This leads to the assessment that production might peak around 2014/2015 at 120 billion m³/yr and decline thereafter. In 2030, Norwegian gas production will have declined by about 50 per cent.

**Figure 62: Field by field analysis of gas production in Norway**

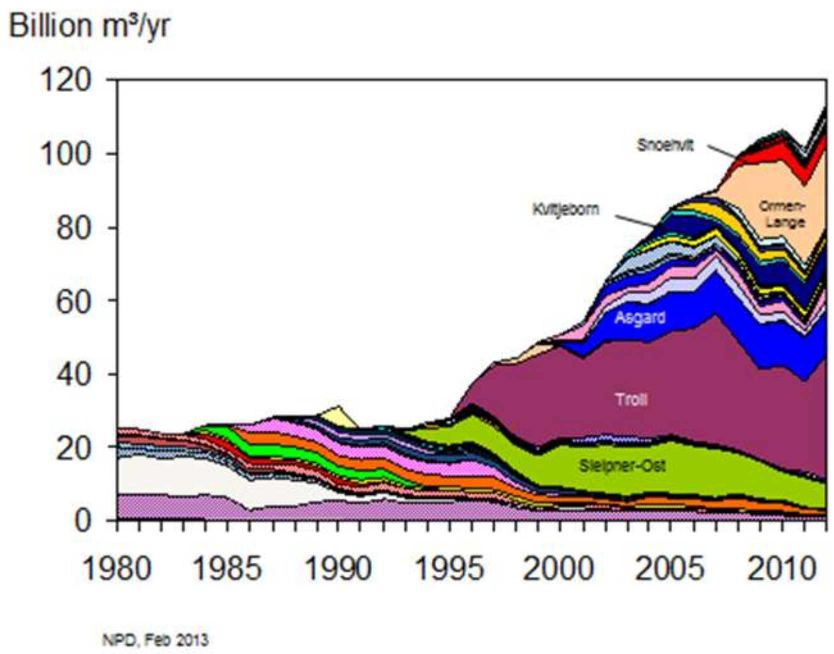
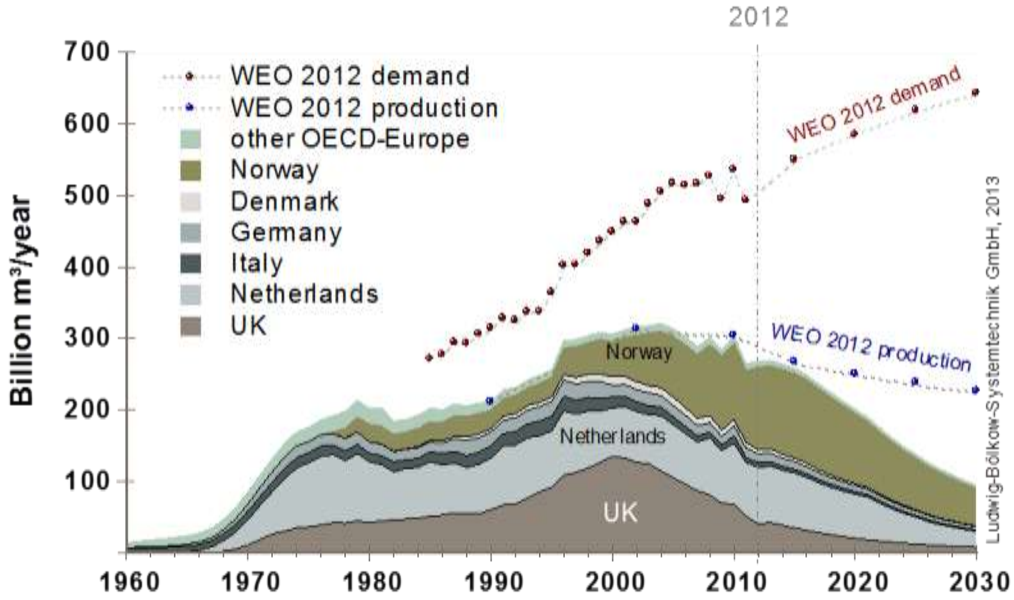



Figure 63 shows an aggregated view of the gas supply of OECD Europe since 1960 with an outlook to 2030. Domestic gas production already peaked and is in decline since 2004 despite the fast production increases in Norway. However, also the expected further rise of Norwegian gas production will not reverse the declining trend.

By 2030, European gas production probably will have declined by 70 percent. The figure sketches a scenario where gas imports by pipeline and LNG are kept constant. In that case, gas imports to Europe must increase by 250 – 300 billion m³ annualy in order to meet the projected demand in the WEO 2012. It is very doubtful that these quantities can be supplied in time. Rising gas imports via pipeline are improbable, especially from Russia. As will be discussed later, Russian gas production is struggling with decline as well and additionally is facing a rising domestic consumption. Possible European imports from the Caspian strongly compete with demand request from Asia where transport distances are much shorter.

Imports of LNG by ship require the fast extension of terminals, but are also in worldwide competition with other customers.

**Figure 63: Gas supply of OECD Europe**




### *Unconventional Gas production in Europe*

In view of declining domestic production and rising import needs accompanied by risks of security of supply, it is tempting to develop the unconventional gas resources in Europe. But in contrast to North America and irrespectible of environmental concerns, unconventional gas will play a negligible role in Europe. At present only vague estimates of unconventional gas resources in Europe exist, none of them having the status of a proven reserve. Therefore, all numbers must be treated with great caution.

Conventional European gas reserves amount to about 4,000 billion m³ which translates into a reserve-to-production ratio of 16 years. Half of that reserve is in Norway and another quarter in the Netherlands. The remaining quarter is shared by the other countries.

In April 2011, the US-EIA published a resource survey of 14 regions outside the United States (EIA 2011). The summary results for European countries are shown in Table 5, with additional data on conventional gas reserves (BP 2012, BGR 2012, LBEG 2012).

**Table 1: Conventional gas reserves and estimate of shale gas resources in Europe**

| Country | Conventional Reserve | Technically recoverable shale gas resource |
|---|---|---|
| France | 6 | 5000 |
| Germany | 80*) | 220 [700-2,300]**) |

| | | |
|---|---|---|
| Netherlands | 1,100 | 480 |
| Norway | 2,060 | 2350 |
| UK | 200 | 560 |
| Denmark | 45 | 650 |
| Sweden | 0 | 1160 |
| Poland | 120 | 5300 |
| Turkey | 6 | 420 |
| others | 80 | 200 |
| Total: | 3,700 | 16,340 |

*) LBEG 2012

**) BGR 2012

Technically recoverable resources are estimated by applying a recovery factor of 25 percent of the gas in place. This is considerably larger than the 10 percent recovery factor which was used by the BGR for Germany.

It must be emphasized that reserve numbers are given for proven reserves. However, proven reserves for shale gas are zero. There are only several estimates of possible resources and of possible technical recovery. Therefore, these numbers are not reliable and have to be treated with caution. According to an interview with the former Polish Prime Minister Wlodzimierz Cimoscewiczx, the unconventional gas resources of Poland are overstated by 90 percent in the Study of the US-EIA. This is due to a simple printing error, where a comma was slipped by one digit.

Cumulative gas production in Europe since 1960 is close to 10,000 billion m³. But as already discussed for the Shale gas production in the United States, besides the size of resources the production dynamics and other boundary conditions will determine whether shale gas production will become relevant.

A basic difference between Europe and the USA is the population density in the shale trends which in most European countries is much higher than in the USA. Secondly, more than 150 years of experience with the production of oil and gas in the USA resulted in a countrywide natural gas grid with about 500,000 active gas wells – 100,000 alone in Texas – and a comparable number of oil wells.

For instance, in January 2013 more than 1,700 onshore rigs were active, drilling for oil and gas in the US.

This is completely different in Europe. In January 2013 only 80 onshore rigs were active in the whole Europe. This sets a limit to the possible development speed of shale gas production since every well has to be drilled by a rig and each drilling takes at least several months. Though the number of active rigs may vary, the number of available rigs sets a limit. The movement of new rigs into a region is time and cost consuming and only possible when these rigs are removed from other areas.

In Germany, for instance, the domestic gas production of 13 billion m³/yr comes from 494 production wells. In 2011, about 50,000 m were drilled for the development of new production wells. These numbers are used as a reference for scenario calculations and would, in the best case, allow the development of 20 to 30 production wells per year. For comparison, in 2011 the Russian Gas giant Gazprom completed a total of 45 production wells (GAZPROM 2011).

### *Gas production in Russia*

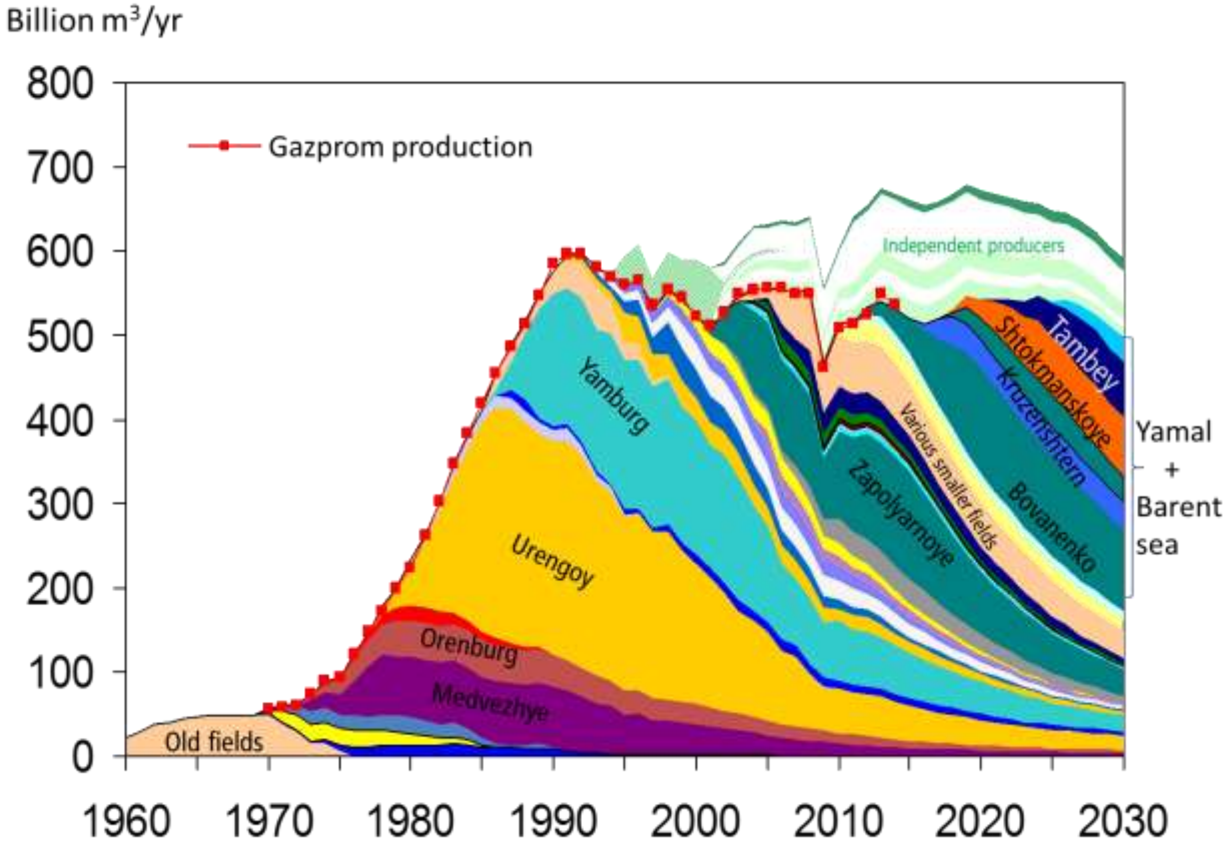
Russian gas production has had a production peak in 1989 when production in its elder large fields Medvezhye, Orenburg, Urengoy and Yamburg peaked. At that time these fields had a production share of more than 90 per cent. In the following years the production decline was due to a lack of new investments in known but not yet developed fields. In parallel, the industry was reorganised by opening it for the investment of private companies.

Figure 64 shows a field by field analysis of Gazprom’s production and of the rising production of new enterprices. Gazprom’s share declined from 100 percent in 1989 to 77 percent in 2011. The analysis includes known but not yet developed fields according to published development plans from 2008 and making corrections for recent developments and assessments. The field decline is extrapolated from past experience with some adaptions in order to match the published total production data until 2008. Production profiles for private companies are derived by extrapolating the production history and fitting them to match proven reserves.

These data are overlaid with recent production data for Gazprom. Total natural gas production of Russia is shown by adding the production of private enterprices on top of the production of Gazprom. Production data from BP Statistical Review of Energy would result in a lower Russian gas production. Future field developments in the Far East are not included as this gas will not be available for Europe. The data also include Gazprom forecasts for production in 2013 and 2014 (Reuters 2012). These numbers (2013: 541 billion m³/yr; 2014: 548 billion m³/yr) match the scenario projections.

Future field developments are given for the development of the Yamal Peninsula and of fields offshore in the Barent sea. Possible offshore developments in the Kara sea (Leningradskoye, Rusanovskoay) are not included as these are expected not to produce before 2030. Gazprom claims to develop them not before 2025. (Source: http://www.gazprom.com/about/production/projects/mega-yamal/ )

**Figure 64: Gas production in Russia with field by field analysis of Gazprom fields**




Data Sources: Gazprom 2008, 2013; J. Stern The Future of Russian Gas and Gazprom 2005; BP 2012
Campbell, Perrodon, Laherrere: The world's gas Potential 1995; LBST Feb 2009

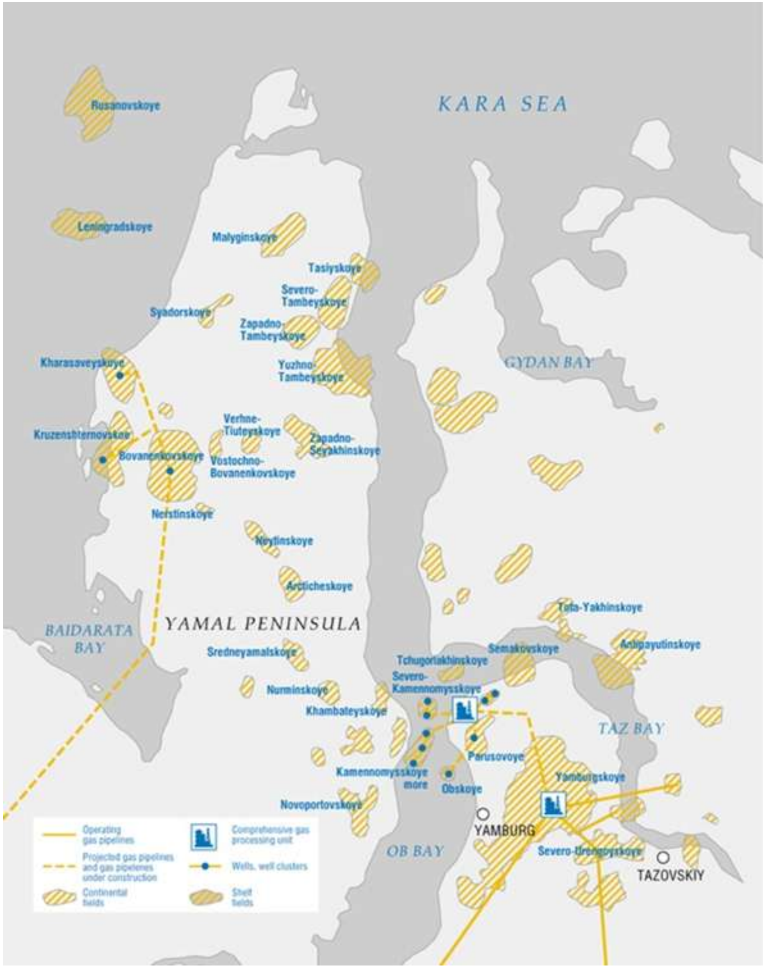
The geographical location of the fields in the Yamal Peninsula and offshore is shown in Figure 65. According to Gazprom, the development of these fields is scheduled into three blocks: (1) Bovanenko with Kharasaveyskoye and Kruzenshternskoye; (2) the Tambey field and satellites, and (3) the southern fields of Yamal Peninsula. The development of Bovanenko and neighboring fields comprises several phases with increasing production volumes. At full development, Gazprom expects these fields to produce at 220 Tcm/yr. However, due to the onset of decline of the fields developed early, the present scenario assumes that combined production from these fields in 2030 amounts to 165 Tcm.

Originally, Gazprom expected the field Stokhmanskoye in the Barent sea to be developed by 2013. This date has been delayed until 2016 or 2017. The joint project development with Statoil and Total was set on hold in summer 2012 (Gazprom 2012a). Recent plans are to continue with the field development. Though some engineering work has already started, first bidding for the construction of an LNG plant is planned to start in 2013 (Gazprom 2012b). Our scenario assumes that the first gas from Shtokmanskoye will flow in 2018.

There are six fields in the Tambey area (Severo-Tambeyskoye, Zapadno-Tambeyskoye, Tasiyskoye, Malyginskoye, Yuzhno-Tambeyskoye and Syadorskoye) with a combined maximum production capacity of 65 Tcm/yr. The scenario assumes that production will start in 2021 and reach full capacity in 2025. In the southern area there are nine fields with a projected total capacity of 30 Tcm/yr. These fields probably will not be developed before 2025. Gazprom expects total output from Yamal to reach 200 – 250 Tcm in 2025 and 310 – 360 Tcm in 2030. In the updated scenario it is assumed that total output from Yamal will reach 230 Tcm in 2025 and 255 Tcm in 2030. Stokhmanskoye is added with 70 Tcm of annual capacity in 2030.

In case no additional fields offshore Yamal are developed until 2030, this production volume will not be enough to compensate for the decline of mature elder fields in Siberia. Probably Russian production will start to decline around 2025.

**Figure 65: Gas fields in the Yamal area and offshore; (Source: http://www.gazprom.com/about/production/projects/mega-yamal/ )**




If there are delays in the development of any of these fields, total production from Gazprom will fall below the profile sketched in Figure 64. This refers to the extension and full development of Bovanenko,  the development of its neighboring fields, the development of the six Tambey-fields and the nine southern Yamal fields, or even a further delay of Stokhmanskoye in the Barentsea.

This scenario does not include gas fields in Central Asia or the Far East which will not impact possible future gas flows to Europe. In 2011 began the development of the field Kovyktinskoye close to Irkutsk which holds up to 1,500 billion m³ of gas. The development strategy for the gas and condensate field Chayadinskoye with reserves of 1,200 billion m³ has been approved in 2007. The development of the gas facitilies is scheduled to start in 2017 (OGJ 2012).

## *World*

### *LNG*

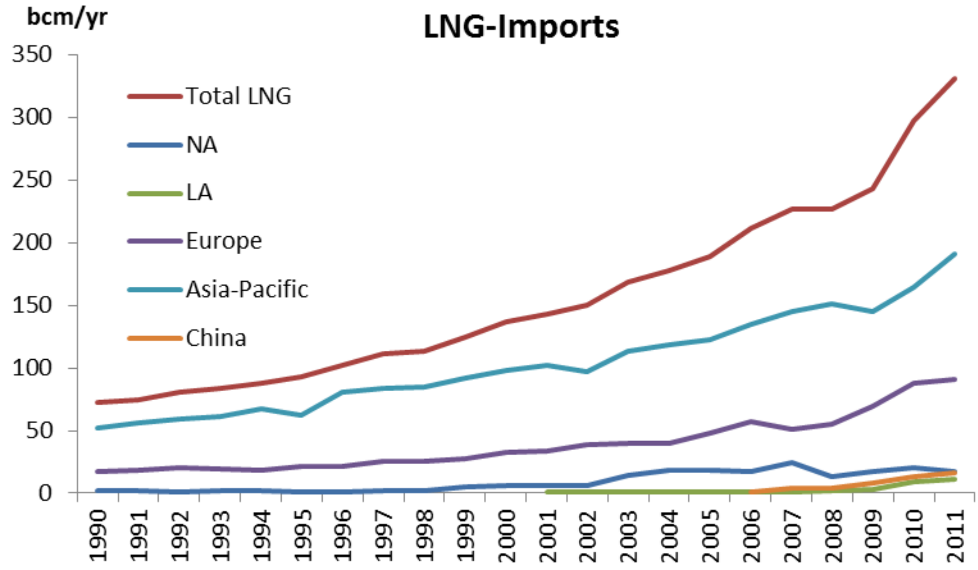
Though LNG imports are no primary source of natural gas, the situation is briefly surveyed in this study. This is because Europe and other countries hope to close the gap between rising demand and declining domestic production by rising LNG imports, in addition to rising imports by pipeline. As the analysis given above reveals, by 2030 Europe has to increase imports of natural gas by at least 200 bcm/yr to keep consumption flat.

Transport of natural gas via LNG began in the 1970s when Spain started to import LNG from Algeria and Japan from Indonesia. Figure 66 shows the LNG import volumes by country since 1990. Within the last 20 years LNG imports quadrupled mainly driven by Asia (Japan and South Korea) and Europe (Spain, France and UK in 2011 having a share of 65 percent of European imports). The share of LNG of total natural gas production increased from 3.6 percent in 1990 to 10 percent in 2011, totaling about 330 bcm of gas or 241 million tons (Mt) of LNG. In 2001, for the first time, LNG was imported by Latin America. LNG imports to China started in 2007. (GIIGNL 2012)

The analysis of US gas production given above revealed that by 2030 domestic production probably will have declined by 400 bcm/yr or 50 percent. Asean demand probably will rise by at least 200 bcm/yr, comparable to Europe.

In a net balance, the global demand for LNG in 2030 probably might increase by at least 700 bcm/yr. This would bring total LNG imports in 2030 to around 1,000 bcm.

**Figure 66: LNG Imports by country or region**

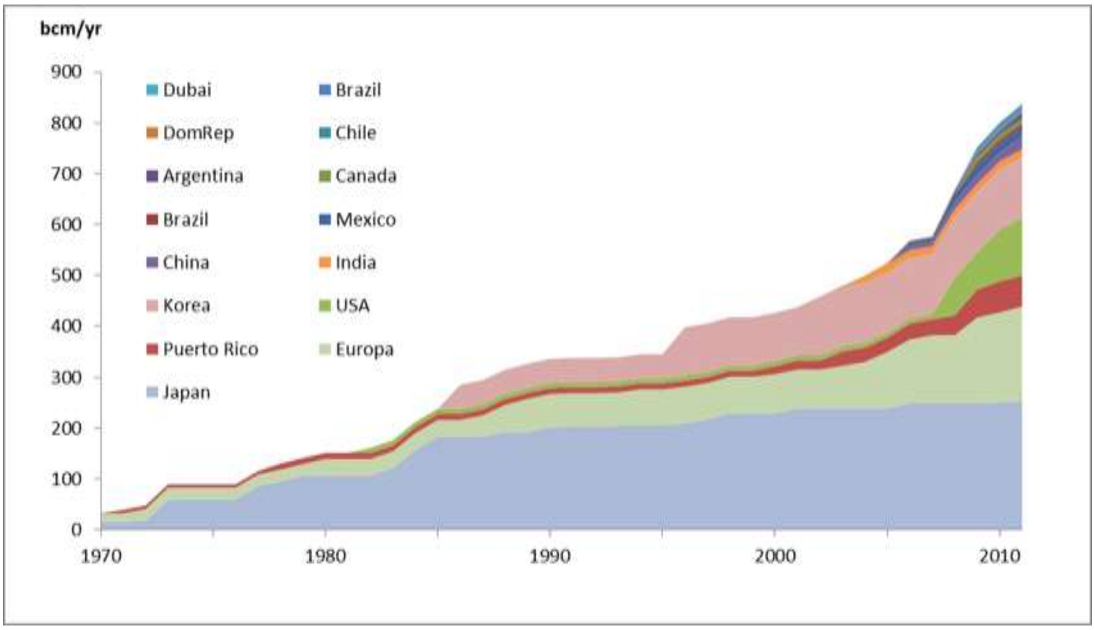



At year end 2011, a total of 89 regasification terminals in 25 countries were reported having a capacity of 640 Mt/yr LNG, corresponding to 870 bcm/yr. Europe has 21 terminals with a total capacity of 190 bcm/yr. However, with 250 bcm/yr by far the largest regasification capacity is in Japan. During the last two decades Europe increased its import capacity by a factor of three (see Figure 67). The figure also reveals that additional countries in Latin America and Asia are increasing their import capacity and will in future increase their imports of LNG, while South Korea and Japan already have sufficient regasification capacity at LNG import terminals enabling them to still increase imports. Actually, the capacity of regasification terminals is utilised at less than 40 percent.

Despite the public discussion about the USA becoming a net exporting country of natural gas, only the import capacity for LNG has been increased over the last few years to more than 100 bcm/yr (see the green area in Figure 67). Moreover, also the rising import capacity of Puerto Rico is mainly intended to fuel the US market.

Only 50 percent of the import capacity of Europe of 185 bcm/yr was utilised in recent years, leaving enough spare capacity to double imports.

**Figure 67: World regasification capacity (GIIGNL 2012)**




The present global import capacity of 870 bcm/yr cannot be supplied by the existing liquefaction plant capacity in exporting countries. In 2011, 24 liquefaction plants in 18 countries had a total export capacity of 278 Mt, of which 87 percent (241 Mt) were utilised (GIIGNL 2012).

As the import capacity of regasification plants in consumer countries is 2.5 times larger than the present export capacity, and capacity utilisation of liquefaction plants in exporting countries stands at almost 90 percent, it is obvious that potentially demand might rise faster than supply.

In recent years, only Qatar has increased its export capacity substantially. The share of new exporters like Norway (from the gasfield Snoevit) and Russia (Sakhalin) is marginal compared with other exporters. Additional liquefaction capacity needed in the next 10 to 20 years predominantly will have to be constructed in Middle Eastern countries. Therefore, rising global LNG export volumes will depend mainly on the eventual provision of new liquefaction terminals in Qatar. This will only be possible as long as domestic natural gas production rises faster than domestic consumption. Once this is no longer possible, there will be great repercussions for world LNG markets. Figure 91shows the development of LNG exports by country between 1990 and 2011.

Figure 68 shows the existing capacities and capacity utilisation of LNG plants in exporting countries. Only Qatar has increased production capacity significantly over the last few years. In order to meet the above estimated rise of LNG imports by 2030 of at least 700 bcm/yr, the now existing export capacity must be increased by a factor of 2.5 to 3, at least.

**Figure 68: LNG exports in 2011 by region (GIIGNL 2012)**

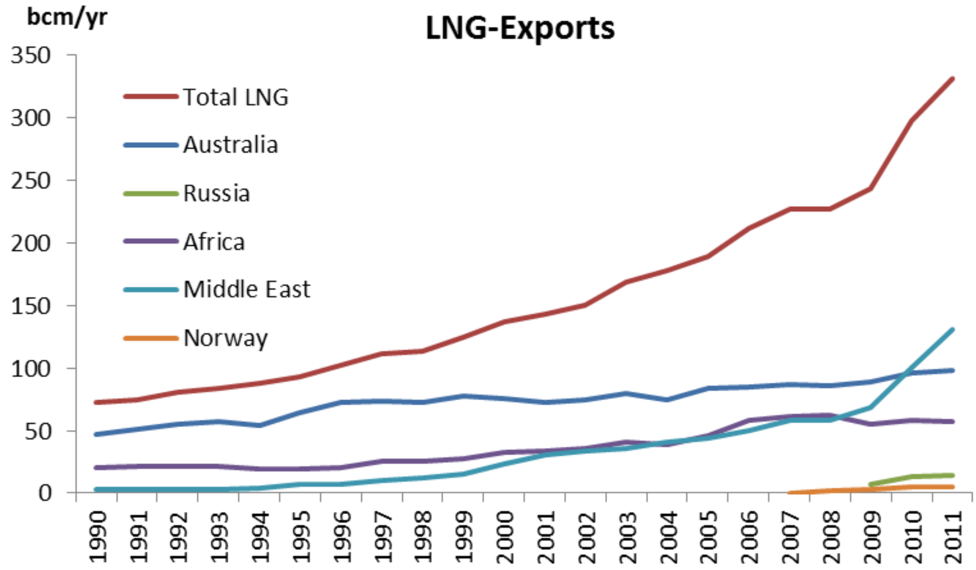
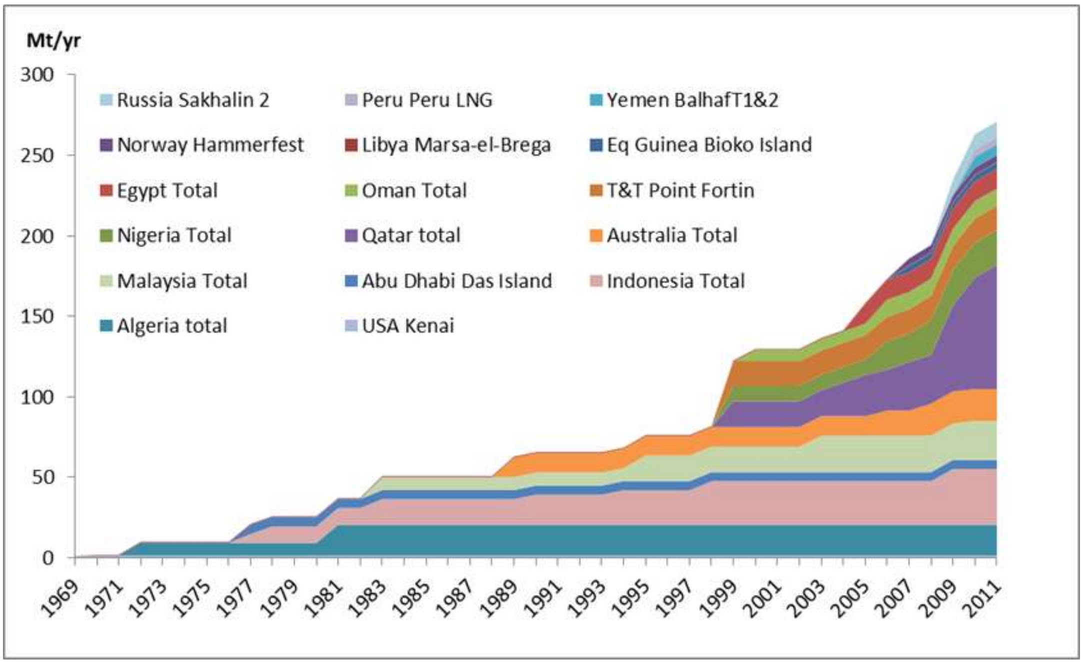



**Figure 69: World liquefaction capacity (GIIGNL 2012)**



### *World Summary and overview*

Figure 70 summarises world natural gas production from 1930 to 2011. The USA and Russia have a share more than 40 percent. The USA holds only 3.3 percent of world reserves, Russia about 30 percent. Qatar and Iran hold another 30 percent of reported reserves.

**Figure 70: History of natural gas production**

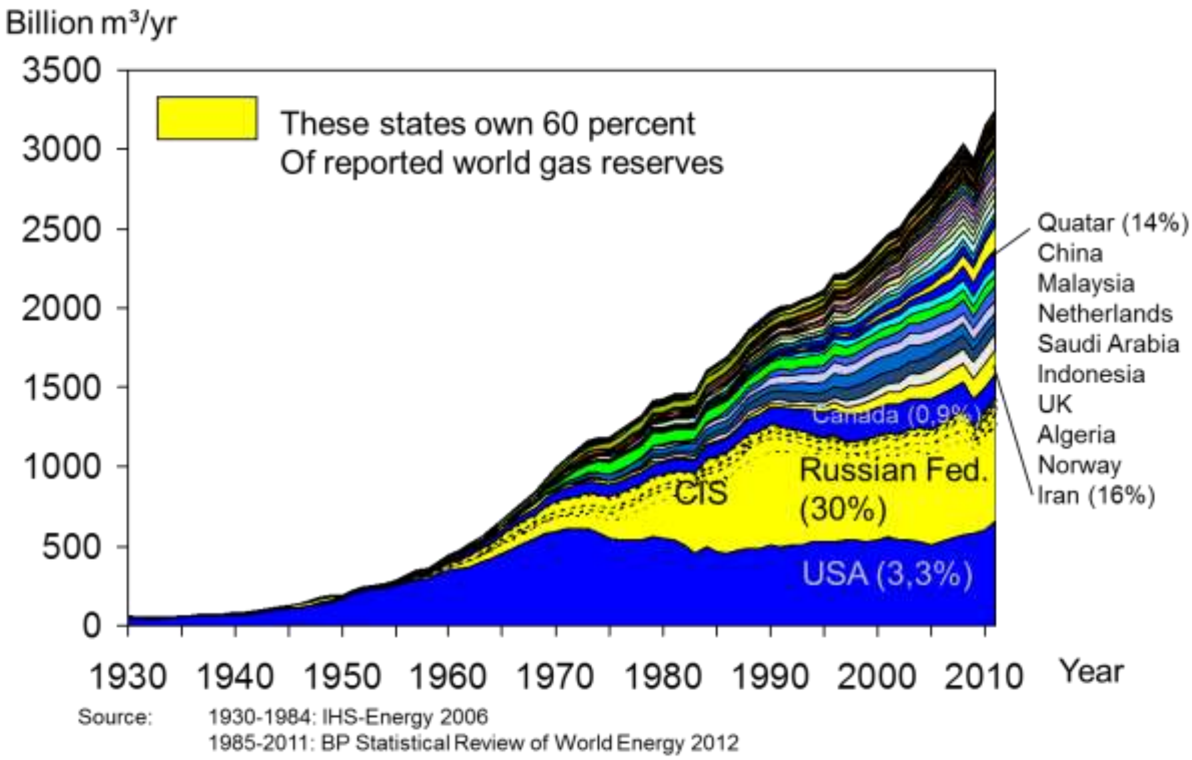
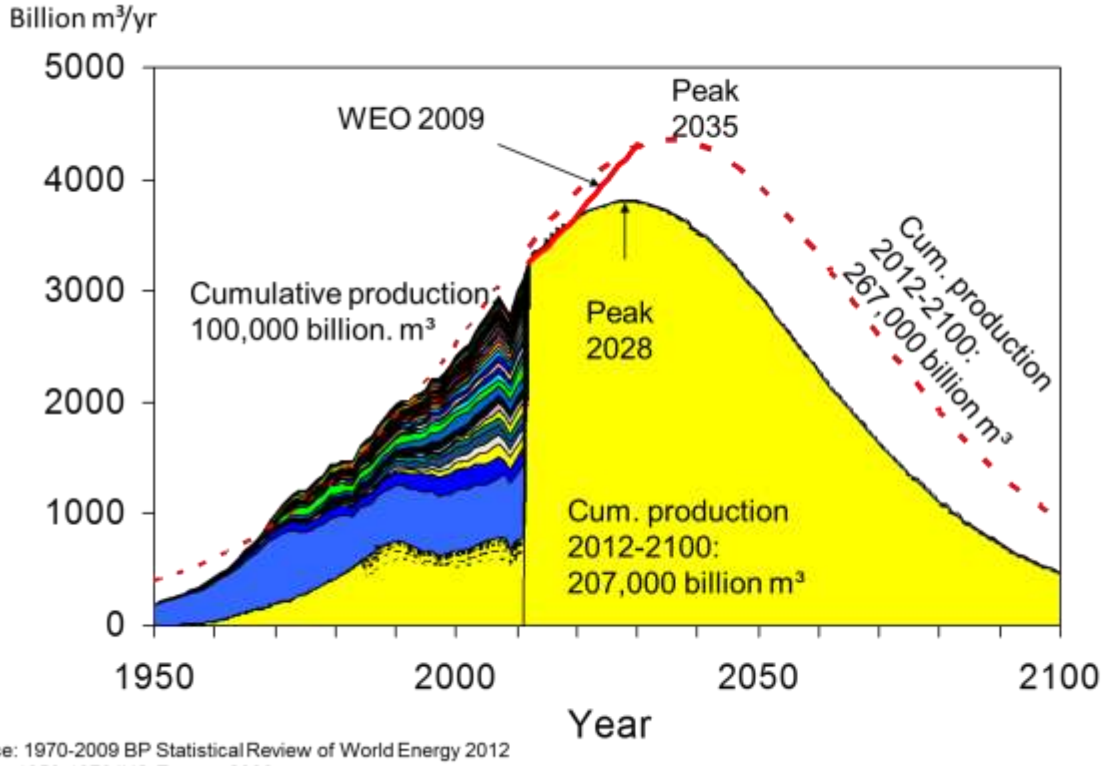



Figure 71 shows a global scenario which matches the historical production trend and projects future production until 2100 based on reported natural gas reserves. The broken red line shows a slightly modified production profile which would imply a total gas production up to 2100 which is almost 30 percent higher than the limit set by currently reported reserves. In case production would follow a bell shaped curve, then peak production might be expected between 2028 and 2035, while 30 percent larger reserves would delay the date of peak production by only 7 years.

This simple scenario demonstrates the inevitable peaking of global gas production which according to this calculation must be expected within the next two decades.

**Figure 71: Production scenario based on historical production profile and total reserves**

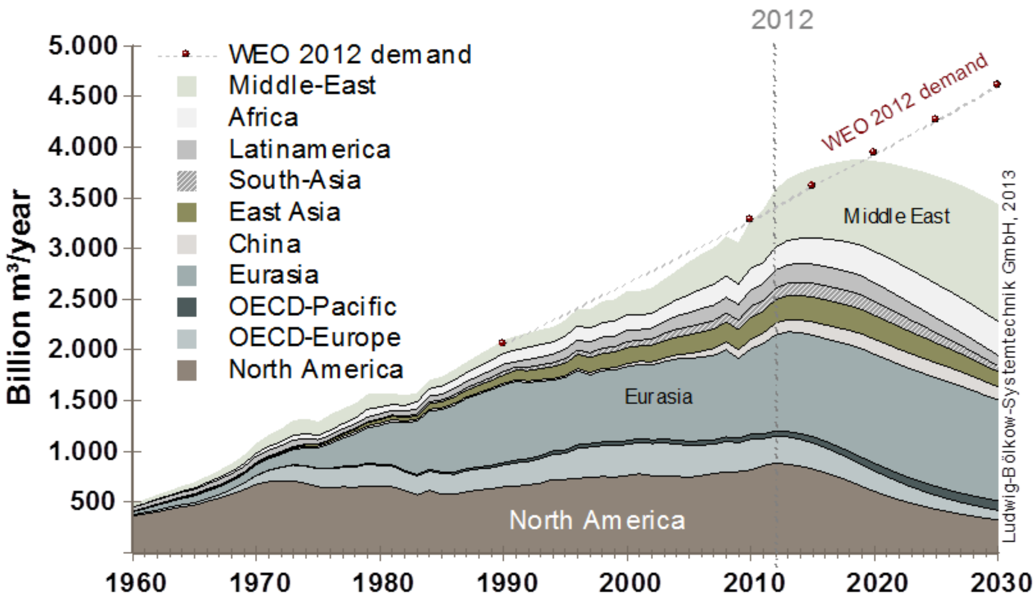



Source: 1970-2009 BP Statistical Review of World Energy 2012
1950-1970 IHS Energy, 2006
2009-2100 LBST-Scenario 2009

In contrast to this aggregated scenario, Figure 72 shows the result of projections based on in depth analysis of individual countries. These projections make use of detailed regional information, as for instance was already shown above for Europe and the USA. Based on these calculations, global peak production is expected to arrive much earlier. According to these calculations, global natural gas production will peak around or even before the year 2020.

In the following subchapter, country by country gas production is shown for each region separately.

**Figure 72: Updated EWG scenario by world region**




### *Regional Summaries*

Figure 73 summarizes the contribution of natural gas production from the individual countries USA, Canada and Mexico which are unified in OECD North America. The contributions from coal bed methane in the USA and Canada and are shown explicitly. The Canadian natural gas production is divided into the marketed gas ("CDA-net" in the figure) and the amount which is expected to be needed for the upgrading of bitumen to synthetic crude oil ("NC-demand" in the figure).

**Figure 73: Natural gas production in OECD North America**

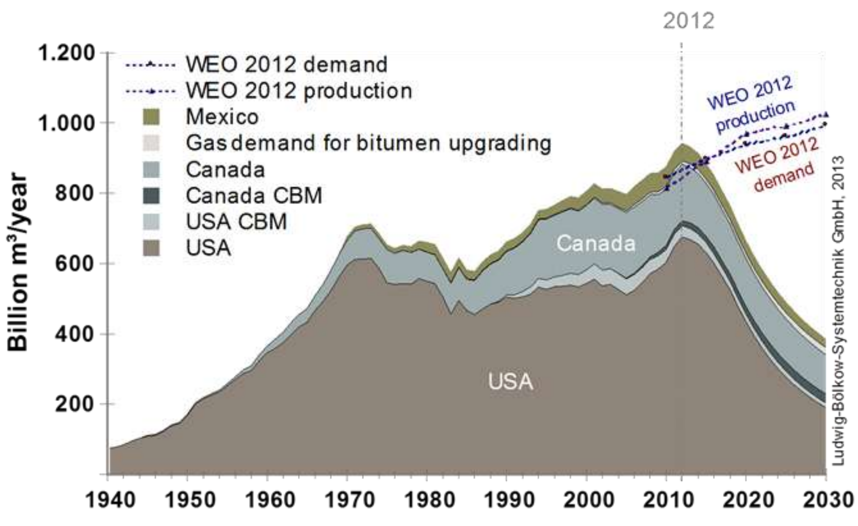


Figure 74 shows the natural gas production in Eurasia which is dominated by the natural gas production in Russia. Production in Kazakhstan is expected to peak in 2020 while natural gas reserves in Turkmenistan are large enough to allow for increasing production still in 2030. However, this gas mainly will flow south or east to China, India and Pakistan instead of Europe. The Caspian sea is a barrier for transport to western countries, which is also enhanced by the much shorter distances to the Chinese border.

**Figure 74: Natural gas production in Eurasia**

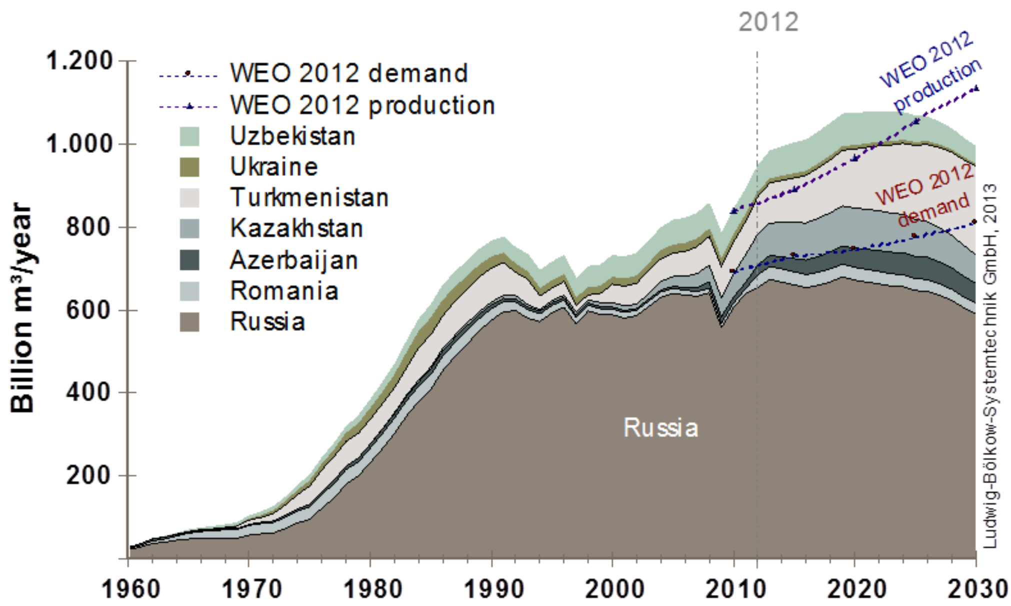



Figure 75 shows the natural gas production in Middle East countries. Even when the reported natural gas reserves in Iran and Qatar and probably also in some other countries are overstated, they are large enough to allow for an increase at least until 2030. This increase will by mainly backed by the reserves of Qatar and Iran, which beside Russia hold the second and third largest gas reserves worldwide. However, the authors believe that the demand pressure until 2030 will rise considerably. This will trigger an production extension in the Middle East as large as possible. This is in contrast to the WEO 2012 which sees no necessity for Middle East countries to rise production above the projected line.

But another aspect becomes apparent. The demand for LNG in 2030 is expected requiring at least 700 bcm/yr more LNG than in 2010 (see above). This additional demand mainly must come from surplus capacity in Middle East countries. However, as the Middle East countries might profit from higher oil and natural gas prices more than any other region, it is very likely that the domestic demand rises even further than projected in the WEO 2012 (see figure). If so, Middle East countries at best might export about 500 bcm/yr in 2030, which is an increase of less than 400 bcm/yr against actual LNG-exports. Based on these calculations it is very likely that in 2030 LNG demand might be stronger than supply. This would result in strong price increases.

**Figure 75: Natural gas production in Middle East**

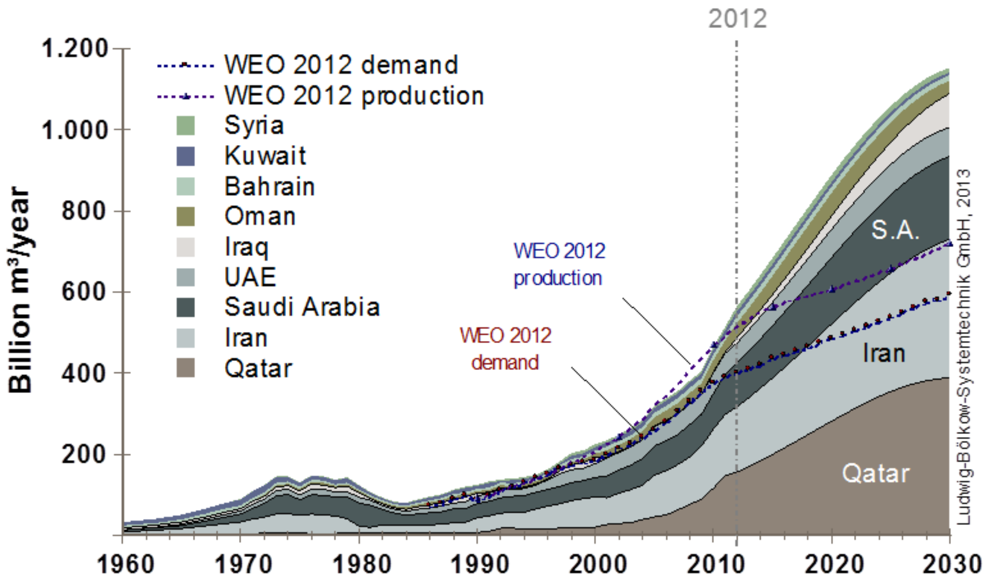



Figure 76 shows future natural gas production in Africa. Which at least until 2025 is close to the projections of the WEO 20120, but incontrast to that study peaks before 2030.

**Figure 76: Natural gas production in Africa**

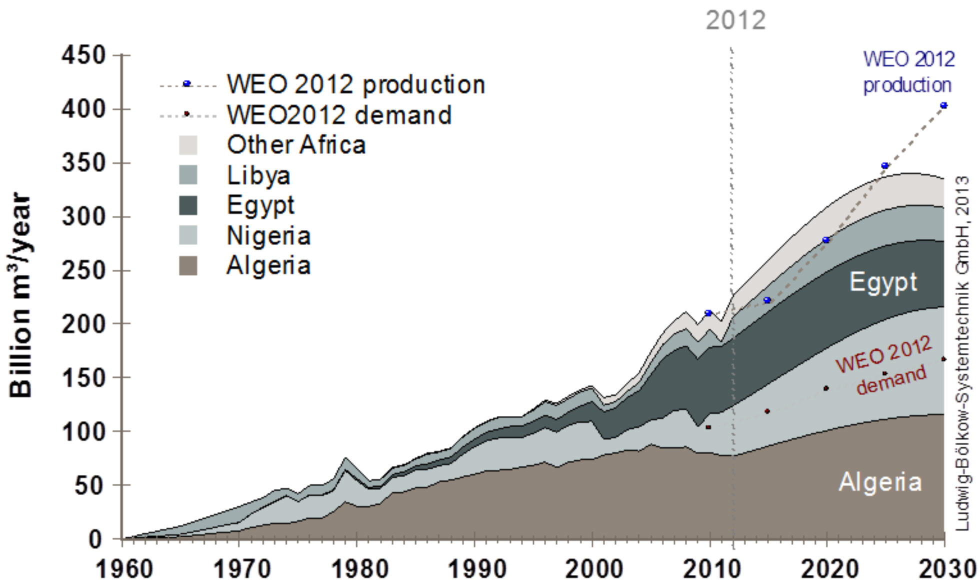



Figure 77 shows natural gas production in Australia and New Zealand. Opposite to the WEO 2012 projections the scenario calculations see a lees steep increase of natural gas production in Australia which might double until 2030.

**Figure 77: Natural gas production in OECD Pacific**

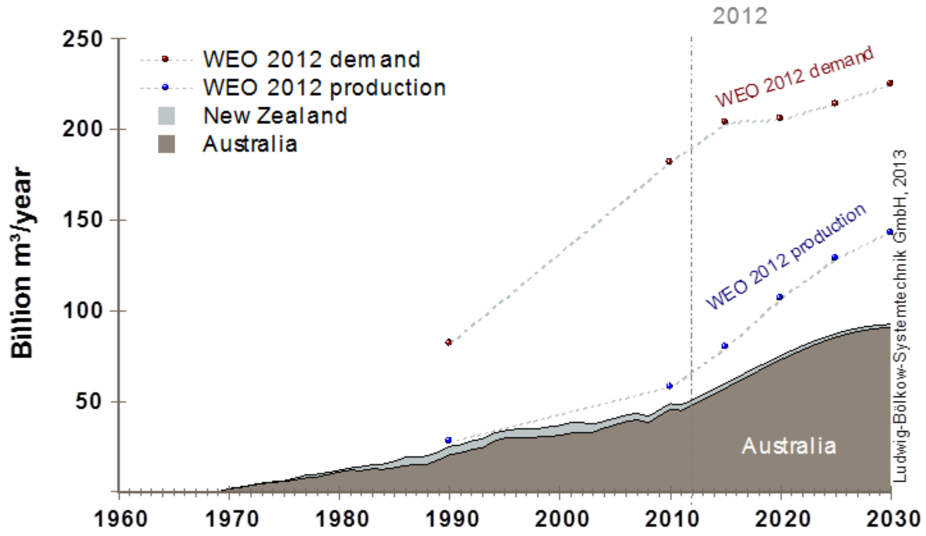



Figure 78 shows natural gas production in China. Peak is expected around 2020, opposite to the WEO 2012 projections which assume a constant production increase until 2030 at least, doubling production against today. The gap between production and demand suggests that import demand rises to between200 – 300 bcm/yr. Partly imports might be from Turkmenistan and Russia, but certainly this huge demand would increase the pressure on LNG markets in addition to the above discussed volumes.

**Figure 78: Natural gas production in China**

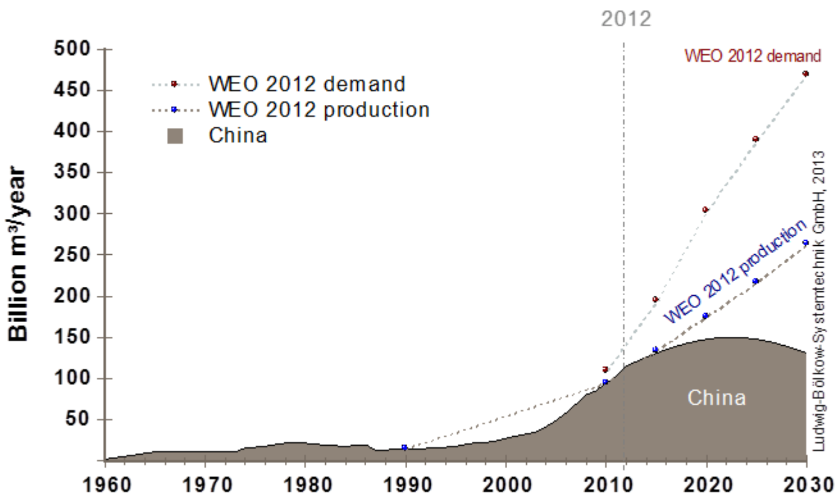



Figure 79 shows natural gas production in Latin America.

**Figure 79: Natural gas production in Latin America**

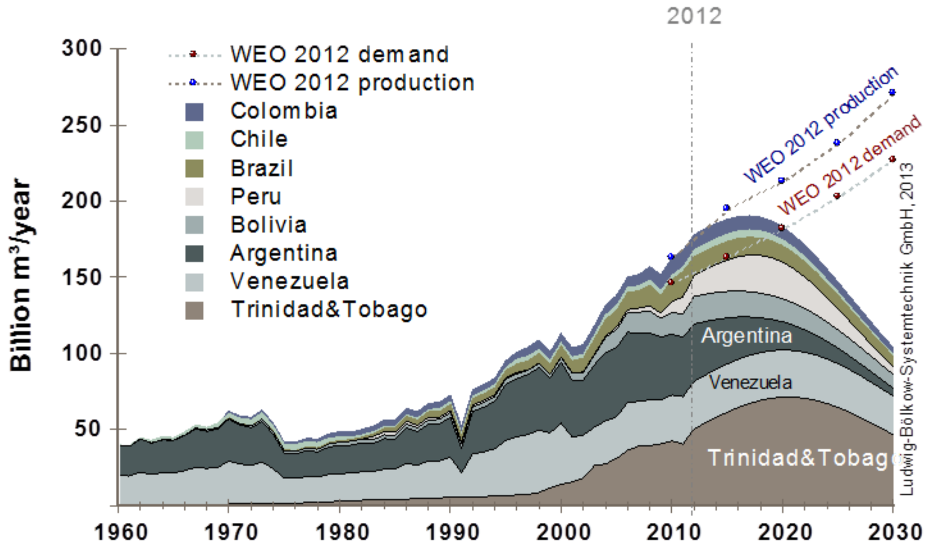
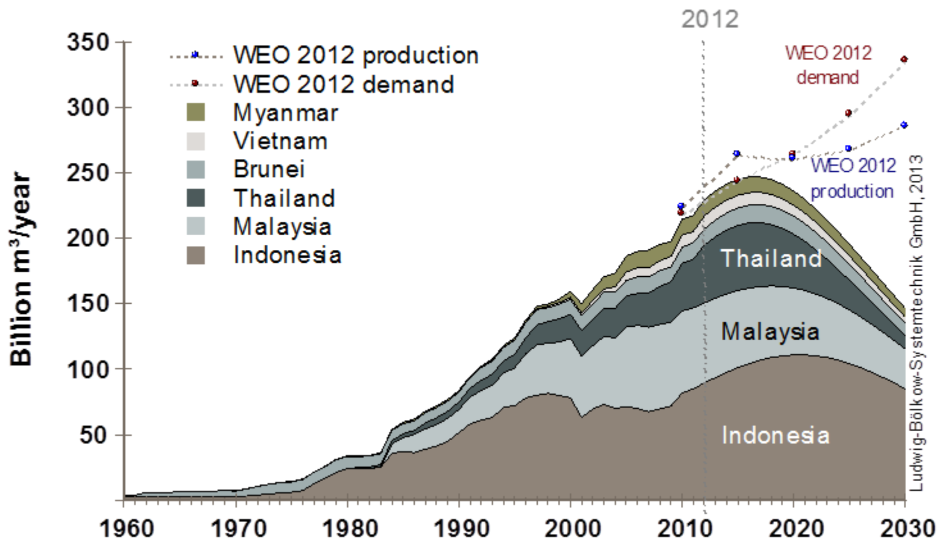



Figure 80 shows natural gas production in East Asia.

**Figure 80: Natural gas production in East Asia**




Though differences huge to the WEO 2012 in the natural gas projections for East Asia, Latin America, and China are apparent, these should not be overemphasised as the total production volumes are small. The general supply situation at world level will be dominated by the future production in the USA, in Eurasia and in Europe.

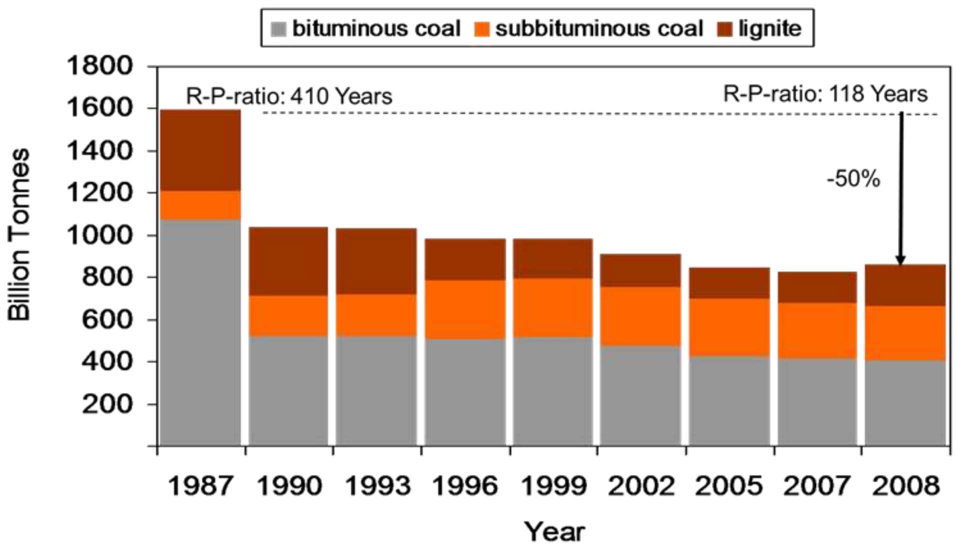
# COAL

## Reserves

Figure 81 shows the development of world coal reserves as reported by the World Energy Council (WEC) report series 'Resources'. Despite huge resources and the conversion of resources to reserves at regional level, world coal reserves in a net balance declined by more than 50 percent between 1987 and 2008. It is noteworthy that the latest update of resource data was performed in 2010 with data for year-end 2008. Between 1987 and 2011, the cumulative production of coal amounted to about 62 billion tonnes. Therefore coal consumption cannot explain the downward revision of reserves by about 500 billion tonnes.

As world coal production almost doubled between 1987 and 2011, the decline of reserves results in an ever larger reduction of the reserve-to-production ratio. At year-end 2011 reported world coal reserves were enough to supply coal for 112 years. Three years earlier the R/P-ratio still was at 118 years.

**Figure 81: Historical reporting of world coal reserves (WEC 2010)**




Quelle: WEC 1989, 1992, 1995, 1998, 2001, 2004, 2007, 2009, 2010,

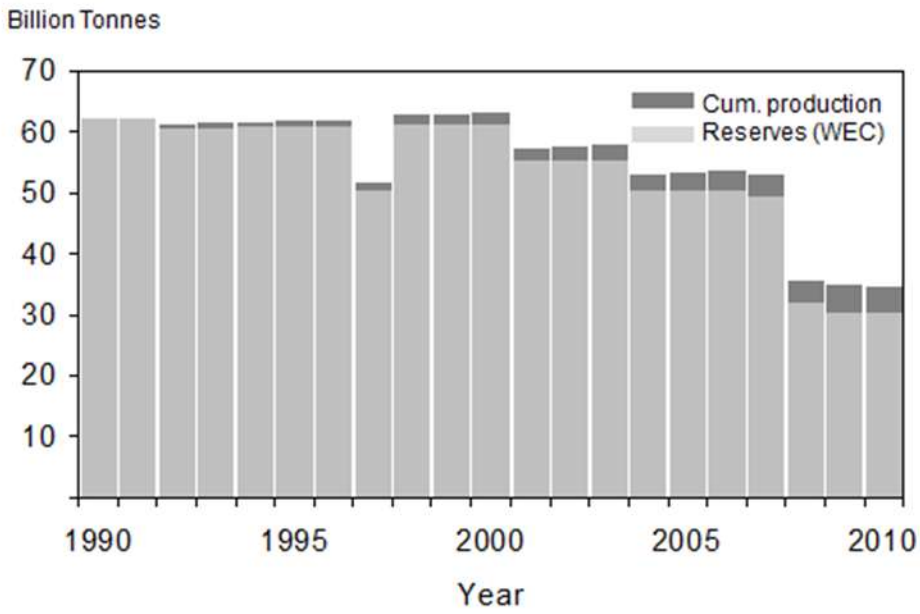
World coal reserves are unequally distributed over the world. Therefore, a better insight is gained by analysing the countries individually. In the following, for this update a number of key countries are surveyed.

### South Africa

Figure 82 shows the development of coal reserves in South Africa based on data by 'Statistics South Africa'. Similar to the historical development of global coal reserves, the reserves in

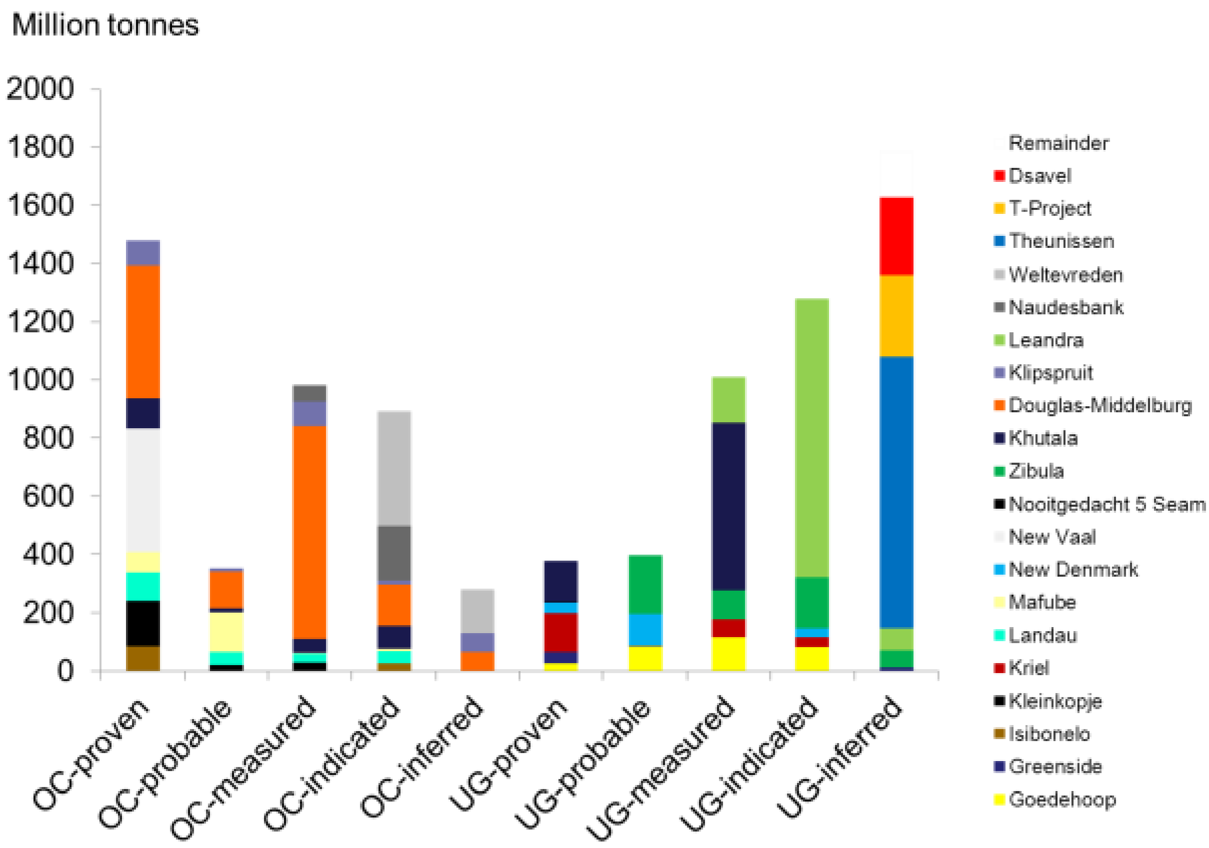
South Africa declined by 50 percent since 1990. This decline is due to downward revisions. The dark bars in the figure represent the cumulative production which must be added to reserves in order to properly describe the historical development of reserves plus cumulative production at a given time. The cumulative production is too small to explain the depletion of reserves. Obviously, reserves have been downward revised much steeper than could be explained by production.

**Figure 82: Reserve reporting of coal mines in South Africa**




84 percent of coal reserves are in coal fields which are already producing. By far the largest field, Witbank is already depleted by more than 50 percent. Figure 83 shows the coal reserves and resources attributed to individual mines in South Africa. Proven coal reserves are mainly concentrated at producing open pit mines. Whereas the greatest part of resources (measured, indicated and referred) are at underground mines. In the past, reserves were depleted by downgrading and production, but these reserves were not supplemented by the development of new mining areas which would have converted resources into reserves. Obviously this was not possible under past economic conditions.

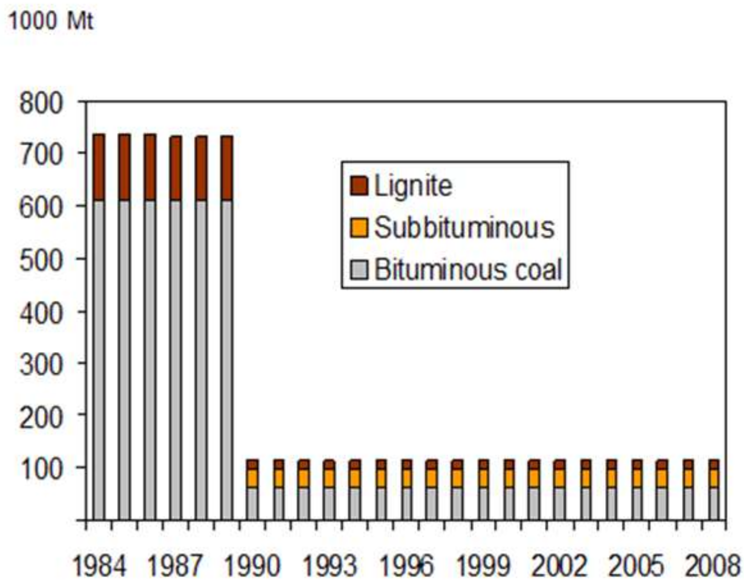
**Figure 83: Coal reserves and resources by mine, distinguishing different reserve and resource classes**




### *China*

According to WEC statistics, the reported coal reserves in China amount to 114.5 billion tonnes, consisting of different coal qualities: 62.2 billion tonnes of bituminous coal, 33.7 billion tonnes of subbituminous coal and 18.6 billion tonnes of lignite. In 1992 these reserves were downward revised by 85 percent, from 610 billion tonnes of hard coal and down from 120 billion tonnes of lignite. Since 1992 the numbers are unchanged. These data are reported by the WEC reports which get their information from the national member countries (Figure 84). Obviously, these data must be treated with caution. If true, the reserves would last for 33 years at the present production rate. If one assumes that the data reported in 1992 were correct, accounting for the 38 billion tonnes of coal which have been already produced between 1993-2011 would reduce these reserves accordingly. In that case the production-to-reserve ratio would fall to 22 years.

**Figure 84: Historical development of Chinese proven coal reserves according to WEC and BP Statistical Review of World Energy**

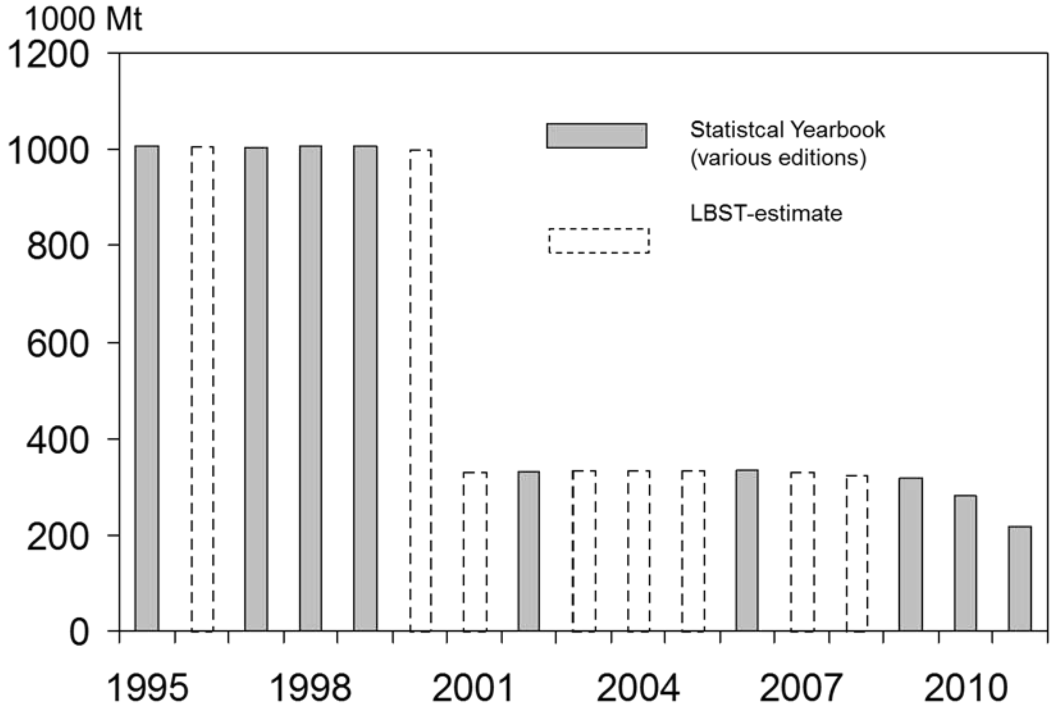



Even though Chinese coal reserve data are reported by the national Chinese board of the World Energy Council, they are not the only reserve data reported by Chinese authorities.

In the China statistical Yearbook additional data are reported. Figure 85 shows these data which are published in various editions of the China statistical yearbook as 'Ensured Coal Reserve'(CSY 2012). These reserve numbers were downward revised from 1,000 billion tonnes in 1998 to 333 billion tonnes a few years later and since then have been kept constant until 2006. Over the last years the ensured coal reserve was additionally reduced by 35 percent down to 217 billion tonnes as of end 2011 which is the reported number in the China Statistical Yearbook 2012.

The definition of 'ensured coal reserve' is not identical to the reported 'proven reserves' in WEC 2010, this being a possible explanation of differing numbers. However, data for 'ensured coal reserve' are revised annually – at least over the last years – accounting for actual production volumes and for additional re-evaluations of reserves. Therefore, these data are believed to be more reliable, coming closer to realistic numbers. The white bars with broken frame in the figure are LBST estimate as the original CSY editions were not available to the authors.

**Figure 85: Reporting of coal reserves in China**

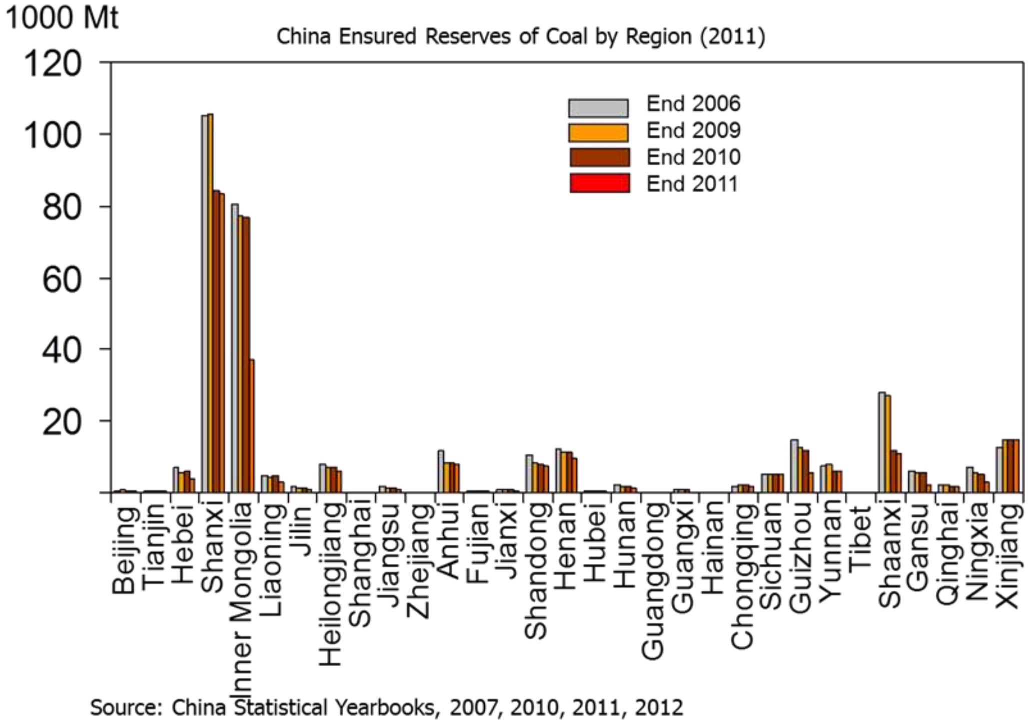


Source: China Statistical Yearbook 2012

The regional distribution of these coal reserves is shown in Figure 86 for the years 2006 and 2009 to 2011. The three provinces Shanxi, Inner Mongolia and Xinjiang have a share of 63 percent of total Chinese coal reserves. The other important coal provinces in descending order are Shaanxi, Henan, Anhui and Shandong which together have a share of 16 percent of Chinese coal reserves. The remaining provinces of China contain the remaining 11 per cent of coal reserves. As already mentioned, the total coal reserve declined by 35 percent between 2006 and 2011. At the regional level, only one province – Xinjiang – slightly increased its reserves. All other provinces reported declining reserves, some to a significant extent. Most pronounced is the decline in the two largest coal producing provinces, Inner Mongolia and Shanxi: Coal reserves of Shanxi declined by 20 percent and those of Inner Mongolia by over 54 percent since 2006. This is noteworthy as these are the two most important coal provinces. Especially Inner Mongolia extended its production capacity in recent years: Shanxi by 60 percent and Inner Mongolia by almost a factor of ten since 1996. As a rule, the development of coal mines also increases proven and probable reserves as former resources are converted into reserves. Therefore, these unexpected reserve revisions might be interpreted as indicators of the fact that the easy to recover coal reserves are now history also in China.

Despite these geological aspects, also environmental , technical and political constraints might limit future coal production in China. Pollution from coal mining and coal burning in power plants has reached a level which more and more outweighs the positive effects of electricity generation. This holds even more as measures to limit pollution increase costs, thereby making renewable alternatives to coal power plants more and more attractive.

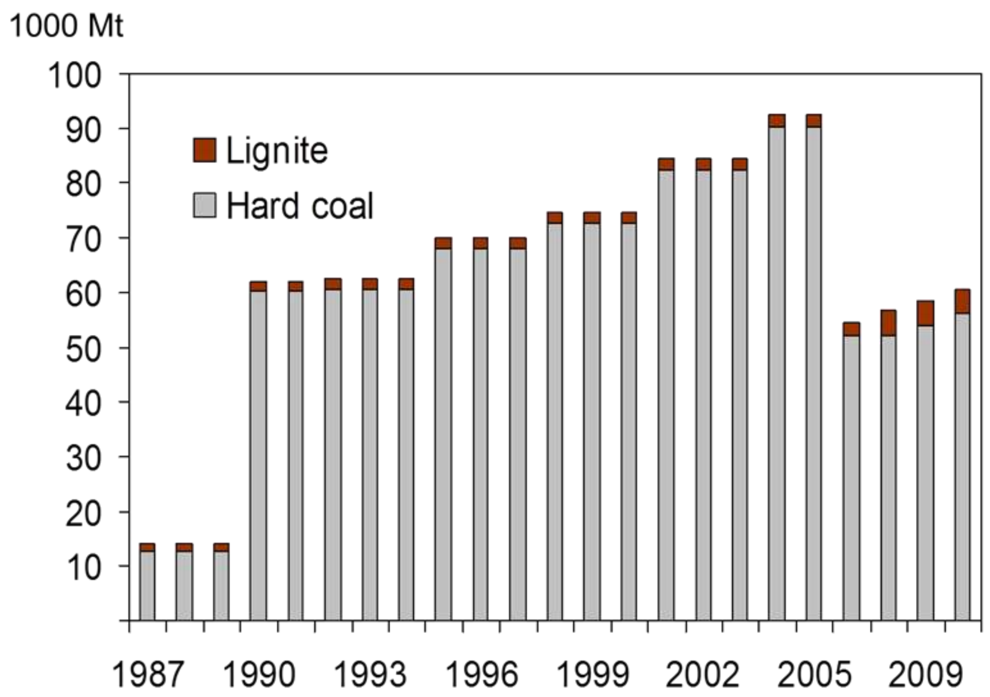
**Figure 86: Regional distribution of coal reserves in China**




### *India*

Figure 87 shows the of Indian coal reserves reported according to WEC 2010 and former editions. As the latest WEC 2010 ends with 2008 data, latest reported data from BP Statistical Review of Energy is added for 2011 showing a slight increase of reserves. Comparison with data from the Indian Ministry of Coal reveals that the sudden decline of coal reserves in 2006 is due to a reporting error in former WEC reports. Up to that time, in-situ coal reserve data published by the Indian coal ministry were reported and thus were falsely interpreted as being recoverable reserves. In 2006 the WEC adapted the reporting by accounting for the extraction losses which result in an yield of only 55-60 percent of in-situ coal reserves. The new data are in line with reserve reporting for other countries as WEC generally reports recoverable reserves and not in-situ reserves.

**Figure 87: reported coal reserves of India (WEC 2010, BP 2012)**



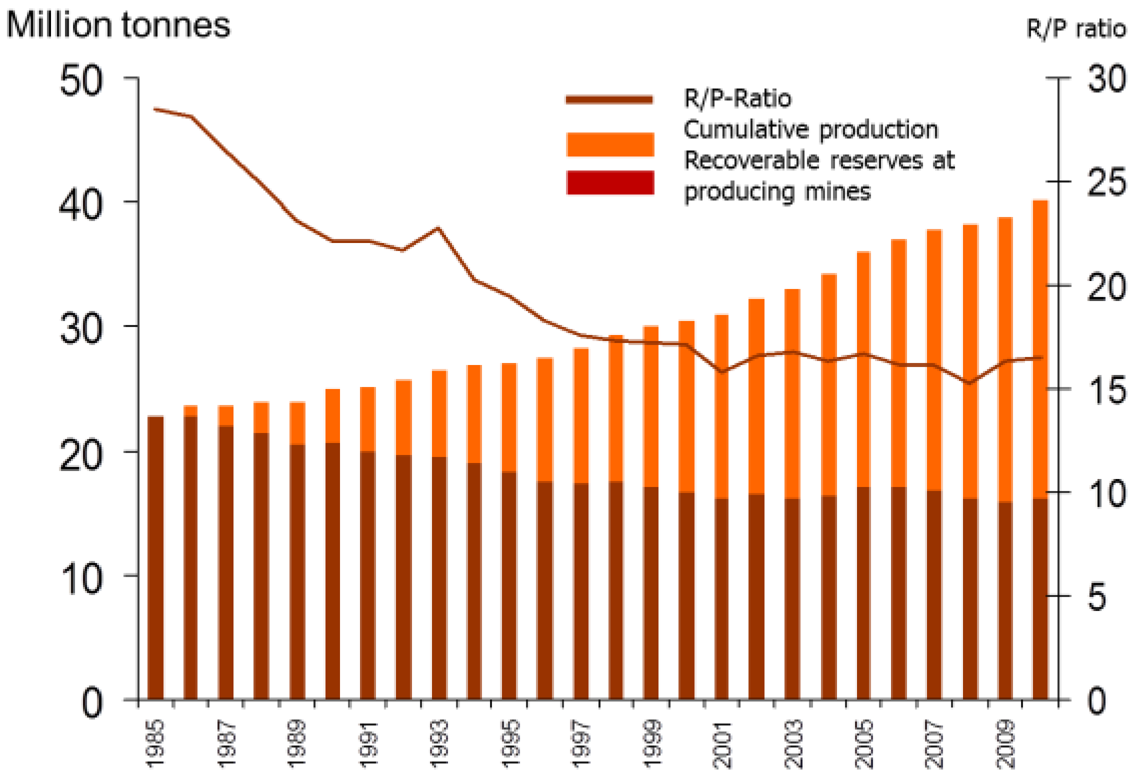

***USA***

The coal reserves of the USA were downward revised from more than 5,000 billion tonnes in 1924 to 237 billion tonnes in 2011 of which only 108 billion tonnes are bituminous with a slight share of anthracite. The rest consists of subbituminous coal and lignite.

Moreover, as already discussed in the previous report (EWG 2007) and in more detail in (Höök 2010), these reserves are overstated because a large part is probably of low quality or is not producible for a number of other reasons and therefore probably will never be produced.

These data – which in the WEC reports and BP statistical review are reported as proved recoverable reserves correspond to estimated recoverable coal resources according to US-EIA definitions. According to that definition the data contain all potential coal deposits irrespective of technical or environmental restrictions, for instance deposits in environmentally sensitive areas, water protection areas or underneath cities. Accounting for these restrictions reduces the reserves by almost 50 percent. Finally, the US-EIA also distinguishes 'coal reserves at producing mines'. This describes reserves at mines which are already developed. The definition of this reserve category is comparable to the definition of 'proved' oil or gas reserves. The share of recoverable reserves at producing mines is about 10 to 20 percent of all estimated recoverable reserves. Figure 88 shows the development of coal reserves at producing mines since 1986 together with cumulative production. Reserves at producing mines declined by 40 per cent since 1986. Yet this decline is smaller than the cumulative coal production since then, showing that some resources have been converted into reserves. Nonetheless, the reserve-to-production ratio has already declined from 25 years to 15 years.

**Figure 88: Coal reserves and cumulative production at producing mines (US-EIA 2010)**



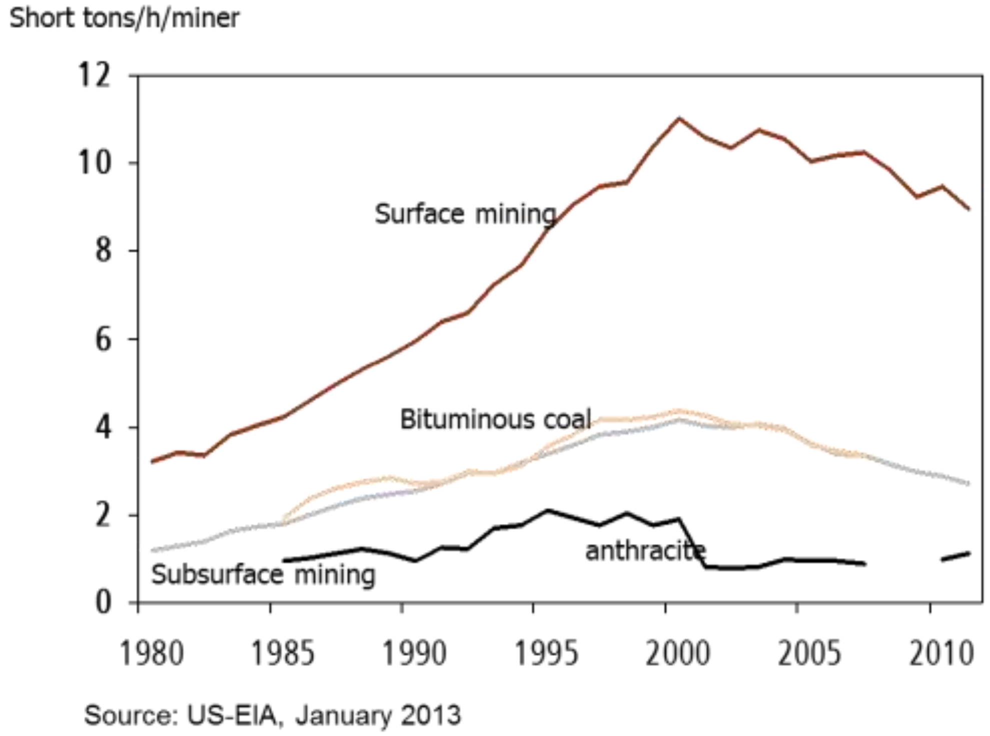

Source: DoE-EIA 2012
Analysis LBST 2012

## ***Labour productivity***

### ***USA***

The labour productivity is an indicator which shows the effort in terms of man power needed to extract the coal. Every company tries to increase labour productivity in order to reduce production costs and optimise the mining process. Figure 89 shows the labour productivity of coal mining in the USA. The data for open pit (surface) and subsurface mining are shown explicitly. Though the absolute numbers differ, the trend is similar for underground and open pit mining: labour productivity has already peaked in 2000 and is in decline since then. This is a sign that production conditions are worsening, in terms of recovered coal per time interval. When this efftrendect can no longer be compensated by an increased labour input, then a region passes peak production.

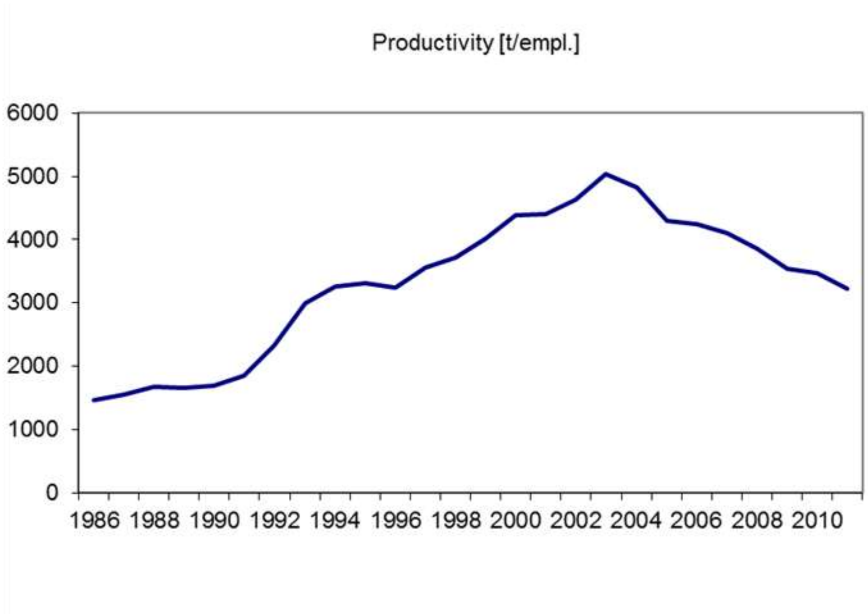
**Figure 89: Labour productivity of coal mining in the USA**




### *South Africa*

Figure 90 shows a similar trend for coal mining in South Africa. Though reserves are still huge, coal quality is in decline which is reflected by the rising effort to extract that coal. Since almost ten years the labour productivity in coal mining is declining in South Africa.

**Figure 90: Labour productivity in the South African coal mining industry**

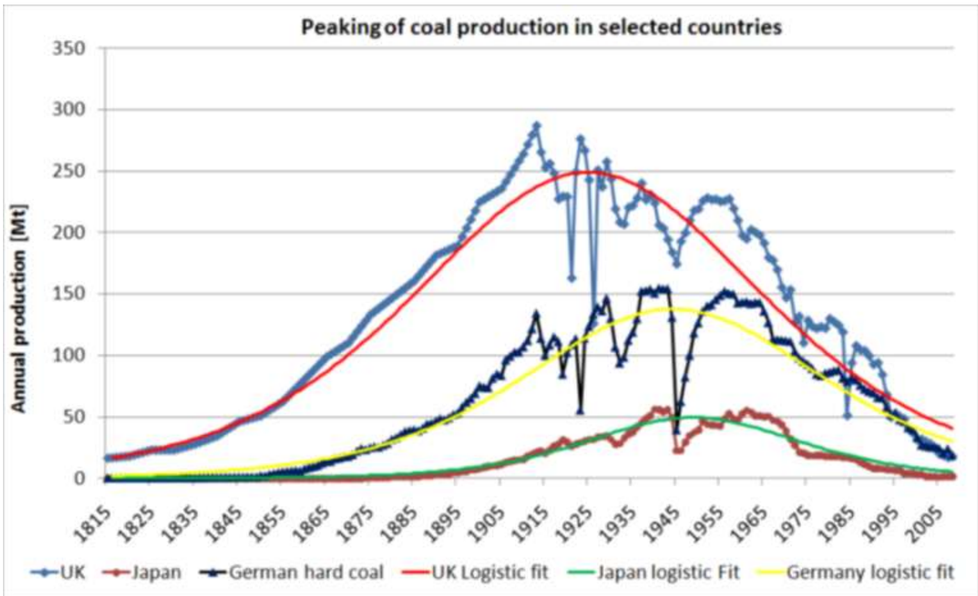


## Coal production

### General pattern of coal production

Aggregated coal production of all mines in a coal basin follows a bell shaped curve. This has already been shown by various authors. Figure 91 shows the coal production of Japan, Germany and UK over two centuries. Though the geological and economic conditions in each of these areas were different, the general production pattern looks quite similar and can be fitted by the derivative of the logistic growth model.

**Figure 91: Historical coal production in Japan, Germany and UK (Höök 2010)**

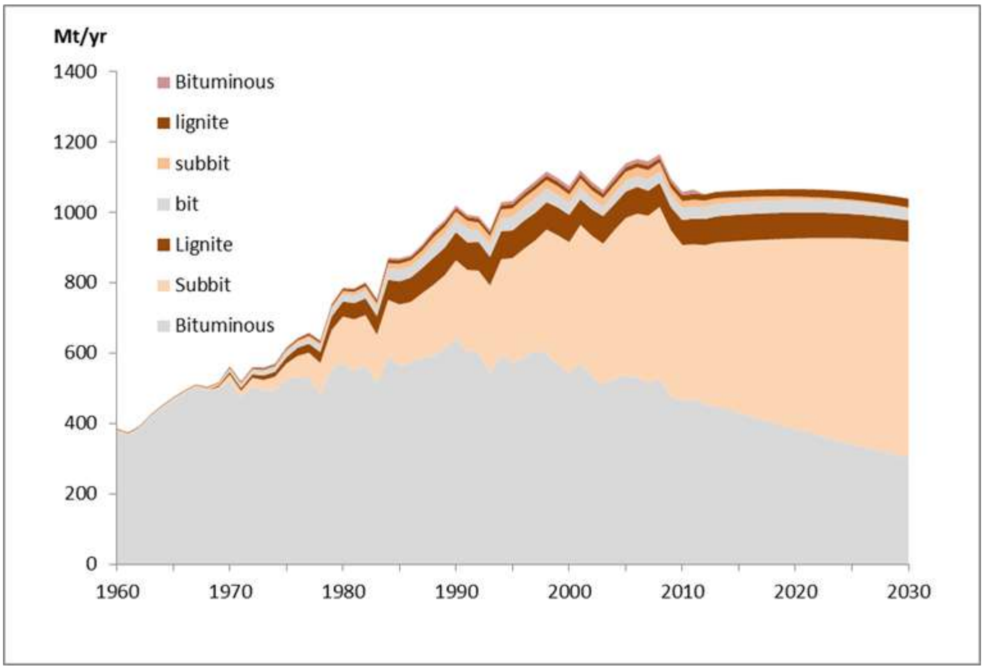



### USA

Figure 92 shows the historical coal production of the USA since 1960 with the projection to 2030. Bituminous coal, subbituminous coal and lignite are listed separately. In the annex a more detailed analysis is given by calculating the production history and projection of each federal state individually.

Bituminous coal production has already peaked around 1990, despite the fact that huge reserves are still reported. However, most of these reserves have a high sulphur content which makes the coal unattractive for markets. Furthermore, these reserves are deeper in ground requiring more labour power. Over the last 20 years only the production of subbituminous coal was considerably expanded. This was almost completely due to the fast expansion of open pit mining in Wyoming which holds the second largest share of coal reserves in the USA. By far the largest coal reserves are located in Montana. However, this is subbituminous coal mainly accessible by open pit mining. Since more than 20 years, Montana produces at a very moderate level contributing only 4 percent to US coal production. The moderate coal production falls far off its potential. Obviously, there are other restrictions such as distance to markets, low coal quality, high environmental impact of open pit mining, area and water use competing with farm land use. These aspects were discussed in greater detail in the EWG (2007) report and still hold today. Since the last EWG coal report in 2007, US production of bituminous coal followed the expected declining trend. However, subbituminous coal production declined faster than expected at that time. Part of an explanation might be unfavourable market conditions. Based on the present analysis, the coal production until 2040 is seen almost flat and declining thereafter. This is one of the major differences to the EWG (2007) study, where a pronounced peak at higher production level around 2030 was expected.

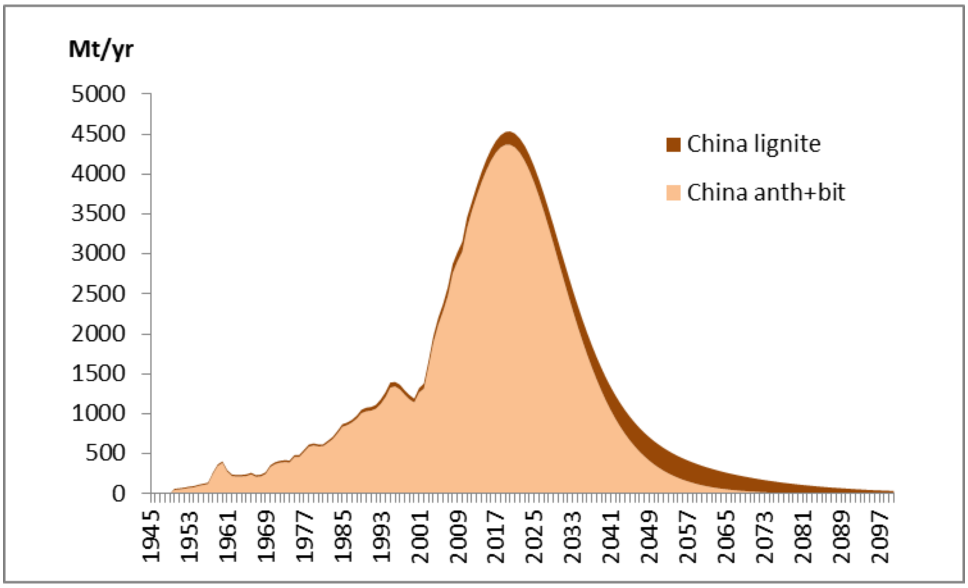
**Figure 92: Coal production in USA**




### *China*

Figure 93 shows coal production in China. Since 2006, Chinese coal production grew faster than expected. This required an adaptation of the projections. Peak production now is seen at 4,500 billion tonnes around 2020. This will be followed by a steep decline in order to match reported reserves. Though reserve data are not highly reliable – as already discussed – the peak of world coal production will be mainly determined by the development of Chinese coal production which holds a share of 50 percent of world coal production.

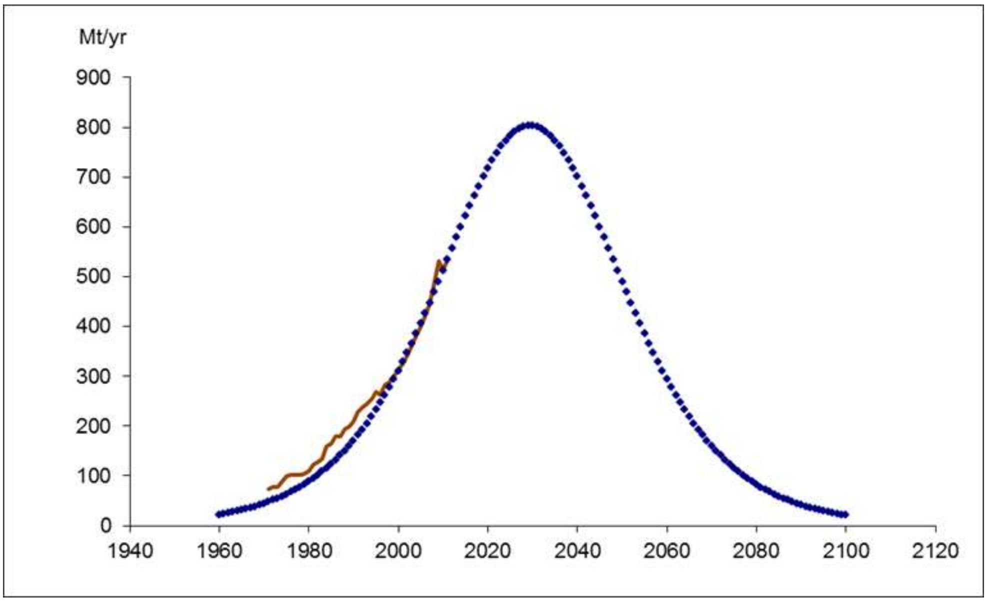
**Figure 93: Coal production in China**




### *India*

Figure 94 shows the bituminous coal production in India. The brown line shows the historical development including data for 2011. Since 2010 coal production stagnates. The blue points show a bell shaped production profile compatible with historical production data. Between 2012-2100 total cumulative production according to this profile would amount to 36 billion tonnes of coal. According to the projection, peak would be reached around 2030 at a production level of 800 million tonnes/year. Though reported reserves are 55 billion tonnes, it is believed, that due to the low quality of the coal with up to 70 percent ash content not all coal reservoirs will be producing during the projection period. Moreover, the high ash content reduces the energy content per tonne up to 70 percent. As only the heating value of marketed already washed coal is known, the average conversion factor from physical tonne to tonne of oil equivalent is not known. In this report it is chosen as 1.5 which is valid for high quality bituminous coal. Therefore, the contribution to worldwide coal production is probably overestimated, which eventually compensates for not producing all reported coal reserves until 2100 in the scenario calculation. Though these differences might be important for the development in India and shift peak production by 5 – 10 years, they are of minor influence to the world coal production.

**Figure 94: Bituminous coal production in India – historical data and projection**

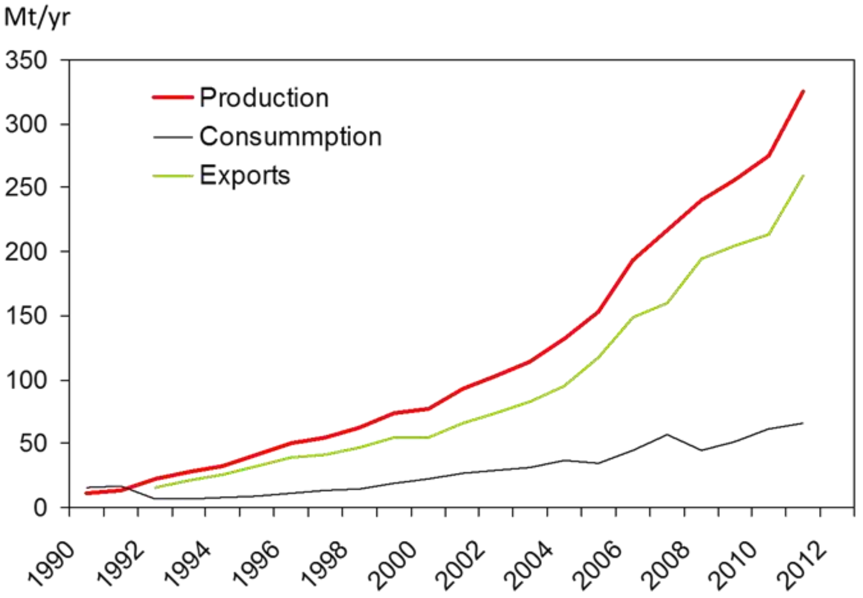



***Indonesia***

Figure 95 shows the historical production of coal in Indonesia and the exports calculated as difference between production and domestic consumption. Since 2000, Indonesia is the largest exporter of thermal coal. Indeed as shown later, the rising demand at global coal markets was mainly supplied by rising exports from Indonesia. However, coal mines in developed areas face problems of depletion. For instance, the deeper than previous mining levels result in increased periods of flooding of the mines. Further development of new mines would require deforestation in natural areas accompanied with long lead times and financial efforts. Indonesia has also promised in bilateral contracts under the UN-Frame Convention of Climate Change (e.g. with Norway) to protect rain forest from further deforestation.

The ministry of coal has already made announcements that coal exports will freeze and slightly decline until 2015 and thereafter. As domestic oil production is in decline, the development of Indonesia's electricity supply is scheduled to raise the domestic coal consumption for power plants.

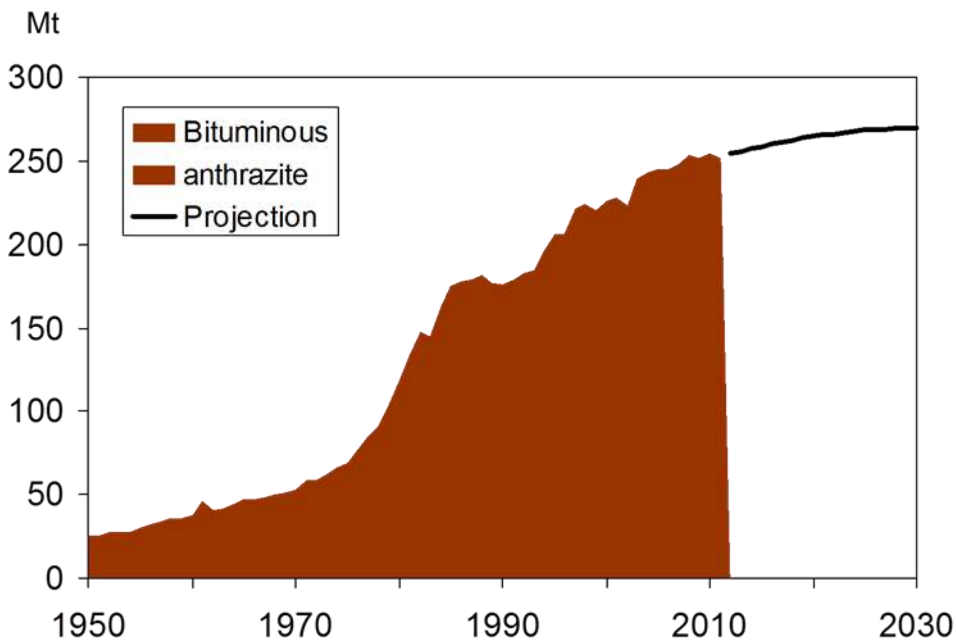
**Figure 95: Production, consumption and export of coal in Indonesia (BP 2012)**




### *South Africa*

Figure 96 shows the historical coal production in South Africa and the projection until 2030. The projected cumulative production between 2012 and 2100 would amount to 20 billion tonnes, which is more than two thirds of reported coal reserves.

**Figure 96: Coal production in South Africa**



### *World*

Figure 97 shows the worldwide production of hard coal between 1960 and 2100. Historical data are from publicly available resources. The projections are taken from the previous EWG (2007) report unless they were described in this report. The major differences to the original EWG-report in 2007 are that Chinese coal consumption grows faster and higher than previously assumed, and that future US coal production will not increase in the future and instead hold a plateau until 2040. Other modification such as differing views on South Africa, India or Indonesia are of minor relevance as their absolute production volumes are too small to have a global influence. Nevertheless these regional developments will be of importance as they will determine the world market of coal exports and imports.

**Figure 97: World hard coal production 1960 – 2100 by region**

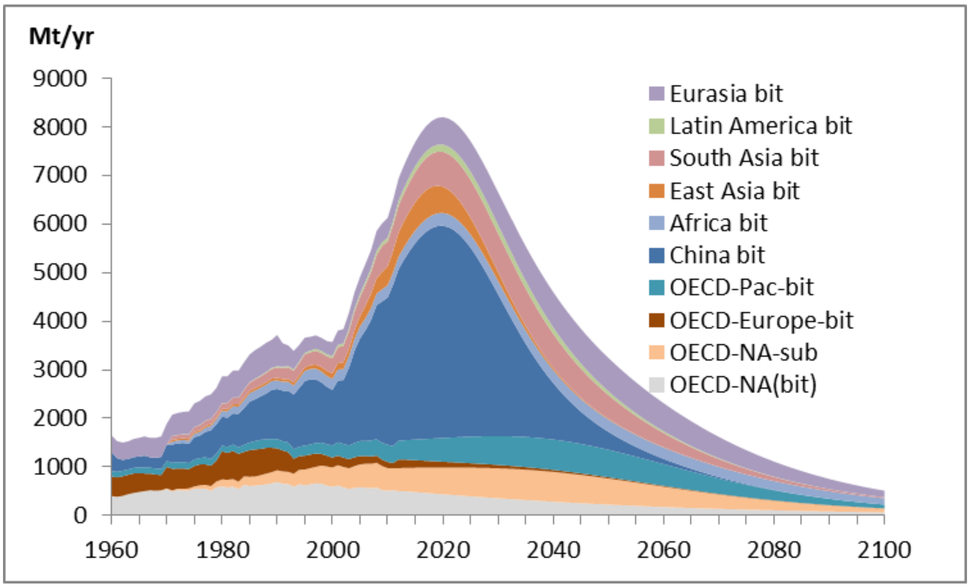
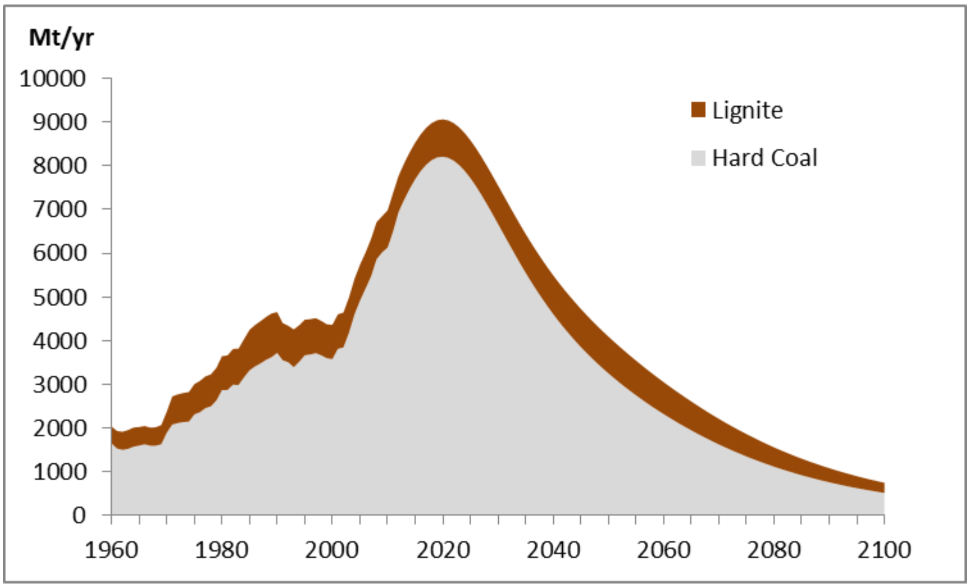



Figure 98 shows the same data as Figure 97 for hard coal together with world lignite production. Compared to hard coal, lignite contributes only a small share to world coal. This is due to the much smaller total production volumes and reserves, but even more for the energy content as will become obvious in the summary, see Figure 116.

**Figure 98: World coal production by coal rank**




## ***Coal exports and imports***

### *World*

Figure 99 shows the ranking of the countries with largest coal exports in 2011. By far the largest exporter of steam coal for thermal power plants is Indonesia, exporting twice as much as the second largest exporter, Australia. However, in total coal exports are dominated by Australia due to its large export volumes of coke. Other important exporters of coke are USA and Canada. The limited coke exports at world market might set a restriction to future world steel production unless no improved steel milling technologies are implemented at large scale, which avoid consumption of coke.

**Figure 99: Major coal exporting countries in 2011 (VdKi 2012)**

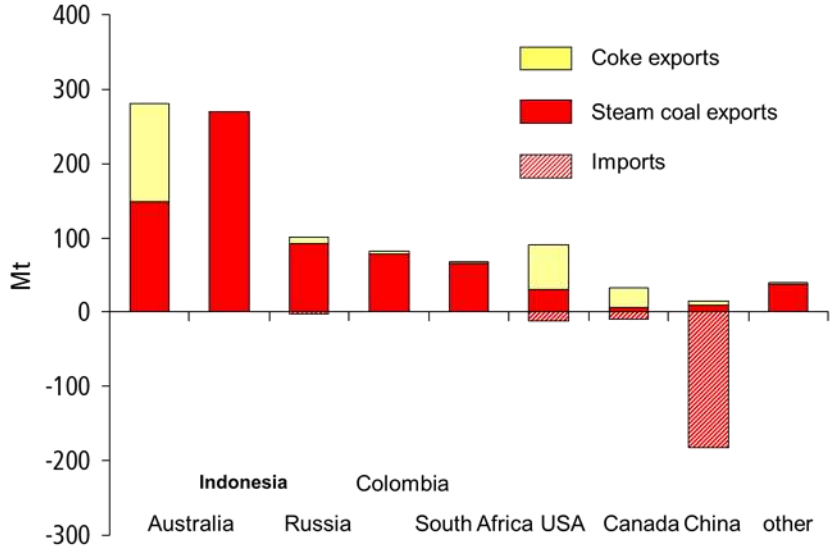



Figure 100 shows the import volumes of the largest coal importing countries in 2011. Three countries, Japan, China and South Korea imported almost equal amounts of steam coal for power plants. Japan was by far the largest importer of coke, due to the demand of its steel industry.

**Figure 100: Major coal importing countries in 2011 (VdKi 2012)**

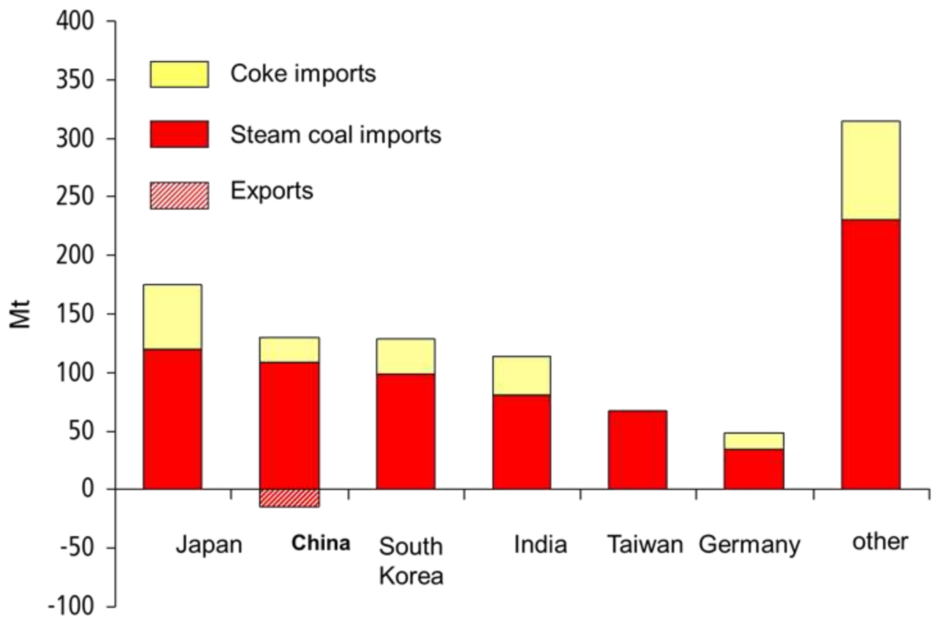
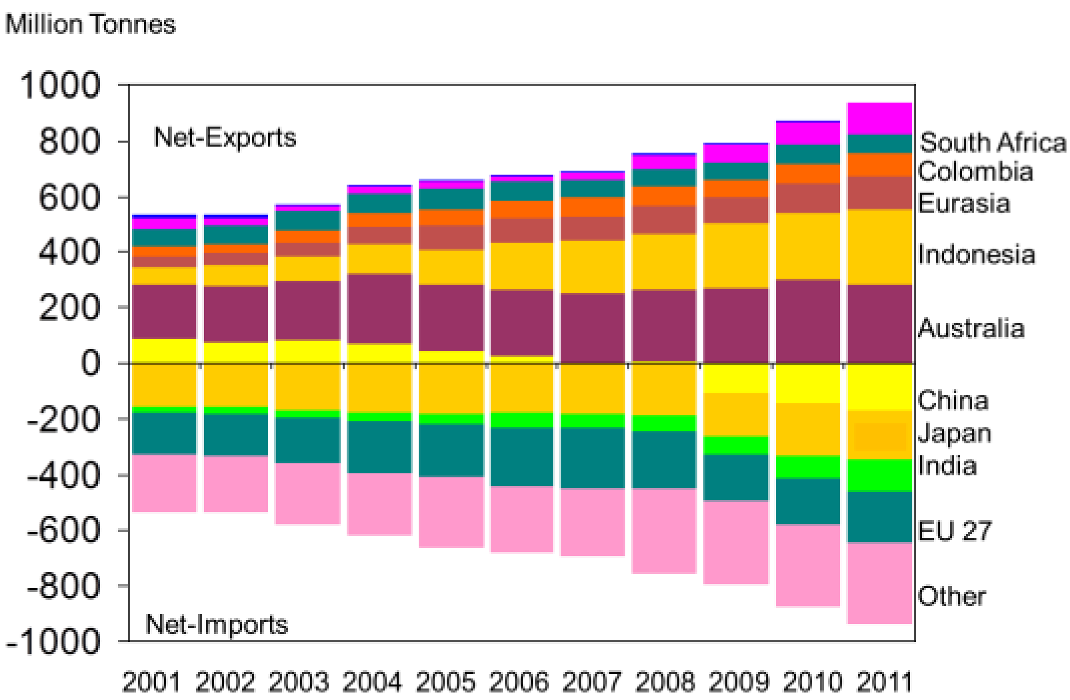



Figure 101 shows the development of coal exports and imports between 2001 and 2011. The upper part of the figure with positive data shows the export by country or region. The lower part with negative data shows the corresponding imports by country or region. Coal imports were mainly driven by India and China. India increased its imports since 2001 from almost zero to becoming the fourth largest coal importer while China switched from one of the largest coal exporting countries in 2001to one of the largest coal importing countries in 2011, rivalling Japan and South Korea.

The rising demand was mainly supplied by export increases from Indonesia and Australia. Coal exports from Eurasia (Russia), North America and Colombia also increased, though at a much smaller share. South Africa did not increase its exports since at least 2001 – vice versa, its coal exports declined over the last 10 years.

This analysis shows that import demand more and more is determined by the rising consumption in India and China. Though both countries belong to the largest coal producing countries with large coal reserves, the demand rose faster than domestic production could follow. In India this can be attributed to the low quality of domestic coal. However, in China various aspects might give reasons for the rising import demand. Long distances between coal mines and consuming areas favour the maritime import by ship. The closure of many old small scale mines also had an influence to total Chinese production. But also the concentration of coal production in almost two provinces, Inner Mongolia and Shanxi, which hold by far the largest reserves, is an indicator of maturing coal production in other areas. The more it surprises that Inner Mongolia downward revised its coal reserves since 2006 by about 50 percent. Usually, proven reserves rise with the development of new coal mines as these developments usually convert resources into reserves.

**Figure 101: Largest coal exporting and importing countries**



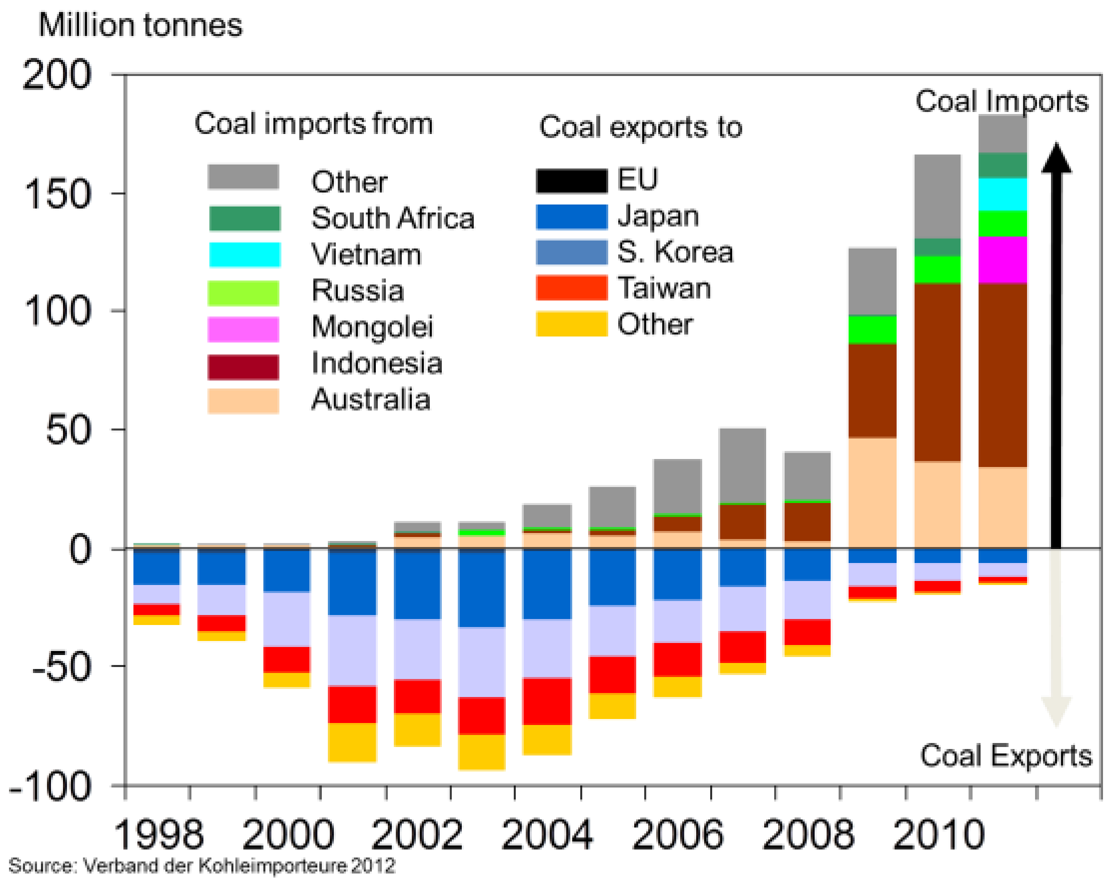

Source: Verband der Kohleimporteure 2012

The fast rise of Indonesian coal exports very soon will come to an end when the production increase ceases due to the depletion of the large developed open pit mines and as the domestic demand is rising fast reducing its surplus export capacity.

### *China*

Figure 102 shows the historical development of coal imports to and exports from China between 1998 and 2011. This documents the fast switch from being a coal exporting to becoming a coal importing country. But the graph also shows that Indonesia is by far the most important external coal supplier to China.

**Figure 102: Regional disaggregation of coal imports to and exports from China**




## ***Conclusion***

Of the global coal production only about 15 percent were traded internationally in 2011. The countries owning the biggest reserves have only a limited export potential. In 2011 China and India together imported 297 million tonnes, i.e. 70 percent more than the imports of Japan in 2010 when Japan was still the biggest importer worldwide. Only 10 years ago China was exporting 70 million tonnes. This rapid change in international coal trade resulted in a doubling of the global import/export market since 2001. The additional volumes were mainly supplied by Indonesia, which expanded its coal production. Yet it is foreseeable that Indonesia will peak within the next five years and exports will subsequently decline. Since exports from South Africa are down from 2005 and are stagnating the future gap in export capacity will have to be closed by increased exports from FSU countries, Columbia and Australia.

Coal demand in China and India will continue to grow. Possibly in the near future this will lead to shortages and rising prices on the world market. Such a development is much more likely than the assumption that in ten years time coal will be abundant and cheap.

**Table 2 Most important coal countries in 2011**

| | Rank 1 | Rank 2 | Rank 3 | Rank 4 | Biggest 4 share of total |
|---|---|---|---|---|---|
| | Country | Country | Country | Country | [%] |
| Reserves [Mtoe] | USA 133 000 | Russia 74 000 | China 64 000 | Australia 42 000 | 57 |
| Production [Mtoe] | China 1 956 | USA 557 | Australia 230 | India 222 | 75 |
| Net Exports [Mt] | Australia 281 | Indonesia 270 | Russia 105 | USA 86 | 72 |
| (Mtoe) | 169 | 162 | 63 | 52 | |

Conversion factors used: Mtoe = million tonnes of oil equivalent (1 toe = 6,841 barrels oil); 1 toe=0,6 t coal with an energy content of 25 MJ/kg. Data sources: BP Statistical Review of World Energy 2012 (reserves and production); Verein der Kohleimporteure, Jahresbericht 2012 (exports/imports). Analysis: Ludwig-Bölkow-Systemtechnik 2012.

Cheap and abundant coal for decades to come – not very likely as we have tried to show. Only a superficial equation of reserves and resources can lead to such a conclusion. And even an uncritical use of reported reserves in modelling future supply will be grossly misleading. Like every finite fossil energy resource, global coal supply is going to peak. In many coal producing countries the peak is already history. Even though the data we have are far from being satisfactory, a reasonably reliable picture of the future can be drawn. We will see some further growth in global coal production followed by a peak in the not so distant future. However, there is definitely no scope for substituting oil and gas in the long run by coal. There will be no regression to coal as the long-term primary fossil energy source. The peak of all fossil fuels is already in sight.

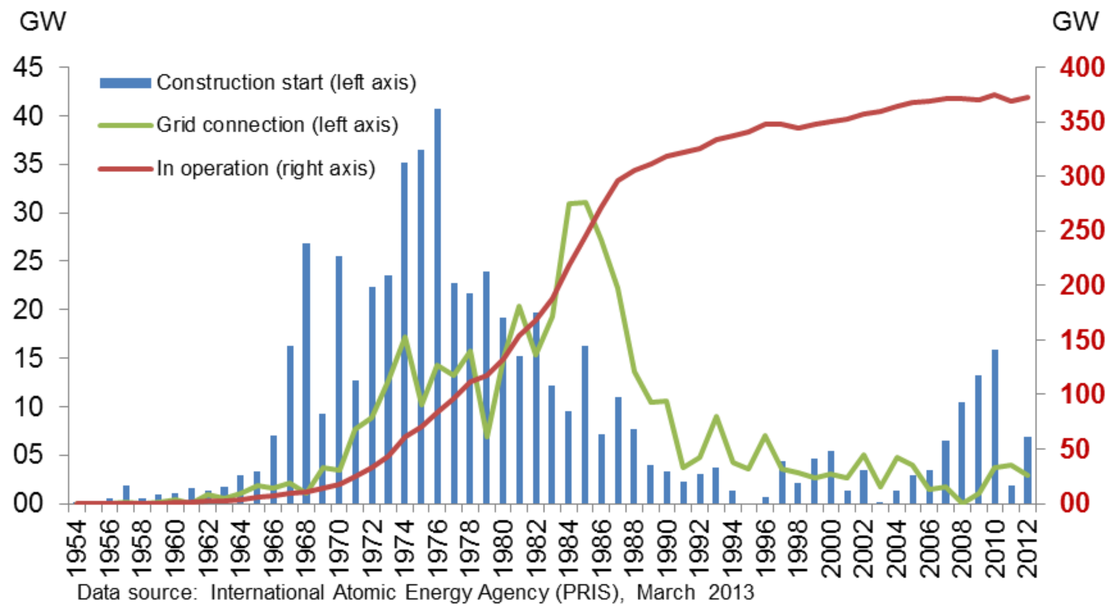
# *URANIUM*

This is an update of the most relevant data and figures of the “Uranium Resources and Nuclear Energy” background paper prepared for the Energy Watch Group in 2006 (EWG-Series No 1/2006).

## *Nuclear Power Plants*

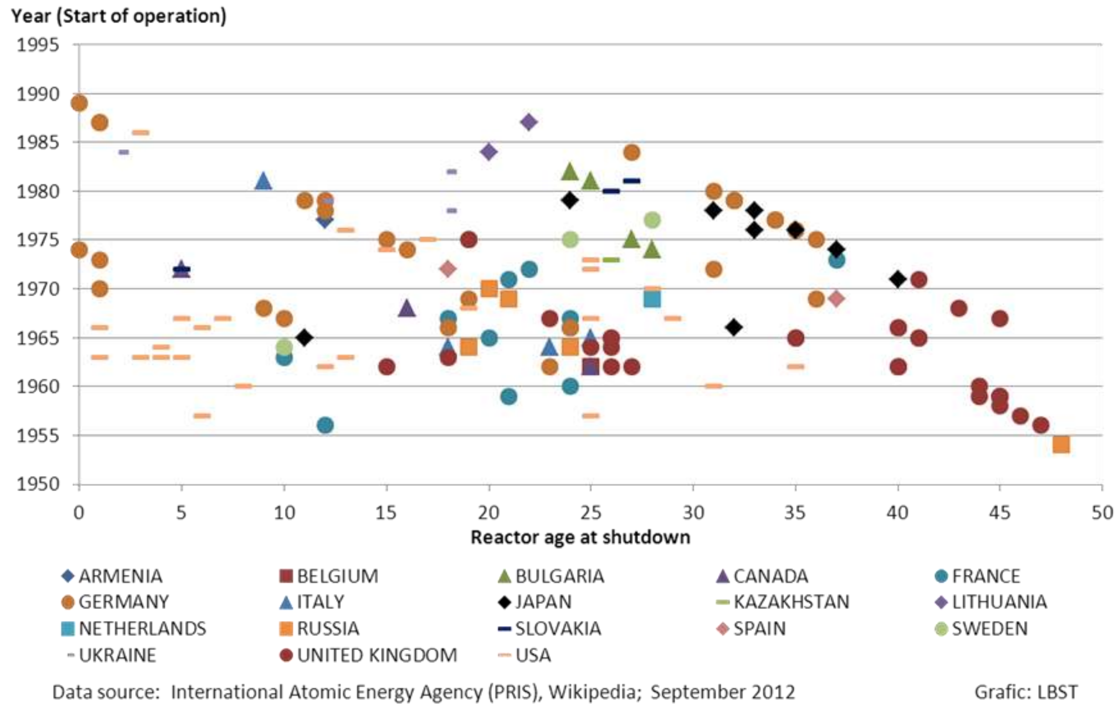
Worldwide 435 operational reactors allocate a total net electric capacity of 370 GW. In recent years the construction start of nuclear power plants has gained momentum. Since 2006, the construction of reactors with an additional capacitiy of 48 GW started. Currently a total of 62 GW are under construction including 10 GW of electric capacity with a construction start prior to 2000. Some of those reactors are under construction since the 1980s. If and when this 10 GW reactor capacity will ever go online is very uncertain. Figure 103 shows the construction starts (blue bars) from 1954 until today. The green line shows the net electrical capacity of plants connected to the grid. The red line (right axis) accumulates the net capacity of all operational nuclear power plants worldwide. The capacity which was shutdown each year is not shown.

**Figure 103: Construction start, grid connection and accumulated net electric capacity of nuclear power plants at world level**




The average service life of reactors, which were brought into and (up to date) were taken out of operation, is about 23 years (see Figure 104). This number is biased by a few reactors in Germany and the USA which were taken out of service shortly after being brought online. Not considering those reactors, the service life for most reactors was between fifteen and forty years.

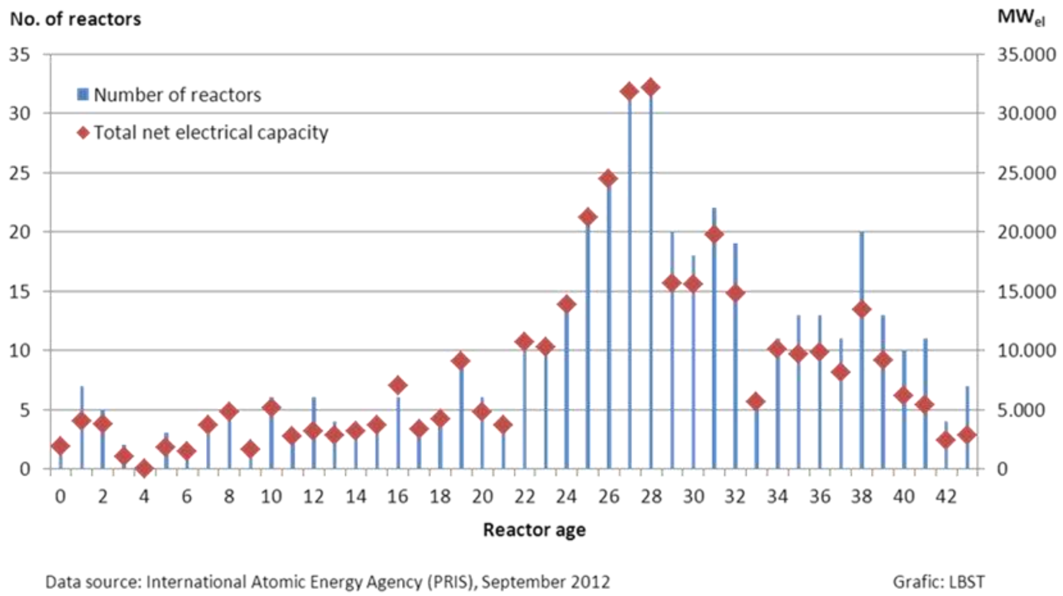
**Figure 104: Age of permanent shutdown nuclear reactors at shutdown (horizontal-axis) sorted by the year operation started (vertical-axis)**




### *Status of Power Plant Fleet*

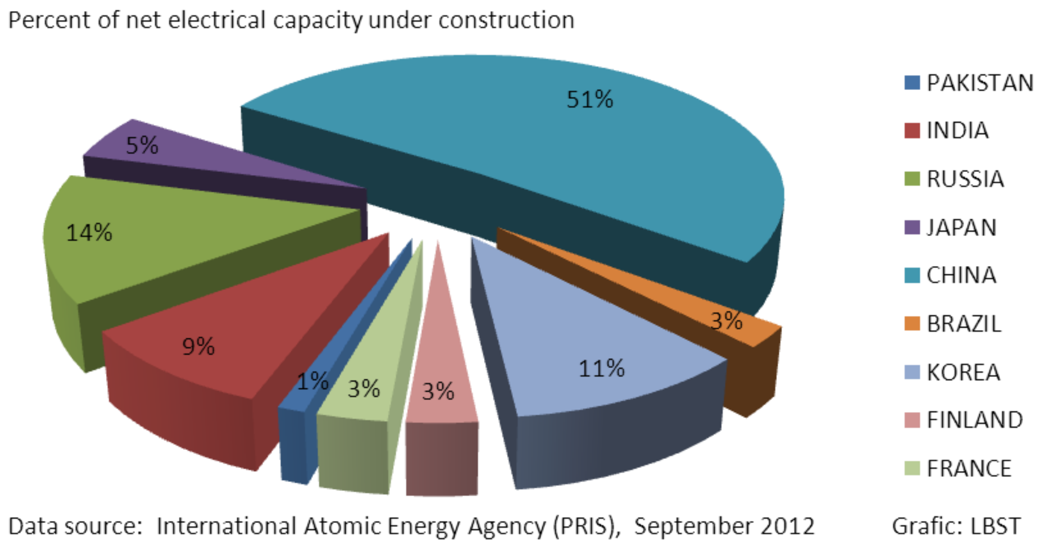
Figure 105 shows the age distribution of the nuclear power plant fleet. The blue bars show the number of reactors of a certain age and the red squares indicate the net electrical capacity of those reactors. Today the majority of the reactors (and capacity) in operation are more than 25 years old. Only 10 percent of the net electrical capacity is below 20 years of age. Considering the age structure of reactors in Figure 105, the majority of operating reactors will be shut down permanently within the next two decades.

**Figure 105: Age of the operational nuclear power plant fleet (Status 2012)**




China, Russia, Korea (Rep. of) and India account for 85 percent of the net electrical capacity being under construction right now (not counting construction starts prior to 2000). With a share of over 50 percent, China is currently constructing the largest capacities. The European share (without Russia) adds up to only 6 percent.

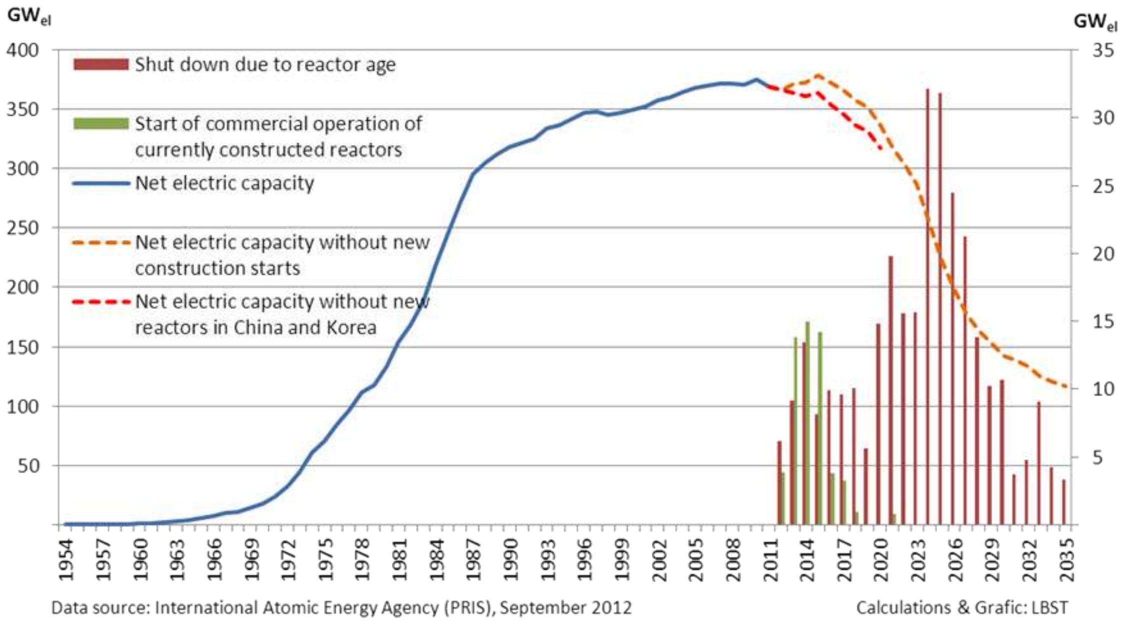
**Figure 106: Reactors currently (2012) under construction at world level (not including reactors with a construction start prior to 2000)**



### *Forecast of nuclear power plant capacity*

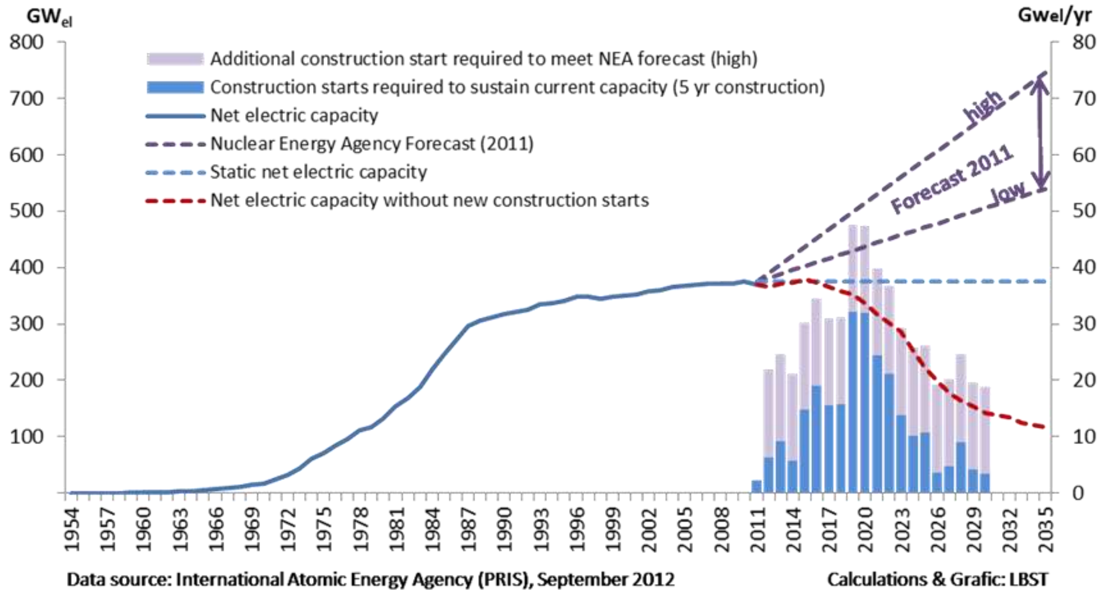
The blue line in Figure 107 shows the development of the net electrical power capacity until today. The green bars (right axis) indicate the net capacity currently being constructed (for the year in which the capacity will come online). If the start-up date for the commercial operation is not known, five years between construction start and completion have been assumed. The red bars (right axis) show the reactor capacity that will have to be shut down each year if an average operation lifetime of 40 years is assumed. The broken orange line shows the future development of the installed net capacity based on the above assumptions. Not including constructions in China and Korea the available capacity will decline as shown by the red broken line.

**Figure 107: Development of the installed net electrical capacity if no new NPP constructions start.**




The Nuclear Energy Agency (NEA) forecasts an installed nuclear net capacity of at least 540 GW (low case scenario) for 2035. In a high case scenario the estimates for 2035 are as high as 746 GW. NEA states that due to the Fukushima Daiichi accident those projections are subject to even greater uncertainty than usual. Despite the accident in Japan the low case projection is 29 GW higher than the projection made in 2009. The high case projection from 2009 has been at 782 GW. Figure 108 shows the cumulated additional capacity required to sustain the current net capacity (blue bars) and the additional capacity required to meet the NEA forecast (low scenario) (purple bars).

**Figure 108: Required construction starts of new power plants to meet NEA forecast of nuclear capacity and to sustain current level**




To sustain the current net capacity of 375 GW about 250 GW (equalling 66 percent of current global capacity) have to be added until 2035. To meet the NEA 2011 low case scenario over 400 GW new net capacity is required until 2035.

The additional required capacity can be supplied either with newly constructed reactors, and/or the prolongation of the life-span of operating reactors, and/or the reactivation of existing reactors currently having the status “longterm shutdown”. The capacity that can be supplied from long-term shutdown reactors is minimal and amounts to only 3 GW (five reactors, shutdown since 1995 and 1997). If the average reactor lifespan is extended from the assumed 40 years to an average of 50 years, the need to construct new reactors is reduced by 95 GW until 2035. With an extended reactor lifespan of 50 years a total of about 150 GW have to be constructed until 2035 to keep the nuclear electricity production at current level.

Assuming a construction time of 5 years, on average the construction of 8 GW per year (50 years reactor lifetime) respectively 14 GW/a (40 years reactor lifetime) has to commence every year between 2012 and 2030 in order to sustain the current production level. To meet the NEA 2011 low case scenario, on average every year a capacity of between 17 GW/yr (50 years reactor lifetime) and 22 GW/yr (40 years reactor lifetime) has to be added.

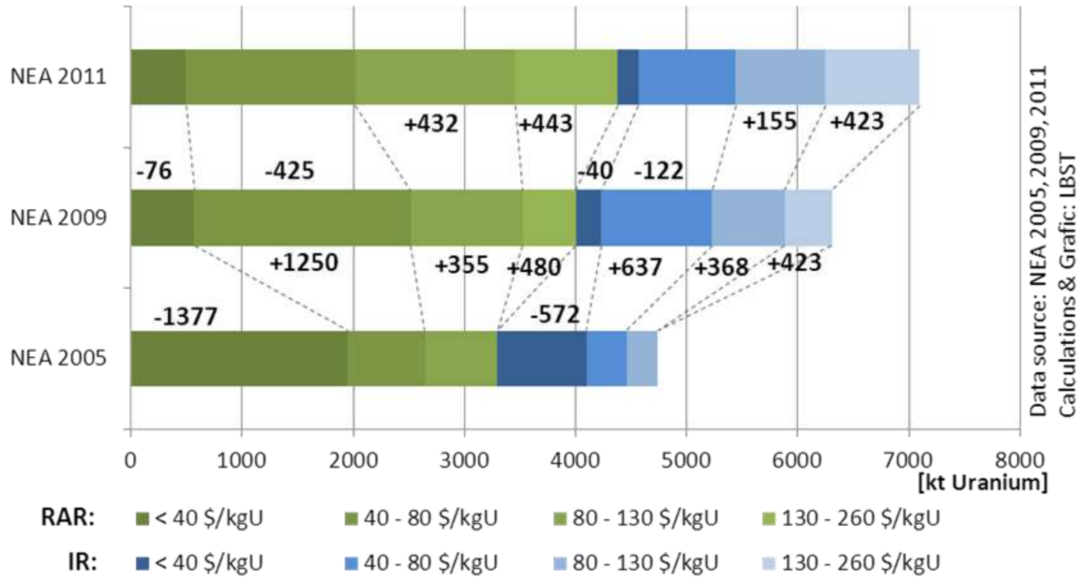
## *Uranium supply*

### *Uranium resources*

In the 2009 NEA report on uranium "Resources, Production and Demand" an additional cost category for both RAR (Reasonably Assured Resources) and IR (Inferred Resources) was added. The new category defines resources recoverable at costs between 130 $/kgU – 260 $/kgU. Including the category added in 2009, the identified resources in the latest NEA 2011 report add up to a total of 7,097 kt uranium. That amounts to an increase of 50 percent compared to the report of 2005 (all cost categories). When only counting resources recoverable at <130 $/kgU, the increase between 2005 and 2011 is 12 percent.

Figure 109 shows the development of resources in each cost category. The green bars represent reasonable assured and the blue bars inferred resources.

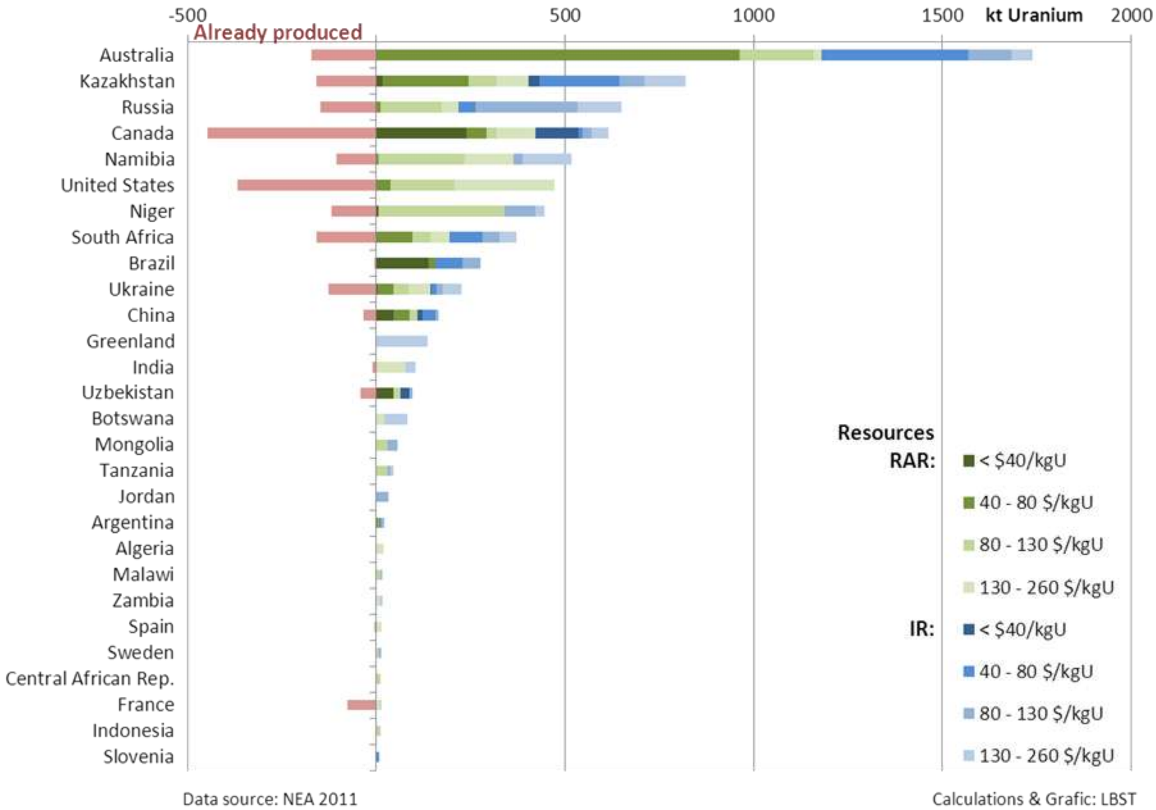
**Figure 109: Reasonably assured and inferred resources in 2005, 2009 and 2011 split in different cost categories**




Comparing the reports of 2005 and 2011, a major shift from cost category <40 $/kgU to higher cost categories occurred. Resources recoverable at <40 $/kgU shrank by a total of 2,065 ktU between 2005 and 2011 reports. This is mainly the effect of the re-classification of resources into higher cost classes.

Figure 110 shows the countries with the largest uranium resources (RAR+IR) as well as already produced quantities for those countries.

**Figure 110: Reasonably assured and inferred resources and cumulative uranium production of the most important countries**




### *Uranium production*

Since about 1994 world uranium production grew from ~ 31ktU/yr to ~54 ktU/yr in 2010. This 75 percent gain was mainly achieved by higher production volumes in Kazakhstan. Without Kazakhstan world uranium production is only slightly above the 1994 level. In 2009 Malawi joined the group of uranium producing countries. Since then the production in Malawi increased from 104 tU/yr to 846 tU/yr in 2011.

Kazakhstan accounts for 33 percent, Canada 18 percent, Australia 11 percent, Namibia 8 percent, Niger 8 percent, Russia 7 percent and Uzbekistan 5 percent of world uranium production in 2010 (rest of world 10 percent). The resource to production ratio of the most relevant uranium producing countries is show in Figure 111. Taking all reasonable assured resources into account Kazakhstan as the biggest producer in 2010 has a resource to production ratio of only 25 years. For Canada the ratio is also below 50 years. The highest ratio of the top producing countries stands for Australia. At the 2010 production level (which is about 40 percent below the 2005 production level) the R/P-ratio for RAR is about 200 years.

**Figure 111: Resource to production ratio for the 6 biggest uranium producers at 2010s production volume**

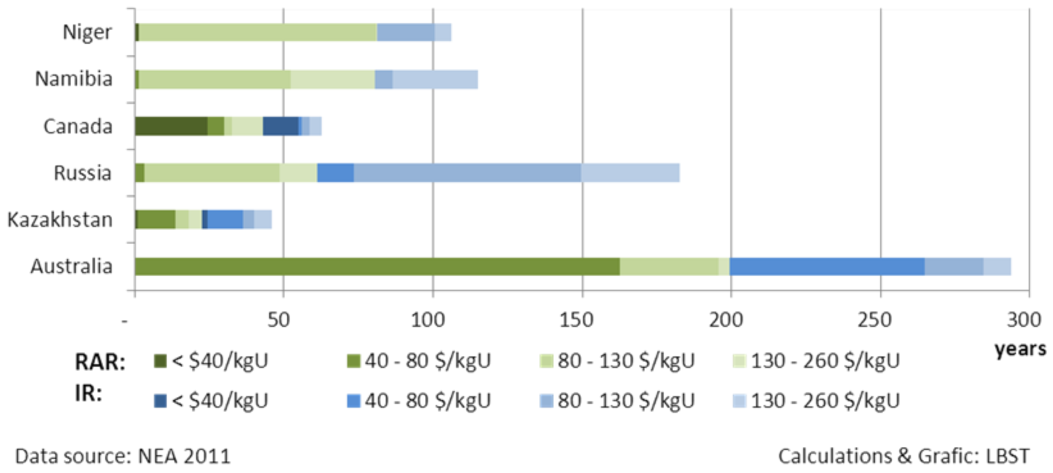
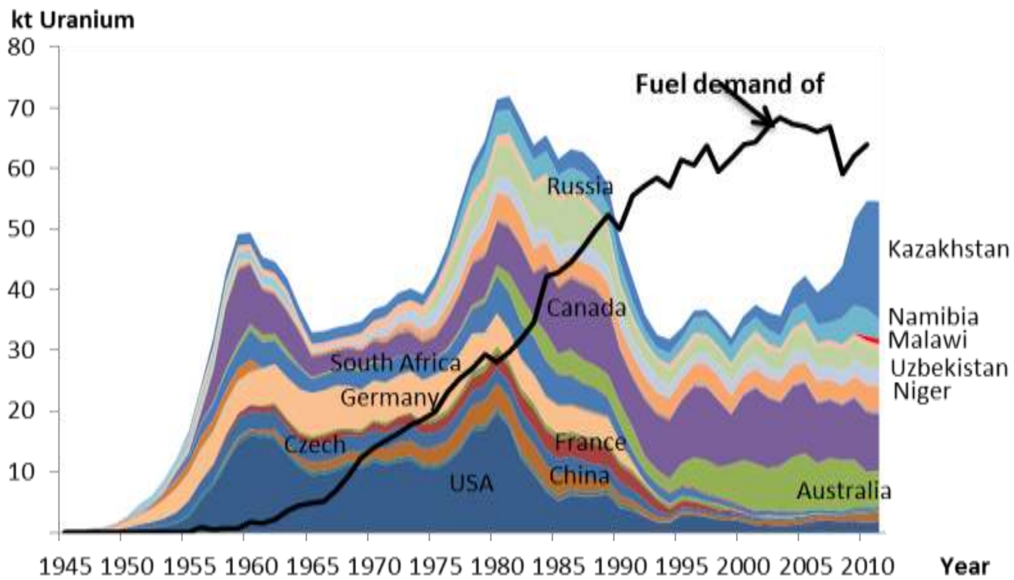



Figure 112 shows world uranium production and demand since 1945. The gap between production and demand is now reduced from its ~25 kt/yr high between 1995 and 2005 to under 10 kt/yr. This was achieved by uranium drawn from stocks at reactor sites and at mines, by reprocessing nuclear waste and by uranium made available by the demobilisation of nuclear warheads.

**Figure 112: World uranium production by country and reactor fuel demand since 1945**

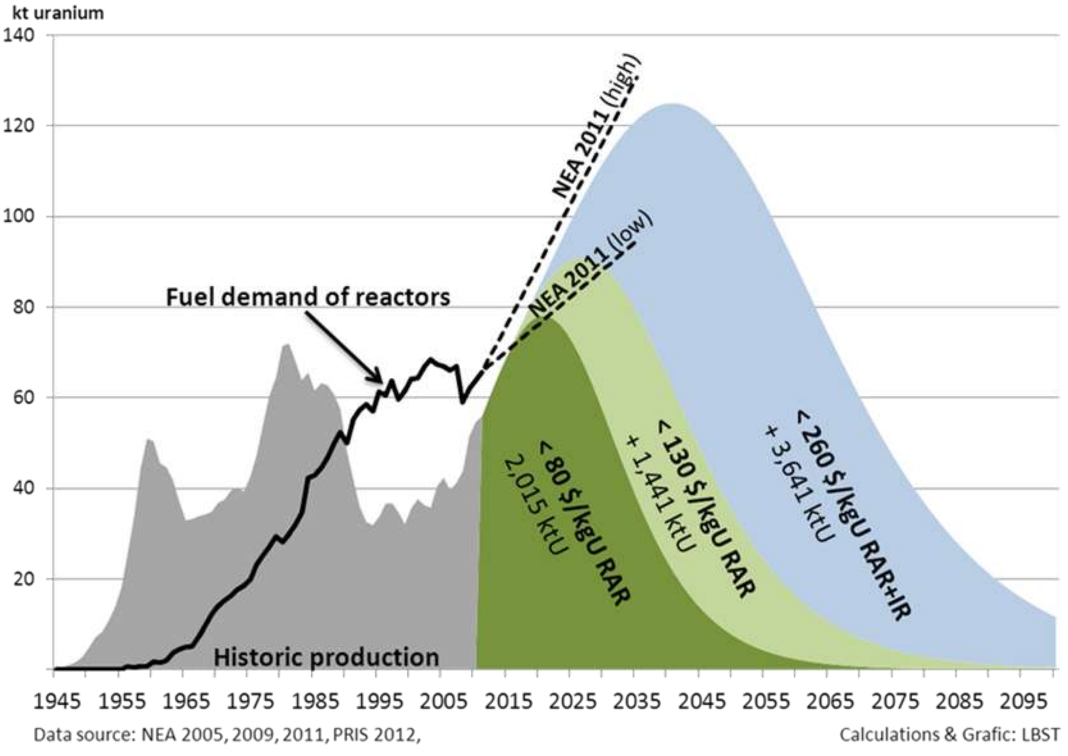


## *Future uranium demand and supply*

The NEA 2011 forecast on nuclear power capacity (540 GW in the low case, 746 GW in the high case) leads to a uranium fuel demand between 95 and 130 ktU/yr in 2035. Assuming a linear capacity growth, a total of 2,000 to 2,500 kt uranium are needed until 2035 to power all reactors. The reasonable assured resources with extraction costs below 80 $/kgU are not sufficient to meet this demand. If the uranium supply is extended to the cost category <130 $/kgU RAR, this would be barely enough to meet the fuel demand in the NEA low case scenario for the next 10 – 20 years.

Figure 113 shows the fuel demand for both NEA 2011 forecasts. The dark green area indicates the possible future uranium production from Reasonable Assured Resources with extraction costs below 80 $/kgU. The light green area indicates additional uranium (+ 1,441 kt RAR) that can be produced at cost of 80 to 130 $/kgU. The blue area shows the maximal amount of additional fuel (+ 3,641 ktU) that can be produced at costs below 260$/kgU while also including Inferred Resources.

**Figure 113: Historic and possible future development of uranium production and demand**




A more precise understanding can be gained when the resources are attributed to the individual deposits and mines. Figure 114 and Figure 115 show detailed production scenarios which are performed for each mine individually, taking care of resources and expansion plans in order to better describe the development of the next years.

Figure 114 is based on Reasonably Assured Resources < 130 USD/kg. Expansion plans are included as far as possible. For instance, the largest mine Olympic Dam is assumed to extent its production from present 3,8 kt/yr to more than 12 kt/yr until 2020 – this would be a tripling of production rate within 7 years. Further production increases are assumed over the next decades. Ultimately, in 2080 the RAR < 130 USD/kg would be depleted. This scenario shows that by far the largest part of resources is located in one mine. As the production rate of this mine cannot be expanded to any value, the above sketched pictury by adapting all resources to a bell shaped production profile is unrealistic and overstates the possible production rates. At current political restrictions, it seems even more realistic to cut any large expansion plan for Olympic Dam due to political resistance.

But even allowing these production increases reveals that probably uranium production from primary sources will not be enough to feed an increasing number of reactors as calculated in the high or low scenario by the National Atomic Energy Administration (NEA/IAEA 2011). Based on the above said it is even possible that before 2020 supply restrictions might happen, when planned mine developments are in delay.

**Figure 114: Historical uranium production and projection until 2100 with mine-by-mine production profiles based on Reasonably Assured Resources < 130 USD/kg**

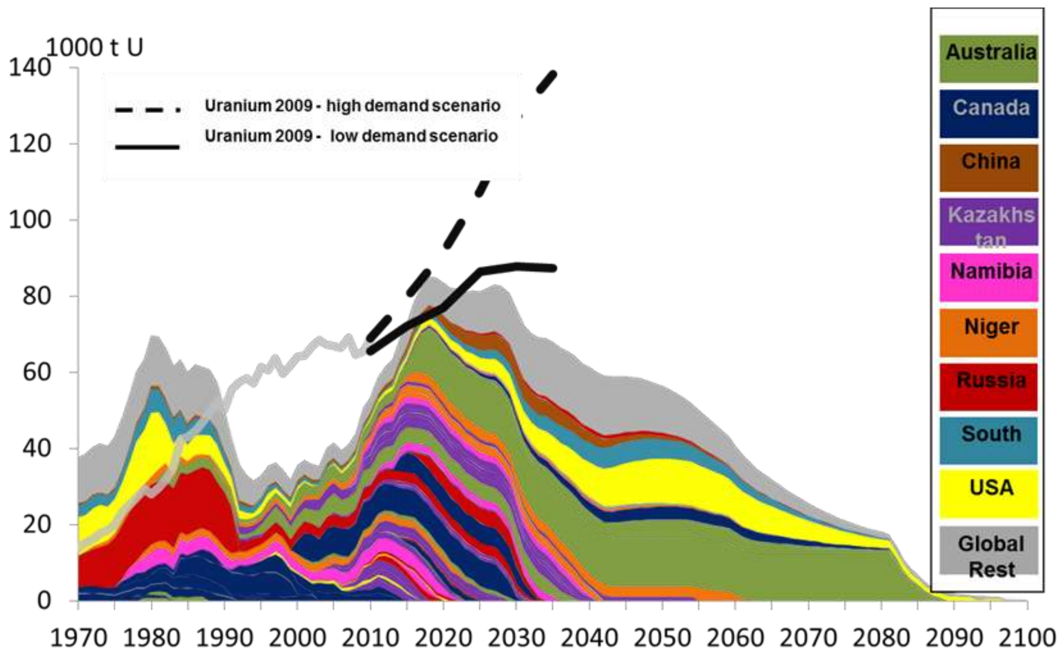
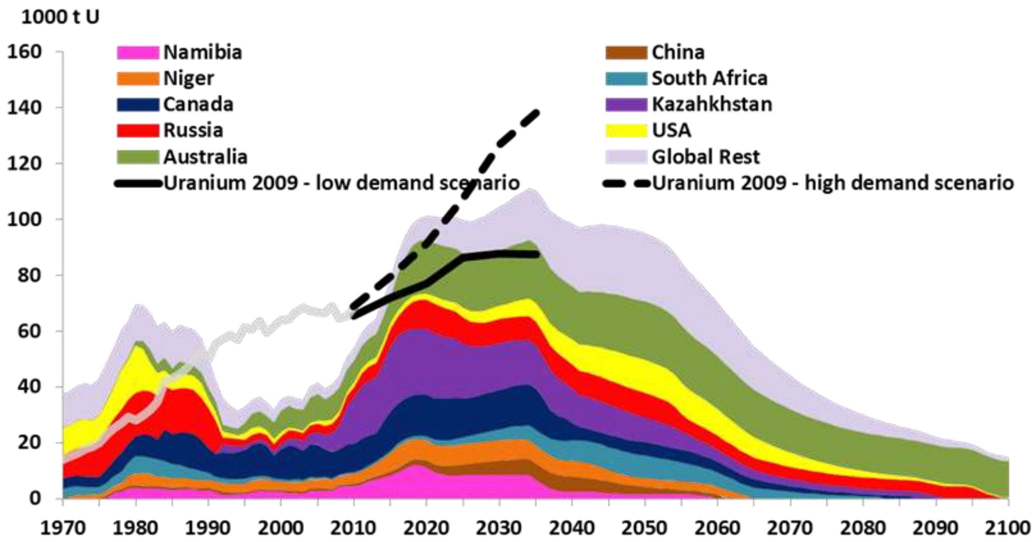


Figure 115 shows the corresponding uranium supply projection when Reasonably Assured Resources < 260 USD/kg and even Inferred Resources <260 UDS/kg are included. This shifts the possible production level by almost 20,000 tonnes/yr to 100,000 tonnes/yr, which in the optimistic case might be kept almost constant until 2050.

However, the supply of an aggressive expansion of nuclear power plant capacity as shown by NEA cannot be fed over the operation time of the reactors which need to be build.

**Figure 115: Historical uranium production and projection until 2100 with mine-by-mine production profiles based on Reasonably Assured Resources < 260 USD/kg and Inferred Resources < 260 USD/kg**




The real development of future uranium mining probably will be somewhere in between the “optimistic” case of Figure 115 and more ”pessimistic” case of Figure 114 which the authors would identify as the most probable development.

## ***Some Case Studies***

### *Update of “The Development of Cigar Lake in Canada”*

(Annex 8 in the 2006 paper)

The construction of the uranium mine at Cigar Lake was originally planned to start in early 2005 and last for 27 month. Production was planned to start in early 2007.

After two water inflows which occurred in April and October 2006 a third inflow took place during the dewatering of the mine in 2008. This was caused by a fissure in the 420m tunnel. In October 2009 that inflow was remotely sealed with an inflatable seal and then filled with concrete and grout. Since the 420m tunnel is not part of the future mine as originally planned, it is now planned to abandon this tunnel filled it completely with concrete. Early in 2010 the dewatering was completed. Remediation and underground construction work has commenced since then. The underground construction is estimated to be 70 percent completed and production is currently planned to start in late 2013. If no further delays occur the mine will start to produce uranium ore almost 6 years behind original schedule. The lifetime of the mine is estimated to be 15 years with full production volumes between 2016 and 2027.

Source: Cameco, Techincal Reports 2007, 2010, 2012

### *Update of "Time Schedules for the New EPR Reactors in Finland and France"*

(Annex 11 in the 2006 paper)

The following example demonstrates the long lead times for the construction of nuclear reactors from the first applications until the reactor starts to operate:

**Example Finland:** (Source: Nuclear Energy in Finland, UIC briefing paper#76, September 2005 (www.uic.au/nip76.htm) and Areva (www.areva-np.com))

- November 2000: Application by Finnish Utility TVO.
- May 2002: Finland's parliament voted 107-92 to approve the building of a fifth nuclear power plant, to be in operation by about 2009.
- January 2003: Approval by the government.
- March 2003: Tenders were submitted by three vendors for four designs.
- October 2003: The site of the new unit was decided to be at the existing Olkiluoto plant. In the same month, TVO indicated that Framatome ANP's 1,600 MWe European Pressurised Water Reactor (EPR) was the preferred design.
- December 2003: TVO signed contracts with Areva and Siemens for the construction of a 1,600 MWe EPR unit effective on 1st January 2004. In January 2004 licence for construction was applied for and granted in January 2005. Construction started in mid-2005 and the reactor was scheduled to start commercial operation in 2009.
- In April 2006 it was reported that construction of the reactor was already 9 months behind schedule. The reactor was then expected to start commercial operation in 2010 (Source: AFX Paris, Finanznachrichten, 24.4.2006, see http://www.finanznachrichten.de/nachrichten-2006-04/artikel-6320902.asp).

- In a 2010 TVO press release it was stated that constructions will be finished late 2012 and that the start of operation is planned for 2013.
- In a 2011 TVO press release the operation start was postponed to 2014.
- In 2012 TVO states that a production start in 2014 cannot be achieved. No new start-up date is released. (http://relevant.at/wirtschaft/ energie/654270/ olkiluoto-3-weiter-langen-bank.story=)
- Both companies are locked in legal battle over compensation fees and delays ( AFP press release, 16th July 2012, see at http://www.google.com/hostednews/afp/article/ALeqM5hKaxOghOftQPa2eN7CIo6kIGNOPw?docId=CNG.915556d46594bef79499a88516257199.8a1 )
- Originally the costs of the plant were estimated to be at 3.3 B €. Currently it is estimated that the costs will increase to 6.6 B €. http://archives.lesechos.fr/archives/2011/LesEchos/21037-96-ECH.htm
- Latest news put the operation start not before 2016 ( see “Finnish Nuclear Plant Won’t Open Until 2016”, New York Times, 11th February 2013, see at http://www.nytimes.com/2013/02/12/business/global/finnish-nuclear-plant-wont-open-until-2016.html?_r=0 )
- Areva at the same day published a press release stating that AREVA is committed to the timely completion of Oilkiluoto 3. In this press release Areva makes TVO responsible for further delays, stating that “the AREVA-Siemens consortium regrets that that TVO continues to not fulfill its obligations to allow for the project to advance properly” (“AREVA committed to the timely completion of Olkilluoto 3 while ensuring the highest level of safety”, Areva, Press release, 11 February 2013, see at www.areva.com ).
- Present cost estimates are seen close to the reactor in Flamanville, which is 8.5 billion Euro.

**Example France (Flamanville):**

- • In 2005 the construction cost were determined by AREVA with3.3 billion Euro.
- • Operation start is delayed until 2016 (AFP press release, 16th July 2012, see at http://www.google.com/hostednews/afp/article/ALeqM5hKaxOghOftQPa2eN7CIo6kIGNOPw?docId=CNG.915556d46594bef79499a88516257199.8a1 )

- • Latest cost projections by Areva claim the actual cost at 8.5 billion Euro (11 billion USD) (“EDF raises French EPR reactor cost to over $11 billion”, Reuters news, 3rd December 2012, see at http://www.reuters.com/article/2012/12/03/us-edf-nuclear-flamanville-idUSBRE8B214620121203

**Example China:**

Areva started the construction of a third EPR-reactor in China in cooperation with the Chinese operator. The latest press release from11th February 2013 (see above) states that the cooperation with the Chinese partner is a key element in keeping cost and time schedules. As part of the cost overruns and time delays of the Finnish and French reactor are due to severe safety risks which resulted in conflicts and many discussions with the Authorities, it might be speculated that the safety standards in China are much lower than was required in France or Finnland. However, at present knowledge this is still a speculation not directly being confirmed, except by critical researchers (BOKU 2013).

# ***SUMMARY: THE FOSSIL FUELS OUTLOOK***

According to our study, coal and gas production will reach their respective production peaks around 2020. The combined peak of all fossil fuels will occur a few years earlier than the peaking of coal and gas and will almost coincide with the beginning decline of oil production.

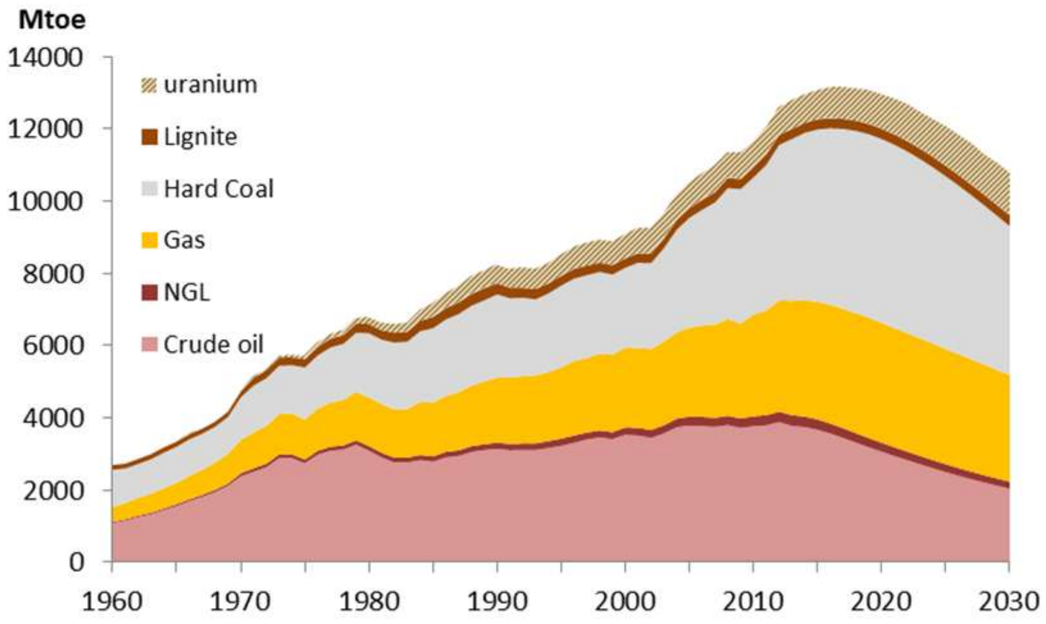
Therefore, the decline of oil production – which is expected to start soon – will lead to a rising energy gap which will become too large to be filled by natural gas and/or coal. Substituting oil by other fossil fuels will also not be possible in case gas and coal production would continue to grow at the present rate. Moreover, a further rise of gas and coal production soon will deplete these resources in a way similar to oil.

The energy contribution of nuclear fuels is too low in order to have any significant influence at global level, though this might be different for some countries. Moreover uranium production experiences the same restrictions as fossil fuels – the depletion of easy and cheap to develop mines.

Figure 121shows the combined supply from oil, gas and coal in energy units. For the calculation the following conversion factors are used:

- 1 Mtoe =7.1 million barrel of crude oil and condensate
- 1 Mtoe = 10 million barrel of natural gas liquids
- 1 Mtoe = 1.16 billion $m^3$ of natural gas
- 1 Mtoe = 1.5 Mt hard coal (1.8 Mt subbituminous coal)
- 1 Mtoe = 3 Mt lignite
- 1 Mtoe = 58 t uranium

**Figure 116: Fossil and nuclear energy supply from oil, NGLs, natural gas, hard coal, lignite and uranium**




Total world fossil fuel supply is close to peak, driven by the peak of oil production. Declining oil production in the coming years will create a rising gap which other fossil fuels will be unable to compensate for.

A typical characteristic of the gold rush in the past was that stories of real successes were accompanied by many rumours and exaggerations. This created an atmosphere where rational thinking had no chance in the public perception. In most cases these rumours were not spread by the successful gold seekers (those kept their secrets for themselves) but by equipment traders which made large profits irrespective of gold seekers' factual successes.

Neither the hype about huge reserves in the Caspian Sea in the year 2000 ("…reserves could rival Saudi Arabia"), nor the deep sea discoveries in the Gulf of Mexico or West of Angola, nor tar sands in Alberta (see the cover story of the ExxonMobil publication "Oildorado" in 2003), nor last year the rush on shale gas developments in the USA or recent news of shale gas in Australia can do away the fact that the era of cheap and abundant fossil fuels is coming to an end. Rather, these new frontiers create more problems than being solutions to problems they promise to solve.

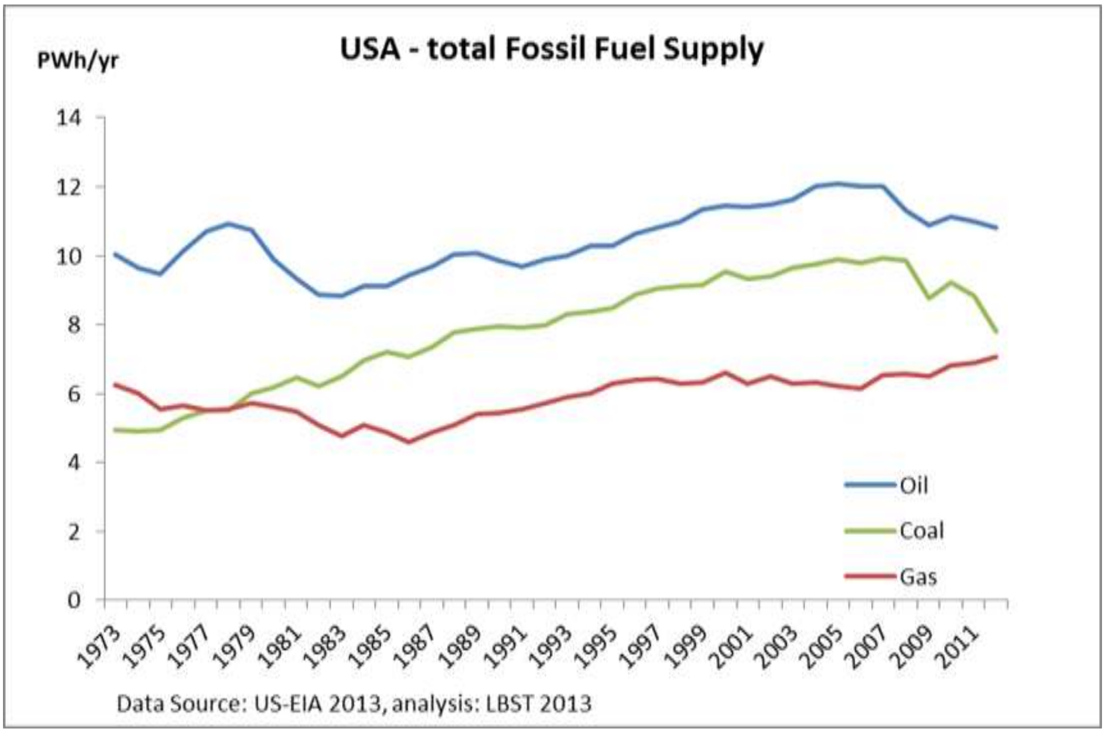
But this is also a good message because climate change forces us to take action along the same lines, namely reducing the consumption of fossil fuels. Therefore, we must face these challenges and start in earnest to develop transition strategies towards a sustainable energy supply. The longer we try to delay that transition by pursuing dead end solutions which are aimed to prolong business as usual, the more we face the risk of falling off a cliff with severe disruptions in economy, politics and society.

# ***ANNEX: FOCUS ON USA***

## ***Fossil energy demand in the USA***

Figure 117 shows the fossil fuel consumption in the USA based on data by the US Energy Information Administration. Since about 1986 the natural gas demand rises continuously with 1.7 percent per year on average. Since 2007 oil and even more coal consumption started to decline considerably.

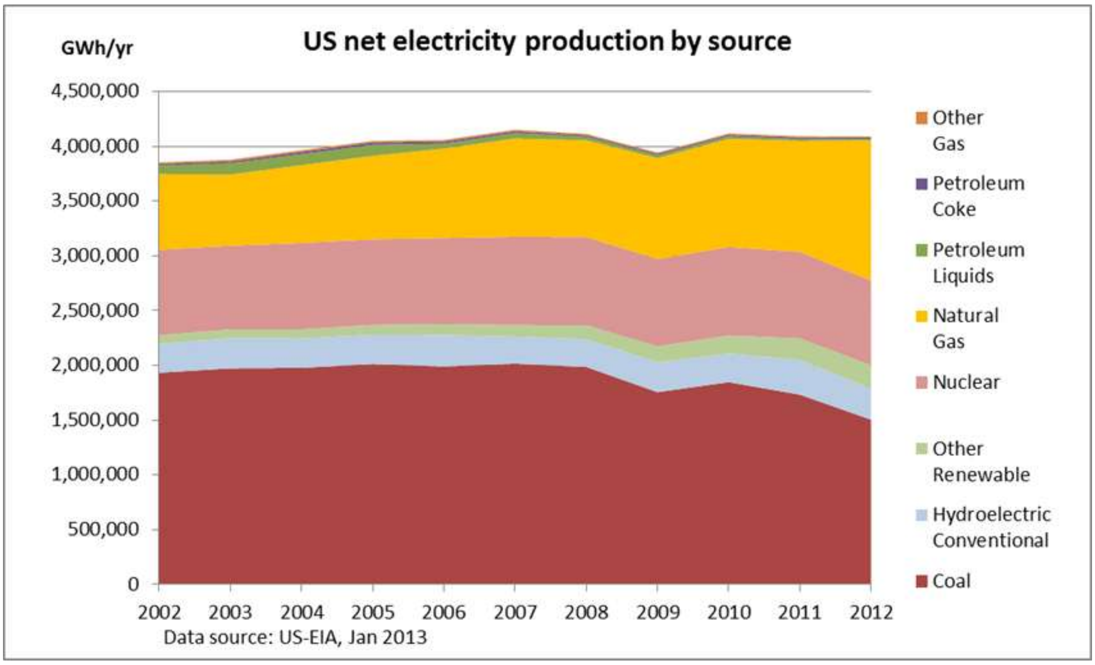
**Figure 117: Fossil fuel consumption in the USA between 1973 and 2012; data for 2012 are extrapolated from monthly data until Sep (coal), Oct (gas) and Nov (oil) (Data source US-EIA 2013**




Interpreting these data, the fossil fuel supply of the USA is in decline since 2007, at a decline rate of about – 2 percent per year, the increase of gas demand is over-compensated by the declining supply of oil (-2% p.yr.) and coal (-5%p.yr.) supply.

Looking a bit more into details, the fuel demand for electricity production also changed over time. Electricity production is almost constant since 2007 (see Figure 118).

**Figure 118: Electricity production by source in the USA; data for 2012 are extrapolated from Jan – Oct**




However, in recent years declining coal supply was substituted by a rising gas use for electricity production with higher efficiency. Based on US-EIA fuel consumption data of coal and gas for power plants and electricity generation, it seems that the overall efficiency for coal plants amount about 22 percent while the efficiency of gas power plants increased from 44 percent in 2002 to 47 percent in 2011. These data indicate that by the substitution of coal to gas the power plant efficiency rose which helped to reduce total fuel demand.

## ***Oil production in the USA***

### *Analysis of empirical production data*

In this subchapter a more detailed analysis of US energy statistics is given. These data should be seen in the context of the latest World Energy Outlook of the International Energy Agency in November 2012 which put the future US oil production in the focus giving it key priority. It is claimed by the IEA that the US have the potential to become the world's leading oil producer. The analysis presented here does not support that statement.

Two aspects are in the focus of this analysis: First, statistical discrepancies between production data for Texas published by US-EIA and by the Texas Railroad Commission are significant. Especially over the last 12 -18 month both statistics deviate considerably while in former years discrepancies were negligible. Secondly, the total production is disaggregated into regional shares in order to identify the geographical regions which have a potential for future production increases. It is shown that the recent success of tight oil production is restricted to small geographical areas while in almost all other areas the production follows the historical trend of declining or stagnating volumes.

Figure 119 shows the total US crude oil production (including condensates) between 1990 and 2012. The data for 2012 are average daily production rates including January to October production volumes.

The red line gives the data published by US-EIA statistics. The green line shows the production data as derived in this report. These data are calculated from US-EIA Statistics by correcting them in such cases where more detailed and reliable regional state statistics are available, predominantly for Texas (data source: Texas Railroad Commission statistics), North Dakota (North Dakota State Government statistics) and Gulf of Mexico (Bureau of Ocean Energy Management statistics; BOEM). Details of this analysis are given in the following. Both data sets match closely over the period 1990 – 2010 but start to deviate in 2011 and are in notable disagreement for 2012.

**Figure 119: US Oil production according to data from US-EIA and according to own calculations by substituting EIA-Data with individual more detailed state statistics where available. Data for 2012 are extrapolated from January to October data.**

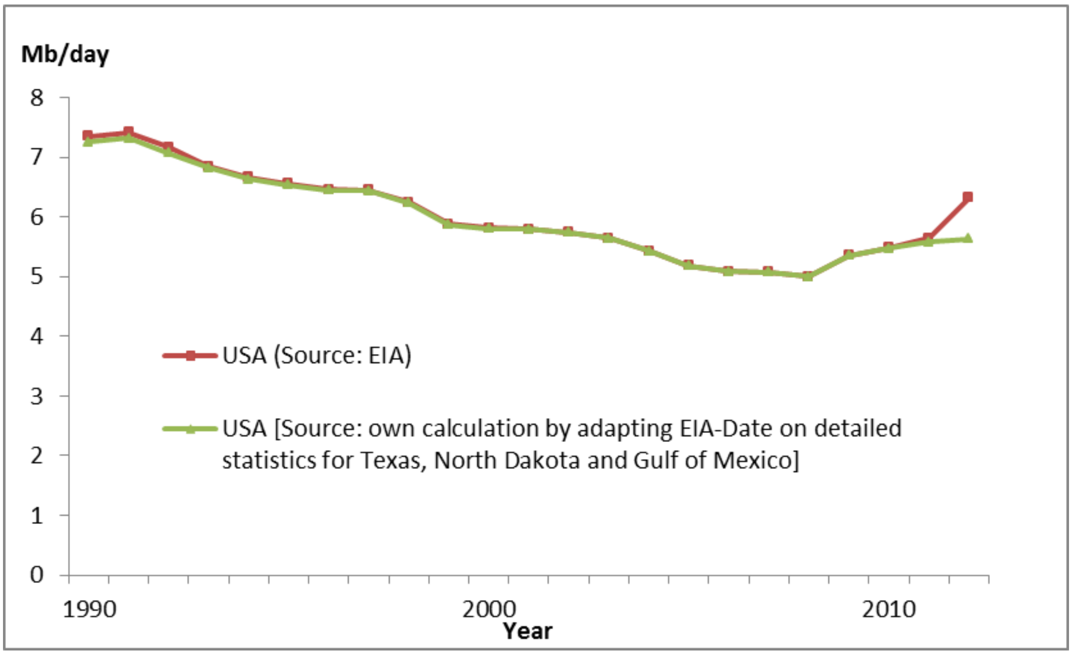
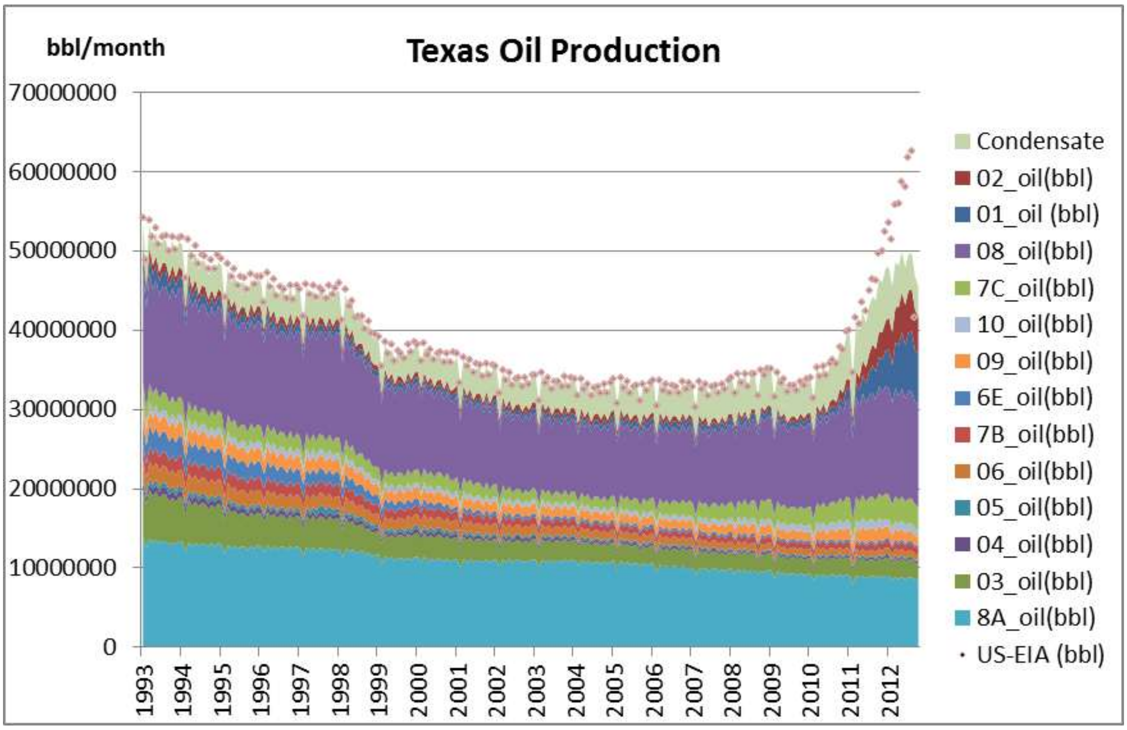



Figure 120 shows a regional analysis of the production data for Texas. The small squares show the total crude oil and condensate production in Texas between January 1993 and October 2012 according to data from US-EIA (last accessed on 4th January 2013). The regional data for each district are accessed from detailed queries of Texas state statistics (RRC Query 2013). These data include only crude oil production. Condensate production is added separately for the whole state from the same database (TRRC Query 2013). It is obvious that in early 2011 these two statistics (US-EIA versus TRRC) started to deviate. The discrepancy rose over the last year considerably. While regional TRRC statistics show a peak of production in the first half year of 2012, US-EIA statistics indicate almost a doubling of oil production between 2010 and October 2012. The US-EIA production data for October 2012 are about 40 percent larger than corresponding data published by the Texas Railroad commission. Due to reporting procedures, the TRRC data of the last few months still will be revised upwards a little over time as some companies have disclosure agreements allowing them to report their data with a delay of several months. However, past experience showed that data quality improves monthly, only slightly being shifted upward within that time period.

While TRRC-Data are based on reported company data, the US-EIA data are estimated for the whole state based on small empirical data sets. Past experience showed that over time the UE-EIA data are revised downward several times, sometimes even for several years back.

**Figure 120:Monthly oil production in Texas based on detailed regional statistics for each district and condensate production compared to monthly totals from US-EIA (Sources: US-EIA 2013; TRRC Query 2013; data last accessed 4th January 2013)**




This figure also reveals an important detail: Though total production since 2012 increased considerably, this increase was restricted to almost only 2 districts, District 1 & 2. In all other districts the production declined according to the historical trend or was only marginally higher. In these districts the net balance of new developments and old field decline is almost balanced. Figure 121 and Figure 122 show the production of individual counties inside of the Texas districts 1 & 2. Even within these districts the production increase is restricted to only a few counties: the production in only 10 counties was responsible for the total production increase of Texas which consists of 254 counties.

This increase is mainly due to recent developments of light tight oil deposits. But a clear separation of tight oil and conventional oil production is almost impossible as the permeability in a formation changes continuously. But nevertheless, by a geographical analysis, the promising assets are identified which are located in "hot spots" which cover only a small area of the whole deposit. These hot spots are concentrated in the few counties mentioned above.

To conclude, in more than Texan 200 counties the recent light tight oil rush did not result in increased production volumes.

**Figure 121: Oil production of individual counties inside Texas District 01(Source: TRRC Query 2013)**

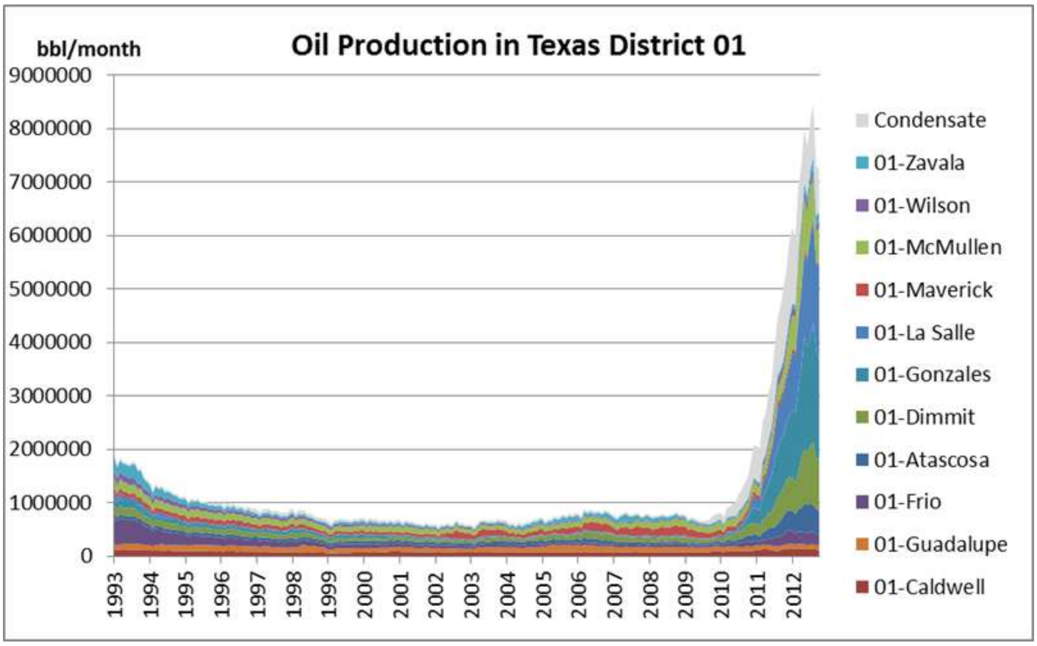
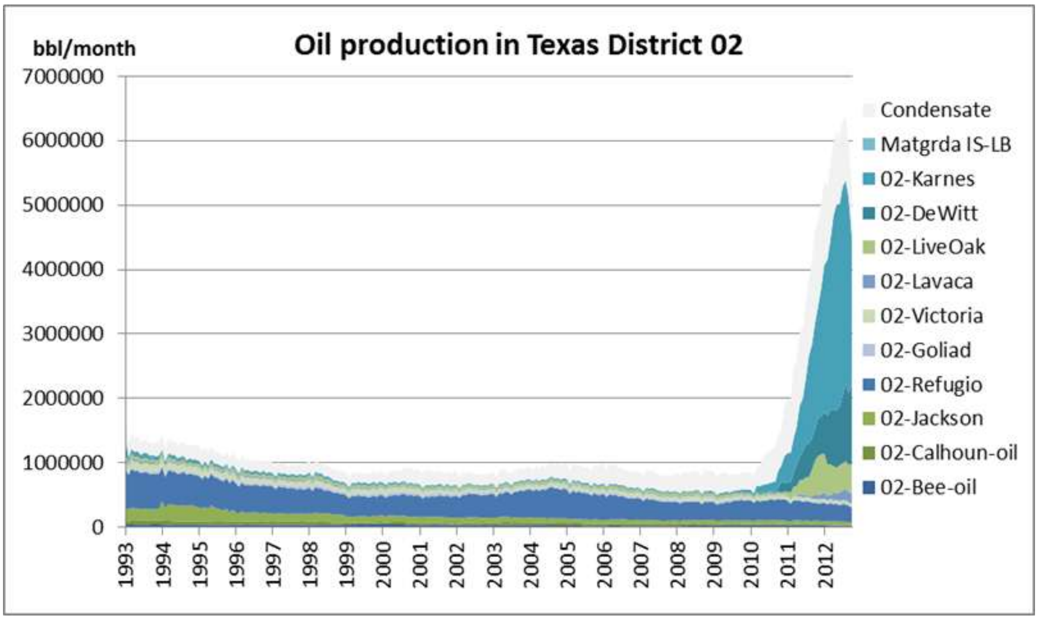


**Figure 122: Oil production in individual counties inside Texas District 02 (Source: TRRC Query 2013)**




North Dakota is the other region where US oil production increased in the last years. In the Bakken formation, the greater part of which is situated in North Dakota, lie by far the biggest light tight oil resources in the US. But also here, though the Bakken formation has a large geographical extension covering 11 counties with a total of 50,000 km², the "hot spots" are restricted to the four counties Dunn, Mc Kenzie, Mountrail and Williams stretching over 23,000 km² (see Figure 123). Within these four counties 90 per cent of the oil of the Bakken is produced.

**Figure 123: Crude oil production in individual counties in North Dakota. Most counties are already showing a decline. The huge production increase only takes place in four counties.(Source: NDG 2013)**

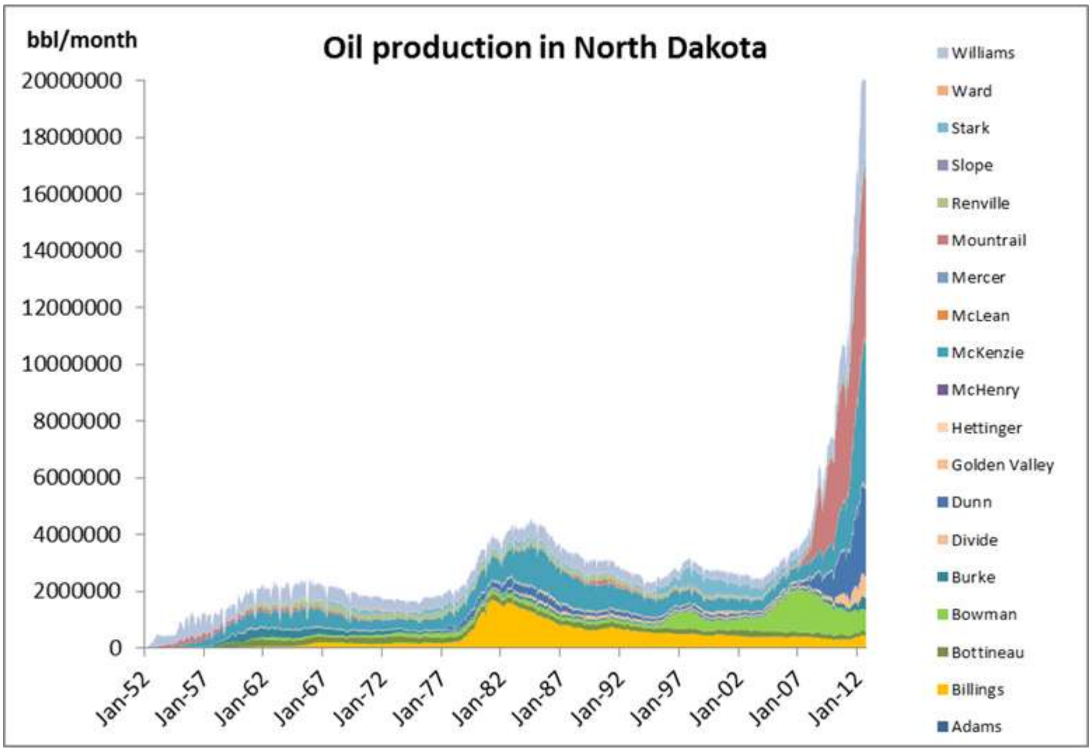
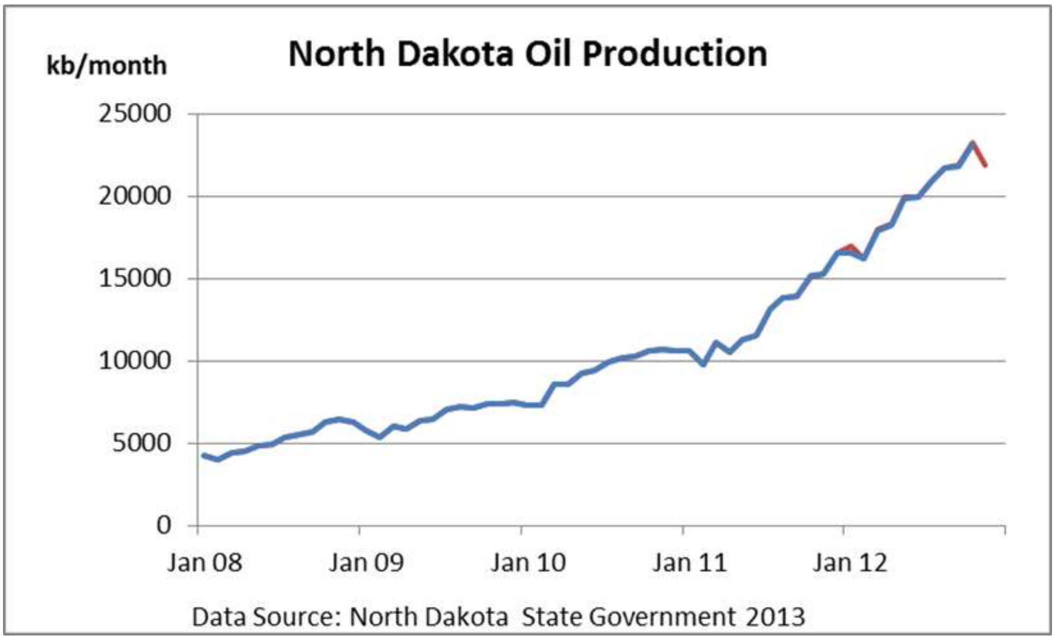



Figure 124 shows the total oil production in North Dakota since January 2008. Almost 90 percent of this production is coming from the 5,000 oil wells at end 2012 in the Bakken formation. The average number of new wells between 2008 and 2011 steadily grew from 35 wells/month in 2008 to 60 wells/month in 2010 and to 100 wells/month in 2011 and to 150 wells/month in 2012. But as soon as the rate of new wells drilled is slowing this will immediately lead to a declining production. January, February and November 2012 saw a slightly lower number of wells than in the other months. This is also reflected in the graph.

Such a detailed analysis is important for forecasting the future development of the production potential of the shale plays. The decline of elder fields starts a treadmill which must be run ever faster in order to compensate for the decline of already producing wells.

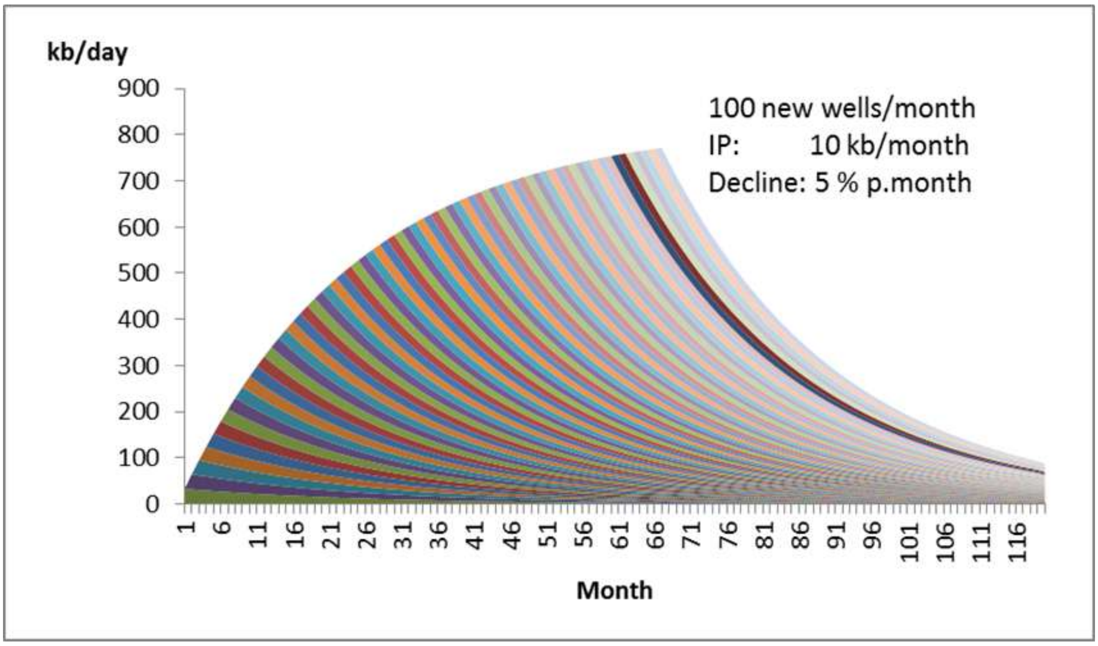
**Figure 124: Monthly total oil production in North Dakota including conventional and unconventional oil production (Source: North Dakota government statistics)**




The above described production pattern can be illustrated by a model calculation (see Figure 125). In this model it is assumed that each month 100 new wells are drilled, each well having an identical production profile with an initial production rate of 10 kb/month and a 5 percent monthly decline rate.

The resulting production pattern is shown in the figure where each area represents the production from the 100 wells developed each month. Due to the decline of aging wells, the total production growth slows until all new wells are needed just to keep the production level flat. The actual development in the Bakken formation was shown above: ever more wells per month were developed. However it is obvious that this treadmill will stop when the rate of drilling is not continuously increased. Then production will begin to decline. Due to the limited geographical extension of the Bakken formation, a scenario of future production can be calculated which fits the observed production growth.

**Figure 125: Theoretical model calculation of tight oil well developments**

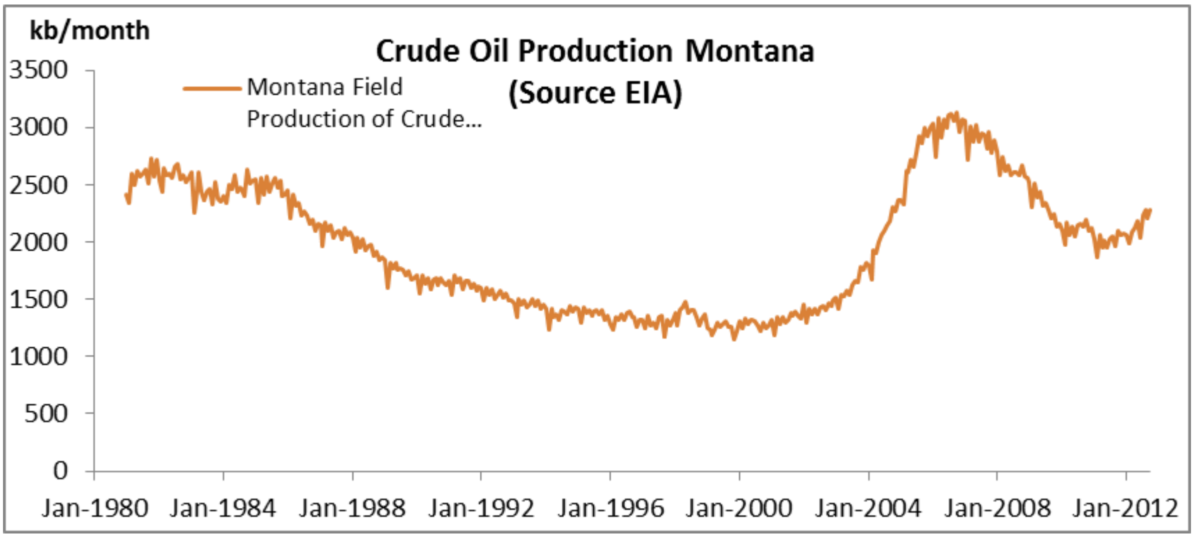



Actually, James Mason performed such an analysis (Mason 2012). Under the assumption that 50 per cent of the total area of the Bakken is completely explored (which in reality will not be the case) and the well productivity remains identical for all wells (which is not realistic) a production level of 2 Mb/d could be reached in 2020 and maintained until 2035. This would require the drilling of up to 3,000 wells per year (in 2011 about 1,200 new wells were developed). Over this period 14.5 Gb of oil would be produced.

It is obvious that such a calculation defines an upper limit which in reality will not be reached. Many detailed discussions on the performance and realistic simulations of Bakken can be found in the web (TOD 2013). Rune Likvern (Likvern 2013), for instance, has analysed the Bakken situation in great detail.

The Bakken formation also includes parts of Montana. But its contribution to the oil production in Montana is very limited (Figure 126). The oil production in Montana is one order of magnitude smaller than in North Dakota, making it not relevant for the US oil production. The increased drilling activity due to light tight oil wells helped to double production of Montana between 2000 and 2006 when it peaked and started to decline again.

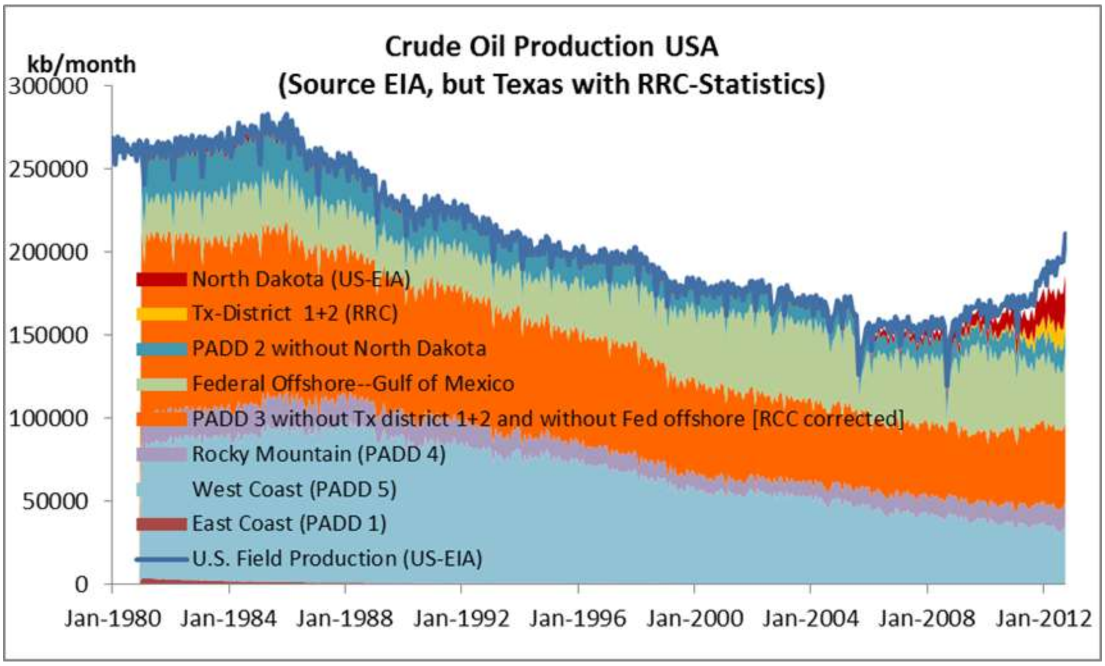
**Figure 126: Oil production in Montana including parts of the Bakken light tight Oil formation; Data source: US-EIA**




Regional crude oil production (incl. condensate) in the USA since 1981 is shown in Figure 127. These statistics are based on US-EIA data. Only for Texas data from the TRRC are used. The blue line gives total US crude oil production according to US-EIA. The regional contributions in PADD 1, PADD 2, PADD 3, PADD 4 and PADD 5 are shown explicitly. However, the data for Texas (which is part of PADD 3) are taken from Texas Railroad Commission statistics. Moreover, production data of Texas are included in PADD 3 only for District 3, 4, 5, 6, 6E, 7B, 7C, 8, 8A, 9 and 10. The production of districts 1 & 2 is shown explicitly. The production data for North Dakota are also shown explicitly and are excluded from PADD 2 production data.

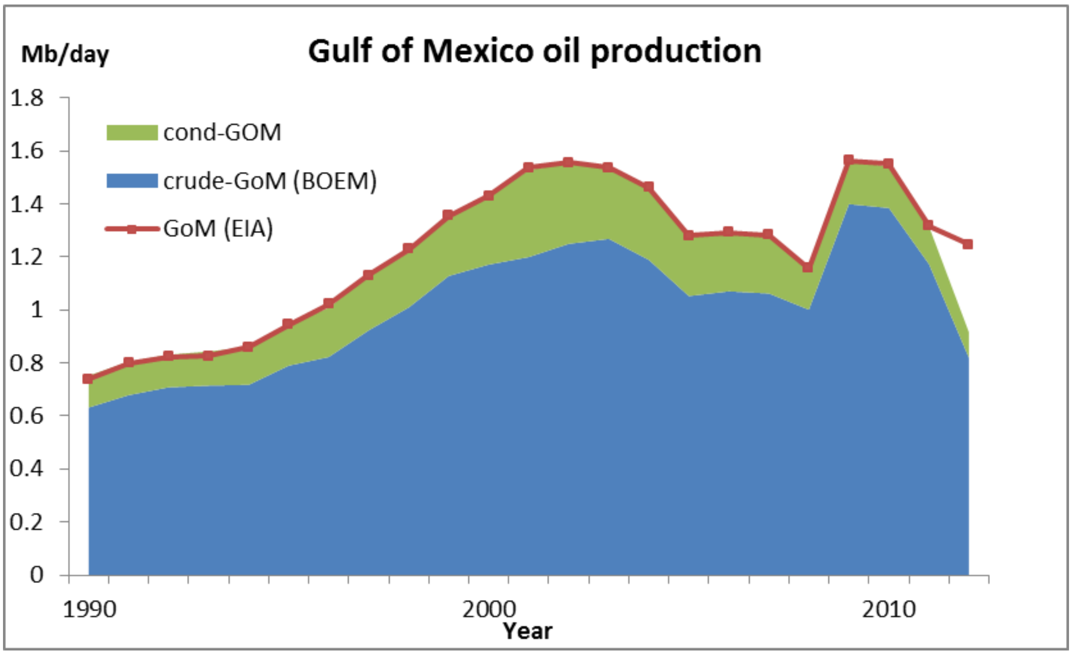
This disaggregation of total US production into the contributions of individual regions reveals that US oil production outside North Dakota and District 1 & 2 of Texas continued to decline in the last years, following the historical trend. In these regions recent developments of light tight oil wells with horizontal drilling and hydraulic fracturing could not compensate for the decline of mature wells. Moreover, it must be expected that the decline in these regions will accelerate as soon as new light tight oil developments have to deal with less promising prospects. The recent production increase is predominantly due to the drilling activities in Texas District 1 & 2 and in North Dakota. The tight oil success in the last years seems to be restricted to a total of 14 counties where net production increased.

**Figure 127: Crude oil and condensate Production in USA: The blue line shows the total production as reported by US-EIA on 28th December 2012; production is shown for the following regions, from bottom to top: PADD 1 (East Coast including the gas rich Marcellus Shale states; brown area) almost not visible, PADD 5 (Westcoast including Alaska; blue), PADD 4 (Rocky Mountains; violett), PADD 3 onshore (Gulf coast including Texas but without districts 1 & 2; orange), PADD 3 Federal Offshore (Gulf of Mexico; green), PADD 2 (Midwest without North Dakota; dark blue); Data for PADD 3 are corrected by state agency data for Texas (TRRC). The difference between the sum of the individual areas and the blue line for total US production shows the data difference between Texas Railroad Commission and U.S. Energy Information Agency.**




When these data are converted into annual production rates another reporting difference comes up with data for the Gulf of Mexico. This is explained in Figure 128. The red line represents the annual production rates in the Gulf of Mexico according to US-EIA statistics. The 2012 data are derived by converting absolute production volumes between January and October into daily average production rates. The Bureau of Ocean Energy Management publishes detailed data for individual wells and also summary tables. On 27 December 2012 the annual summary tables were last updated including full year data for 2012 showing crude oil and condensate separately. These data are also converted into daily production volumes. The two data sets almost agree in the years 1990 to 2010. But for 2012 both data sets differ considerably.

**Figure 128: Oil production in the Gulf of Mexico; The US-EIA data are averages for January to October, published on 28th December 2012; the Bureau of Ocean Energy Management (BOEM) data are full year data published on 27 December 2012.**

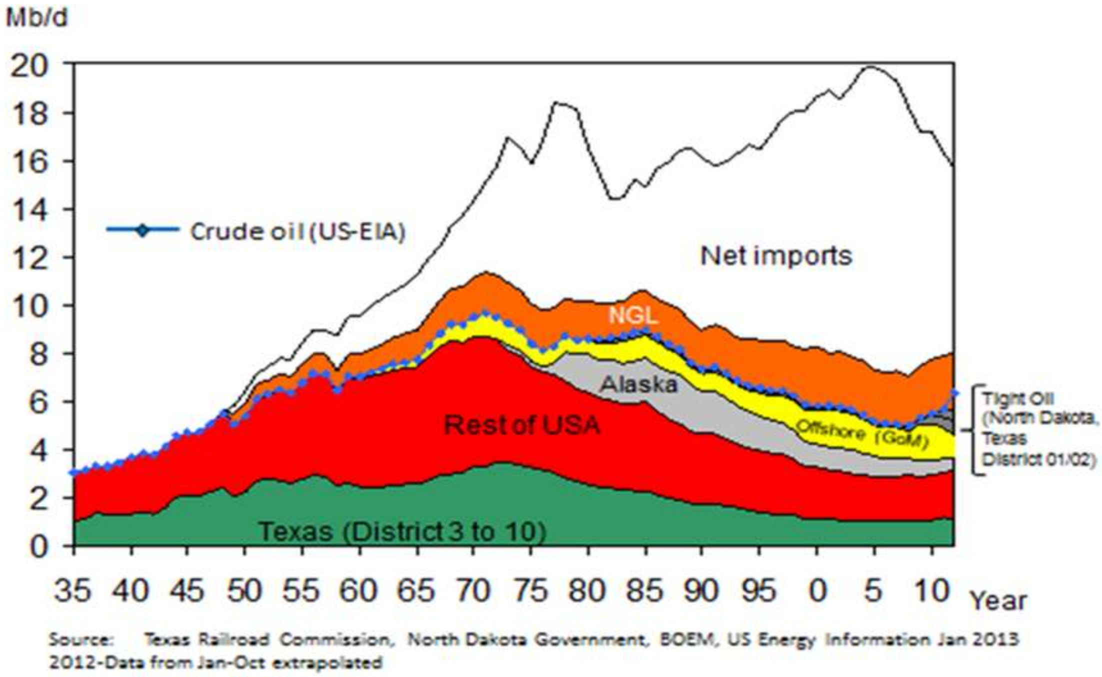



It is obvious that statistical data for the last few months are preliminary and may be revised in forthcoming months. Therefore, these data must be treated with caution. However, what is apparent from the above analysis is the systematic reporting difference: Preliminary US-EIA data almost every time report inflated data which in future reports are revised downward. These revisions sometimes are performed several years back.

Regional state statistics are also updated and improved in future month. However, past experience shows that these changes are performed faster and converge rapidly. Three to six month old data are almost exact only being revised marginally later on. Therefore this systematic difference in data reporting between US-EIA data and regional data cannot be explained by poor primary data.

Figure 129 gives the historical oil production in the US since 1935 exhibiting long term trends. For this graph annual data are used, mainly based on US-EIA statistics, but corrected for Texas (TRRC statistics) and GoM (BOEM statistics). The conclusion from of this figure is that without the recent developments in North Dakota and Texas Districts 1 & 2 total US production follows its long term trend. Since a few years, this declining production trend is superimposed by the production of more expensive to produce light tight oil. Actually US-EIA statistics show that well development costs have been rising significantly since a few years (horizontal drilling and hydraulic fracturing in less hydrocarbon-rich areas such as light tight oil formations – See cost Figure 130).

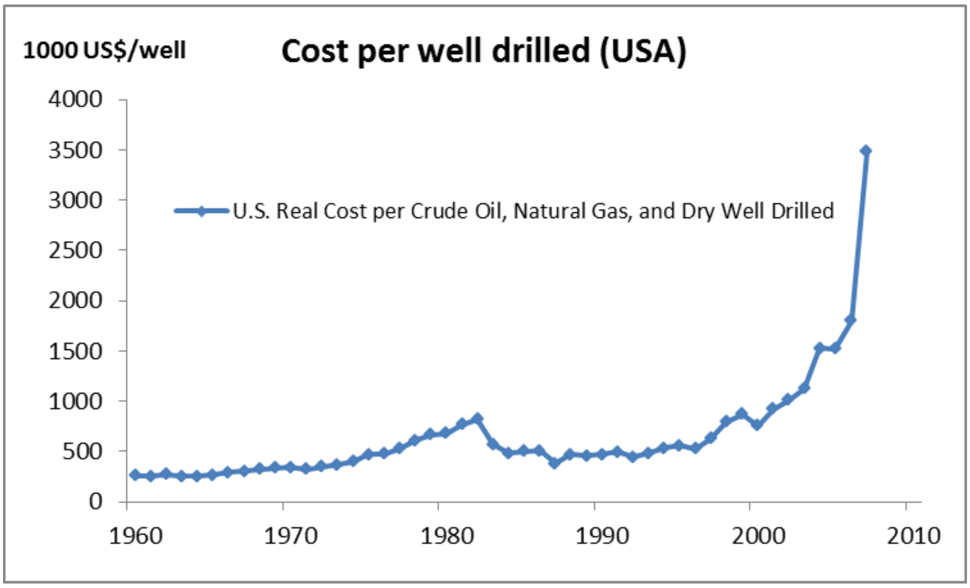
**Figure 129: US Oil production based on US-EIA statistics, but corrected with regional data for Texas, North Dakota and Gulf of Mexico; data for 2012 are extrapolated from monthly statistics including Oct data.**




The reporting difference is also visible by comparing the blue line (US-EIA statistics of crude oil production) with the production data corrected by Texas RRC-Data and BOEM data. To both datasets the NGL production volumes as reported by US EIA are added.

Figure 129 also exhibits that since about 2005 the total US supply (consisting of production plus net-Imports) is in steep decline – long before the financial crises pushed the US economy into recession. This decline is almost comparable to the demand reduction around 1980. This demand reduction is the major reason behind recently declining imports, much more relevant than the growth of domestic production.

**Figure 130: Cost per well drilled in the USA (source: US-EIA, August 2012); in 2007 costs were three to four times higher than in 2000.**




### *US oil production scenario until 2030*

Figure 131 shows the future of US oil production until 2035 as seen by the US Energy Information Administration in its American Energy Outlook 2012 (AEO 2012). Deep water production from the Gulf of Mexico is expected to rise with production peaking around 2020. Light ight oil production in the USA is claimed to rise slowly until 2020 and then to remain constant at least until 2035.

Just one year later, in the just published new AEO 2013 (early release, see Figure 132) this projection looks quite different: The production of the Gulf of Mexico is still revised upward though empirical data indicate a much steeper than expected decline from producing wells. The production of light tight oil is upgraded considerably, now bringing total US crude oil production to 7.5 Mb/day in 2020, whereas the old report projected a production rate of 6.7 Mb/day in 2020. (See below). Light tight oil is expected to produce 2 Mb/day even in 2040 – a level which seems impossible to reach from today’s knowledge.

**Figure 131: US oil production 1990-2035 according to Annual Energy Outlook 2012; http://www.eia.gov/todayinenergy/detail.cfm?id=4910 ;**

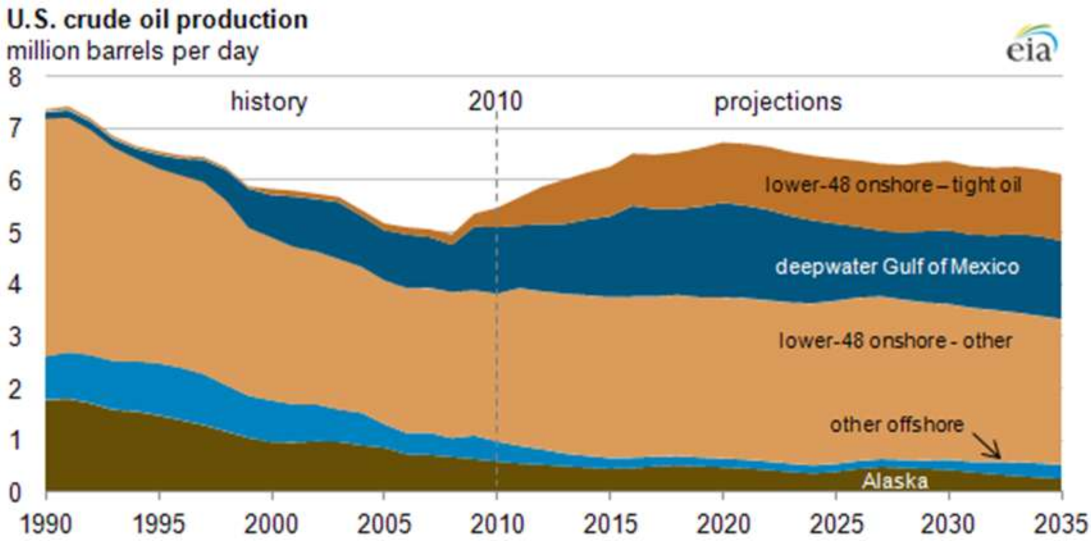
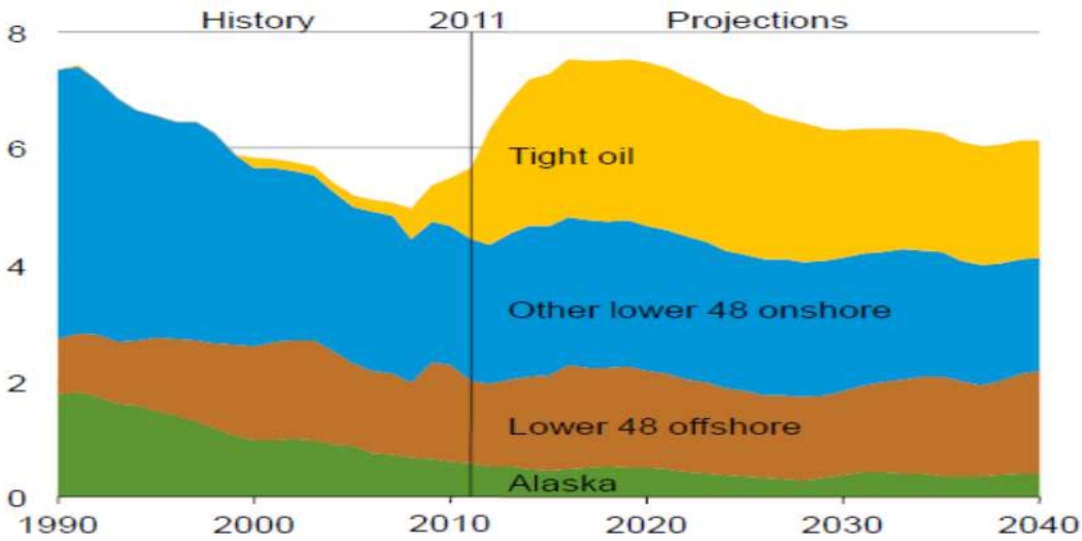
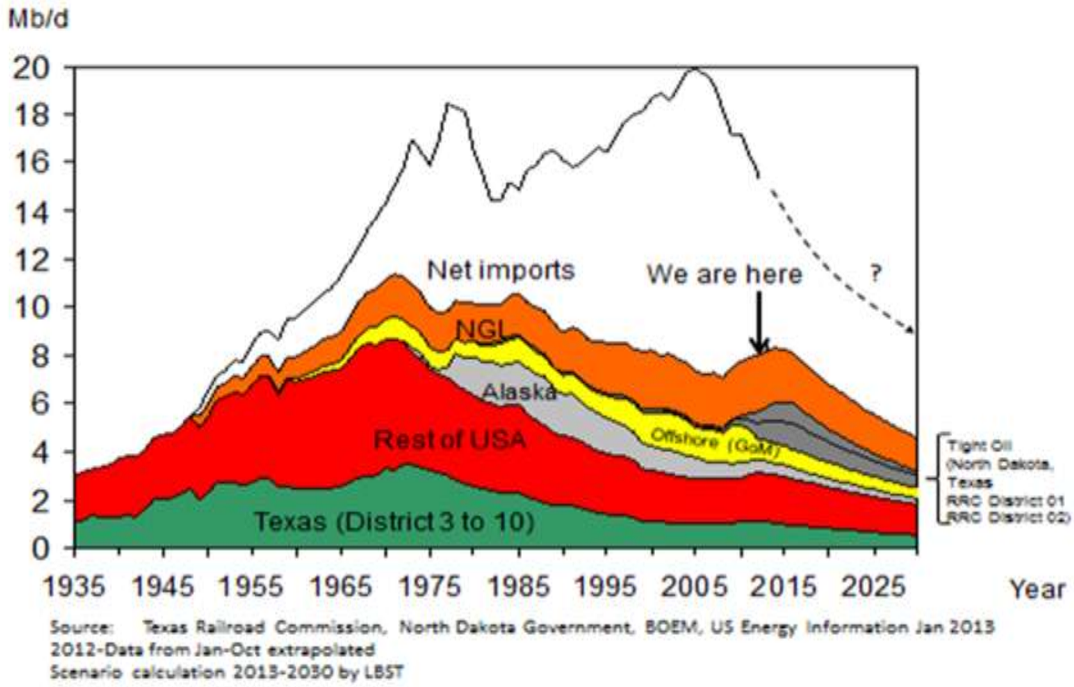



**Figure 132: US oil production 1990-2040 according to Annual Energy Outlook 2013; http://www.eia.gov/forecasts/aeo/er/index.cfm )**




Due to the insufficient quality of available data, at present it is not possible to construct an empirically confirmed scenario which might match the future development exactly. However, the authors are confident that the future development might come close to the scenario projection in Figure 133 which was prepared by using much of the detailed information described above.

**Figure 133: US oil production and import scenario until 2030; This scenario is based on cumulative domestic production between 2011-2030 of 34 Gb which by far exceeds proven reserves.**




### *US oil reserves*

Though proven reserves do not necessarily dominate future production rates, nonetheless they are still important. Therefore oil and gas reserves are discussed in the following.

Figure 134 shows the proved oil and condensate reserves classified into "reserves in already producing fields" and "reserves in non-producing fields". More than two-thirds of oil reserves are situated in already producing fields. Typically, these reserves are in mature fields which show a declining production. The average decline of producing fields is in the order of 6-8 percent. This decline must be compensated by the timely development of new wells in not yet producing fields.

Total US oil and condensate reserves at end 2010 (i.e. latest available US-EIA statistics) are stated as 25.2 Gb of which 17.5 Gb are in producing fields and 7.7 Gb in non-producing fields.

By far the largest reserves are located in Texas, the Gulf of Mexico, Alaska and California. More than 80 percent of oil reserves in Alaska and California are in already producing fields.

The remaining reserves in non-producing fields are too small to reverse the declining production trend.

In Alaska proven reserves continuously declined since 1978 from 9.4 Gb to 3.7 Gb at present. This is in line with the declining historical production since 1989 which declined from 2.1 Mb/day in February 1988 to 0.55 Mb/day in October 2012.

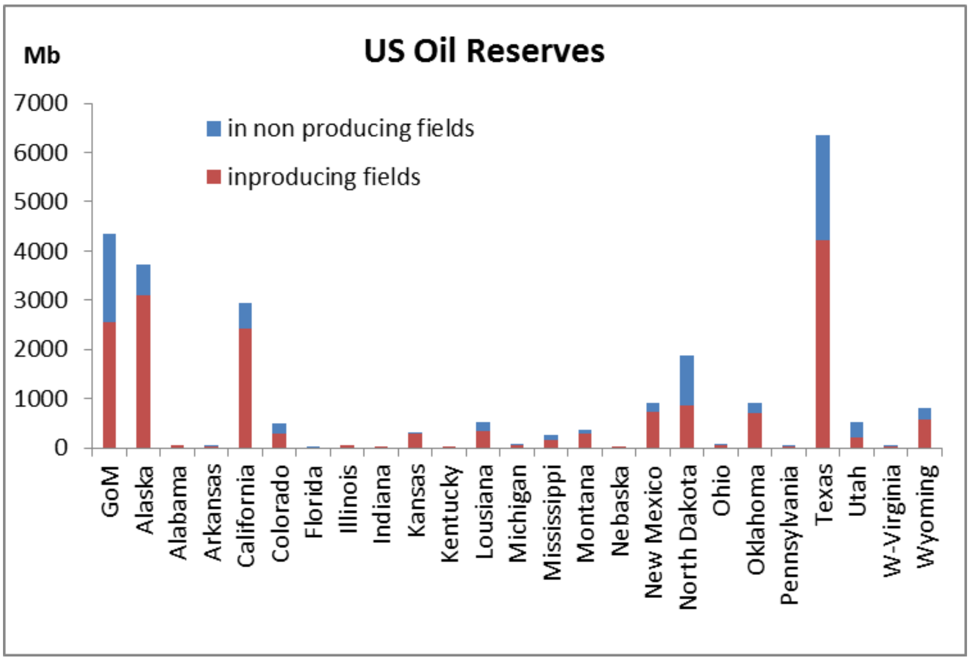
The situation in California is quite similar: Reserves declined from 4.9 Gb in 1988 to 2.9 Gb in 2010. Production declined from 1.08 Mb/day in 1985 to 0.53 Mb/day in October 2012.

The only areas which have a share of 30 or more percent of reserves in non-producing fields are the Gulf of Mexico, Texas and North Dakota. Therefore, possible future growth of US production must be concentrated in these regions.

Proved reserves in the Gulf of Mexico already declined from more than 4.5 Gb in 2003 to 4.1 Gb. Reserves in non-producing fields declined even steeper, from about 3 Gb in 2003 to 1.7 Gb at end 2010 – their share on total reserves declined from 40 to 30 percent. Production in the Gulf of Mexico is already in decline. The last production increase occurred in 2010 after the giant fields Thunderhorse and North-Thunderhorse came onstream in 2009, which have been discovered in 1999/2000. The development of these fields were several years delayed. Moreover, in September 2012 production had declined by an stonoshing nearly 90 percent since peak production in September 2009. Almost all fields in the Gulf experience an unprecedented decline rate which is much higher than anybody had expected before.

According to available data, it is highly probable that the decline of GoM production will continue. There is no justification for the optimism shown in Figure 132.

**Figure 134: Crude oil and condensate reserves in USA at end 2010 (Source: US-EIA)**




Only North Dakota and Texas have the potential for a temporary growth of production.

Proved reserves in Montana are already in decline since 2005, the share of reserves in producing fields amounts about 80 percent due to the fact that the Montana part of the Bakken formation has been developed since 2001.

The economically more promising part of the Bakken formation is located in North Dakota. Reported proved reserves have increased rapidly, from about 0.4 Gb in 2006 to 1.8 Gb at end of 2010 (the latest published data). The resource potential has been studied since 1974, when the first resource estimate was published by Williams with 10 Gb oil in place of which up to 30 percent were claimed to be producible. Later studies steadily increased the resource potential. However, only the latest USGS study in 2008 dampened this optimism by arriving at significantly reduced numbers for the technically recoverable resource:

**Table 3: Resource estimates of oil in place of the Bakken formation (Source: Fever/Helms 2006)**

| Author | Year of publication | Estimated oil in place |
|---|---|---|
| Williams | 1974 | 10 Gb |
| Webster | 1982 | 92 Gb |
| Schmoker/Hester | 1983 | 132 |
| Price | Unpublished | 271-503 Gb |

| | | |
|---|---|---|
| Meissner/Banks | 2000 | 32 Gb |
| Flamery/Kraus | 2006 | 200 - 300 Gb |
| USGS-2012 | | 4.35 Gb (technically reco verable) |

However, what counts are not reserve or resource estimates. More important is the yield factor which determines the share of oil in place which can be extracted. Estimates vary between 3, 10, 18 and up to 50 percent. While the highest estimate was given by Price, 18 percent were estimated by the Headington oil company for specific wells in Montana. The North Dakota Industrial Commission Oil & Gas Hearings gives a range of 3 – 10 percent which seems more realistic (Fever/Helms 2006 and references therein).

If the 200-300 Gb oil in place are realistic anda 3-10 percent recovery rate is possible, the potential oil production could amount to 6 – 30 Gb. The USGS figure puts that range further down to about 3 - 4.35 Gb. [USGS 2008]

But the size of the possible resource and the probable extraction yield are only part of the analysis. Equally important are the production dynamics and limiting side effects such as restrictions due to competing land uses, economic, technical, environmental or administrative aspects, not to forget rising public opposition to fracking.

At end 2012 about 1 Gb of oil has already been produced. For the scenario it is assumed that the present production growth can still continue for a few years until 2016, with an annual peak production rate of 1.1 Mb/day which might be followed by an annual decline rate of 5 percent. This would sum up to a cumulative production between 2013 and 2030 of 5.1 Gb. In view of present reserves of 1.8 Gb, the beginning decline in some counties (see above) and the marked regional concentration of promising well sites, such a development seems not unrealistic.

The region with the largest reserves is Texas. Locations of current production and promising prospects are concentrated in limited areas. Figure 135 shows the regional distribution of proved reserves. These are concentrated mainly in the districts 8 and 8A. However, in both districts the share of reserves in producing fields is high with 60-80 per cent. In addition, past well developments in these districts did not result in sizeable production increases – rather, the total production in these areas continued to decline in recent years and months. Only the two districts 1 and 2 achieved significant production increases in the past years. However, these are only backed by small reserves of about 400 Mb.

**Figure 135: Crude oil and Condensate Reserves in Texas (Source US-EIA)**

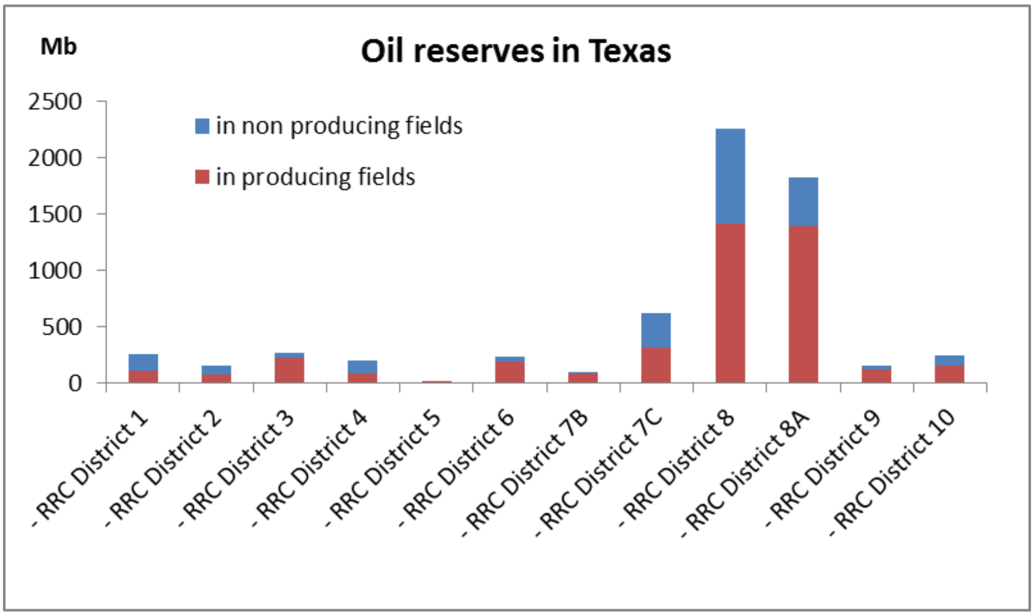



Figure 133 combines historical production with updated scenario projections until 2030. The future production profiles of the individual regions are based on the analysis outlined above. Updating the scenario for the Energy Watch Group in 2008, three production profiles had to be modified according to improved insights gained in the meantime:

- First the future production in the Gulf of Mexico is projected to be smaller than previously anticipated. It is highly probable that the GoM region has already passed peak production. The decline rate is estimated at 4 percent annually, bringing cumulative production between 2011 and 2030 to 5 Gb, about 20 percent larger than proved reserves.
- Secondly, the two Texan districts 1 and 2 are separately investigated while the decline rate in the rest of Texas is estimated at 5 percent. The cumulative production between 2011 and 2030 then is 6 Gb, which comes close to the total proved reserves in producing and non-producing fields.
- Third, North Dakota is modelled separately with a cumulative production between 2011 and 2030 of 6 Gb, about 3 times larger than the proven reserves in that region.

Production in Alaska is projected to decline further at 3 percent per year. Cumulative production between 2011-2030 with 2.8 Gb is about 30 percent smaller than proven reserves. Production in the rest of the USA continues to decline with 3 percent annually. Cumulative production with 12 Gb in this period almost matches proved reserves. Finally, production of natural gas liquids (NGL) is declining by 3 percent annually. Cumulative production NGLs between 2011-2030 is 13 Gb. Total cumulative production of crude oil (and condensate) between 2011-2030 amounts to 34 Gb. This is 50 percent larger than proven reserves.

Certainly, it is impossible to draw a complete picture of the future oil production

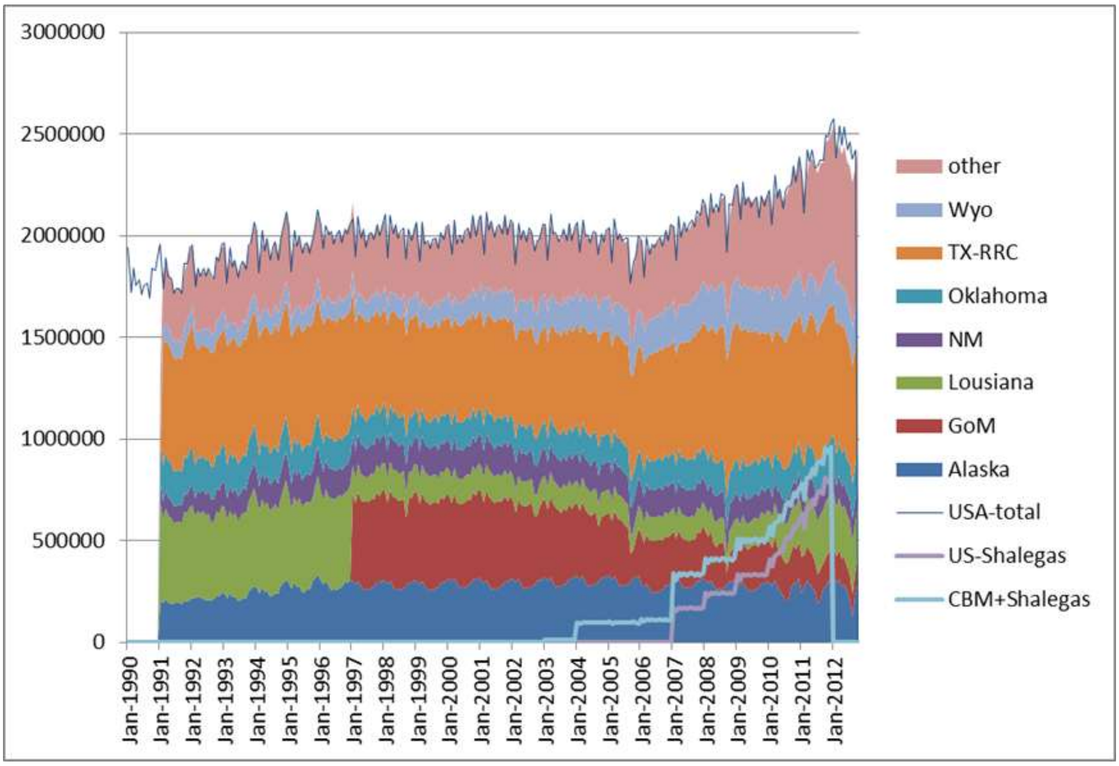
Nonetheless, the authors believe that that the scenario presented in Figure 133 has a high probability. This assertion is based on detailed analyses of historical trends of individual regions, on the observation of production trends, and on the continuous work on scenario projections for more than 10 years. To conclude, the US might be well advised to prepare for a situation where domestic production declines even further while oil imports are becoming more and more scarce due to the rising competition with other nations and declining production in exporting countries.

## *Natural gas production in the USA*

### *Analysis of empirical production data*

This section investigates the natural gas production in the US in more detail. Figure 136 shows the natural gas production in the USA, disaggregated into regional contributions. The blue line gives total production data. All data are published by US-EIA except those for Texas where data from Texas railroad commission are preferred as these data are based on more disaggregated collected data.

**Figure 136: Monthly US gas production (gross withdrawals) according to US EIA and corrected by Texas Railroad Commission data for Texas.**



In 1997 EIA separated Gulf of Mexico data from those of Louisiana onshore production. The two lines in the lower right part of the figure give the shale gas and shale gas plus coal bed methane gas production according to available US-EIA Statistics.

Detailed monthly statistics are published including October 2012 (status: January 2013). These are analysed in the following. Figure 137 to Figure 150 show detailed regional data, partly from state agencies, and partly from US-EIA. These data show some inconsistencies which cast doubts on the statistics of US-EIA. For instance, shale gas production is only reported since2005 and up to 2010 (partly 2011). However, at regional level, most data are available until recently. The neglection of shale gas production before 2005 and beyond 2010 results in strange counting of gas production from gas wells. (see e.g. Figure 141, Figure 143, Figure 147 or Figure 148). The statistics of coalbed methane production shows similar deficits as can be seen in the same figures, but also in Figure 142.

Even more strange are the data differences for shale gas production itself, when comparing regional state data with data from US-EIA (see Figure 145 and Figure 146).

Most of the data shown in the following graphs are presented here as background information. These data partly reveal the above mentioned strange discrepancies between different statistics, but also reveal that gas production in most shale assets has already passed peak production.

Figure 137 gives natural gas production in Alaska. Most of the gas is reinjected in oil fields in order to enhance oil production from mature fields. Total production slightly declined over the last years. Though it is possible to market more gas once reinjection into oil fields stops the major hurdle is the long distance to consumers which would require huge investments in gas transport infrastructure.

**Figure 137: Gas production in Alaska (Source: US-EIA Jan 2013)**

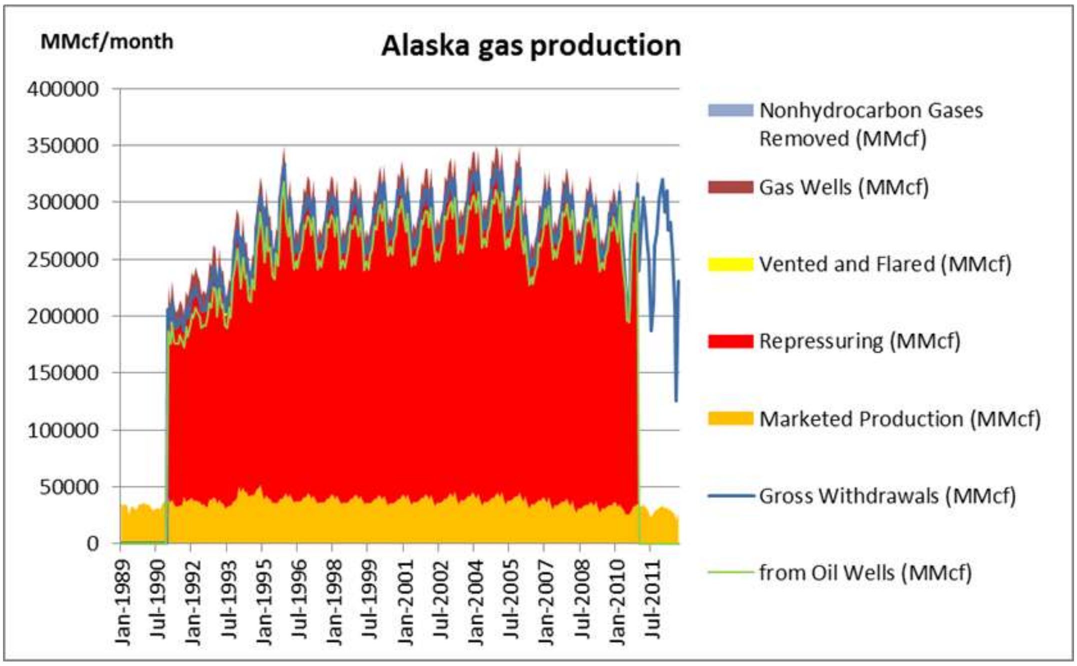



Figure 138 gives natural gas production in the Gulf of Mexico. Since about 2001 gas production in the Gulf of Mexico is in decline.

**Figure 138: Gulf of Mexico gas production (data US-EIA Jan 2013)**

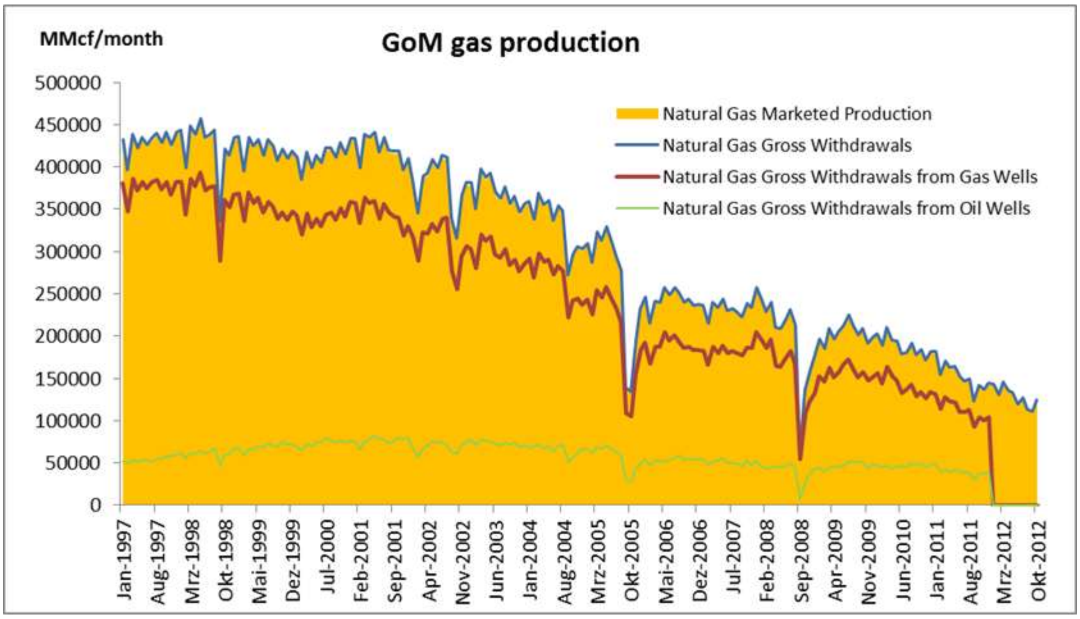


**Figure 139: Louisiana monthly gas production 1991 – Nov 2012 excluding offshore and exhibiting Haynesville share (Source: Louisiana Department of Natural Resources 2013).**

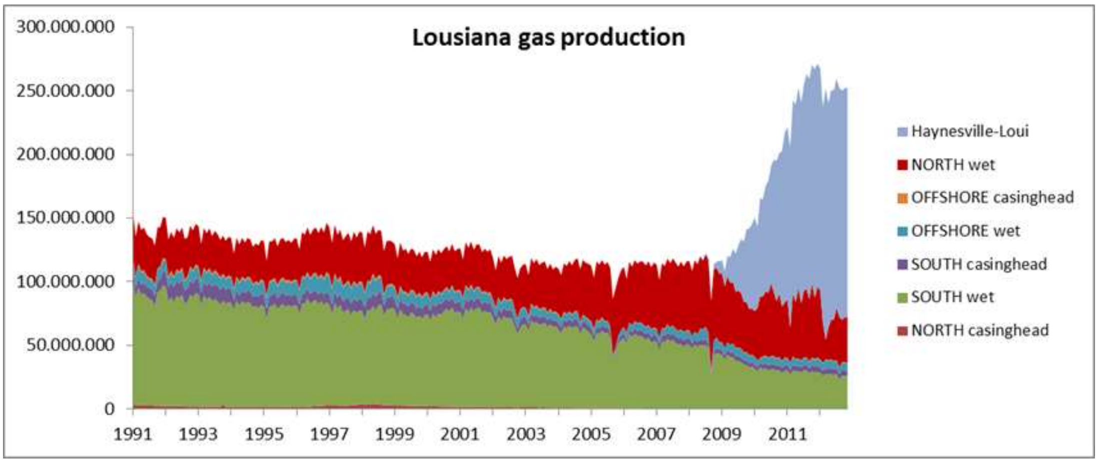



**Figure 140: Louisiana Gas production 1945 – 2012 (data 2012 from Jan – Nov extrapolated) (Source: Louisiana Department of Natural Resources 2013)**

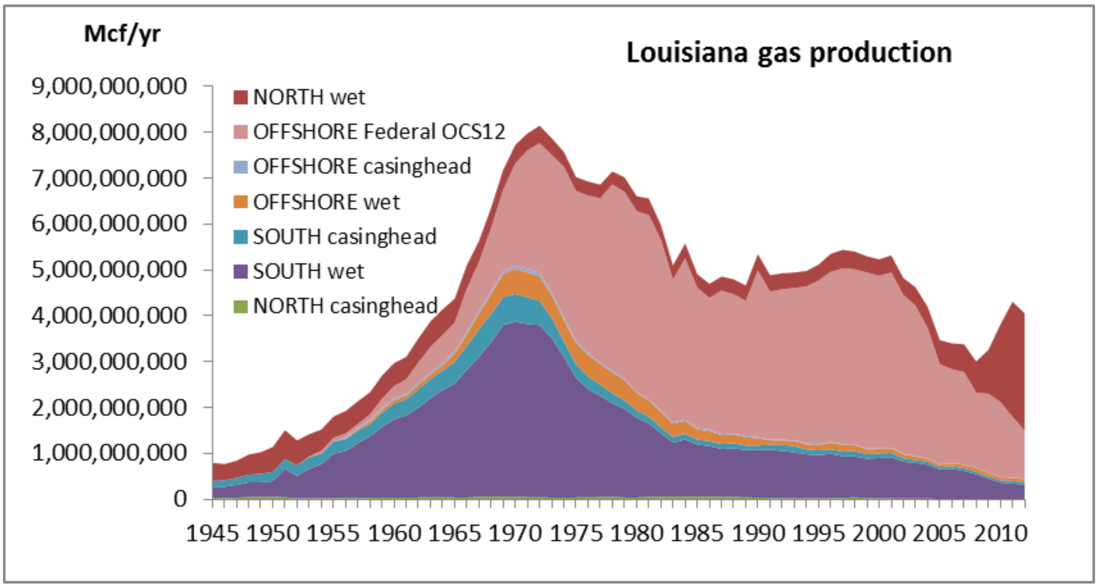


**Figure 141: Natural gas production in Louisiana according to US-EIA statistics**

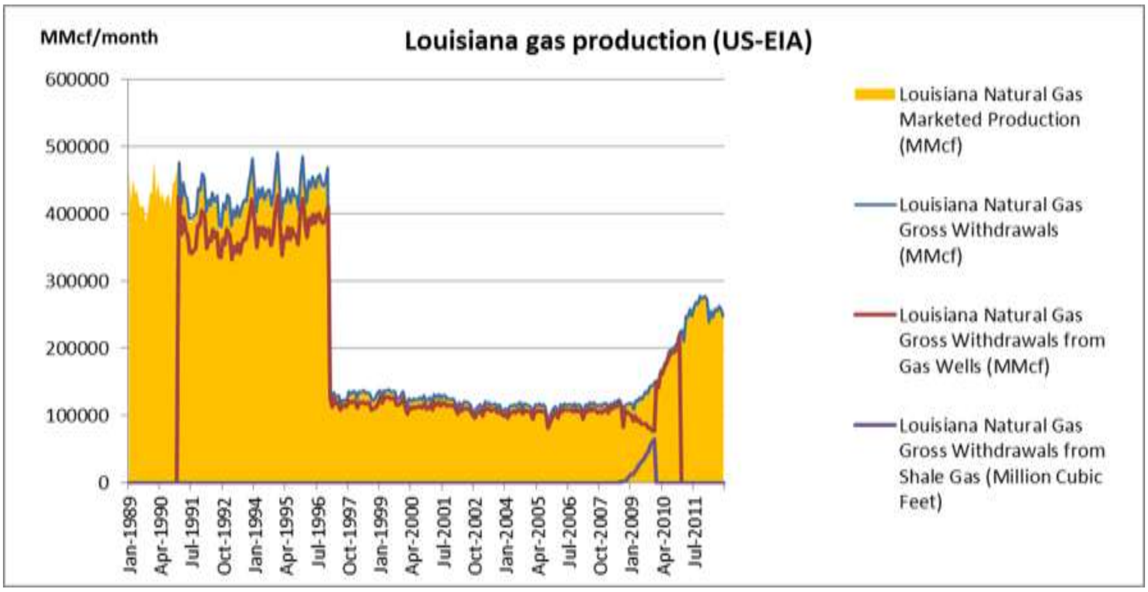



**Figure 142: Natural gas production of New Mexico according to US-EIA statistics**

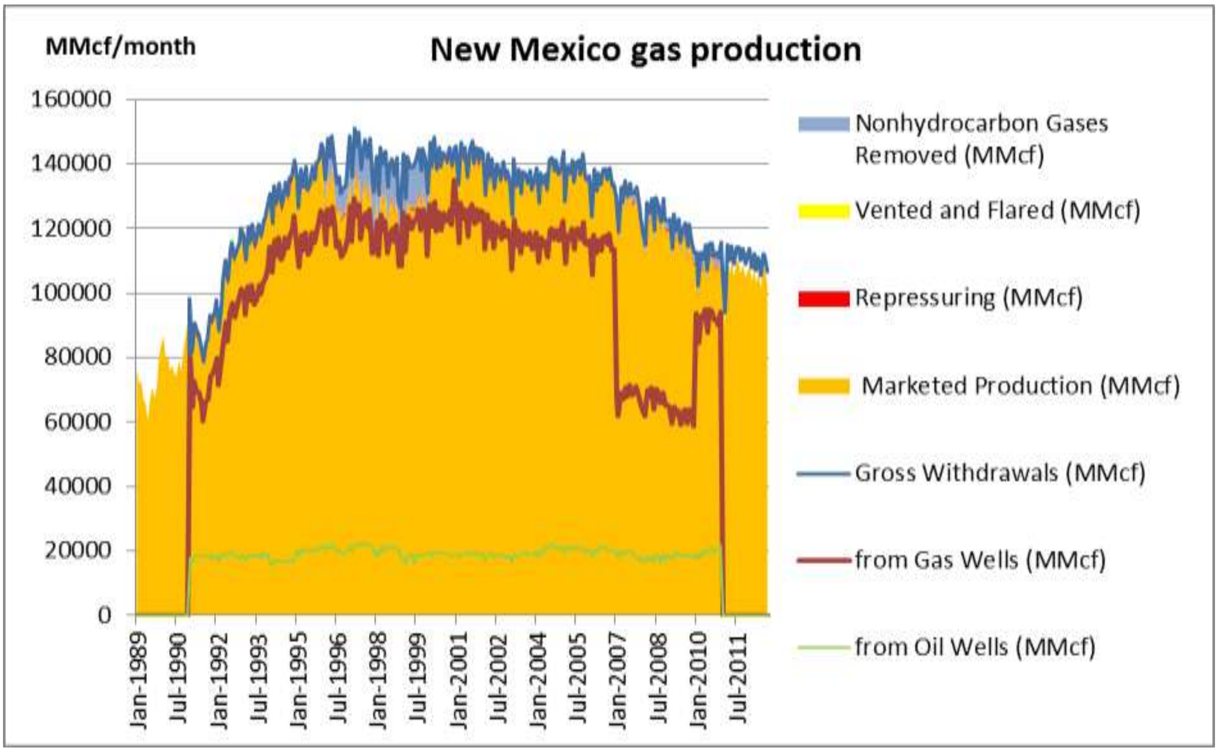


**Figure 143: Natural gas production of Oklahoma according to US-EIA statistics**

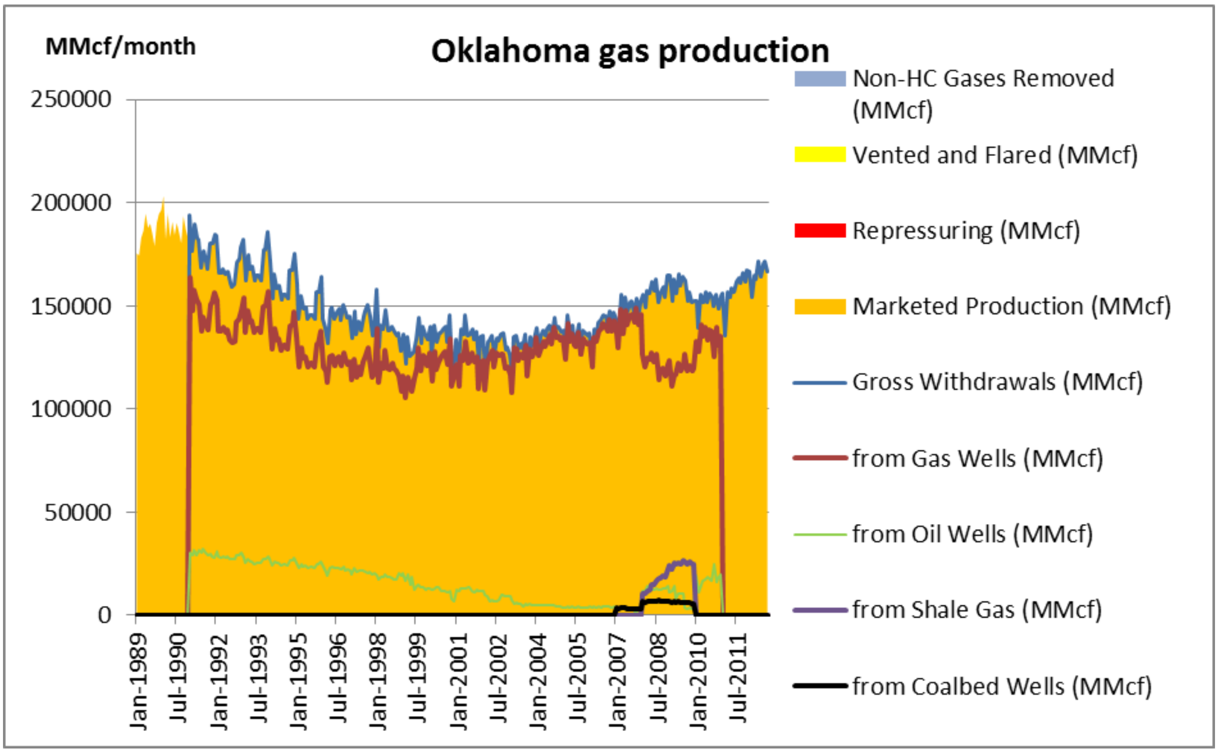



**Figure 144: Natural gas production in Texas according US-EIA and compared with detailed statistics by Texas Railroad Commission statistics**

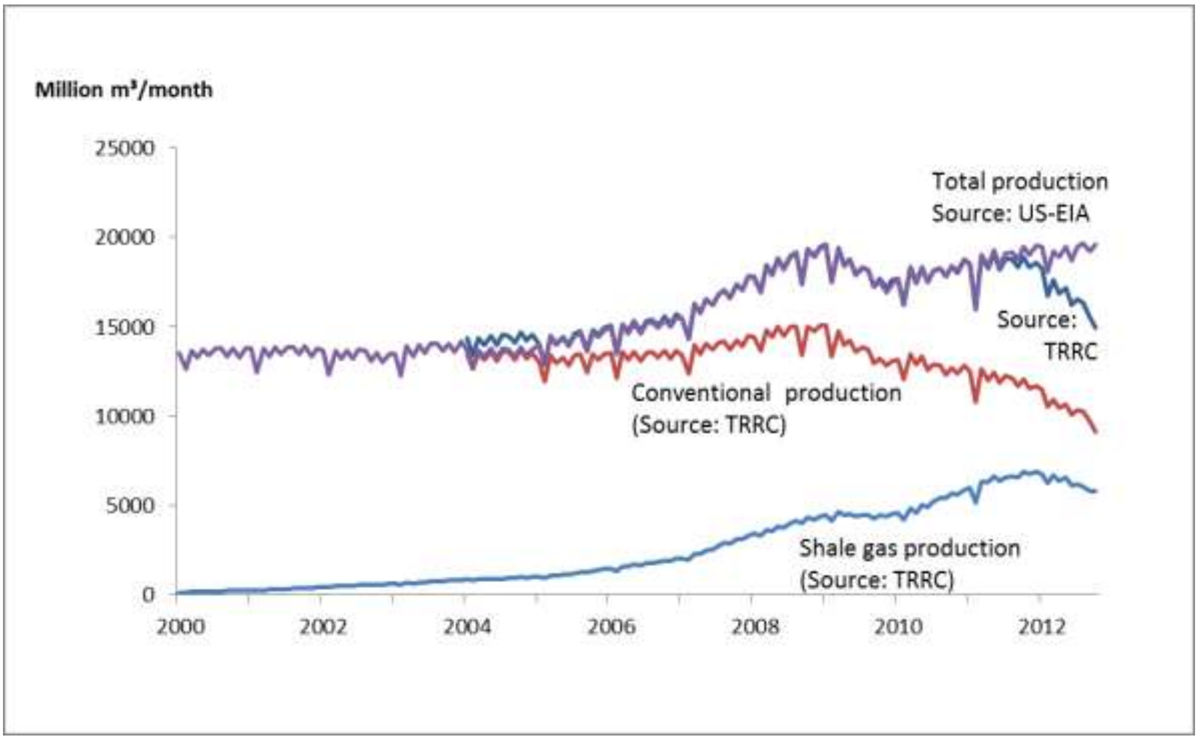


**Figure 145: Shale gas production in Texas according to TRRC statistics (areas) and compared with US-EIA statistics (orange line)**

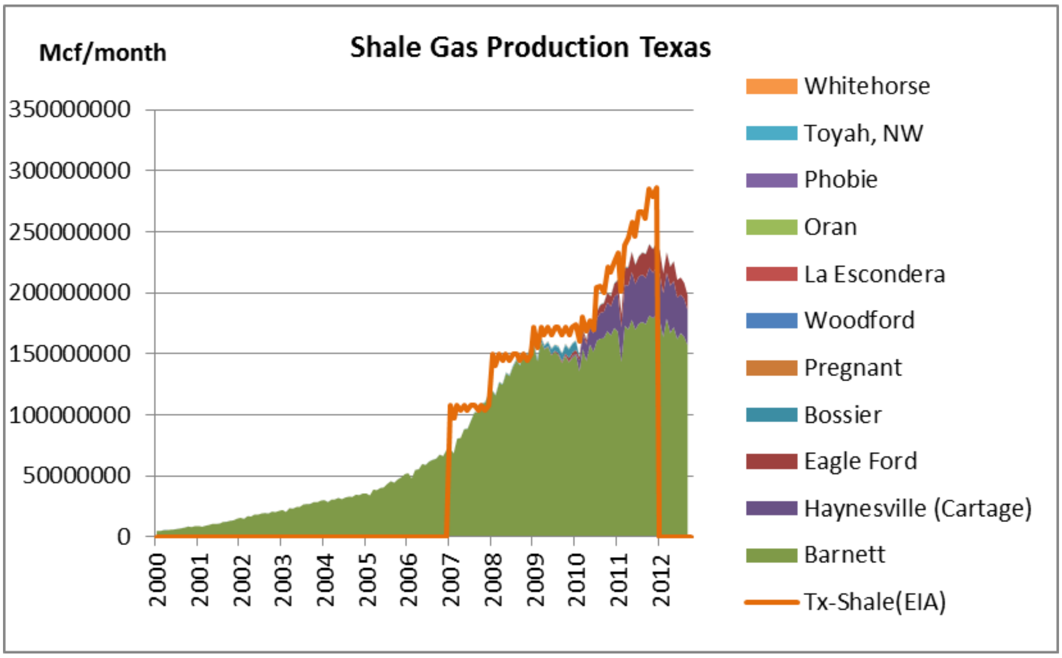


**Figure 146: Natural gas production in Arkansas and in the Fayetteville Shale according to data by US-EIA and Arkansas Oil and Gas Statistics**

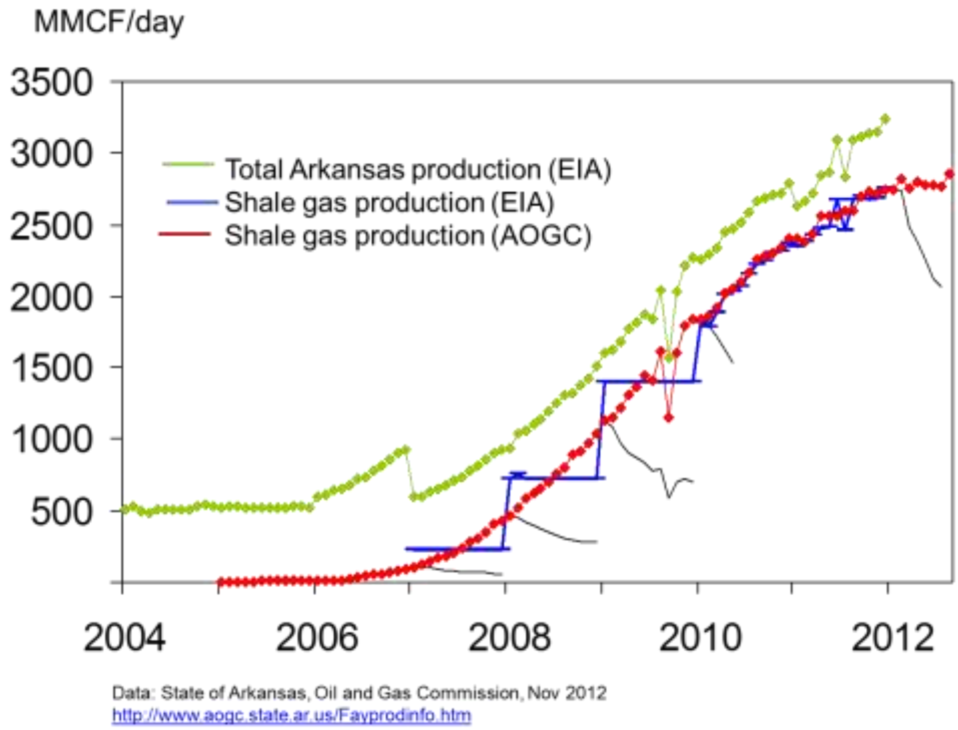



**Figure 147: Natural gas production in Wyoming according to US-EIA statistics**

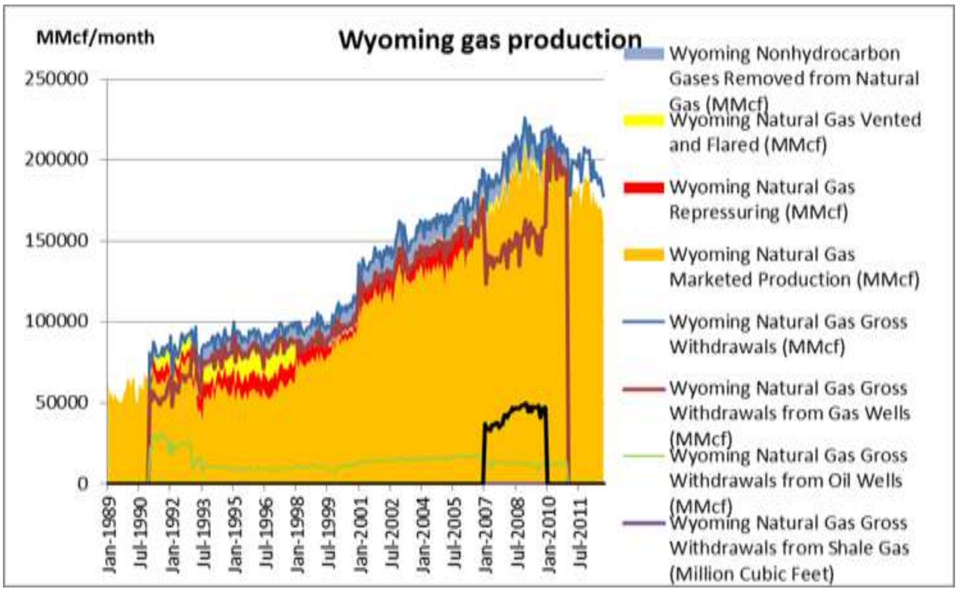


**Figure 148: Natural gas production in "other states" according to US-EIA**

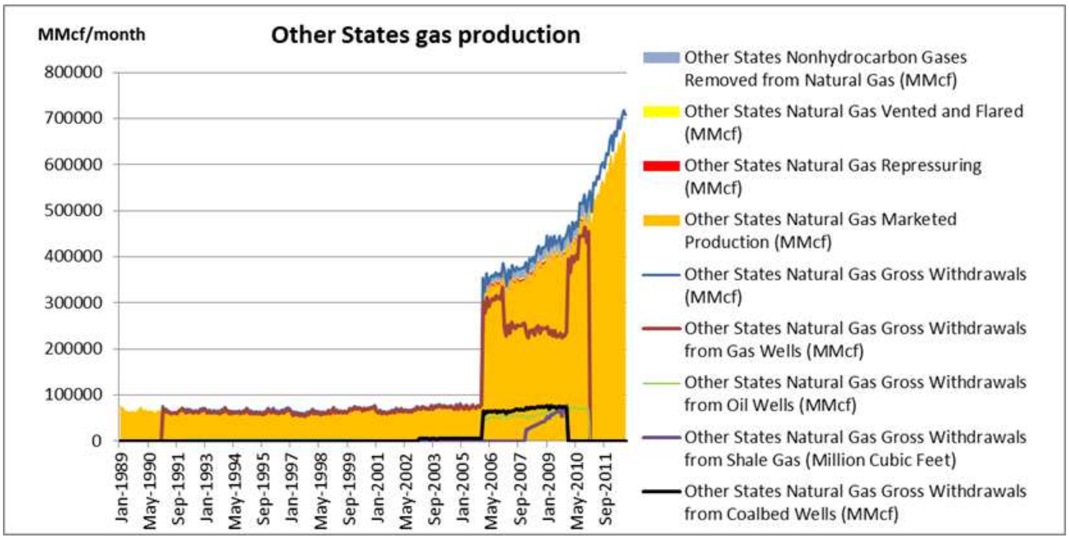
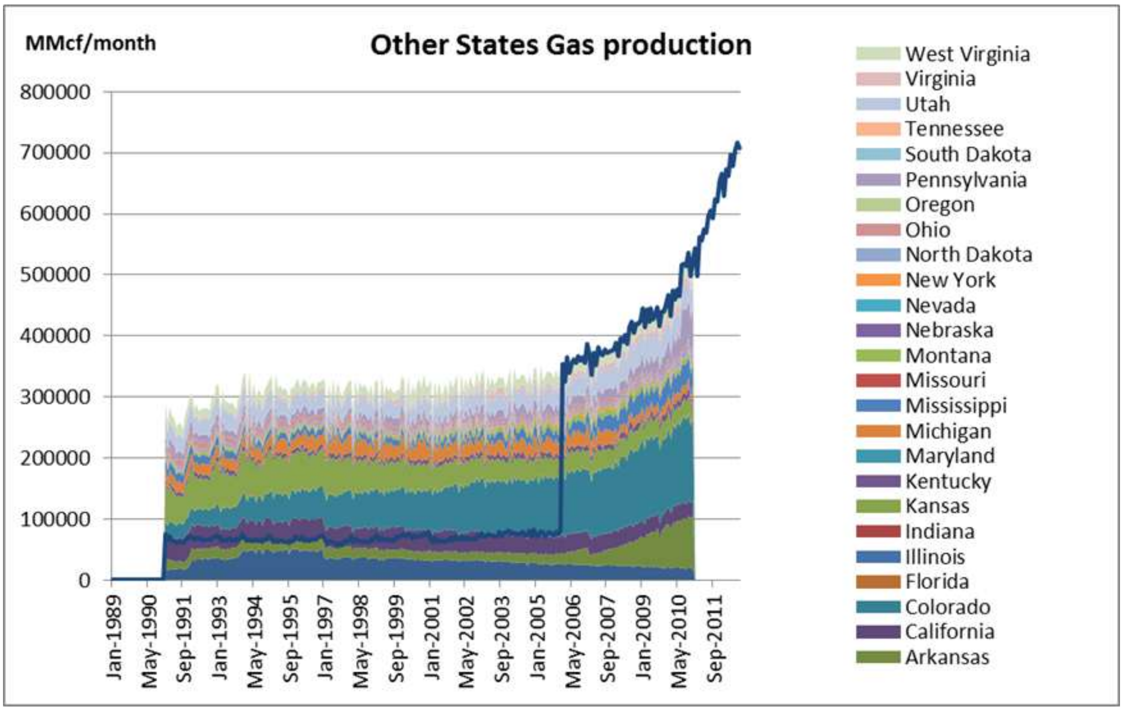



**Figure 149: Natural gas production in "other states" according to US-EIA**




Colorado

**Figure 150: Natural gas production from the major shale gas plays in the USA according to various sources (TRRC, Labyrinth Consulting)**

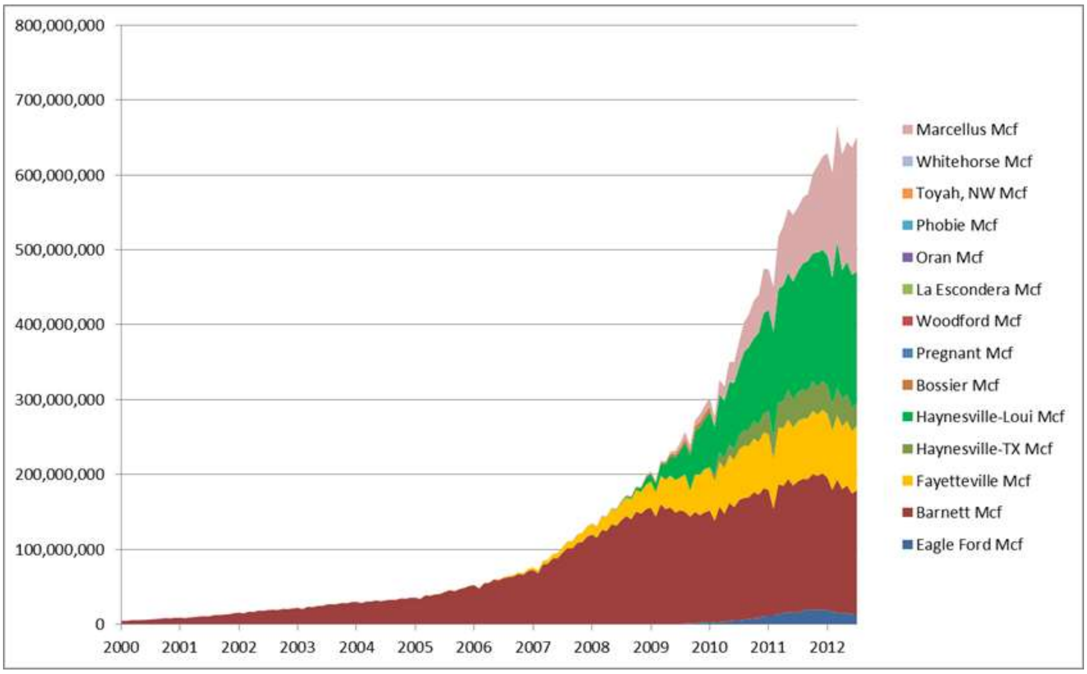



**Figure 151: Natural gas production in the USA with the individual contributions from conventional onshore, conventional offshore, tight gas, coalbed methane and shale gas**

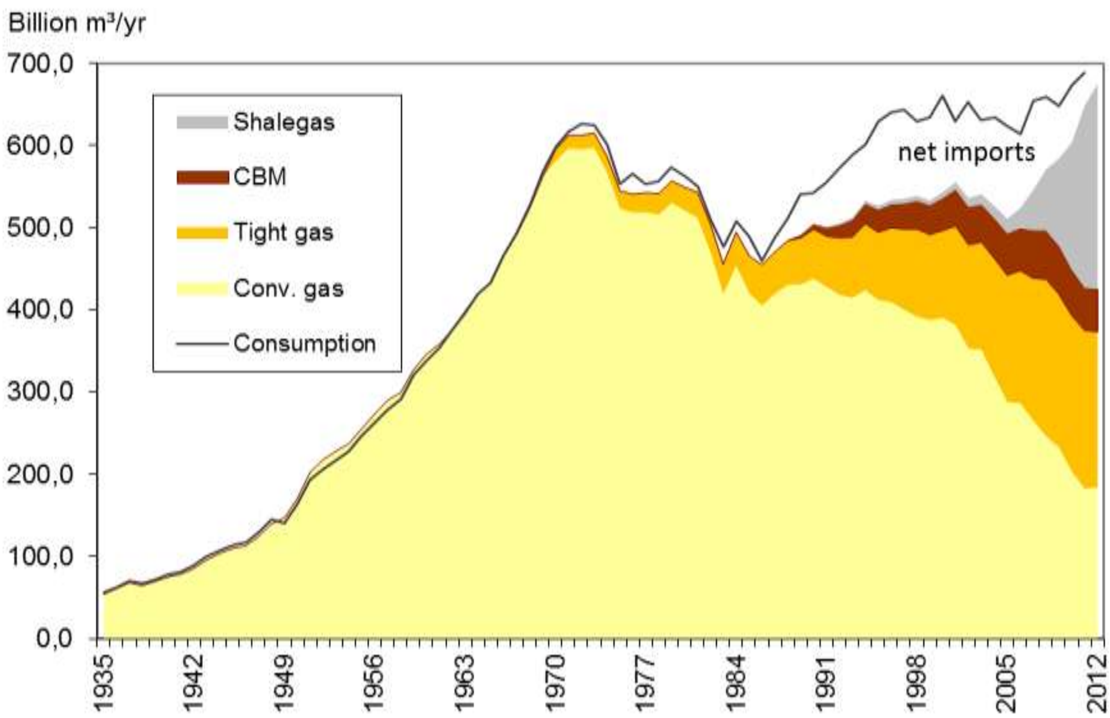
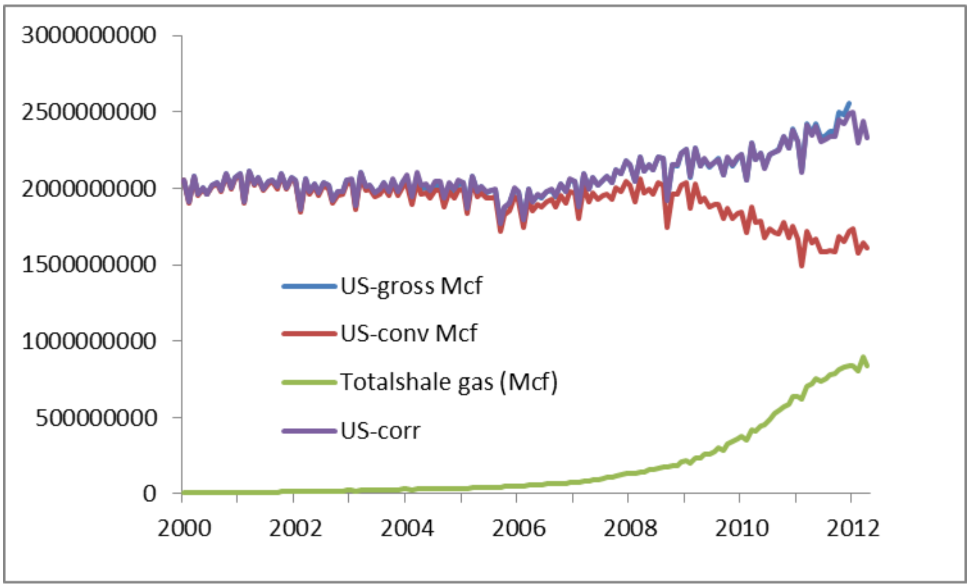


**Figure 152: Domestic US gas production distinguishing conventional (including CBM and tight gas) and shale gas production.**




### *US natural gas production scenario*

**Figure 153: Production scenario for coalbed methane**

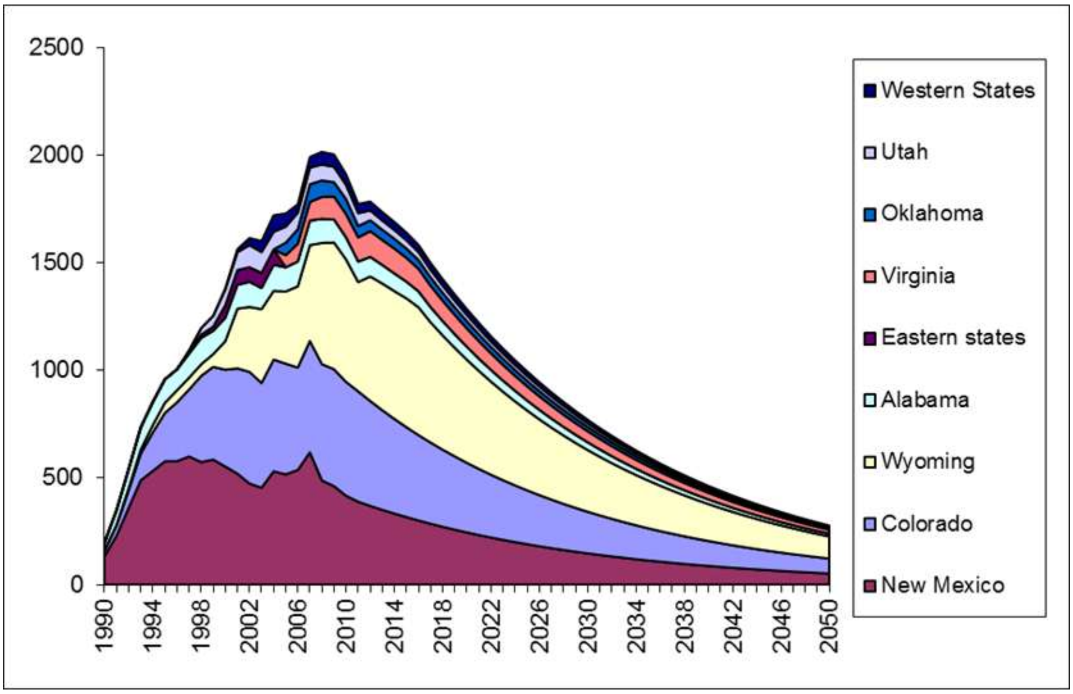


**Table 4: Changing estimates of dry gas resources in the USA (US-EIA)**

| Year | 2000 | 2005 | 2011 | 2012 |
|---|---|---|---|---|
| Proved reserves | 167 | 187 | 245 | 273 |
| Resources | 703 | 631 | 703 | 632 |
| Additional | | | | |
| - Alaska | 257 | 257 | 282 | 272 |
| - Shale gas | 52 | 86 | 826 | 482 |
| - CBM | 55 | 80 | 117 | 122 |
| - Tight gas | 270 | 321 | 369 | 423 |

**Figure 154: US dry gas resources according to US-EIA**

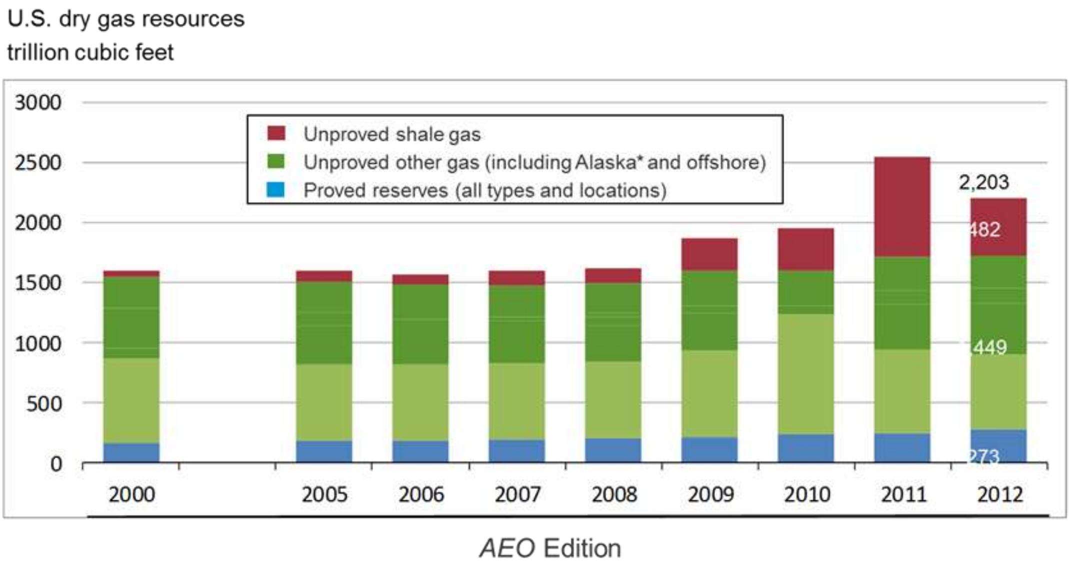


**Figure 155: Development of natural gas production from shale gas deposits in the USA (high case)**

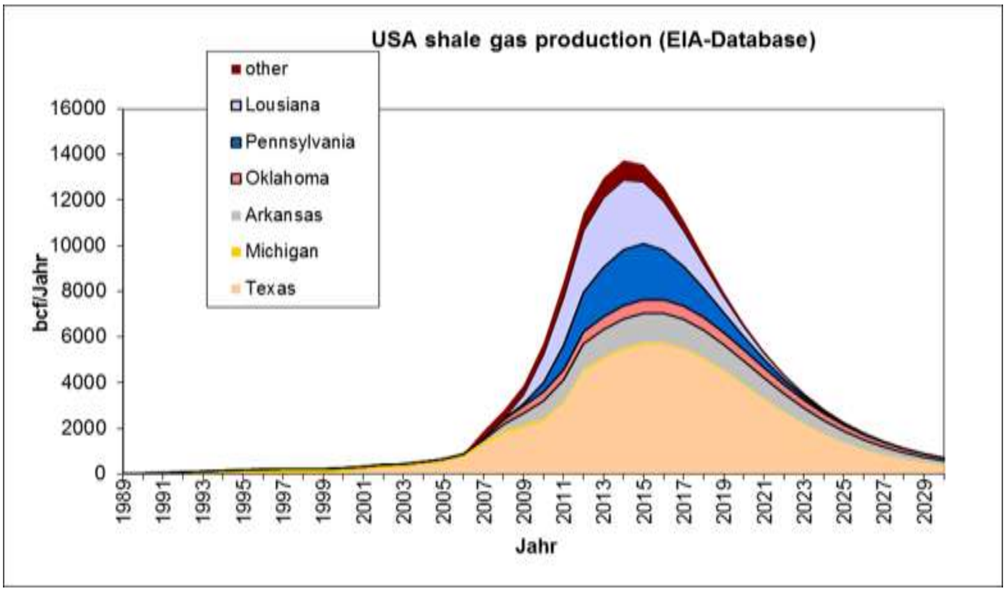



**Figure 156: Scenario calculations 2030 based on US-EIA and regional data for Texas, Louisiana (Haynesville) and Arkansas (Fayetteville) and other (Marcellus) including monthly data until September 2012**

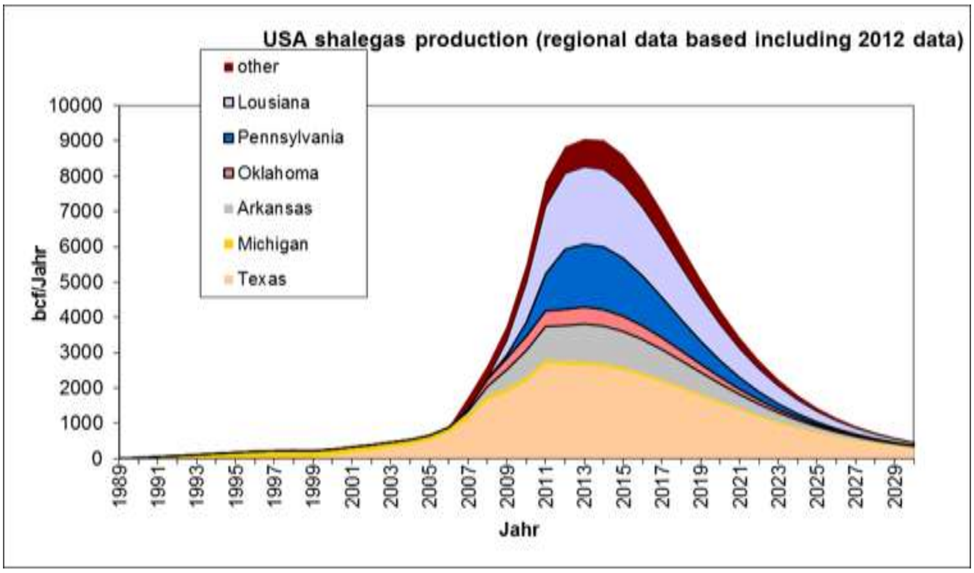


**Figure 157: US Gas production and scenario based on official data (US-EIA Jan 2013)**

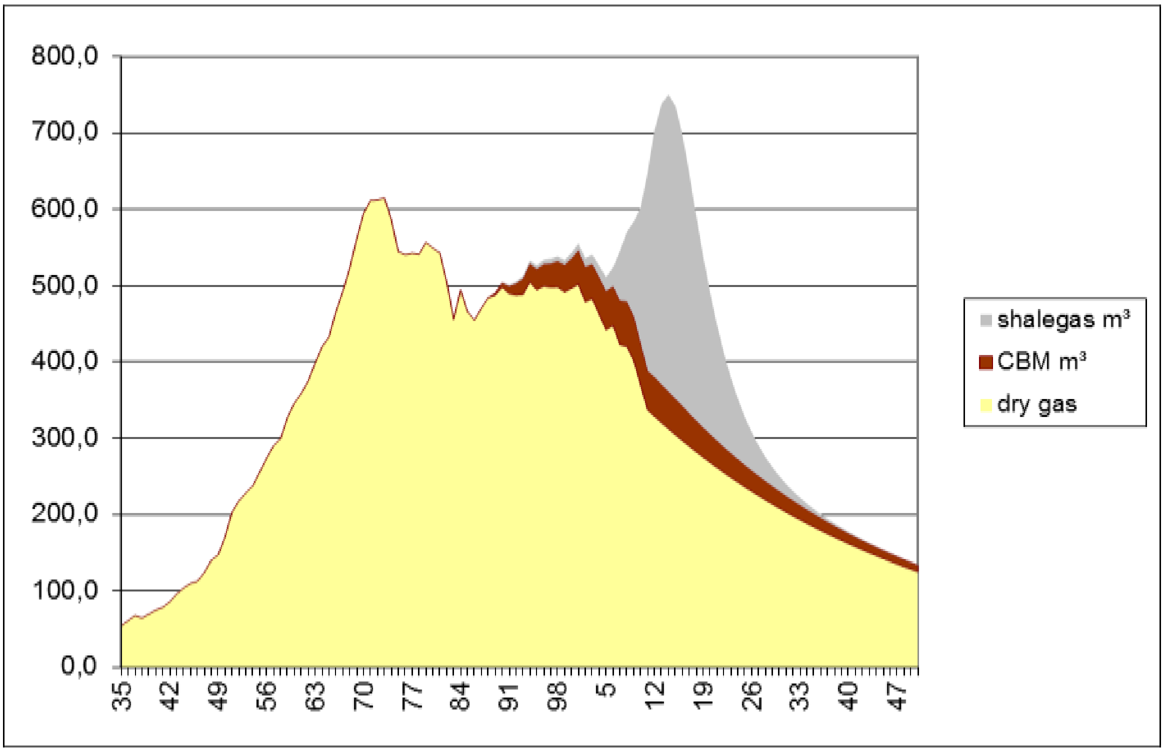
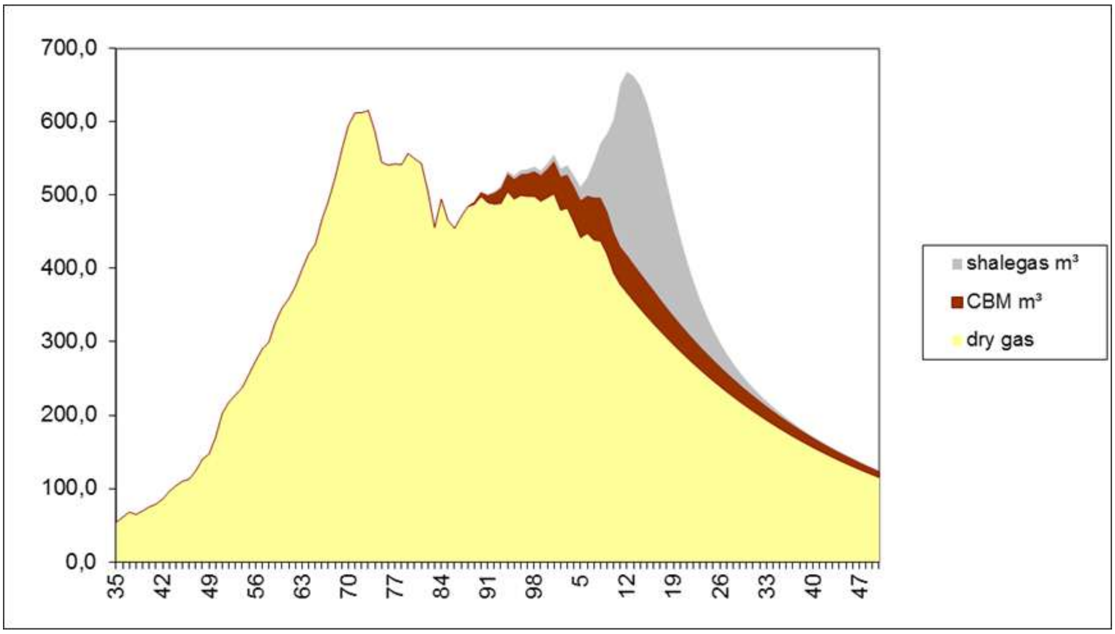


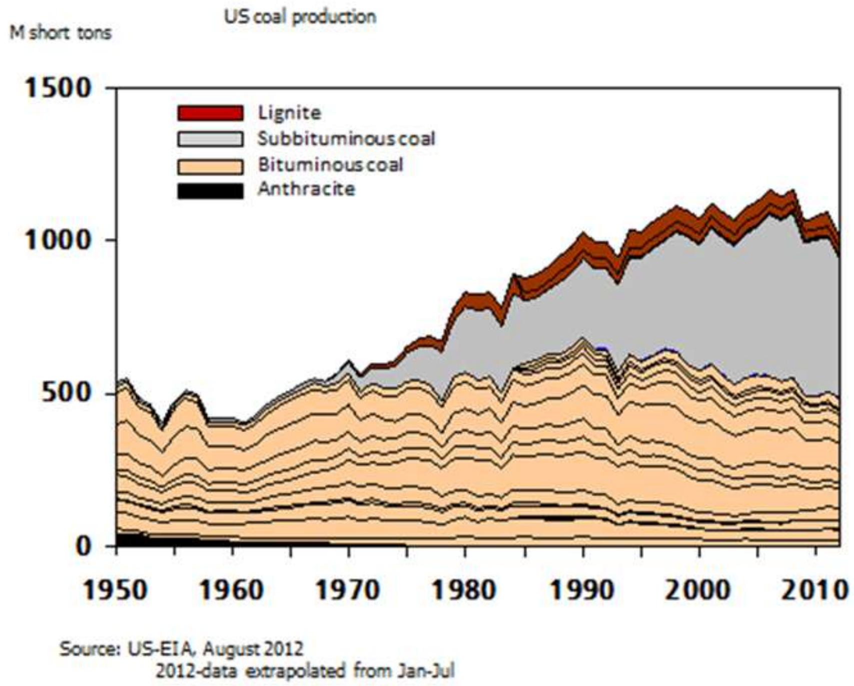

**Figure 158: US Gas production and scenario based on shale gas data by Texas RRC; Other data from US-EIA**



## Coal production in the USA

### US historical coal production

**Figure 159: US coal production by state (US-EIA 2013)**




### Labour productivity in coal mining

**Figure 160: Labour productivity in various federal states in USA (i)**

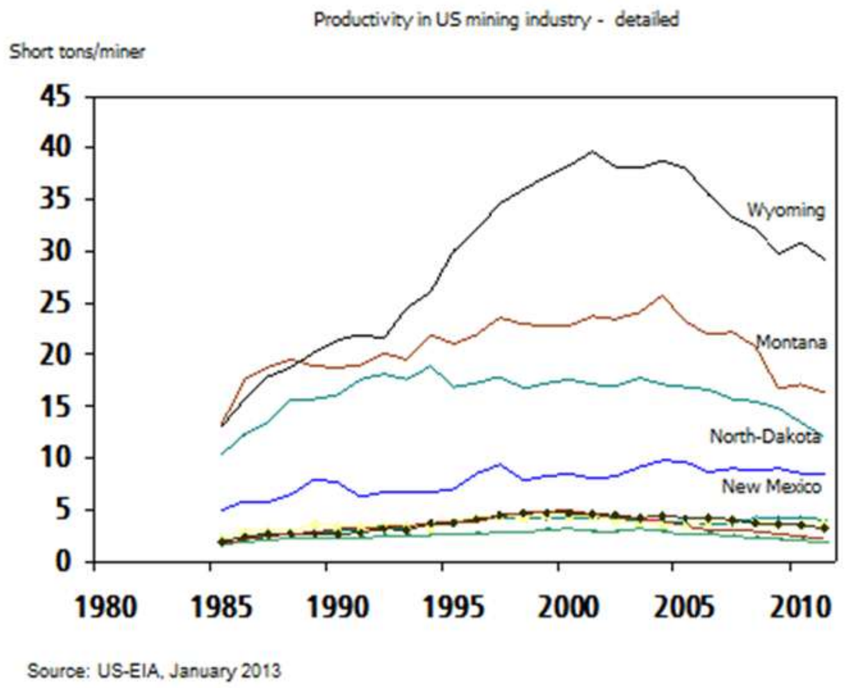
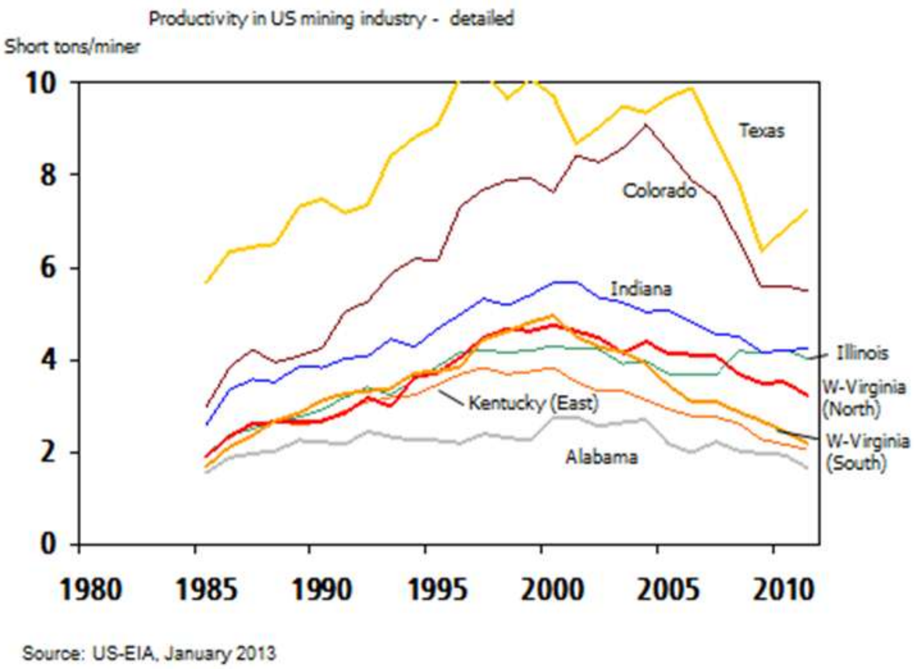


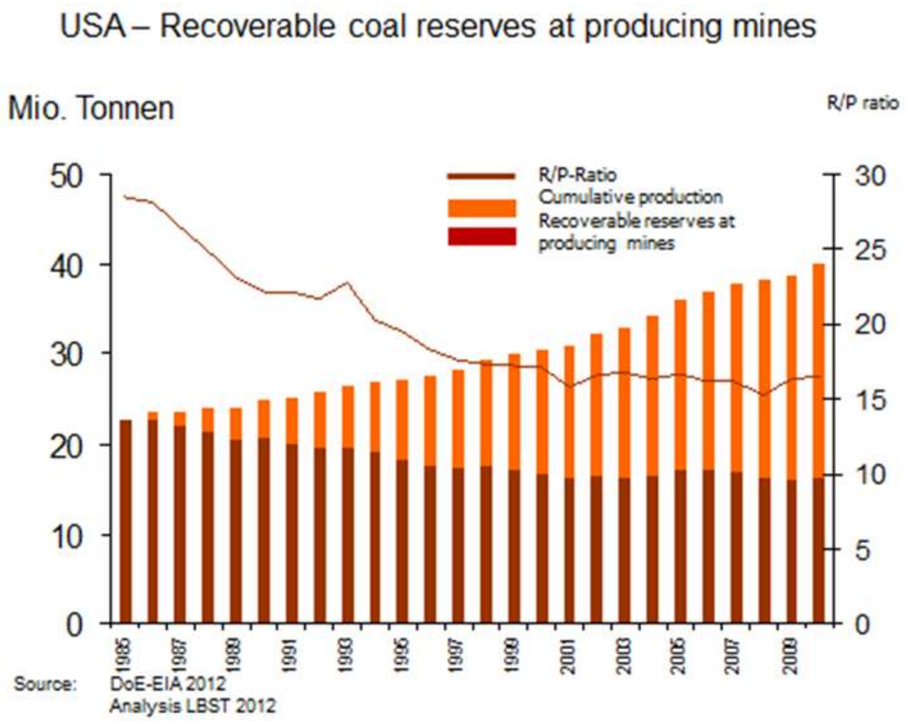
**Figure 161: Labour productivity in various federal states in USA (ii)**




***Development of US coal reserves***

Reserve decline base production , through all states

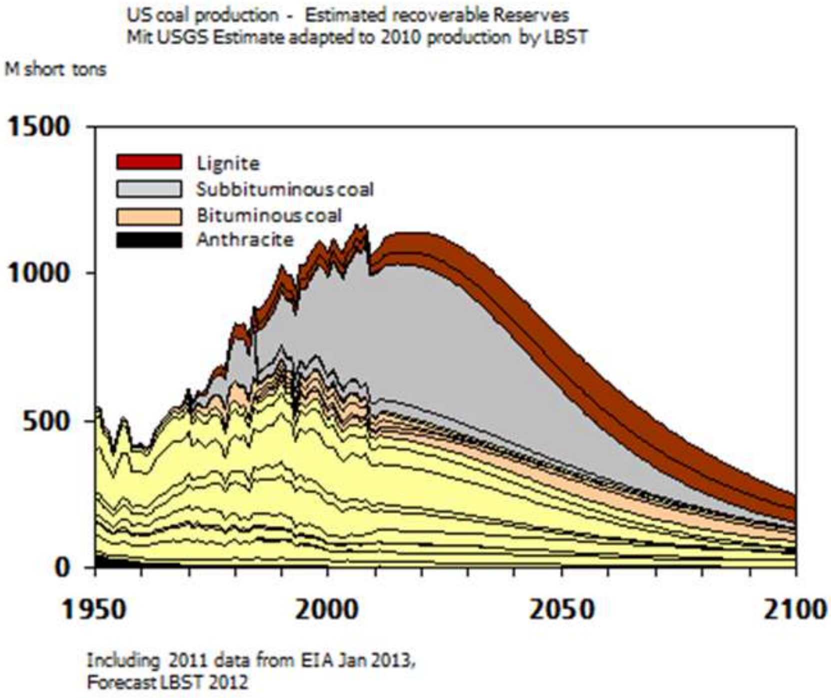
**Figure 162: Development of recoverable coal reserves at producing mines and cumulative production (US-EIA 2013)**




***US coal production scenario***

Production scenario including all states

**Figure 163: Production scenario of coal in USA**




## ***Uranium production in the USA***

The following data on uranium production and resources in the USA are shown in order to demonstrate that reasonably assured resources are by no means 'assured'. As Figure 164 and Figure 165 show, the reasonably assured resources and the inferred resources increased as long as uranium production increased. However, when production declined in 1981 considerably, inferred resources were reduced to zero, while reasonably assured resources were considerably downward revised.

The production decline was due to the closure of many small uranium mines, either for environmental reasons and/or for legal easons as soon as Native Americans did no longer allow for uranium mining at their territories. Figure 166 shows the locations of the many closed mines.

Today, only two mines are still operating in the US. Figure 167 shows the historical uranium production and various projections based on different resource classes of RAR and IR.

**Figure 164: Uranium resources of USA according to various edition of the red book (IAEA/NEA)**

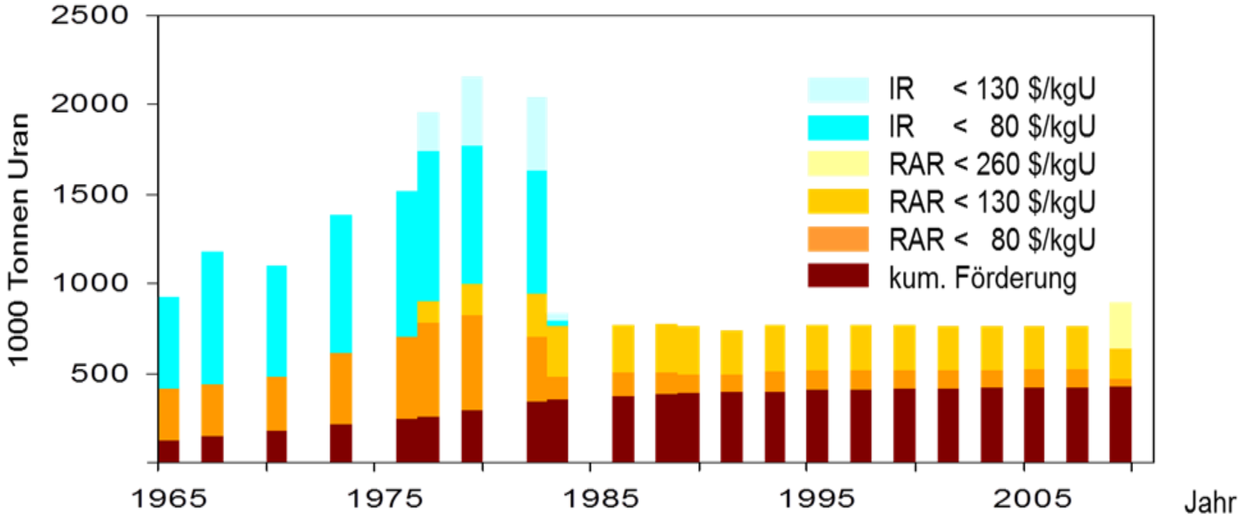



**Figure 165: Uranium production in the USA (IAEA/NEA various editions)**

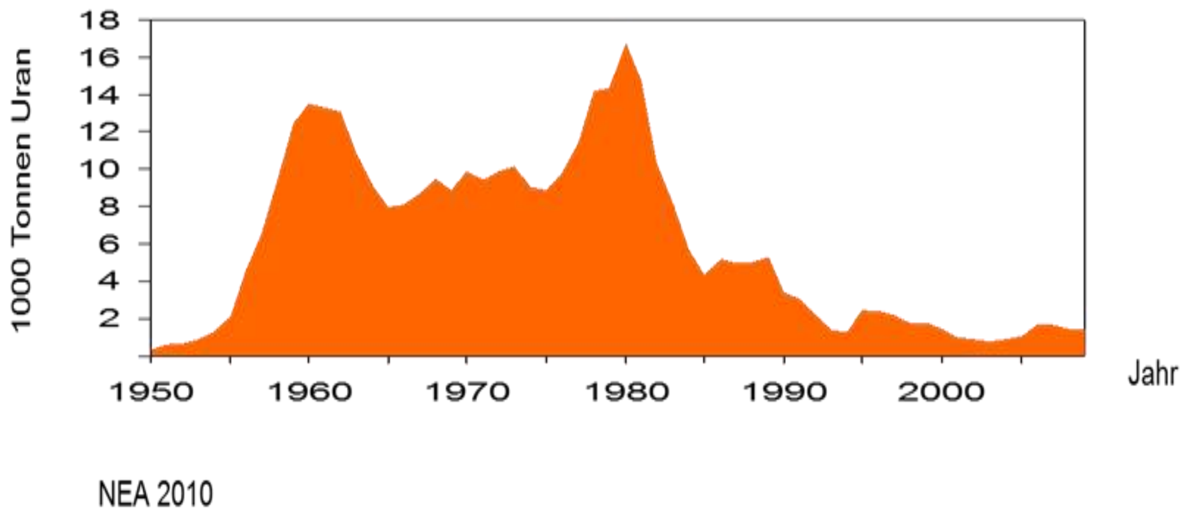


**Figure 166: Location of closed uranium mines in the USA (Source: www.wise-uranium.org)**

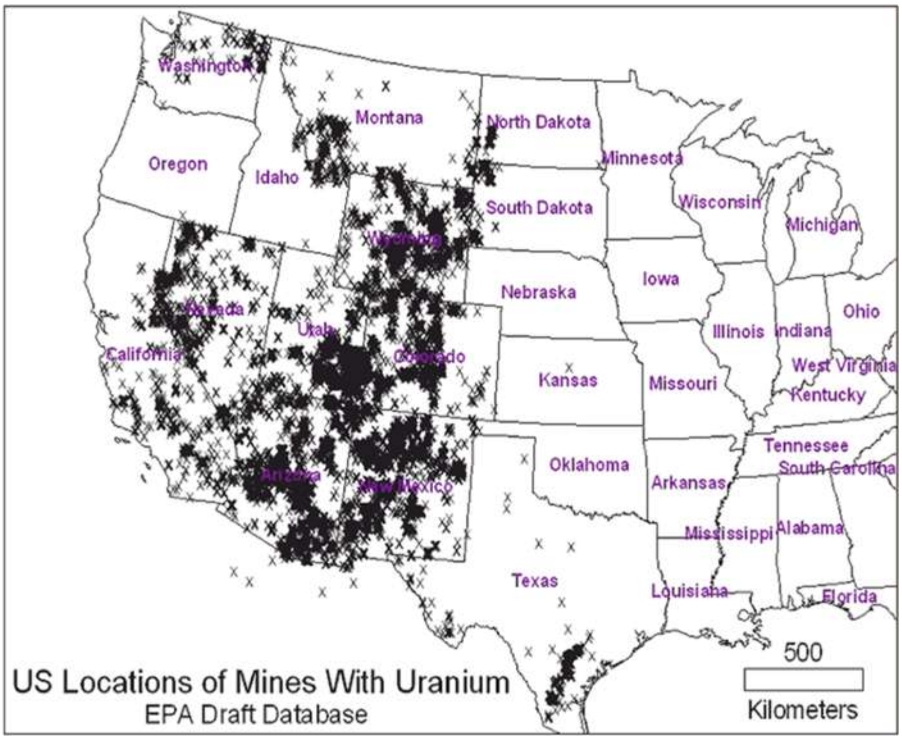
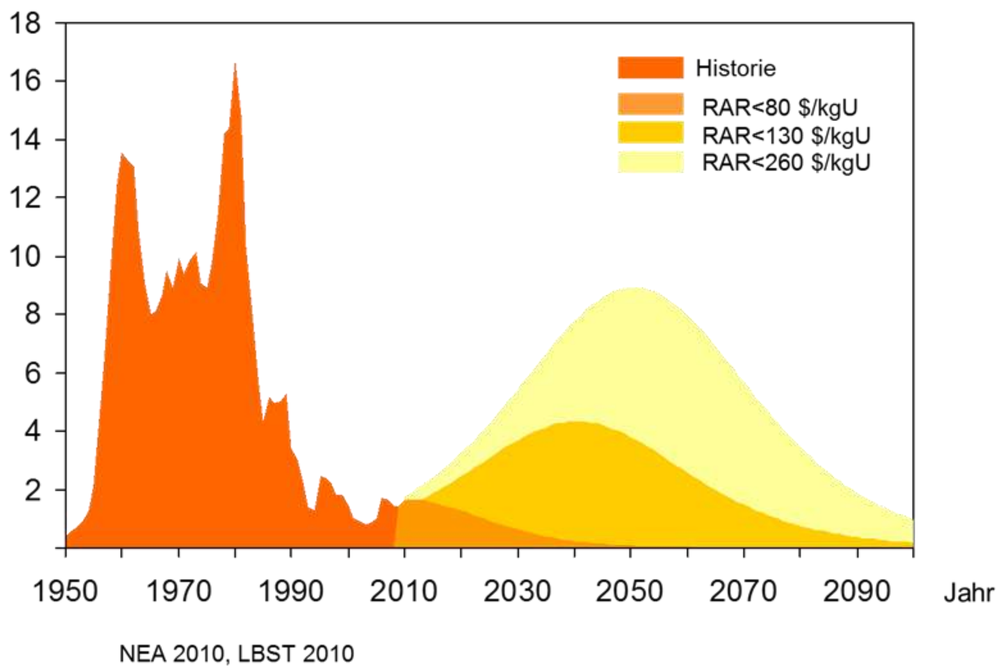



**Figure 167: Various production senarios of uranium in the USA based on different classes of resources**



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