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LONG TERM PROSPECTS FOR FOSSIL FUEL PRICES

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Preface

ECN Policy Studies and EEM Consult BV have carried out the present study under a contract of VROM, i.e. the Dutch Ministry of Housing, Spatial Planning and Environment. The ECN project number is 7198. Several external experts were interviewed and provided useful insights. The authors like to acknowledge explicitly the valuable comments made by Prof. P.R. Odell (professor emeritus of Erasmus University Rotterdam) and Prof. J.A. van der Linde (Department of Economics, University of Amsterdam, Department of International Economic Affairs, State University of Leiden) on a previous draft. Nonetheless, the sole responsibility for the contents of the present report rests with the authors. It is to enable VROM to gain insight in the most adverse impact possible on fossil fuel prices of global implementation of CO_2 reduction policies.

Abstract

The present report analyses the present supply costs and considers the price prospects in Europe of fossil fuels over the coming 25 years. Projections of minimum required prices are made on the basis of a review of existing literature. Incremental supply curves have been derived for oil, gas and coal respectively. In fact, these provide a lower bound for projections of market prices at the demand levels considered. Estimates are presented of the resource base and the production costs of oil, gas and coal respectively. At the request of VROM, incremental supply curves for oil, gas and coal have been matched with two specific demand scenarios prepared by IPCC in 1992, i.e. IS92a and IS92c.

Oil is a strategically important commodity. Border prices of crude are not only determined by the marginal production costs to meet present demand from the cheapest sources available, but do also reflect importantly the priority given by importing countries to diversify sources of supply. This is a main reason why oil prices reflect the relatively high costs to produce and transport oil from remote (Alaska) and offshore (North Sea) areas to the market place, as compared to oil originating from vast low-cost Middle East oil reserves. To some extent, this is also applicable to natural gas, be it that transport costs have a much more pronounced bearing on the price formation of natural gas. Compared to oil and gas, coal has an enormous resource base and many sources of supply. Therefore, under varying demand conditions the market price of seaborne coal tends to be more stable and closer to minimum required price levels than is the case with oil and gas.

Projections of minimum required prices in terms of marginal costs for oil and gas under the two distinct IPCC scenarios considered differ considerably, reflecting large differences in demand projections for these fossil fuels. As already set out above, the price differences for coal are envisaged to be more moderate.

CONTENTS

SUMMARY

ECN Policy Studies and EEM Consult BV have analysed the long term prospects of fossil fuel prices on behalf of VROM, the Dutch Ministry of Housing, Spatial Planning and Environment.

Current policies to reduce the amount of CO_2 emissions are, to a large extent, determined by the great scientific uncertainties related to the climate change issue. One of the questions to be answered is the most probable development of fossil fuel prices under various future energy demand projections. This study presents an overview of global fossil fuel reserves by region and of the costs to produce fossil fuels and to bring them on the market. Moreover, it broadly analyses technological and other factors that hitherto have shaped the development of production and transport costs of oil, gas and coal to a major extent. Minimum required future fossil fuel prices are presented by way of supply curves. These curves are combined with two energy demand scenarios, IS92c and IS92a, of the Intergovernmental Panel on Climate Change (IPCC) for the year 2020, resulting in two sets of minimum required prices of oil, gas and coal corresponding to the two scenarios.

With respect to oil it can be concluded that proved oil reserves could fuel the world economy for at least 40 years, based on the current level of oil demand. If unconventional resources are taken into account, this period of time could be extended considerably. Industrialised countries seek ways to diversify their energy systems in order to minimize dependence on Middle Eastern oil. It is commonly assumed that the main oil exporting countries in the Middle East and oil consuming countries have different interests. However, some major Middle Eastern swing producers - Saudi Arabia and Kuwait - have a strong alliance with the USA. The USA is highly dependent on oil from this vulnerable region and, therefore, the U.S. government tries to control production. Middle Eastern countries are keen to stabilize their income from oil at a reasonably high level. Moreover, OPEC countries and other oil producing countries are becoming more and more dependent on western oil companies for technology and investment resources. All in all, both major oil consuming countries and oil producing countries seem to have a common interest in stimulating oil production, meanwhile maintaining the oil price at level that will just permit high cost producers to stay in business.

Reserves of conventional and unconventional gas in the world are large in proportion to current demand; the Reserve/Production (R/P) ratio for proven reserves is currently some 65 years. Depletion effects are not likely to determine gas prices to a large extent within the next decades. It should be noted, however, that supply of gas will come more and more from remote locations that are hard to access (Yamal, Siberia). Oil and gas prices have been rather close over de last decades per unit of calorific value. Although worldwide there is scope for enlarged gas production, international gas prices much lower than oil (product) prices do not seem probable. Rather it is likely that a premium on the gas price over the oil price will evolve.

Reserves of coal are huge compared to those of oil and gas. The demand for coal is rather stable. Coal prices are stable too, based on 'cost-plus' pricing. In case of a substantial growth of coal demand, additional demand could be met by increased production in the main producing and exporting areas. One has to consider some

upward trend in coal prices in that case, due to a shift toward more remote and deep coal reserves.

At the request of VROM two energy demand scenarios developed by IPCC, i.e. scenarios IS92a and IS92c, are considered. Business-as-usual scenario IS92a presumes a solid growth of oil, gas, and coal demand. Annual demand for oil would be 25% higher in year 2020 as compared to year 1990. Scenario IS92c, interpreted for the purposes of the present study as an enhanced environmental policy scenario, projects much lower demand levels for fossil fuels. The price projections for year 2020 under these two scenarios will be set out below.

The minimum required cost approach assumes that oil will be procured from the sources that are cheapest from a global economic perspective. From this point of view economic rents can be considered as transfers and would not denote real costs. Furthermore, also user costs (making allowance for the option value of using a depletable energy source as compared to use of the next-best alternative source) are disregarded. This is in line with the prevailing perception and actual treatment of the whole government take including user charges as a negotiable windfall profit to host governments rather than as a provision to secure energy supplies for the future world population. The following minimum required prices CIF Western Europe, expressed in US$ of year 1993, are projected for year 2020:

Fuel	Scenario	Price range			
Oil	IS92a	$/b	12-20	$/GJ	2.1-3.5
	IS92c	$/b	8-12	$/GJ	1.4-2.1
Gas	IS92a	$/mbtu	4.5-5.0	$/GJ	4.8-9.3
	IS92c	$/mbtu	3.0-3.5	$/GJ	3.2-3.7
Coal	IS92a	$/t	55	$/GJ	2.1
	IS92c	$/t	47	$/GJ	1.8

In the wake of the second world oil price hike after the Iranian revolution energy price projections of most energy analysts working on behalf of international bodies, such as IEA, World Bank, and IIASA have tended to overshoot price market price realisations by far. Yet, in reaction in the current low oil price era it has become quite fashionable for official energy analysts to assume that the long-term trend for future market prices will be closely in line with minimum required prices. In addition, recent technological advances have aroused huge optimism on the sustainability of technological advances at the current rate. As further explained in chapter 6, the authors of the present report take issue with current main-stream low energy price projections and envisage that quite some divergence will occur between minimum required prices and market prices, especially for oil and gas. The following market price ranges for fossil fuels are projected for Western Europe:

Fuel	Scenario	Price range			
Oil	IS92a	$/b	25-35	$/GJ	4.4-6.1
	IS92c	$/b	18-22	$/GJ	3.2-3.9
Gas	IS92a	$/mbtu	5-7	$/GJ	5.2-7.4
	IS92c	$/mbtu	4-5.5	$/GJ	4.2-5.9
Coal	IS92a	$/t	65-90	$/GJ	2.5-3.4
	IS92c	$/t	45-50	$/GJ	1.7-1.9

1. BACKGROUND

Current policies to reduce the amount of CO_2 emissions are, to a large extent, determined by the great scientific uncertainties related to the climate change issue. These uncertainties are perceived differently by national governments and, consequently, different criteria are being applied by the various countries for CO_2 reduction policy. So far, the CO_2 reduction policies in the Netherlands can be characterized as risk-avoiding. These were mainly based on the 'no regrets' principle. The emphasis was put on those measures that were economically viable and, at the same time, would result in a reduction of CO_2 emissions.

However, most of the 'no regrets' measures have already been implemented. The potential of 'no regrets' still to be implemented is not sufficient to achieve CO_2 reduction goals. Additional measures, possibly less cost-effective, are needed. This requires a new policy framework which incorporates explicitly the uncertainties associated to the climate change issue. For this reason the Ministry of Housing, Spacial planning and Environment (VROM)[1], Directorate General Environment, has initiated a research programme entitled 'Strategy CO_2 Reduction Policy'. The programme consists of a number of studies aiming at the development of new methodology to determine the strategic orientation for CO_2 reduction policy. The new methodology should incorporate the uncertainties related to the climate change issue in order to be able to express this issue in terms of probabilities rather than uncertainties. The programme encompasses the following studies:

- hedging against climate change;
- long term prospects for fossil fuel prices;
- the global potential for joint implementation; and
- the probability of climate change.

This report concerns the study on long term prices of fossil fuels. Since the 1980s, projections of future prices of oil, coal and gas often had to be scaled down. Currently, a widely held opinion is that at best energy prices will vacillate around current depressed levels for a considerable period of time but may just as well go down further in real terms (i.e. after having made allowance for general price inflation). Yet low energy prices affect the cost-effectiveness of energy conservation measures in a strongly negative way and may seriously hamper the implementation of CO_2 reduction policy as a result. The risks of low fossil fuel prices facing policy making with regard to CO_2 reduction constitute a major reason for the Ministry of VROM to initiate a study on long term prospects for fossil fuel prices. In considering these price prospects, the Ministry of VROM has requested the authors to approach the issues concerned from a perspective of long-run marginal cost analysis. Hence, encuing analysis sets out to project 'required prices', that evolve form a perspective of long-run marginal cost analysis. It should be emphasized that because of factors relating to politics and market organisation 'market prices' may be appreciably higher at times than the long-run marginal costs.

The present study sets out to provide insight into the main factors underlying future price developments for fossil fuels. More specific objectives of the study are:

[1] See Annex A for abbreviations.

- to present an overview of global fossil fuel reserves by region and to depict their extraction costs by way of supply curves;
- to broadly analyse technological and other factors that hitherto have shaped the development of extraction and transport costs of oil, gas and coal to a major extent;
- to consider the long-run costs of fossil fuels over a time horizon till the year 2020 under two scenarios, namely the scenarios IS92a and IS92c[2] of the Intergovernmental Panel on Climate Change (IPCC) [1].

This study is based on a survey of existing literature. The literature survey has been complemented by valuable consultations with reputed specialists. Two experts consulted have provided detailed comments and have been acknowledged in the preface of this study. Given the objectives of the study, the resources available were modest. Consequently, in spite of the efforts put in being larger than foreseen, not all aspects could be dealt with at depth. Nonetheless, great care has been taken to derive the report's main findings.

The contents of this report can be outlined along the following lines. Chapter 2 provides an overview of the research approach. Chapters 3, 4 and 5 provide detailed specification of the various production cost components, price formation and reserves of oil, gas and coal respectively. In chapter 6, the final chapter, results are presented of price projections based on the two IPCC energy demand scenarios.

The study has been conducted by the Netherlands Energy Research Foundation (ECN) and EEM Consult BV, ECN being the leading institute. EEM Consult has drafted the chapter on oil. ECN has prepared the remaining chapters.

[2] The latter objective was added to the original terms of reference of the study.

2. REMARKS ON STUDY APPROACH

2.1 Introduction

This chapter briefly explains some major methodological aspects. First, some common energy units are set out in section 2.2. Next, section 2.3 presents some notions of fossil fuel reserves. Some distinct aspects of oil, gas and coal with regard to price setting are addressed in section 2.4. Section 2.5 gives an overview of current global energy demand with special reference to the use of fossil fuels. Finally, in section 2.6 an overview is presented of the 1992 scenarios of the IPCC, two of which at the request of the Ministry of VROM have been used as reference for this study.

2.2 Time horizon

The authors have been requested to analyze long run prospects for fossil fuel prices from a perspective nof long-run marginal costs. Given the great uncertainties surrounding e.g. economic prospects for energy conservation and renewable energy, the factual basis for an outlook beyond 25 year ahead is considered too small to be justifiable for the purpose of policy design. Hence a time horizon up to the year 2020 has been considered in this study. If a more detailed data base would have been available, the results of the study could have been applicable to a more distant time horizon.

2.3 Energy units

A plethora of energy quantity numéraires are used for specifying reserves, production and consumption at aggregated level as well as for price quotations at micro level. This situation is quite confusing. A lot of researchers in continental Europe use Standard International units. Yet this convention does not alleviate the confusing situation because of the simple fact that this convention is not widely adhered to (e.g. not in the USA).

For example, in the distinct fossil fuel production and distribution industries adoption of SI units is not a common practice in the world at large and even not in continental Europe. Nor do international bodies such as World Bank and the Paris-based International Energy Agency (IEA) consistently adopt SI units. This report adopts a practical approach. Those energy units are used that are most widely adopted in the energy industry considered. In the remainder of this section an overview is given of some very common energy units and approximate conversion factors. It is emphasized that these are average conversion factors, as - at times wide - differences by fossil fuel reservoir occur.

The most common unit of account for energy quantities when expressing energy quantities from different sources is Mtoe (million tonnes of oil equivalent) at macro level. This unit is currently used by trend-setting agencies such as World Bank and IEA. Alternative, multiples of the SI unit J (Joule) can be used, e.g. TJ (= 10^{12} J), PJ

(= 10^{15} J) or EJ (= 10^{18} J). The following approximate conversion factors hold for widely used specific units for aggregate quantities per period are shown in Table 2.1.

Table 2.1 *Selected conversion factors for energy units to Mtoe/y and TJ/y*

Energy industry			
Oil industry	mb/d[1]	49.8 Mtoe/y[2]	2.085 EJ/y
Gas industry	mbtu[3]	0.0252 toe	1.055 GJ
	bcm/y[4]	0.9076 Mtoe/y	38.0 PJ/y
	bcf/y[5]	0.0257 Mtoe/y	1.076 PJ/y
Coal industry	tonne[6]	0.63 toe	26.4 GJ
	tce[7]	0.7 toe	29.31 GJ
	mt/y	0.63 Mtoe/y	26.4 PJ/y
	mtce/y	0.7 Mtoe/y	29.31 PJ/y

[1] mb/d = million barrels (b or bbl) per day.
[2] Mtoe/y = million tonne of oil equivalent (toe) per year.
[3] mbtu = million btu (British Thermal Unit).
[4] bcm/y = billion cubic meter per year.
[5] bcf/y = billion cubic foot per year.
[6] metric ton of coal, used as reference in this study.
[7] tce = tonne of coal equivalent.

Energy quantity units used in this study tend to adhere to common practice for the energy industry concerned. In order to facilitate comparison between the different energy carriers, most figures presented on energy quantities have Y-axes both in a unit, common for the energy industry concerned and in an SI unit.

2.4 Some notions of fossil fuel reserves

It is useful to throw some light on some concepts of fossil fuel reserves, that are frequently used (explicitly or tacitly). Identified and unidentified reserves, in addition to cumulative production, make up the *ultimate resources*. The following classification of reserves can be made according to CEDIGAZ [2]:

- *Proved reserves:* correspond to discoveries of which the production is reasonably feasible under current economic and technical conditions. These reserves are located in thoroughly explored reservoirs, already equipped to produce or now being equipped.
- *Probable reserves:* correspond to discovered reserves exhibiting a good probability of being produced in economic and technical conditions similar to those of proved reserves. These are measured roughly. The reservoirs are not (yet) equipped to produce.
- *Possible reserves:* correspond to identified reservoirs, but of which identification is tentative, in undrilled zones adjacent to proved or probable geological reservoirs. The assessment of these reserves inevitably relies on assumptions of geometry and impregnation of these reservoirs.
- *Potential resources:* correspond to unidentified resources. This class denotes a more hypothetical class of resources.

A wealth of publications on ultimately recoverable fossil fuel resources with a wide variation of estimates exists (see e.g. WRR report [3]). As distinct from the coal industry, the oil and gas industries have less reliable data on resources still to be discovered. Oil and gas reservoirs are mostly small compared to coalfields. Their inventories cannot generally be assessed with much precision before a reasonable period of production. Moreover, exploration tends to be more costly for oil and gas than for coal. However, the locations of sedimentary rocks of interest for oil and gas are largely known, although not always in detail. Assuming the potential in unexplored areas is just as good as it has proved to be in highly explored areas, the world's ultimately recoverable resources of oil and gas can be roughly estimated. The various estimates differ by a factor of three or four. Part of the uncertainty lies in the percentage of oil and gas regarded as recoverable from already discovered reservoirs [4].

2.5 Incremental supply curves for oil, gas, and coal

Four major aspects justify a distinct treatment of oil, gas, and coal developments:
- differences in certainty of ultimately recoverable resources;
- differences in proven reserves;
- differences in upfront investment costs for development and transportation; and
- differences in per unit cost of transportation.

The first aspect has already been addressed in the preceding section. As for the second aspect, the next three chapters will exhibit that coal and, if to a much lesser extent, natural gas have an appreciably larger resource base in relation to current annual production than oil. Consequently, the depletion outlook at global level varies widely.

Upfront investment costs for development and transportation are the highest by far for gas and the lowest for coal, though transport costs for coal are generally higher than for oil. Because of the high upfront investment costs to open up oil and gas fields and to transport gas, discrete investment decisions and political factors in importing and exporting nations play a major role in resource availability and price setting for oil and gas rather than for coal. This aspect is reinforced by disparities in the resource base throughout the world as far as oil and gas is concerned.

Transport cost play a modest role in the determination of the oil price. These costs can be roughly put at 1$/b to 1.5 $/b, i.e. a modest fraction of the total cost in major oil consuming countries. For coal and, even much more so, for gas the picture is quite different. Especially for gas the relatively high transport costs, which in some instances makes up 50% of total costs, preclude the existence of a genuine global market.

All in all, these are compelling reasons to make a distinct analysis of the outlook for the oil, gas and coal markets. Moreover, the authors consider the aggregation of fossil fuel reserves in terms of carbon content in the form of a supply curve a concept that may seem attractive for reasons of energy and environmental policy, but untenable from the perspective of scientific uncertainties. These uncertainties not only concern the size of (ultimate) resources of each of the fossil fuels, but also the costs that have to be incurred for exploration, development and production of the various fossil fuel reserves, and the subsequent costs to bring them on the market (transport costs).

The authors set out to derive incremental supply curves for oil, gas and coal based on 'required price' estimates from a survey of available literature. In some cases these supply curves are specific for Western Europe: sometimes the import demand from main exporting regions is used as reference (coal), in another case the incremental demand compared to current contract obligations is the reference (natural gas). However, taking into account some specifics of the international markets of oil, gas and coal, the supply curves and resulting prices for oil, gas, and coal can provide useful indications of the development of fossil fuel prices in the rest of the world.

2.6 World energy consumption

Historical trends in the use of various types of energy

At the beginning of the nineteenth century, fuelwood, agricultural wastes and wind and water power supplied most of the energy in addition to animal and human muscle power. The replacement of energy sources during the last 150 years is a remarkably gradual process, that can be captured to a major extent by a sequence of logistic curves [5]. The share of coal started to rise during the second half of the last century, and attained its saturation level around the year 1920. A rapid expansion of oil consumption can be noticed since the beginning of the century, ultimately resulting in an oil share exceeding that of coal by the year 1970.

Current energy consumption

In 1993, world consumption of commercial energy amounted to some 7,850 Mtoe. Table 2.2 presents the use of fossil fuels and others (nuclear and hydro) in 1993 by region, based on 'BP statistical review of world energy' [6,7].

Non-commercial energy is not included in Table 2.2 because statistics on these types of energy are not available or of poor quality. However, estimates for world non-commercial energy consumption mentioned in the literature are in the order of magnitude of some 1,100 Mtoe, almost 80% of which is consumed in developing countries.

Table 2.2 clearly shows the large differences in energy use between the regions. In 1993, the OECD member states, comprising only 16% of global population, accounted for nearly 55% of total world energy consumption. The average per capita world energy consumption in 1993 was 1.4 toe, compared to 7.5 toe for North America and 0.8 toe for developing countries. Remarkable differences of energy intensities can be noted between the different economies. In 1990 world average intensity amounted to 428 toe/mln $ of Gross Domestic Production (GDP). For the transition economies this figure was 1,450, and for OECD countries 256.

Table 2.2 *World energy consumption by region and by fuel; 1993 [Mtoe]*

	Oil	Gas	Coal	Other	Total
Developing countries[1]	740	196	856	98	1890
Africa	98	35	77	9	219
Asia[1]	463	100	761	53	1377
Latin America	179	61	18	36	294
Middle East	172	104	5	1	282
Transition economies	328	587	383	92	1390
FSU[2]	272	535	238	74	1119
Other Europe	56	52	145	18	271
OECD	1880	940	899	574	4293
North America	938	610	517	245	2310
Europe	651	259	265	252	1427
Pacific	291	71	117	77	556
Total	3120	1827	2143	765	7855

[1] Excluding Middle East.
[2] Former Soviet Union.

Sources: [6,7]

World primary energy consumption rose from 6,431 Mtoe in the year 1983 to 7,855 Mtoe in 1993, implying an average annual growth of 2% during this decade. It is noteworthy that this growth rate is appreciably lower than in the preceding period from 1945 onward. Since 1990, growth of world energy consumption was attenuated a result of the economic reforms and accompanied economic downturn in Central and Eastern Europe and the economic recession in the OECD countries.

World oil consumption rose by some 1.2% annually during the last decade. The 1993 consumption level amounted to 3,120 Mtoe (63 million b/d). The OECD still accounts for 60% of oil consumption, but the share of developing countries is increasing rapidly and amounted to 29% in 1993.

World consumption of natural gas rose rapidly from 1,330 Mtoe in 1983 to its 1993 level of 1,827 Mtoe, implying an average annual growth rate of 3.2%. Very high growth rates of almost 6% annually were recorded for the Former Soviet Union (FSU) during the 1980s. However, due to the economic reforms and the coinciding collapse of industrial activity, the consumption of natural gas in this region started to fall in 1992. In 1994 gas consumption in the FSU was 17.5% less than in 1991 [7].

Between 1983 and 1992, total world demand for coal rose steadily from 1,918 Mtoe in 1982 to reach its highest level of demand (2,262 Mtoe) in 1989. Thereafter consumption has fallen to 2,143 Mtoe in 1993. In 1993 15% of total coal consumption consisted of coking coal and the remaining part of steam coal. Almost 88% of world coal demand is met by indigenous production.

2.7 IPCC scenarios

The global scenarios presented by the Intergovermental Panel on Climate Change (IPCC) in 1992 have been used as a framework for this study. Table 2.3 gives a summary of assumptions, underlying the six 1992 scenarios [1]. In the following each of the scenarios is briefly described:

- *IS92a*
  Scenario IS92a is characterized by a relatively high growth of population and of Gross Domestic Production (GDP) for the entire world. Fossil fuel resources are ample, and the stringency of environmental policy generally does not exceed current international agreements.
- *IS92b*
  Scenario IS92b has the same world population and economic growth assumptions as IS92a. However, OECD countries generally try to stabilize or reduce CO_2 emissions.
- *IS92c*
  Scenario IS92c is a scenario with a relatively low growth of world population and a relatively low economic growth. Fossil fuel resources are assumed to be more constrained than in IS92a and IS92b. Costs of nuclear energy fall in real terms. Environmental policies are assumed to be similar to the ones of scenario IS92a.
- *IS92d*
  Scenario IS92d has the same population and economic growth as IS92c. Oil and gas resources are constrained too. However, costs of renewable energy is assumed to level off at a lower level than in other scenarios. Environmental policy is more stringent than in IS92a.
- *IS92e*
  Scenario IS92e could be considered as a variant on IS92a. Economic growth is higher. Resources of conventional oil are higher too. Nuclear energy is assumed to be phased out. Emissions controls are somewhat stricter than in IS92a.
- *IS92f*
  Scenario IS92f has a very high world population in 2100. Economic growth is as high as in IS92a. As for IS92e conventional oil resources are very large. Both costs of solar electricity and nuclear power are higher than generally assumed.

Table 2.3 *Summary of assumptions in the six IPCC 1992 alternative scenarios*

Scenario	Population	Economic growth	Energy supplies	Other	CFCs
IS92a	World Bank 1991 2100: 11.3 billion	1990-2025: 2.9% 1990-2100: 2.3%	12,000 EJ conventional oil 13,000 EJ natural gas Solar costs fall to $0.075/kWh 191 EJ of biofuels available at $70/barrel	Legally enacted and internationally agreed controls on SO_x, NO_x, etc.	Partial compliance with Montreal Protocol. Technological transfer results in gradual phase out of CFCs also in non-signatory countries by 2075.
IS92b	World Bank 1991 2100: 11.3 billion	1990-2025: 2.9% 1990-2100: 2.3%	Same as 'a'	Same as 'a' plus commitments by many OECD countries to stabilize or reduce CO_2 emissions.	Global compliance with scheduled phase out of Montreal Protocol.
IS92c	UN Medium Low Case 2100: 6.4 billion	1990-2025: 2.0% 1990-2100: 1.2%	8,000 EJ conventional oil 7,300 EJ natural gas Nuclear costs decline by 0.4% annually.	Same as 'a'	Same as 'a'
IS92d	UN Medium Low Case 2100: 6.4 billion	1990-2025: 2.7% 1990-2100: 2.0%	Oil and gas same as 'c' Solar costs fall to $0.065/kWh 272 EJ of biofuels available at $50/barrel	Emission controls extended worldwide for CO, SO_x, NO_x, etc. Halt deforestation. Capture and use of emissions from coal mining and gas production and use.	CDC production phase out by 1997 for industrialised countries. Phase out of HCFCs.
IS92e	World Bank 1991 2100: 11.3 billion	1990-2025: 3.5% 1990-2100: 3.0%	18,400 EJ conventional oil Gas same as in 'a' Phase out nuclear by 2075.	Emission controls (30% pollution surcharge on fossil energy).	Same as 'd'
IS92f	UN Medium High Case 2100: 17.6 billion	Same as 'a'	Oil and gas same as 'e' Solar costs fall to $0.065/kWh Nuclear costs increase to $0.09/kWh.	Same as 'a'	Same as 'a'

This study focuses on fossil fuel prices to be expected in the year 2020, based on estimates of the reserves of oil, gas and coal. Each of the following chapters will give insight in the characteristics for oil, gas, and coal respectively. In Annex B an overview is given of the historical development of oil, gas, and gas reserves, based on common BP statistics.

At the request of the Ministry of VROM scenarios scenarios IS92a and IS92c are used as reference. Demand for oil, gas and coal is relatively high for IS92a and relatively low for IS92c. Contrary to the divergent levels of oil and gas resources assumed for IS92a and IS92c by the IPCC, in this study generic values for resources of oil, gas and coal are used. These are derived from the analysis for each of the fossil fuels.

The demand for oil, natural gas and coal is quit different under scenario IS92a and IS92c. This goes back to the large differences in world population growth and economic growth: high in IS92a and low in IS92c. Therefore, the demand for oil, gas and coal is much higher in scenario IS92a than in IS92c, both in year 2000 and in year 2020, as shown in Figure 2.1. Data for 1990 and 1994 is taken from the last 'BP statistical review of world energy' (1995). Annex C gives an overview of projected demand for oil, gas, and coal by region for the scenarios IS92a and IS92c.

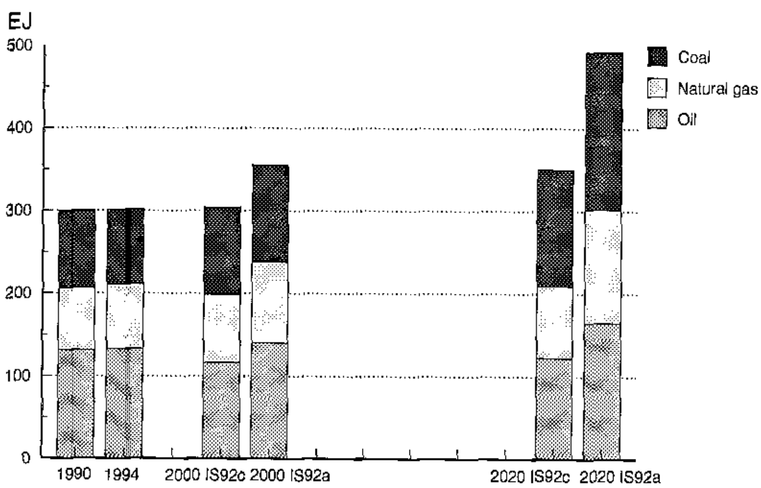

Figure 2.1 *Demand for oil, gas and coal, IPCC scenarios IS92a and IS92c*
Sources: [1,7]

3. OIL: MARKET, RESERVES, COSTS

3.1 Supply and demand trends

Prior to 1973, rapid growth in worldwide demand for oil was stimulated by abundant, low cost supplies. Production was dominated by a relatively small number of large oil companies and some small American oil companies in North African oil producing states. Since the fifties newly emerging nationalism and a coinciding need for self-determination in the third world resulted in a trend toward nationalisation of oil production activities. Around 1973 this phenomenon became more general, with the emergence of national oil companies in the main exporting countries that took control of the exploitation of their country's petroleum resources. These national oil companies took over most, if not all, of the production operations from the international oil companies, traditionally dominating oil markets. After 1973 international oil companies found themselves controlling a much smaller share of world wide production and, consequently, became price takers. Control of world oil prices had shifted to the main exporting countries, creating a de facto cartel: OPEC, the Oil Producing and Exporting Countries (see e.g. [8]).

The first and second oil price shock

The political overtones, that accompanied the emerging national consciousness, culminated in 1973 in oil being declared as OAPEC's[3] weapon, which was used to come to the rescue of the opponents of Israel in their conflict with that country. The oil embargo against the USA and the Netherlands and the ensuing quadrupling of the oil price from October 1973 to June 1974 were direct results of this 'oil as a weapon' concept. It should be noted that some years earlier the market already had become a sellers market. Some (verbal) threat combined with panic among the main oil consuming regions was enough to trigger the oil price surge.

With the oil price escalation in 1973-1974, a new era arised: most of OPEC countries were experiencing an almost unmanageable influx of capital. Third world countries were suffering from staggering oil costs. Industrialised countries were formulating structural adjustments in their energy policies, to reduce dependence on imported oil and to reduce oil consumption. After a period of slowly decreasing real oil prices, another crisis in the Middle East broke out. After the political revolution in Iran in 1979, oil prices trebled, ending up in prices of $33/barrel (b) (and even higher for some time) in 1981 - equal to $50/b in 1993 $ - as shown in Figure 3.1.

[3] OAPEC = Organisation of Arabic Oil Producing and Exporting Countries.

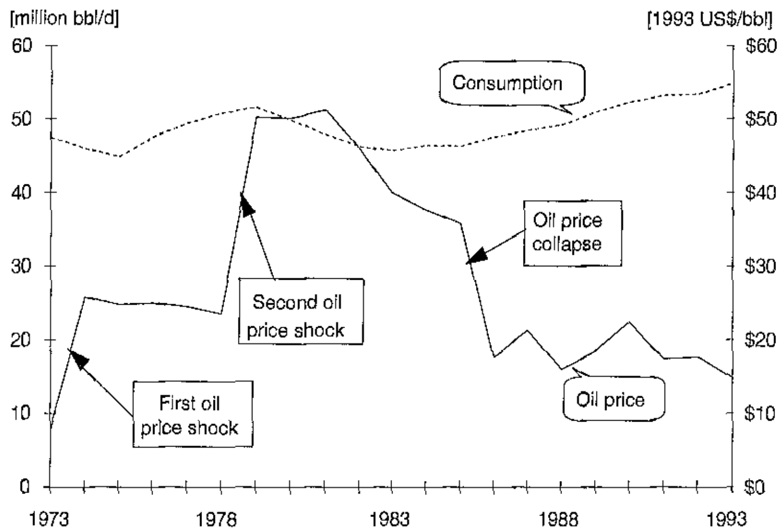

Figure 3.1 *Oil consumption versus price; 1973-1993*

Note: Total consumption excluding FSU, Eastern Europe and China.

Consuming countries' response

On the demand side, after the first oil price shock in 1973, governments of the industrialised countries responded with the formulation of policies to diversify their energy sources and to reduce their dependence on oil. Some countries indeed diversified their energy supply. In general the supply of oil became more diversified: in the USA oil from the Gulf of Mexico and later on from Alaska and in Western Europe oil from the North Sea set the stage. Consumers also gradually changed their demand patterns and invested in more energy efficient appliances, cars and houses, thereby reducing their expenses on energy carriers (oil products, natural gas). The combined effect of energy conservation and changes in demand patterns resulted in oil demand growth initially slowing between 1973 and 1980, and in the end actually declining between 1980 and 1985 (Figure 3.1).

Oil companies' response

On the supply side, international companies found themselves shut out of many existing production operations. Sometimes this had only limited consequences, sometimes their normal oil business changed abruptly. They shifted their exploration and development focus to new areas where they were given access. For example, rapid exploration for and development of offshore oil fields in the Gulf of Mexico and in the North Sea during the seventies, and rapid development of the Prudhoe Bay field in Alaska during the first half of the eighties were a direct result. Likewise, increases in Exploration and Development (E&D) activities resulted in increased production in Latin America, the Far East and Africa (Figure 3.2) [6].

The net result of the concerted effort of the private oil companies in the so-called market economies to establish new production in areas not controlled by OPEC was an increase in oil production in non-OPEC countries from about 15 million b/d in 1973 to 22 million b/d in 1985. Moreover, efforts in centrally planned economies - i.e. the Former Soviet Union (FSU), China and Eastern Europe - resulted in an increase in oil production from about 10 to 15 million b/d during the same period (Figure 3.3) [6].

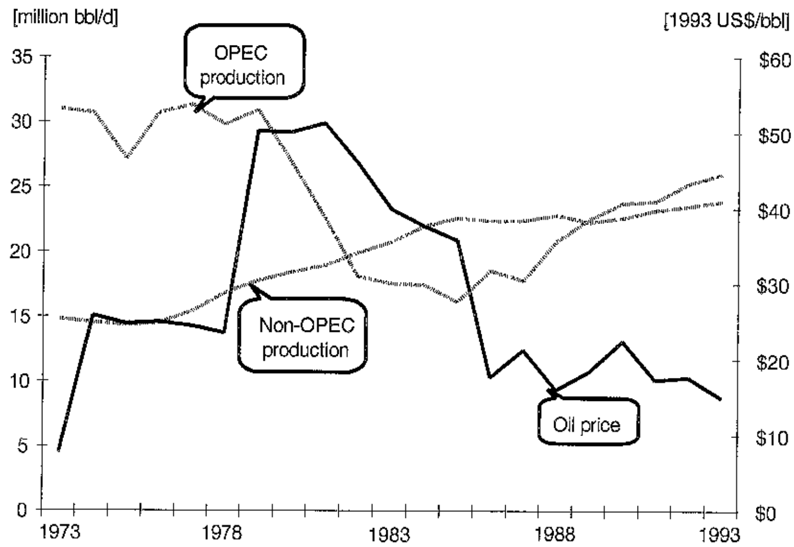

Figure 3.2 *Oil production, consumption and price; 1973-1993*

Source: [6]

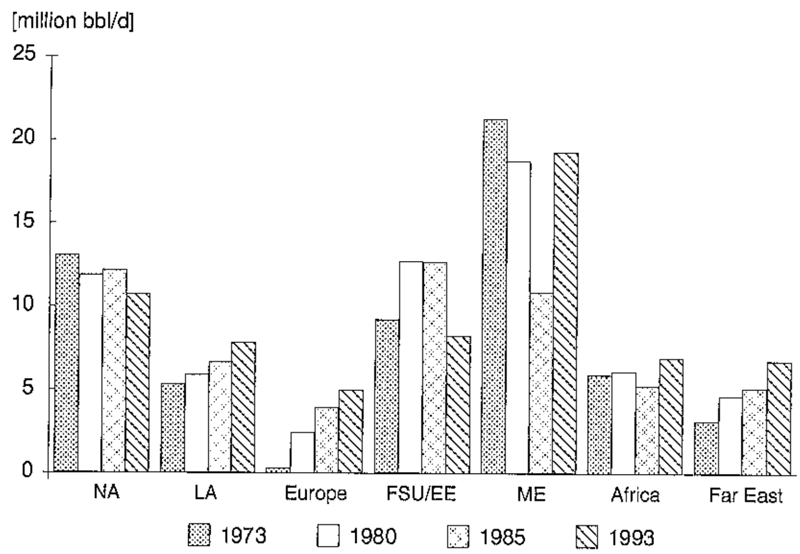

Figure 3.3 *Historical crude oil and NGL[1] production by region*

Notes: NGL = Natural Gas Liquids; NA = North America; LA = Latin America; Europe = Western Europe; EE = Eastern Europe; ME = Middle East.

Source: [6]

The oil price collapse of 1985

For a number of years OPEC - more specifically Saudi Arabia, Kuwait and the UAE - (United Arabic Emirates) - was the world's swing supplier of oil. The combined effect of rapidly increasing non-OPEC production and declining demand after 1980 made it more and more difficult for OPEC to control oil price levels by concerted production cutbacks that were shared among the member states. OPEC, in an attempt to control overall supplies and thereby oil price levels, had to reduce production significantly.

In the period 1980-1985 Saudi Arabia, used to shut in production if prices started to slide and to increase production if prices increased rapidly, at last became reluctant to reduce its oil production. Continuous cheating by other member states on their production quotas had forced Saudi Arabia effectively to absorb increasingly large production cutbacks to support oil prices. In 1985, it abandoned its role as a swing producer and increased its production level. This aggravated the price slide that began in 1981. The other producers had to follow suit not wanting to loose market share. Apparently they fear a further expansion of production by Saudi Arabia.

The combined effect created a glut of oil on the market and prices dropped rapidly to well below $15/b. By now the oil price seems to be stable at about $18/b. The rather sudden change in oil production by Saudi Arabia in 1985 seems to have had positive results for that country. Pumping 2.2 million barrels per day (mb/d) in 1985 at a net profit of $30/b yielded $66 million daily, while pumping 8 mb/d currently at a net profit of $15/b resulted in a near doubling of their revenue [9]. Apart from the sharp decline in oil prices in $/b, the period from 1980 to 1986 was characterised by a dramatic fall of the US$ against other currencies. For some main oil importing regions like Western Europe and Japan the real oil price decreased even more than would be suggested by the price in $/b.

Oil prices after 1985

After 1985, prices stabilized between $15/b and $20/b, except for a very short spike during the Iraq/Kuwait conflict. As can be expected, consumers too responded to lower crude oil prices by a general upturn in demand. In many industrialised countries the net effect of the price drop on consumers was significantly reduced by a commensurate increase in end-user taxes, especially on products such as gasoline. Even so, between 1985 and 1990, demand for oil rose by an average of 1.9% per year.

Oil production trends from 1973 to 1993

The changes in oil production that resulted from the shift in ownership of oil production in the oil exporting countries and the increase in E&P activities in non-OPEC regions varied significantly between the different main producing regions in the world. Between 1973 and 1993, production in these different regions changed as follows [10]:

- In North America combined production of the USA and Canada declined by almost 2 million b/d (or 20% relative to 1973 levels), even taking into account the fact that between 1980 and 1985 production in the region increased when Alaska production came on stream; the decline in production in the lower 48 states indeed was rather heavy.
- In Latin America production increased by about 2.5 million b/d from 5 million b/d.
- In Western Europe production increased from an almost negligible level in 1973 to 5 million b/d in 1993.
- In the Former Soviet Union (FSU) and Eastern Europe (EE) production increased by about 4 million b/d from 9 million b/d in 1973 to 13 million b/d in 1980, at which level it remained until 1987, to decline precipitously to 8 million b/d in 1993.
- In Africa production increased slightly from about 6 million b/d to about 7 million b/d.
- In the Far East production increased significantly from about 3 million b/d in 1973 to about 7 million b/d in 1993.
- In the Middle East, the swing producing region, production declined from about 22 million b/d in 1973 down to about 11 million b/d in 1985, to increase again to 19 million b/d in 1993 when worldwide demand rose again, in response to much lower prices after 1985.

3.2 Reserves

Strikingly, even though oil prices fell with two third's between 1980 and 1990 proved reserves of crude oil increased significantly during that same period, mostly as a result of large increases in estimated reserves in the Middle East and other areas (Figure 3.4).

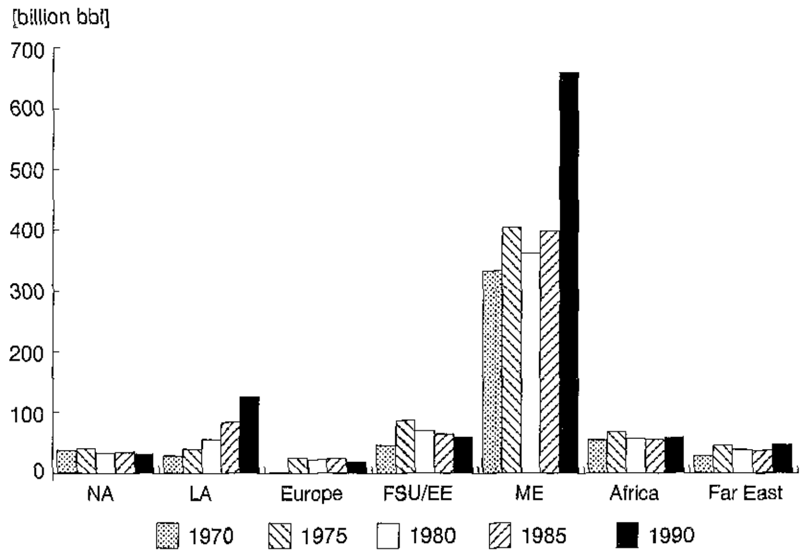

Figure 3.4 *Proved oil reserves; 1970, 1975, 1980, 1985 and 1990*

Note: NA = North America; LA = Latin America; WE = Western Europe; FSU = Former Soviet Union; EE = Eastern Europe; ME = Middle East.

Source: [6]

Consequently, proved oil reserves, about 1000 billion barrels, are more than enough to sustain production on this level for over forty years. In addition to proved reserves, there are probable reserves still to be discovered that could be economically produced. As shown in Table 3.1, the size of these undiscovered reserves is estimated at about 400 billion barrels [11].

Table 3.1 *Oil reserves and resources; 1993 [barrels and EJ]*

	Identified		Reserves to be discovered		Resources		Resource base			
							Reserves & resources		Additional occurrences	
	[10^{12} b]	[EJ]	[10^{12} b]	[EJ]	[10^{12} b]	[EJ]	[10^{12} b]	[EJ]	[10^{12} b]	[EJ]
Conventional	1.06	6,028	0.43	2,430			1.48	8,459	1.77	1,009
Unconventional	1.25	7,117			2.50	14,627	3.75	21,394	2.54	14,496
Total	2.30	13,145	0.43	2,430	2.50	14,627	5.23	29,851	4.30	24,576

Source: [11]

In the next decades, Enhanced Oil Recovery (EOR) techniques are expected to play an increasingly important role in extension of the production of proved and probable oil reserves[4]. However, full scale economic application of EOR techniques will require higher than today's oil prices. Under such circumstances the marginal barrel produced by EOR techniques could dictate the oil price level. Stricter environmental regulation and legislation could add to production costs by EOR techniques.

Beyond proved and probable conventional oil reserves and beyond EOR resources, so-called unconventional oil deposits - oil shales and tar sands - could be made available. Only a tiny fraction of current oil production is based on unconventional oil. These resources are large; however, their size and production costs are more or less uncertain[5]. Recovery will generally become economic oil prices being substantially higher than today's. Not only the production costs themselves are of interest, but also economic risks associated with investment in new production technology. The size of EOR and unconventional resources is estimated at 3,750 billion barrels [11].

Access to reserves

Even though proved reserves are more than enough to meet projected demand for another forty to fifty years, the development and production decisions for those reserves mostly lie with the national oil companies. Their production decisions are seldomly purely driven by market considerations. Access to by far the largest part of the total oil reserves base is controlled by national governments that prefer to have their oil reserves developed by their national oil companies. In principle, this limits the ability for Western oil companies to increase worldwide production.

This picture, however, is largely based on the market situation just after the fall of the oil prices around 1985. In the meantime, a number of oil-rich OPEC countries, such as Algeria and Irak, have difficulty to invest in new production capacity without participation of international oil companies. This is due to lack of financial resources, technical and managerial know-how. Also a lot of oil producing developing countries have become more and more dependent on international oil companies.

The largest percentage of the worldwide oil reserves, that are mainly developed and produced by national oil companies, is found in OPEC countries (Figure 3.5). As discussed earlier, in the seventies the OPEC cartel had little problems to control oil prices for a number of years. In the period 1982-1985, when demand for oil from OPEC countries declined significantly, the OPEC still managed to control prices by production cutbacks that were shared among their members. Yet, the ability of OPEC to control crude oil prices has greatly diminished since then.

Even so, most of the world's reserves are controlled by a handful of governments that have an uneasy alliance with each other as well as with Western nations. On the one hand, this constitutes an inherently destabilising factor for oil prices. On the other, the OPEC cannot afford to lose its market share in the most broad sense of the word, either by a larger share from non-OPEC countries or by full-scale energy conservation.

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[4] *Enhanced oil recovery* or tertiary oil recovery includes all recovery techniques that change the physical characteristics of the oil and the reservoir rock such as the viscosity, the permeability and porosity; it encompasses steam and carbon dioxide injection.

[5] In the late seventies and early eighties, when oil prices were generally expected to continue to rise in real terms, results of small scale pilot projects showed that large scale exploitation of those unconventional resources was not economically feasible at the high oil price levels of those years. Current, albeit limited, evidence suggests that large-scale production of shale oil and tar sands will generally require price levels exceeding $30/b. Strict environmental regulation and legislation will increase to those production costs.

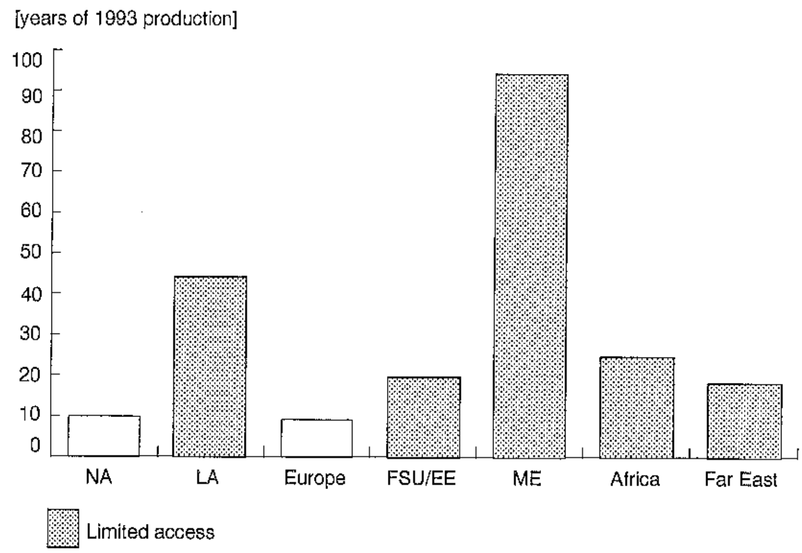

Figure 3.5 *Reserves/production (R/P) ratio in main producing regions*

Note: NA = North America; LA = Latin America; OECD Eur = OECD Europe; FSU = Former Soviet Union; ME = Middle East.

Source: [6]

The expansion of oil production capacity, needed to supply a growing worldwide demand for oil, therefore will continue to be a mix of political decisions and market forces. Objectives of governments of oil exporting nations are not the same as those of the main oil consuming nations. As such, supply decisions of swing producers will generally not synchronise with the demand development that is mostly driven by market economics. In other words, industrialised countries depend on the swing producing capacity of Middle East countries, but are not easy with that dependence.

Major swing producers, notably Saudi Arabia and Kuwait, presently have strong strategical alliances with the USA. The USA is highly dependent on oil from this vulnerable region, and therefore tries to control production. Saudi Arabia and other swing producers are keen to stabilize their income from oil at an affordable level. Moreover, as already stated above, OPEC countries and other oil producing countries are becoming more and more dependent on western oil companies for technology and investment resources. All in all both some major oil consuming countries (notably the USA) and oil producing countries seem to have a common interest in stimulating oil production, meanwhile maintaining the oil price at an acceptable level.

3.3 Production costs

Trends in production costs

Private company crude oil production costs consists of the following [12,13,14]:

- taxes, including royalty payments and income taxes paid on revenues from crude oil sales;
- cost of funds needed for investments in plants and equipment, consisting of borrowing costs and the return on investment that shareholders require;
- costs for Exploration and Development (E&D) of oil reserves;

- production costs, i.e. the costs incurred to operate and maintain production facilities, including pipelines, storage and treatment facilities needed for oil exports.

In general, other things being equal, E&D costs in a producing area will increase as the smaller reservoirs in an area are developed and the productive quality of the reservoirs becomes less: the depletion effect. This depletion effect can be offset by cost reductions that result from technological improvements and improvements in efficiency (Figure 3.6).

To the extent that technical cost reductions and efficiency improvements will more than offset the depletion effect, average costs to explore, develop and produce oil fields in an area will go down. This appears to have happened between 1980 and 1990.

In the wake of the precipitous drop of oil prices that took place between 1981 and 1986, oil exploration, development and production costs declined by an estimated 60% in real terms for private oil companies[6]. However, average company E&D costs appear to have gradually increased again since 1990. Hence, sooner or later continuing technical cost reductions may be more than offset by the depletion effect. The reasons for the steep decline in average E&D costs so far have been the following:

- *Price squeeze for services and materials suppliers*
  Between 1980 and 1986 most of the decline in costs was probably due to a price squeeze for subcontractors. With the price of oil falling by more than 50%, E&D activities by the oil industry were cut back sharply, particularly from 1985. This resulted in a surplus of services and materials, causing service companies and manufacturers to reduce their prices to maintain their share of a rapidly shrinking market. This surplus had a global character, in the sense that in some regions exploration and development was maintained (North Sea, Alaska), while in the Middle East exploration and development slowed down.
- *Technological improvements*
  Between 1985 and 1990, the continuing but much lower rate of cost reductions at least partly reflected ongoing improvements in technology, such as 3-D seismic, horizontal drilling, offshore platform construction and installation methods.
- *Rationalisation of company activities*
  Some of the cost reductions between 1985 and 1990 have also resulted from rationalisation of company activities. For example, companies reduced overall E&D costs by concentrating more on areas where they had a better understanding of the petroleum geology and where they had developed a substantial knowledge base. Apart from that the 'core business approach' became popular. Companies increased productivity by outsourcing of services and by organisational changes that, for example, did away with redundant levels of management.

[6] I.e. companies that publish annual reports, enabling analysis of the average annual E&D expenditures over time.

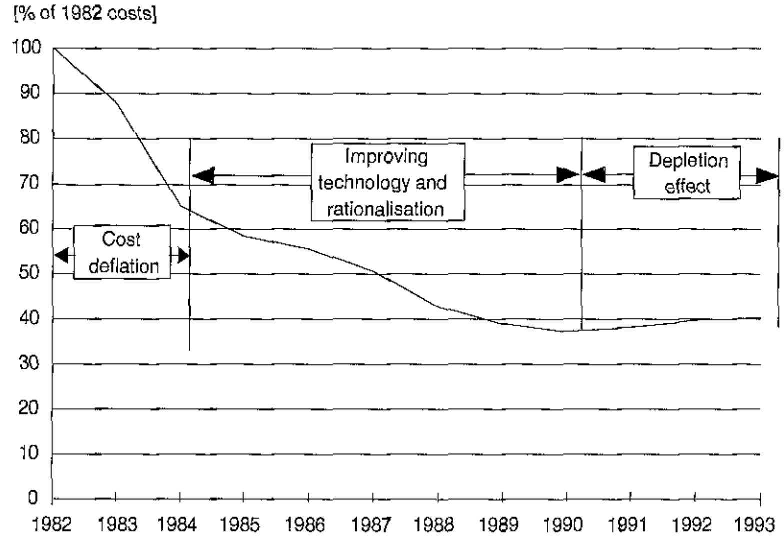

Figure 3.6 *Average company oil and gas exploration and development costs as % of 1982 costs; 1982-1993*

Note: Exploration and development costs expressed in 1993 US$ using the USA GDP deflator.

Source: Company reserves replacement and exploration and development cost statistics

As mentioned earlier on, between 1980 and 1990 these cost reductions more than offset the depletion effect that companies continuously face. However, it appears that since 1990 the reduction in E&D and production costs are tapering off, and could start to rise soon. This would imply that cost reductions from technological improvements and organisational changes may soon not fully offset the depletion effect.

Minimum required prices[7]

Even though oil prices declined by more than 65% since 1980, they still are about twice as high in real terms as the levels prevailing before the first oil crisis in 1973 (Figure 3.1). The question is now whether they can decline any further, and, if so, whether that is likely to happen. Whether oil prices can continue to decline in real terms, depends on the following [15]:

- Are the minimum required prices (i.e. costs to explore, develop and produce oil, and finally to decommission oil production sites and rigs in an environmentally compatible way) in the different regions in the world much lower than today's prices?
- Do sufficient proved reserves exist in the low cost regions to sustain projected production levels for the next decades?
- Is it likely that the production capacity in the low cost regions will be allowed to expand, even if it implies that most of the high cost production in other regions will have to be shut in?

[7] The discussion is about minimum required prices at the point of export (i.e. Free on Board or FOB price). To obtain CIF prices (Costs Insurance Freight), tanker rates need to be added to FOB prices. Tanker rates have fluctuated between $1/b and $1.5/b throughout the period from 1980 to 1993.

What are the minimum required prices for existing reserves?

To add incremental oil producing capacity in the different areas in the world, oil companies not only need to earn back their E&D expenditures and cover their operating costs and indirect taxation, but they also need to earn a return on investment that is sufficiently high to compensate their shareholders for risking their money in these activities. These costs are not known with a large degree of accuracy. However, by using cost data and production information for the different producing regions and by comparing these with the more complete cost information that is available for regions such as the North Sea and the USA, it can be estimated how the costs in the different regions compare.

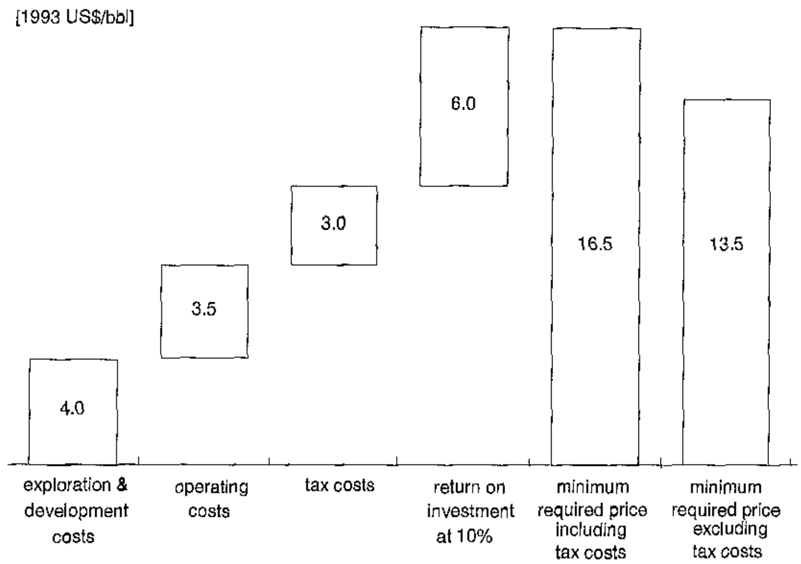

Figure 3.7 *Minimum required price[1] for North Sea oil*

[1] Minimum required price with discounted return on investment of 10%.

Source: [16]

For example, it can be estimated that in the North Sea the cost to explore, develop and produce an incremental barrel of crude oil, is about $16.5/b on average from the perspective of the private operating agent and about $13.5/b from a societal point of view (see Figure 3.7) [16].

To add an incremental barrel of crude oil, companies would have to incur $4.0/b in E&D costs, $3.5/b in operating and maintenance costs, $3.0/b in tax and royalty payments, while requiring $6.0/b to earn a return on investment of 10% in real terms[8]. Therefore, the minimum price companies require in the long term for an incremental barrel of oil would be about $16.5/b. It should be noted that this is a rough estimate for North Sea oil, a production area with significant differences in production costs. At a real return of 15%, the minimum required price for incremental production capacity in the North Sea would be roughly $19.5/b.

[8] From a societal point of view, inclusion of the government take component ($3.0/b) is a contentions matter. Yet for operators it designates a real cost. See also section 4.5 of this report.

It can be expected that oil production in the North Sea will level off and ultimately decline early in the next century. The maximum level and the start of decline will depend on the rise in production costs and the level of world oil prices. Another factor is the fiscal regime of the Norwegian and UK governments. Given a current tax burden of about $3/b, governments still have considerable flexibility to make continued investment in offshore oil economically attractive by lowering taxes.

Combining estimates for the minimum required prices to explore, develop and produce incremental oil volumes in the different main producing regions with the 1993 producing capacity in those regions, enables us to construct an oil supply curve, which is shown in Figure 3.8. The lower level conforms with minimum required prices for the different regions at a 10% rate of return per year; the higher curve conforms with prices based on a rate of return of 15% per year.

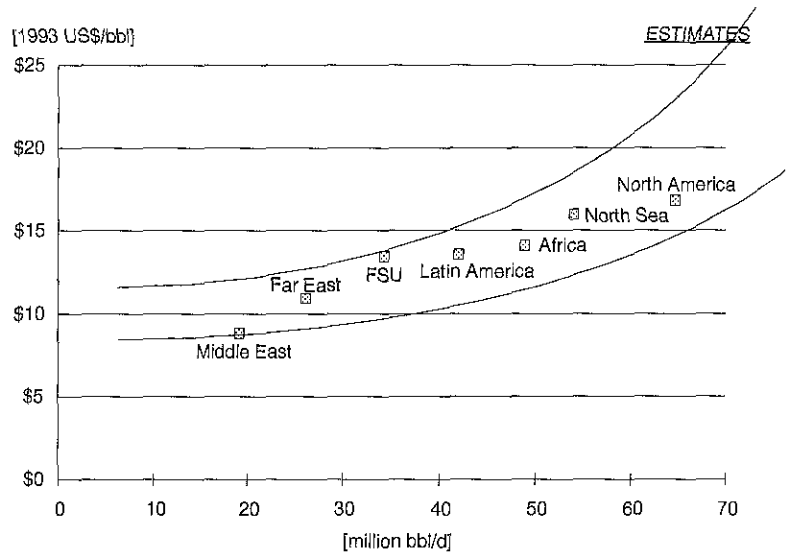

Figure 3.8 *Estimated oil supply curve based on minimum required prices*[1] *for main producing regions*

[1] Full cycle economic costs to develop and produce an incremental barrel of oil.

Source: Company reserves replacement and exploration and development cost statistics

At today's price levels, the costs of incremental production from the USA generally exceeds current price levels. It is a matter of fact that the US oil production has been falling for more than a decade, despite the availability of additional production capacity, e.g. in Alaska.

Are low cost reserves sufficient to meet projected demand?

Figure 3.9 shows the supply curve that we get if we use the minimum required price estimates that were made for proved reserves in the different regions in the world and extend these estimates to the other categories of estimated reserves and estimated resources that were discussed earlier (see Table 3.1).

As discussed earlier, about 65% of the world's proved reserves resides in five countries in the Middle East; most of these reserves are low cost reserves [17]. If we assume that world oil production demand would continue to grow at an average rate of 0.75% per year, then current proved reserves would suffice for some 40 years. The five Middle East countries with the largest reserves could supply the world with oil at this level for

25 years. As shown in Figure 2.9, those reserves would be economical to produce at prices of around $10/b. The reserves in the higher cost regions would suffice for another 15 years and would be economic to produce at between $12/b and $25/b.

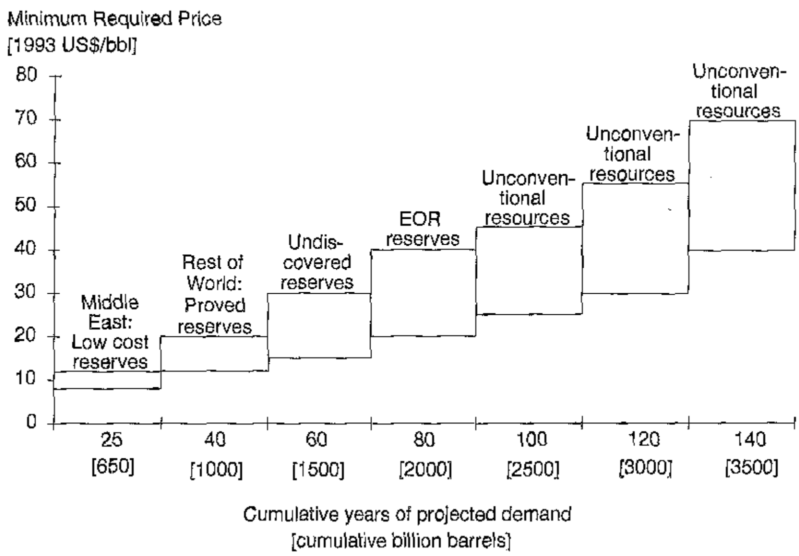

Figure 3.9 *Years of projected oil demand from reserves and resources versus estimated minimum required price*[1]

[1] Assuming 0.75% annual demand growth; minimum required price at 10%/yr discounted cash flow rate of return.

Undiscovered reserves would be large enough for another estimated 20 years of oil production at the current demand level, and probably be economic to produce at between $20/b and $30/b. Large scale application of enhanced oil recovery techniques would economically extend the production life of existing reserves and reserves still to be discovered by another twenty years, at prices of between $20/b and $40/b.

Unconventional resources - tar sands and shale oil - would facilitate 60 years of oil production at current demand levels and probably require oil prices of at least $30/b to $40/b, as indicated by footnote 6. Current experience with this kind of oil production is so limited that the margins of uncertainty are relatively high. It could be that the bulk of unconventional oil resources would necessitate price levels in excess of $40/b to be produced in large quantities and at economic terms.

Will low cost production in the Middle East replace most higher cost production?

Trends of production expansion and contraction in the different main producing regions during the last twenty years show that even at price levels much higher than today's prices, likely capacity expansion outside the Middle East will not be sufficient to provide for increases in demand foreseen. As shown in Figure 3.10, between 1985 and 1993 even with sizeable continuing increases in capacity in all producing regions, except for the USA and the FSU, the Middle East increased production by about 8 mb/d to meet the rising demand during that period[9].

[9] The reason for production levels in the FSU to go down is a lack of general economical and legal infrastructure, and not so much a straightforward economic downturn. Given time, production could increase again, even if today's prices would not go up for some time.

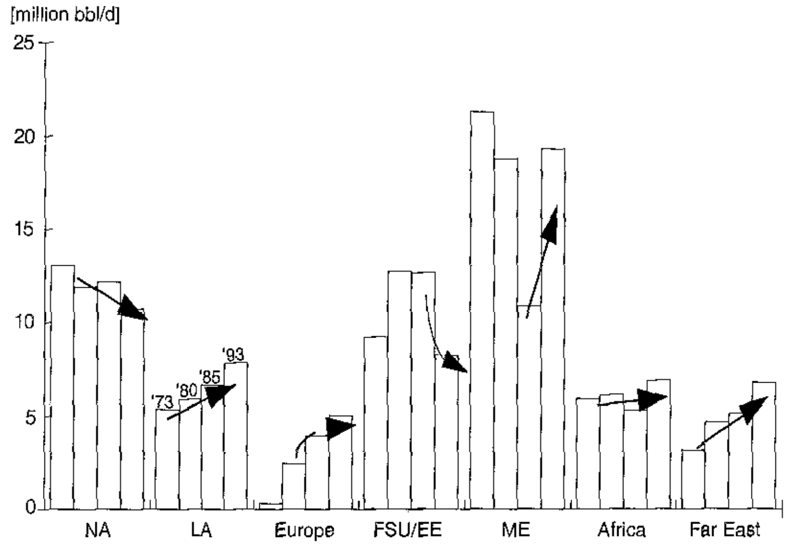

Figure 3.10 *Possible direction of production changes in main producing regions*

Note: NA = North America; LA = Latin America; Europe = Western Europe; FSU = Former Soviet Union; EE = Eastern Europe; ME = Middle East.

Source: [6]

If the trends in the different producing regions of the last five years continue, then at price levels between $15/b and $20/b production in the USA will probably continue to decline. Production in the North Sea will probably peak and then start to decline by the year 2000 or a few years later. Production in the FSU will probably bottom out and then start to increase. Production in the Far East and Latin America will probably continue to increase. However, the net additions (if any) to productive capacity from the expanding areas may not be enough to meet net additions to projected demand. If so, the balance will have to come from capacity additions in the Middle East.

If price levels would fall consistently below levels of $15/b, production in various regions outside the Middle East would become economically marginal. This might imply, that over a period of five to ten years, the 45 b/d of relatively high cost production would gradually be displaced by expansion of low cost production in the Middle East. This might be a feasible scenario, but it is not a (politically) likely one.

3.4 Price prospects

The experience of the last 25 years has shown how difficult it is to make a long term prediction of future oil prices. As mentioned earlier, 65% of the world's proved oil reserves resides in five Arabian Gulf State countries. Moreover, these reserves could be economically produced and transported to the main markets in the world at prices of $10/b or less, which is well below current oil prices of about $16-20/b. They would suffice to sustain projected worldwide demand for at least 25 years.

However, oil is considered a strategically important commodity by most consuming countries, for which domestic oil reserves are insufficient to meet their demand. Therefore, these countries are not only concerned about oil prices but also about security of supply and price stability [18,19]. Consuming countries, essentially all countries that lack adequate indigenous oil resources, do not want do depend for the supply of such an important commodity on just four or five countries whose economic and political aspirations do not necessarily coincide with their own, and whose political, social and economic stability are uncertain. The extreme oil price fluctuations during the last 25 years vividly demonstrate what such a dependence can lead to, if it is allowed to exist without some counterbalancing forces. Consequently, there are strong political forces that can be counted on to oppose a growing dependence on Middle Eastern oil.

Nevertheless the Middle East countries are the swing producers of the world, and the western world is well aware of that. Therefore, particularly the USA is strongly motivated to control the flow of oil from these countries. For Saudi Arabia and other swing suppliers a reliable and affordable level of income from oil export seems to be the price they are willing to pay for tutelage by the USA. Also, for other oil producing countries income generated from oil exports is essential for their economic development. Production costs for less well endowed countries are higher than those of the low cost producers in the Middle East. Moreover, several of these countries are members of OPEC. This organisation has as its stated goal to secure a steady revenue for its member countries, while securing a fair return of capital invested in the oil industry and ensuring stability of prices in the international oil markets[10]. The relatively small number of major low cost producers in this organisation will probably not be in the position to expand production capacity to a point where production in most of the other oil producing regions in the world would become uneconomical. Such a scenario might give rise to severe tensions within the OPEC organisation, eventually causing the demise of OPEC.

For the time being, oil prices are and probably will be the result of an uneasy symbiosis of the richly endowed low cost producers in the Middle East and the rest of the world. As far as the USA is concerned, they consider Saudi Arabia and other swing suppliers in the Middle East as vital to their national interests. This causes a somewhat artificial alliance between these countries. Other industrialised countries also depend on the swing producing capacity of the Middle East, but are not easy with that dependence. However, they seem to be willing to pay a higher price for oil, if that results in a more secure and more diversified supply, as has been witnessed in the last decade.

At the rate of demand currently projected, increasing dependence on oil from the Middle East appears likely. Under an optimistic scenario, that would lead to gradually increasing oil prices, in real terms. Prices would increase slowly because capacity expansion in the Middle East would be slow and gradual enough for high cost areas, such as the North Sea, to maintain or even expand production while not causing

[10] Article 2 of OPEC's Statute stipulates that OPEC strives to:

- coordinate and unify member country petroleum policies and to determine the best means for safeguarding their interests, individually and collectively;
- ensure the stability of prices in the international oil market with a view of eliminating harmful and unnecessary fluctuations;
- secure a steady revenue for member countries with due regard, at all times, to the interests of the producing nations;
- ensure an efficient, economic, and regular supply of oil to consuming nations; and;
- secure a fair return of capital to those investing in the petroleum industry.

economic disruptions. This scenario virtually excludes crises, which are so characteristic for the social and political fabric of the Middle East.

However, given that costs of incremental production in that region will be higher rather than lower, it appears to be unlikely that in such a stable world prices will be allowed to gradually go down much, if at all, below today's levels. It is more likely that they will gradually go up to keep up with rising costs in real terms.

Under a more pessimistic, but probably more realistic scenario that allows for an unstable rather than a stable world, oil prices will continue to fluctuate as they have done during the past twenty years. There is speculation about the stabilizing role of Saudi Arabia, taking into account social and political upheaval in other oil producing states in the past [9]. But even if countries like Saudi Arabia would become less stable and reliable as oil exporting countries for the western world, the oil price again would more likely fluctuate around a long term trend of gradually increasing prices rather than showing a gradually decreasing trend. This is because even the low-cost oil producers in the Middle East cannot afford really low oil prices, taking into account their dependence on oil income.

4. GAS: MARKET, RESERVES, COSTS

4.1 Supply and demand trends

Over the past thirty years, the role of gas in world energy supply has gained in importance. BP statistics on natural gas [20] show that world gas production has increased by a solid 2.9% per year to 2095.3 bcm in 1993 (see Table 4.1). Regional growth rates, if from a low base, have been the highest in Africa and Other Asia over the past thirty years. Notably, the Former Soviet Union (FSU) and the Middle East have also realised high long-term growth rates of gas production, topping at 6% per annum over the 1973-1993 period, although FSU gas production declined considerably since 1990 (see inter alia [21]).

On a global scale the rate of increase in world gas production slowed down to 1.3 % per year over the period 1990-1993 due to prevailing adverse economic circumstances in the FSU and Eastern Europe (EE). Gas demand in these regions and, consequently, gas production in notably the gas-rich FSU may well pick up again soon. The latest macroeconomic statistics suggest that the economy in several EE countries has turned around in 1994 with a resumption of positive rates of growth of industrial production and GDP. Furthermore, some early statistical harbingers indicate that the Russian economy, badly shaken by the transformation process, might by now be close to its nadir.

Table 4.1 *World production of natural gas, by region; 1970-1993 [bcm]*[1]

Region\year	1973	1980	1985	1990	1993	Average annual growth [%]				
						1973-1993	1973-1980	1980-1985	1985-1990	1990-1993
North America	698.6	636.8	552.0	613.5	658.4	-0.3	-1.3	-2.8	2.1	2.4
Western Europe	132.8	177.8	178.8	184.4	212.2	2.4	4.3	0.1	0.6	4.8
Eastern Europe	31.5	43.5	46.0	32.0	27.0	-0.8	4.7	1.1	-7.0	-5.5
FSU	218.0	404.3	599.8	759.9	708.7	6.1	9.2	8.2	4.8	-2.3
OECD Pacific	7.9	14.4	19.2	27.3	31.8	7.2	8.9	5.9	7.3	5.1
Middle East	33.1	41.8	63.2	103.4	122.6	6.8	3.4	8.6	10.3	5.8
Africa	8.8	30.1	47.3	67.1	76.9	11.5	19.3	9.4	7.3	4.7
Other Asia	24.8	54.9	91.7	133.4	156.5	9.6	12.0	10.8	7.8	5.5
Latin America	36.6	60.7	75.8	93.9	101.1	5.2	7.5	4.5	4.4	2.5
World	1192.1	1464.3	1673.8	2014.8	2095.3	2.9	3.0	2.7	3.8	1.3

[1] Excluding gas flared and reinjected.

Source: [20]

To date, the two most important gas producing world regions are:
- the FSU (notably the countries Russia: 574.7 bcm in 1993, Turkmenistan: 60.6 bcm, Uzbekistan: 41.9 bcm); and
- North America (USA: 531.5 bcm, Canada: 126.9 bcm).

Each region accounts for roughly one third of world gas production. Other important gas-producing regions are Western Europe (Netherlands: 69.8 bcm, Great Britain: 63.0 bcm, Norway: 28.9 bcm), Other Asia (Indonesia: 55.0 bcm, Malaysia: 25.5 bcm, Australia: 24.6 bcm), the Middle East (Saudi Arabia: 35.9 bcm, Iran: 27.1 bcm, United

Arabic Emirates (UAE) 25.0 bcm), Latin America (Mexico: 27.7 bcm, Venezuela: 26.2 bcm, Argentina: 25.0 bcm) and Africa (Algeria: 51.2 bcm).

The most important gas consuming world regions are North America, the FSU and Western Europe, as brought out by data presented in Table 4.2. In 1993, these regions accounted for 651.6 bcm, 601.2 bcm and 289.1 bcm, i.e. 32.6%, 30.1% and 14.5% of world gas demand respectively. Except for North America which had an already well developed gas market in the early seventies, gas demand in all world regions has shown robust growth rates over the 1973-1993 period. Gas made quite some inroads into national and regional energy markets all over the world. The most important end-use sectors of major consuming regions are as follows:

- in North America the power sector (including independent power producers), industry, and residential/commercial account for 12.6%, 33.9% and 37.0% respectively of gas end use in 1993;
- the corresponding shares for OECD Europe are: power sector 16.0%, industry 32.5%, residential/commercial 43.5%;
- and for OECD Pacific: power sector 58.5%, industry 19.4% and residential/-commercial 21.3% [17].

Table 4.2 *World consumption of natural gas, by region; 1973-1993 [bcm]*

Region\year	1973	1980	1985	1990	1993	Average annual growth [%]				
						1973-1993	1973-1980	1980-1985	1985-1990	1990-1993
North America	671.8	628.3	549.2	602.1	651.6	-0.2	-1.0	-2.7	1.9	2.7
Western Europe	145.5	203.3	222.3	255.3	289.1	3.5	4.9	1.8	2.8	4.2
Eastern Europe	38.5	72.0	75.1	75.3	61.6	2.4	9.4	0.9	0.1	-6.5
FSU	233.3	355.5	544.1	676.6	601.2	4.8	6.2	8.9	4.5	-3.9
OECD Pacific	10.2	37.3	56.9	73.9	78.2	10.7	20.3	8.8	5.4	1.9
Middle East	19.8	39.9	50.4	80.9	90.7	7.9	10.5	4.8	9.9	3.9
Africa	3.5	19.2	28.8	37.2	39.4	12.8	27.3	8.5	5.2	2.0
Other Asia	15.6	29.2	43.4	74.4	96.0	9.5	9.4	8.2	11.4	8.9
Latin America	37.2	60.4	72.9	80.0	88.3	4.4	7.2	3.8	1.9	3.3
World	1175.4	1445.1	1643.0	1955.6	1996.1	2.7	3.0	2.6	3.5	0.7

Source: [20]

North America has a well developed gas market and especially a considerable penetration of gas in the residential and commercial sector. Beginning from the late sixties, gas penetrated notably in major energy markets of Western Europe as well. All gas consumed in Japan is imported in the form of Liquid Natural Gas (LNG) from Indonesia, Malaysia, Australia and the Middle East, the border prices of which are relatively high. Therefore, penetration of gas in Japan is confined to relatively few end uses with high netback values, such as power generation in combined cycle plants (except for base load) and, if to a lesser extent, space heating for small users in the residential and commercial sectors and industrial feedstock (methanol and fertilizer production). In Russia, final gas consumption in 1993 amounted to 382.9 bcm, 163.9 bcm (42.8%) of which for power generation [20]. In the 1980s, a successful gas for oil substitution drive had been mounted in the FSU to save oil for foreign exchange generation.

Table 4.3 gives an overview of regional gas supply-demand balances. At global level, production exceeded demand in 1993 by 99.1 bcm, i.e. 5% of world gas demand. The production surplus is mainly accounted for by losses during conversion and transportation (gas treatment, compression, pipeline leakages, liquefaction, cooling of LNG during maritime haulage, and gasification of LNG). Depending on applied definitions these losses appear in statistics on production and gas demand as production surplus.

Table 4.3 *Regional supply/demand balance of natural gas; 1970-1993[1] [bcm]*

Region\year	1973	1980	1985	1990	1993	Production as % of consumption				
						1973	1980	1985	1990	1993
North America	26.8	8.5	2.8	11.4	6.9	104.0	101.4	100.5	101.9	101.1
Western Europe	-12.7	-25.5	-43.5	-70.9	-76.8	91.3	87.5	80.4	72.2	73.4
Eastern Europe	-6.9	-28.5	-29.1	-43.3	-34.6	82.0	60.4	61.2	42.5	43.8
FSU	-15.3	48.8	55.7	83.3	107.5	93.4	113.7	110.2	112.3	117.9
OECD Pacific	-2.3	-22.9	-37.7	-46.6	-46.4	77.6	38.6	33.8	37.0	40.6
Middle East	13.2	1.9	12.8	22.5	31.9	166.6	104.8	125.5	127.8	135.2
Africa	5.2	10.9	18.4	29.9	37.5	247.5	156.8	163.9	180.3	195.1
Other Asia	9.2	25.7	48.3	59.0	60.5	159.1	188.0	211.5	179.3	163.0
Latin America	-0.6	0.3	2.9	13.9	12.8	98.3	100.5	103.9	117.4	114.5
World	16.7	19.2	30.7	59.2	99.1	101.4	101.3	101.9	103.0	105.0

[1] Discrepancies between consumption and production statistics include:
- gas consumed in field operations;
- statistical measurement deviations;
- pipeline (and other) leakages.

Source: [20]

With this caveat in mind, from data presented in Table 4.3 some clear broad patterns can be discerned:
- As yet, North America is more or less self sufficient, while intra-regional gas trade (US imports from Canada) is quite significant. Nett extra-regional imports into the US (a.o. from Venezuela and Algeria), still almost insignificant today, may give a modest contribution in the years to come.
- Major gas-deficit areas are Western Europe, OECD Pacific and Eastern Europe, while the FSU, Other Asia, Africa and the Middle East have exportable production surpluses.
- In Western and Eastern Europe dependence on interregional imports increases. In OECD Pacific (notably Japan) reliance on interregional imports of gas has always been high.

The bottom line is that a trend emerges - if as yet still modest but gradually gathering strength - 'toward macro-regionalisation' of international gas markets. Yet a genuine globalisation of international gas markets is not likely to materialise in the foreseeable future.

Table 4.4 and 4.5 provide some insight in the resulting gas trade flows. Most of international gas trade is conducted by pipeline. Gas trade by way of pipeline topped 254 bcm in 1993, i.e. 12.7% of world gas demand. Gas trade through LNG tankers accounted for 61 bcm or 3.1% of world gas consumption. Although gas trade by ship still covers a modest share of world consumption, its annual growth rate outstrips annual growth of world gas consumption. In 1993, the main international trade movements were:
- by pipeline:
  - 100.9 bcm from FSU to Western and Eastern Europe;

- 60.9 bcm from Canada to the USA;
- 43.1 bcm from the Netherlands to Western Europe;
- 24.6 bcm from Norway to Western Europe;
- 13.9 bcm from Algeria to Western Europe;

• by LNG tanker:
- 32.0 bcm from Indonesia to OECD Pacific/Other Asia (Japan, Korea, Taiwan);
- 17.9 bcm from Algeria to Western Europe;
- 10.5 bcm from Malaysia to OECD Pacific/Other Asia;
- 7.5 bcm from Brunei to OECD Pacific/Other Asia;
- 6.7 bcm from Australia to OECD Pacific/Other Asia;
- 3.4 bcm from United Arabic Emirates (UAE) to OECD Pacific (Japan).

These trade movements are indicative of prevailing interregional sourcing patterns. At present, Western and Eastern Europe procure extra regional gas mainly from countries of the FSU and from Algeria, while major gas deficit countries/territories in the Far East (Japan, Korea, Taiwan) rely on gas from Indonesia, Malaysia, Brunei, Australia and the Middle East.

Table 4.4 *Trade flows by pipeline; 1993 [bcm]*

Exporter	North America	Latin America	Europe	FSU	Africa	Asia & Australia	Total exports
USA	1.42	1.05					2.47
Canada	60.94						60.94
Bolivia		2.23					2.23
Mexico	0.03						0.03
Denmark			1.61				1.61
Germany			1.50				1.50
Netherlands			43.10				43.10
Norway			24.64				24.64
UK			0.28				0.28
FSU			100.9				100.9
Iran				0.50			0.50
Algeria			13.88		0.55		14.43
Malaysia						1.50	1.50
Total imports	62.39	3.28	185.91	0.50	0.55	1.50	254.13

Source: [20]

Table 4.5 *Trade flows by LNG tanker; 1993 [bcm]*[1]

Exporter	North America	Europe	Asia & Australia	Total exports
USA			1.41	1.41
UAE			3.35	3.35
Algeria	2.32	17.93		20.25
Libya		1.60		1.60
Australia		0.04	6.65	6.69
Brunei			7.54	7.54
Indonesia			31.93	31.93
Malaysia			10.47	10.47
Total imports	2.32	19.57	61.35	83.24

[1] Billion cubic meters of gas, not LNG.

Source: [20]

4.2 Reserves

In this section an overview is presented on data released to the public domain of world gas reserves. First, data is presented on proved reserves from BP publications (Table 4.6) [20]. Second, IIASA's latest published estimates of ultimate recoverable gas reserves [11] are shown and discussed. Finally, estimates of IGU (the International Gas Union) [22] of world gas reserves at the outset of year 1993 are discussed. IGU includes many but not all important current and potential gas producing countries. As will be discussed further below much caution is in order in interpreting reserve estimates because of the many different definitions applied.

Table 4.6 *BP estimates of world proved reserves of natural gas, by region; 1970-1993 (year ultimos) [trillion cubic meters, tcm]*[1]

Region\year	1973	1985	1993	R/P ratio [years]			% of world reserves		
				1973	1985	1993	1973	1985	1993
North America	8.4	8.0	8.4	12.1	12.6	15.2	14.6	10.4	8.5
Western Europe	5.4	4.0	6.4	41.0	22.2	35.9	9.5	5.1	6.5
Eastern Europe	0.3	0.4	0.5	10.1	8.8	9.8	0.6	0.5	0.5
FSU	20.0	31.1	42.5	91.7	77.0	70.8	34.7	40.5	43.1
OECD Pacific	1.5	1.1	0.7	190.1	77.5	36.6	2.6	1.5	0.7
Middle East	11.7	18.5	24.2	353.9	443.6	383.4	20.3	24.1	24.6
Africa	5.3	5.7	5.6	606.8	188.8	118.9	9.2	7.4	5.7
Other Asia	2.3	3.7	5.0	92.3	67.0	54.6	4.0	4.8	5.1
Latin America	2.6	4.4	5.4	70.7	71.7	70.8	4.5	5.7	5.4
World	57.6	76.9	98.7	48.3	52.5	58.9	100.0	100.0	100.0

[1] 1 tcm of natural gas = 38 EJ.

Source: [20]

Table 4.6 gives some trends over the past 30 years of world proved gas reserves, taken from BP publications[11]. BP's published statistics are from government sources and published data. In interpreting these statistics due allowance has to be made for the following factors:

- For reasons of bargaining power with respect to contracts on gas development and gas sales, quite some relevant information known to prospecting oil and gas companies and governments of gas-rich countries is held back from the public domain.
- The assessment and publication of proved reserves is a function of:
  - the world crude oil price;
  - the level of (potential) demand;
  - prevailing gas exploration/development/transportation technology, making the timing of exploration and drilling an important parameter (for a given location: the later the Exploration and Development (E&D) efforts, the higher the estimates of proved reserves); and
  - the priority felt by gas-rich country governments to entice foreign investments toward development of national gas resources.

[11] BP's definition of *proved reserves* is: 'generally taken as those quantities which geological and engineering information indicate with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions'.

- Based on a given set of primary data, inferences made with regard to proved reserves differ. By way of example, assessments made by gas authorities in the USA tend to be more conservative (lower) than assessments by gas authorities in many other countries.
- Mainly because of better accessibility (for political reasons) of gas reserves to the world's major private oil and gas companies, some regions - e.g. North America and Western Europe - have been prospected for oil and gas much more intensively than other regions[12].

Some remarkable trends are brought out by data shown in Table 4.6. First, compared to oil proved gas reserves are more evenly dispersed over the globe. Hence, the consecutive oil price hikes in 1973/74 and 1979/81 and the political ramifications thereof gave a boost to development of gas reserves. Oddly enough, gas as an energy resource was considered inferior to oil before the Yom Kippur war in 1973. Increased gas E&D efforts since 1973 as well as major technological advances resulted in large additions to proved gas reserves as witnessed by the rising quantity of proved world gas reserves (98.7 tcm as per ultimo 1993 versus 57.6 tcm ultimo 1973)[13].

Most regional R/P ratios exhibited an upward trend. As a result, the dependence on gas imports of main energy demand regions is less pronounced than dependence on oil imports. However, additions to reserves have been concentrated in gas-rich regions: FSU and the Middle East[14].

IIASA's latest published estimates on global fossil fuel reserves [8], are reproduced in Tables 4.7a and 4.7b as far as gas is concerned.

[12] Recently accessibility of hydrocarbon reserves in the Middle East, developing countries, and the FSU to the oil and gas majors has greatly increased, due to public finance problems and/or transition toward a market oriented economy.

[13] *Proved gas reserves* are even expected to outstrip *proved oil reserves* in the near future. Current proved gas reserves are equivalent to about 95% of current proved oil reserves.

[14] R/P ratios in these regions have been negatively affected by fast increasing production levels (see Table 4.1).

Table 4.7a *IIASA estimates of conventional and unconventional gas reserves and probabilistic estimates of undiscovered conventional; 1990 [EJ]*[1]

Region\year	Identified reserves of conventional gas[2]		Identified reserves of unconventional gas[2,3]		Undiscovered conventional gas at probability					
					95%[2]		50%[2]		5%[2]	
North America	418.7	(8.7)	669.9	(9.8)	494.0	(18.2)	615.5	(14.0)	1394.2	(12.8)
Western Europe	217.7	(4.5)	301.4	(4.4)	146.5	(5.4)	230.3	(5.2)	535.9	(4.9)
Eastern Europe	0.2	(0.0)	41.9	(0.6)	0.2	(0.0)	0.3	(0.0)	87.9	(0.8)
FSU	1653.8	(34.5)	2051.5	(29.9)	787.1	(29.1)	1310.5	(29.7)	3475.0	(31.9)
OECD Pacific	0.0	(0.0)	0.3	(0.0)	0.1	(0.0)	0.2	(0.0)	54.4	(0.5)
Middle East & North Africa	1578.4	(32.9)	1473.8	(21.5)	632.2	(23.3)	979.7	(22.2)	2064.1	(19.0)
Sub-Saharan Africa	280.5	(5.8)	523.4	(7.6)	171.7	(6.3)	334.9	(7.6)	942.0	(8.7)
Other Asia	251.5	(5.2)	1239.3	(18.0)	284.6	(10.5)	498.3	(11.3)	1272.9	(11.7)
Latin America	263.8	(5.5)	535.9	(7.8)	159.1	(5.9)	385.2	(8.7)	1050.9	(9.7)
Not specified elsewhere	133.5	(2.8)	33.1	(0.5)	33.4	(1.2)	53.8	(1.2)	0.0	(0.0)
World	4798.1	(100.0)	6870.5	(100.0)	2708.9	(100.0)	4408.7	(100.0)	10877.3	(100.0)

[1] 1 tcm = 0.02632 EJ.
[2] Figures in brackets denote preceding column amounts as percentage points of column totals.
[3] Devonian shales, aquifers, and coal-bed methane.

Source: [11]

Table 4.7b *IIASA estimates of conventional and unconventional gas reserves and probabilistic estimates of undiscovered conventional gas; 1990 [trillion cubic meters, tcm]*[1];

Region\year	Identified reserves of conventional gas[2]		Identified reserves of unconventional gas[2,3]		Undiscovered conventional gas at probability					
					95%[2]		50%[2]		5%[2]	
North America	11.0	(8.7)	17.6	(9.8)	13.0	(18.2)	16.2	(14.0)	36.7	(12.8)
Western Europe	5.7	(4.5)	7.9	(4.4)	3.9	(5.4)	6.1	(5.2)	14.1	(4.9)
Eastern Europe	0.0	(0.0)	1.1	(0.6)	0.0	(0.0)	0.0	(0.0)	2.3	(0.8)
FSU	43.5	(34.5)	54.0	(29.9)	20.7	(29.1)	34.5	(29.7)	91.4	(31.9)
OECD Pacific	0.0	(0.0)	0.0	(0.0)	0.0	(0.0)	0.0	(0.0)	1.4	(0.5)
Middle East & North Africa	41.5	(32.9)	38.8	(21.5)	16.6	(23.3)	25.8	(22.2)	54.3	(19.0)
Sub-Saharan Africa	7.4	(5.8)	13.8	(7.6)	4.5	(6.3)	8.8	(7.6)	24.8	(8.7)
Other Asia	6.6	(5.2)	32.6	(18.0)	7.5	(10.5)	13.1	(11.3)	33.5	(11.7)
Latin America	6.9	(5.5)	14.1	(7.8)	4.2	(5.9)	10.1	(8.7)	27.7	(9.7)
Not specified elsewhere	3.5	(2.8)	0.9	(0.5)	0.9	(1.2)	1.4	(1.2)	0.0	(0.0)
World	126.3	(100.0)	180.8	(100.0)	71.3	(100.0)	116.0	(100.0)	286.2	(100.0)

[1] 1 EJ = 38.0 tcm.
[2] Figures in brackets denote preceding column amounts as percentage points of column totals.
[3] Devonian shales, aquifers, and coal-bed methane.

Source: [11]

IIASA puts the world total of:

- identified reserves[15] of conventional gas at 126.3 tcm or 60 times current annual world gas production [23];
- additional potential reserves of conventional gas (undiscovered reserves) at 116.0 tcm[16] (55 times current annual gas production);
- identified reserves of unconventional gas at 180.8 tcm (86 times current annual gas production).

IIASA's estimates of potential reserves of gas encompass an intrinsically speculative element. Yet, the IIASA's figures on conventional reserves suggest that, *contingent on the rate of growth of gas extraction and the future price of gas, depletion of world's conventional gas resources is not likely to become a real issue until well into the 21th century*. Estimates by IGU of total world gas reserves [22] (Table 4.8) corroborate this conclusion.

Table 4.8 *IGU estimates of world gas reserves as of 1 January 1993 [trillion cubic meters, tcm]*[1]

Region	Proved reserves		Additional reserves		Total reserves	
	[tcm]	[%]	[tcm]	[%]	[tcm]	[%]
North America	9.43	6.6	53.65	21.1	63.08	15.9
Western Europe	6.49	4.5	5.58	2.2	12.07	3.0
Eastern Europe, FSU	55.80	38.9	103.25	40.6	159.05	40.0
Middle East	44.81	31.2	29.43	11.6	74.24	18.7
OECD Pacific, Other Asia	12.35	8.6	45.20	17.8	57.54	14.5
Africa	9.00	6.3	10.50	4.1	19.50	4.9
Latin America	5.57	3.9	6.76	2.7	12.33	3.1
World	143.45	100.0	254.37	100.0	397.81	100.0

[1] 1 tcm = 0.02632 EJ.

Source: [22]

IGU's estimate of *proved* reserves at world level is clearly higher than BP's with a world total of 143 tcm against a BP estimate of 99 tcm. It is even higher than IIASA's estimate of *identified* reserves (see footnote 15). IGU's estimate of *total reserves* is also quite high: 398 tcm or 190 times current annual gas production. This estimate of *total reserves* is close to that of IIASA (identified reserves of conventional and unconventional reserves plus undiscovered conventional reserves), namely 423 tcm (Table 4.7b).

As far as the distribution of gas reserves over the regions is concerned, the pattern is broadly similar to the ones of BP's and IIASA's estimates. One striking distinguishing feature of IGU's estimates is the high estimate of additional (economically) recoverable reserves in North America. This is partly accounted for by IGU's reclassification of Mexico as being a North-American country. Next, information given from the IGU publication [22] is summarized on the regional gas supply situation with emphasis put

[15] '*Identified reserves*' include approximately economically recoverable proved, probable, and possible reserves in an American sense and hence incorporate significantly more resources than commonly reported *proved reserves*.

[16] A quantity of 116.0 tcm at 50% probability (Table 4.7b).

on world regions that are of major significance to the European gas market. For each of the various regions the following characteristics can be given.

North America

Gas resources in North America are fairly abundant. This region has made major strides in improving production technologies. Stepping up and even maintaining current high levels of production require a massive inflow of investment resources and rapid dissemination of technology. A salient feature is that in this region the extraction of non-conventional gas resources (tight formation gas, coal-bed methane, shale gas) is predicted to assume a role of modest but increasing importance in the foreseeable future.

Western Europe

Western Europe has a fairly moderate gas resource base in relation to steadily growing demand levels. IGU puts current proved recoverable reserves at 6.5 tcm and additional recoverable reserves at 5.6 tcm. Reserves in Norway, UK and the Netherlands correspond to 87% of total reserves. The region is bound to reach its indigenous gas supply plateau in the near future. Roughly 80% of present reserves are offshore. State-of-the-art technology will be essential for the region's future gas development. IGU puts the region's supply potential at 259-279 bcm in year 2000 and 165-206 in 2020 against 196 bcm of indigenous supply in 1992[17].

Eastern Europe (EE)

The EE countries are poorly endowed with gas, rendering this region importantly import-dependent. Annual production of gas amounted to 29 bcm in 1992 and is set to taper off to 15-20 bcm in 2020.

Former Soviet Union (FSU)

The FSU encompasses the highest amount of proved and additional recoverable reserves, 54.6 tcm and 102.0 tcm respectively. Russia possesses the bulk of the gas resources in the FSU (especially various mega fields on the Yamal peninsula, north-western Siberia), but also Turkmenistan, Kazakhstan and Uzbekistan have substantial gas production and export potential. A pipeline from Central Asia to northern China is presently under serious consideration. Future gas supply development is surrounded with uncertainty by the volatile political and economic situation. IGU forecasts a supply potential of the FSU of 1,010-1,030 bcm in year 2000 and 1,030-1,190 bcm in 2020 against an actual level of 728 bcm in 1992[18].

Middle East

Another region very well endowed with low-cost (at wellhead) natural gas is the Middle East with 44.8 tcm of proved and 29.4 tcm of additional recoverable reserves. Half of the region's proved reserves are located in Iran, while other countries with major reserves are Qatar, the UAE, Saudi Arabia, Iraq and Kuwait. Iran and Qatar share the largest non-associated gas field in the world. Whereas a number of ambitious interre-

[17] Prof. Odell, who kindly commented on a previous draft, deems the IGU projections for Western Europe to be much too conservative. He holds much higher expectations with regard to future gas production on the continental shelves off Norway and the UK.

[18] Jonathan Stern in a recent, well-documented, publication [21] reckons for Russia with a very large surplus supply potential of low-cost gas. He expects European markets to be flooded with low-cost gas. Yet, this report's authors consider Stern's expectations on prospective domestic (FSU) gas demand to be on the low side, while Stern's unit cost projections would seem too low.

gional pipeline proposals have been floated, the region's most straightforward option to cash in on its gas wealth is LNG. Of any conceivable interregional pipeline project, a pipeline to FSU would seem the most likely to the authors of this report, contingent on the solution of some tedious political issues (e.g. unstable conditions in the Caucasus region). Such a pipeline would enable economically sound swaps of gas export contracts between Iran and southern FSU on one hand and between (northern) Russia and Western Europe on the other, enabling both Iran and gas-rich FSU countries to bolster foreign exchange earnings. Alternatively, should India's economy continue to show solid growth rates, a pipeline to the Indian subcontinent and even further (South-China, SE Asia), may also become feasible. IGU foresees an increase in the region's annual supply potential from 117 bcm in 1992 to 166-193 bcm in 2000 and 267-237 bcm in 2020. Finding market outlets with an acceptable profitability and raising the capital resources required are two major constraints.

Other Asia
In other Asia, including OECD Pacific, the distribution of the gas resource base is rather uneven. Almost one third of gas production is exported from gas-rich countries such as Indonesia, Malaysia, Brunei and Australia to gas-poor Japan, Korea and Taiwan. Many countries in Asia are experiencing high economic growth with an attendant upbeat energy market. Future gas import demand within the region will to some extent be met extra regionally, i.e. from the Middle East and probably from Central Asia and Russia (eastern Siberia) as well.

Africa
IGU estimates Africa's proved gas reserves at 9.0 tcm and additional recoverable reserves at 10.5 tcm, 90% of which in Algeria, Libya, Nigeria and Egypt. In total some 20 countries in Africa have significant proved gas reserves. In the near future the following major developments are envisaged:

- the TRANSMED (Algeria-Tunisia-Italy) pipeline capacity will double to 30 bcm/-year;
- construction of the MAGHREB (Algeria-Morocco-Spain) pipeline with a design capacity of about 10 bcm/year is nearing completion;
- LNG facilities in Algeria and Libya are upgraded and new ones are under construction that may increase liquefaction capacity to 40 bcm/year;
- should gas prices rebound from current depressed levels, Nigeria has the potential to become the second largest producer in Africa; a major LNG project bound to cater for the European and US gas markets is expected to be in place by the end of the century;
- Africa's supply potential, especially in North Africa, may increase from 74 bcm/year in 1992 to 140-152 bcm/year in 2000 and to 174-227 bcm in 2020.

South America
South America is well endowed with gas reserves. Venezuela accounts for 65% of all proved reserves in South America, i.e. 5.6 tcm as per 1 January 1993 (excluding Mexico). Most of South America's gas production will cater to indigenous demand. Exports of LNG are envisaged for Venezuela, that could also play a marginal role for the European market.

4.3 Sourcing and costs of incremental European gas supply

Sourcing patterns are not only determined by gas economics. Political expediency is an important complementary factor. Consuming countries tend to accept a gas price that sets some premium on enhanced supply security. Supply security can be enhanced by way of sourcing patterns:

- that entail a relatively well diversified portfolio of contracts for future gas supply;
- that imply access to a substantial share of world gas reserves with a perspective of supply continuity in the more distanced future;
- that give a relatively high weight to producing countries and gas transit countries (pipelines) perceived to be politically stable.

Moreover, in some instances the same line of reasoning may well prompt future mega investments in LNG transport facilities in some gas producing countries (e.g. possibly Iran and Nigeria) to the exclusion of mega investments in interregional pipeline options that could on the one hand imply lower 'technical' unit transport costs (excluding transit fees) but on the other hand involve perceived high-risk gas transit countries.

Other factors that count in shaping future gas supply patterns are (see i.a. [24]):

- the ability to meet possible demand in gas-deficit countries at reasonable cost relative to competing supply options;
- the speed at which this supply could be made available (boosting supplies from existing mega fields and, proximate 'satelite' fields can occur at much shorter notice than new development of major reservoirs with typical lead times for the latter of 6-10 years);
- as distinct from oil and - if to a lesser extent - coal, gas transport denotes a very substantial cost component in gas supply from remote reservoirs; gas transport infrastructure development incurs huge capital resources;
- timely development of transport infrastructure with, if applicable, a judicious compromise between cost effectiveness and prospects for operational reliability in transit countries.

In the foreseeable future the following sourcing patterns of - widening - regional gas production deficits in Europe and the Far East are envisaged:

- for Western and Eastern Europe: FSU (pipeline), Algeria (mainly pipeline, the remainder LNG), Middle East (LNG, possibly pipeline), Nigeria (LNG), and possibly Venezuela (LNG); Table 4.9 shows projections of future European gas demand and gas sourcing patterns;
- for OECD Pacific/ Other Asia (Japan, Korea, Taiwan): Indonesia (LNG), Malaysia (LNG), Australia (LNG), Brunei (LNG), Middle East (LNG) and possibly Central Asia (pipeline) and Siberia (pipeline).

What levels of incremental gas supply to the EU-15 have to be secured for the period up to year 2020? Table 4.9 brings out that indigenous supply of non-FSU Europe is expected to reach its plateau before the turn of the century and to gradually diminish thereafter.

Table 4.9 *Projections of European gas demand and supply; 2000-2010 [bcm]*

	Actual		Projections				IPCC			
			IEA		Eurogas[1]		(1992)[2]			
		(1991)		(1993)		2000	2020	2000	2020	
	1990	1993	2000	2010	2000	2010	Scen. IS92a	Scen. IS92a	Scen. IS92c	Scen. IS92c
Demand										
Western Europe[1]	255	289	370-390	450-480	325	387	345	379	292	234
Eastern Europe	75	62	90-110	120-170			103	121	87	89
Total	331	351	460-500	570-650			447	500	379	324
Supply										
Intraregional supply										
Western Europe[1]	158	187	171-186	151-176	172	124	172	120	172	120
Eastern Europe	32	27	10-30	10-20			20	15	20	15
Contracted imports from outside EU-15[3]										
Western Europe from:										
- Norway	26	24,83	32-39	37-39	31	37	37	37	37	37
- FSU	60	60	63-67	63-67	54	54	54	54	54	54
- Algeria	28	32	38-40	38-40	38	38	38	38	38	38
Eastern Europe from:										
- FSU	40	40	40	40			40	40	40	40
Total[3]	344	372	361-407	346-392	296	253	341	289	341	289
To be contracted[4]	-	-	53-139	178-304	29	134	106	211	38	35
Memorandum items:										
National gas production										
- Netherlands	61	70			65	54				
- UK	47	63			66	34				
- Italy	17	19			19	17				
- Germany	18	18			15	13				
- Denmark	3	4			6	6				

[1] Projections under Eurogas on EU-15 only.
[2] Supply projections in 'IPCC' columns (last four columns) are imputed by the authors.
[3] Including envisaged contract renewals and contract extensions.
[4] Projections 'to be contracted' disregard the coverage of intraregional transport losses.

Sources: [22] and additional unpublished Eurogas data

As for the European Union (EU), present public-domain knowledge suggests that contracted imports in addition to new indigenous supplies (mainly high-cost offshore gas from offshore UK) are bound to fall short of the drop in supplies from currently productive indigenous sources. According to unpublished Eurogas projections, further incremental gas supplies to the European Union totalling 29 bcm in year 2000 and 134 bcm in 2010 have to be contracted[19].

IPCC reference scenario IS92a forecasts a European gas demand of 447 bcm (13.7 EJ) and 500 bcm (14.4 EJ) in years 2000 and 2020 respectively[20]. At the projected volumes of indigenous supply and contracted imports shown in Table 4.9, incremental supplies have to be secured for non-FSU Europe to the tune of 106 bcm/year in year

[19] Once more it is stated that some analysts (i.a. Prof. Odell) consider these projections to be too pessimistic, especially as far as gas supply from the UK and Norway is concerned.

[20] As stated already, at the request of the Dutch Ministry of Housing, Spacial Planning and Environment (Directorate General Environment) special consideration has been given to the IPCC scenarios IS92a and IS92c.

2000 and 211 bcm in 2020. Under IPCC's scenario IS92c, Europe's incremental gas supply requirements would be substantially lower, i.e. 8 bcm in 2000 and 35 bcm in 2020.

The next point to raise is the costs of incremental European gas supplies. In fact, it is quite hard to get hold of reliable information on gas supply costs (without access to classified information). For one thing, tradability of gas is hampered by high transport costs in relation to its CIF market value, while for gas development and transport very lumpy investments have to be incurred. Therefore, border prices are poor indicators of supply costs. For another, the international market for gas - at least in Europe and the Far East - still tends to be dominated by relatively few selling and buying agencies. In such a situation, market players on both sides try to make a good assessment of their mutual negotiation margin. Buyers try to estimate genuine supply costs, while sellers try to estimate what 'the market can bear' through net-back pricing exercises. Under the given circumstances, major stakeholders in gas production and marketing (governments of gas-producing countries, the oil and gas majors, and major gas buying agencies in export markets) will tend to be reluctant to 'show their cards', i.e., to divulge much information on relevant negotiation margins regarding the gas supply price and the government take. Hence, unbiased and detailed supply cost information is not readily available.

Nonetheless, much effort has been made to make realistic estimates of the order of magnitude of major cost components for envisioned major sources of incremental European gas supply. Estimates have been based on:
- scattered cost data published in specialist journals (Oil & Gas Journal a.o.);
- relevant studies (including [25,26,27]);
- personal communications of knowledgeable experts.

Resulting unit gas cost estimates for future incremental Western European gas supply at present prices are shown in Table 4.10. Two main cost components have been distinguished, i.e. production costs and transport costs. When applicable, transport costs have been broken down further into 'technical costs' and 'transit fees'.

Gas production costs encompass exploration and development costs, including gas treatment (in addition to the cost of transport to the gas treatment facilities) and a notional 0.5 $/mbtu resource rent appropriation by the government in the producing country. Accordingly, it is assumed that a lower government take otherwise than over a short period will be unacceptable to gas-producing countries. Production costs imputed in Table 4.10 are based on i.a. [25] and contain a speculative element, as no reliable quantitative information is available in the public domain.

Table 4.10 *Tentative production cost estimates for main sources of incremental natural gas supply to Europe [$/mbtu]*

Departure	Via/to	Total pipeline length (km)	Length in in third countries	No. of third countries crossed	LNG distance (naut. miles)	Transport cost Technical cost	Transit cost	Total[2] fees	Production cost	Total supply
Pipeline										
Norway: Troll	Germany	1300				1.5		1.5	2.0	3.5
Norway: Tromm	Germany	2700				2.6		2.6	2.4	5.0
Russia: Yamal	Belarus	4200	1300	2		1.8	0.4	2.2	1.8	4.0
Algeria	Italy	1100	300	1		0.9	0.1	1.0	1.7	2.7
Iran	Ukraine	4800	3200	5		2.5	1.0	3.5	1.3	4.8
LNG										
Qatar/Iran	Europe				3600	2.8		2.8	1.3	4.1
Nigeria	Spain				4000	2.8		2.8	1.5	4.3

[1] Exploration and development cost, including gas treatment and 0.5 $/mbtu government take.

Source: [25]

Very low wellhead costs have been reported for major Middle East reservoirs, notably the common North Field (Qatar)/South Pars Field (Iran). Also in Nigeria and Algeria incremental supplies can be made available at low production cost. As a result of geological and/or climate circumstances gas from northwestern Siberia and from offshore Norwegian reservoirs are being or can be developed for incremental supplies at relatively high cost. This is especially applicable to large Northern Norwegian reservoirs (such as Tromm) and offshore northwestern Siberian reservoirs.

Technical international gas transmission costs were based on a simple cost model, and unpublished expert data. As a result of the break-up of the FSU and the importance of Russian gas to gas markets in Western and Eastern Europe, the political dimension of gas transit fees is getting increasing attention. For example, in October 1992 Russian gas exports to Germany were cut by 75% for a week because of a Russian-Ukrainian dispute over gas payments [28]. A rate of 0.03 $/mbtu per 100 km of third country, was used to assess the transit fee element. Based on the cost estimates presented in Table 4.10 and projected incremental supply capacities an incremental European gas supply curve has been made over a range of 220 bcm per annum, shown in Figure 4.1.

Total costs per unit of incremental gas supply to Western and (non-FSU) Eastern Europe are estimated to vary between 2.7 $/mbtu for pipeline gas from Algeria delivered to Italy and 5.0 $/mbtu for gas originating from offshore arctic Norwegian. This range indicates the minimum required CIF border price of gas supply to Europe.

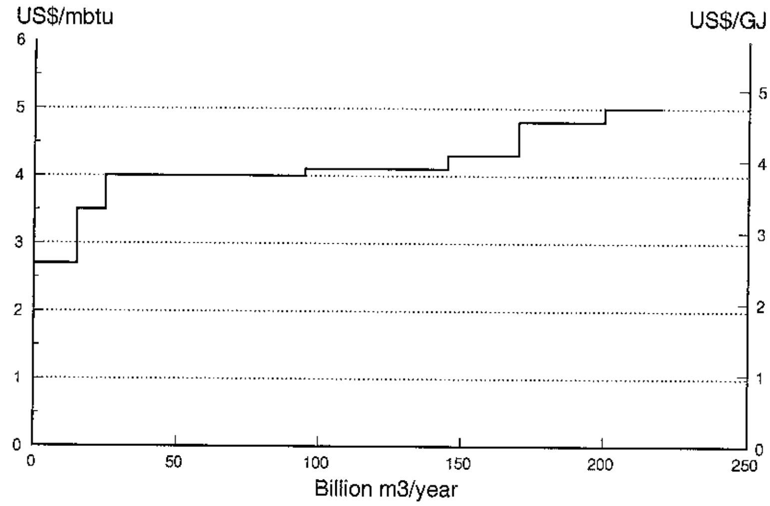

Figure 4.1 *Incremental European gas supply curve at 1993 costs*

Natural gas prices derived from this supply curve should be compared with the minimum required oil prices for the same scenario (see Chapter 3). If there would be a wide margin in favour of natural gas, this would indicate a distortion of a competitive market, which could be interpreted as follows:

- either a relatively low gas price compared to the oil equivalent is the consequence of temporarily abundant gas supplies;
- or, which is more representative for long term conditions, gas prices will be lift near to the price of the equivalent oil product, as gas suppliers are aware of its market value as an environmentally benign energy carrier.

4.4 Factors affecting supply costs

High levels of oil and gas exploration and development activities coupled with falling oil and gas prices as from 1981 created serious cash flow problems for the drilling industry. Companies had to address with an urgent need to streamline operations, to increase efficiency and to reduce cost. Technologies aimed at reducing costs or improving recoveries came into use and set new industry standards. What has been a relatively stagnant technology of gas recovery in early years showed marked improvement by the mid-1980s. Typical of the new improvements are:

- the use of improved computer technology linked with three dimensional seismic data;
- improved drilling procedures (e.g. slim hole drilling, horizontal drilling);
- advanced sub-sea production technologies;
- deepwater technologies, such as floating platforms;
- measurement while drilling;
- improved fracturing in low permeability formations;
- improved well completion techniques.

As a result, many more gas deposits, such as coal-bed methane, are now economically suitable for production and the search for economic reservoirs has become more efficient (IGU, [22]). The trend toward increasing productivity and attendant cost reductions in E&D costs of gas reserves is likely to continue for some time. However, as with E&D and production costs of oil the trend could reverse, reflecting more harsh (production) conditions (deep sea, arctic or semi-arctic reserves).

For the most important component of the bulk of European gas supplies, transportation, no major cost reductions are foreseen. There is some scope for realising economies of scale in LNG transport. Present state-of-the-art LNG tankers have a capacity of some 135,000 DWT. In the medium term, tankers with 200,000 DWT capacity may become feasible. Yet, as such tankers would require further high-cost expansion of LNG facilities, including porthandling facilities, total transport cost reductions would be relatively small. The prospects for major cost reductions in gas pipeline transport look even more remote. Notably in countries in transition like Russia, the cost of major cost components, such as right-of-way and labour, may even go up in real terms.

The scope for reductions in the minimum required prices (in real terms) for incremental gas supplies to Europe is limited. Over the period 1995-2020 a downward shift of the incremental supply curve within a margin up to 0.5 $/mbtu is a possibility to be allowed for. A higher downward shift seems unlikely.

4.5 Price prospects

As noted already, three major import markets for internationally traded gas exist, i.e. (Western and non-FSU Eastern) Europe, the Far East (Japan, Korea, Taiwan) and North America. Major price movements in one of these markets tends to be transmitted to the others through price arbitration as a result of oil/coal-to-gas or gas-to-gas competition. This is brought out by year-to-year price movements as shown in Table 4.10.

Oil/coal-to-gas competition is caused by the fact that gas is a substitute:
- for oil and coal in power generation, i.e. for diesel oil in producing peaking power and for fuel oil and coal in base load;
- for light fuel oil (space heating), LPG and kerosene (cooking) in the household sector;
- for fuel oil (boilers) in the industrial sector;
- possibly for gasoline and diesel in the transportation sector (Compressed Natural Gas, CNG).

Interregional gas-to-gas competition is a relatively new phenomenon, mainly as a result of LNG trade. For instance, Middle-East LNG exporters have the option to sell to the Far East (European clients), either through contracts or on the spot market, when European importers (importers from the Far East) do not offer an attractive price.

Significant short-term deviations of the actual price of gas from the long-run marginal costs of gas supply can occur. The following factors are significant in determining the level of border prices for natural gas [29]:
1. the long-run marginal costs of gas supply;
2. oil/coal-to-gas competition;
3. gas-to-gas competition;
4. policies in gas-producing countries regarding government take.

Long-run marginal supply costs

In the short run, marginal costs of gas supply depend on the operating costs. Compared to the capital cost, operating costs of marginal gas supplies tend to be low. Once expensive gas production and transportation infrastructure is in place, cash-strapped gas supply agents meeting less favourable market circumstances than foreseen at the time of the investment decisions may consider (part of) the capital cost as sunk cost. In turn, this can occasion short-term price movements to levels far below long-term marginal costs. However, border prices below the minimum required supply price cannot last without jeopardising supply security. This is because eventually new high-cost sources of supply have to meet future demand, as demand is bound to rise while currently producing wells will eventually be depleted. Potential investing agents (gas supply and distribution agencies of gas-producing and gas-consuming countries as well as private gas production companies) are unlikely to be disposed to put up high capital requirements to develop new sources unless they perceive the probability of generating acceptable profits on risky giant investments as adequate. Such an event is not likely at actually loss-generating gas prices.

Oil/coal-to-gas competition

Once connected to the gas distribution networks, to most consumers gas is the preferred fossil fuel because its convenience of use. Moreover, the premium consumers are prepared to pay for gas over competing fueloil or coal may be boosted because of environmental regulations. In some countries, e.g. in Germany, fueloil and coal become increasingly less acceptable as alternative fuel, thereby raising the netback value of gas for the pertinent applications as this value may be based on the next closest, more expensive substitute, e.g. gasoil in the case of thermal power plants.

Gas-to-gas competition

In the USA gas-to-gas competition is presently very strong. This is so as the gas market in this country is well developed with many buyers and sellers. Second, the pipeline infrastructure in this country for gas transmission and distribution leaves buying agents with multiple options to meet their requirements from different sources. Third, recent advances in gas production technology have occasioned a, probably, temporary gas bubble hanging over the market. These conditions enabled the US government to introduce radical competition-bolstering regulations, such as Third Party Access (TPA) to gas pipelines. For the time being, introduction of equally far-reaching regulations in the EU appears be less appropriate, as gas industry in Europe still has, by and large, by far less options to meet requirements. Moreover, the giant investments needed in the development of new gas supplies would be jeopardised by market volatility that would result from an early complete liberalisation of the European gas market.

Government take

The government take is a flexible component that denotes a cost from a private perspective. From a societal point of view, in as far as the tax payments are made by national entities the tax component should be considered as a transfer payment rather than a cost component. By changing the level of the government take governments can influence exploration and development activity levels in their area of jurisdiction.

As noted already, three major import markets for internationally traded gas exist, i.e. (Western and non-FSU Eastern) Europe, the Far East (Japan, Korea, Taiwan) and

North America. Major price movements in one of these markets tends to be transmitted to the others through price arbitration as a result of oil/coal-to-gas or gas-to-gas competition. This is brought out by year-to-year price movements in Table 4.11 [22,30,31].

Table 4.11 *Border (CIF) prices on major markets [$/mbtu]*[1]

Year	Gas			Crude oil
	United States	Western Europe[2]	Japan[3]	OECD[3]
1980	4.42	3.35	5.01	5.71
1981	4.84	4.00	5.83	6.35
1982	4.94	4.65	5.74	5.91
1983	4.51	3.95	5.16	5.22
1984	4.08	3.85	4.90	5.06
1985	3.19	3.45	4.99	4.81
1986	2.53	2.65	3.98	2.61
1987	2.17	2.20	3.29	3.13
1988	2.00	2.10	3.22	2.59
1989	2.04	2.15	3.26	3.05
1990	2.03	3.05	3.60	3.87
1991	2.02	2.60	3.98	3.37
1992	1.97	2.63	3.61	3.23
1993	1.98	2.43	3.51	2.86

1 For LNG imports: price before regasification.
2 Average of import price interval. Price at mid-year.
3 For LNG imports: price before regasification. For oil: average costs of IEA oil imports.

Sources: [22,30,31]

Furthermore, Table 4.12 shows recent European border prices [32]. If the costs of incremental supply in Figure 4.1 hold true, current European gas prices are well below minimum required prices for incremental supplies. This would imply, that gas prices have to go up sooner or later in order to secure adequate long-term gas supplies. Figure 4.1 suggests that European border prices have to go up to 4 $/mbtu or more to enable the investments needed for making the European market accessible to supply from the Yamal peninsula and the Middle East.

Table 4.12 *European border prices of gas; November 1, 1994 [$/mbtu]*

From:	FSU	Netherlands	Norway	Algeria[1]	Libya[1]	Average
To:						
Belgium		2.64	2.39	2.73		2.69
France	2.49	2.65	2.45	2.89		2.62
Germany	2.44	2.63	2.41			2.49
Italy	2.43	2.65		2.78		2.62
Netherlands			2.43			2.43
Spain			2.56	2.58	2.73	2.62
United Kingdom			2.43			2.43
Average	2.45	2.64	2.45	2.75	2.73	2.57

Source: [32]

5. COAL: MARKET, RESERVES, COSTS

5.1 Introduction

World coal resources are large, and can meet demand for a much longer time than oil and natural gas. Some countries - USA, China, India, Japan, South Korea, Taiwan - show a rising coal demand. On a global scale, coal demand has been relatively stable over the last few years. Substitution of coal for oil and gas is impeded by low fossil fuel prices. Considering the current excess capacity in coal mining, and the modest role of internationally traded coal (some 10% of world coal production), it will be relatively easy to meet future coal demand from mines in the production or development stage and from additional mines.

One of the problems gaining momentum on the political agenda is the global warming effect of CO_2 emission from fossil fuel combustion and deforestation. If the CO_2 problem would prove to be as serious as some publications from the IPCC (Intergovernmental Panel on Climate Change) do indicate, of all fossil fuels demand for coal were to be affected most negatively.

In the following sections the availability and production costs of coal will be highlighted. At first trends in seaborne coal trade and coal prices for electricity generation in the Netherlands will be analysed. For the main coal exporting regions supply curves for steam coal are presented, as well as a cumulative supply curve for coal from those regions destined for Europe.

5.2 Supply and demand trends

5.2.1 Trends in seaborne steam coal trade

International coal exports (metallurgical and steam coal) have increased dramatically, as shown in Table 5.1 [33,34]. Also the average length of haul increased strongly to 5,600 miles in 1990 (Figure 5.1) [30]. Several (interdependent) factors contribute to the growth of worldwide trade:

- new and enlarged coal ports in coal exporting countries; and
- increasing tonnage of bulk carriers.

Table 5.1 *Seaborne coal trade 1965-1993 [million tonne]*

Exporting country	1965	1970	1975	1980	1985	1990	1993
Australia	7.1	18.3	29.9	42.8	88.6	106.1	131.8
USA	31.4	47.5	44.4	66.1	69.2	81.9	67.2
South Africa	0.7	1.3	2.7	27.9	44.5	49.5	51.2
Canada	0.9	4.0	11.7	15.3	27.3	29.6	28.3
Poland	7.4	14.7	22.7	19.3	18.6	17.3	25.0
China	-	-	-	-	3.0	17.0	19.8
Russia	5.9	7.7	8.3	5.3	6.7	7.0	19.2
Indonesia	-	-	-	-	1.0	4.7	19.0
Colombia	-	-	-	-	5.0	15.0	16.9
Others	5.8	7.7	7.7	11.1	7.0	13.0	7.4
Total	59.2	101.2	127.4	187.8	270.9	341.0	385.8

Sources: [33,34]

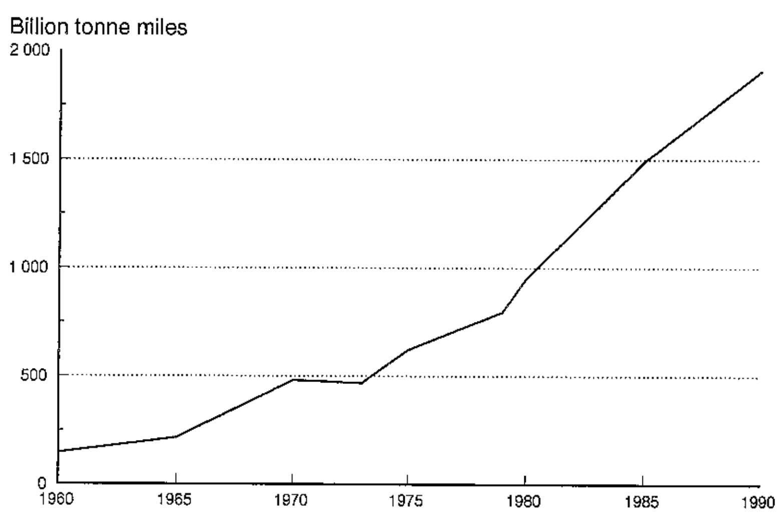

Figure 5.1 *Total distance of coal hauls; 1960-1990 [billion tonne mile]*

Source: [33]

Both factors reflect the rise in international steam coal demand, following the oil crises in 1973 and 1979. Coal exporting countries and coal traders have made massive investments in new mining, handling and transport capability: mines, ports and bulk carriers. In Australia foreign investments (Japan, USA, South Korea) are welcomed and become regular [35].

The development of demand for seaborne steam coal is illustrated by Figure 5.2. Note that some regions, notably China and North America, are characterised by a very high coal demand from indigenous supply.

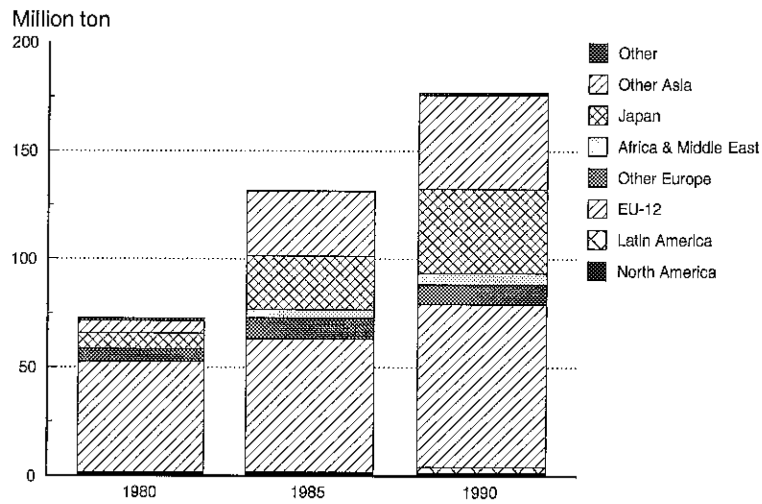

Figure 5.2 *Demand for seaborne steam coal by region, 1980-1990*
Source: [33]

Europe, Japan and other Asian countries have demonstrated the largest increase in overseas coal demand. In other parts of the world (Latin America, Africa, Middle East) demand for steam coal is more modest. In the former Soviet Union and Eastern Europe steam coal production and demand generally has declined steeply since demise of communist regimes and the subsequent economical downturn.

It is an open question whether seaborne steam coal demand will continue to rise, or will decline sooner or later due to policies to mitigate global warming. The development of seaborne steam coal trade will mainly depend on economic growth in different parts of the world, on prospective measures of individual countries and country groupings (Japan, NAFTA, EU) to counter the global warming effect of CO_2 and other greenhouse gases, and on price developments of competing fuels. All in all, demand prospects are uncertain.

5.2.2 Trends for the Dutch power sector

Coal demand for power generation in the Netherlands soared from the years of construction and retrofitting of coal fired power plants until 1988. Since then coal use by power plants has stabilised (Figure 5.3) [36].

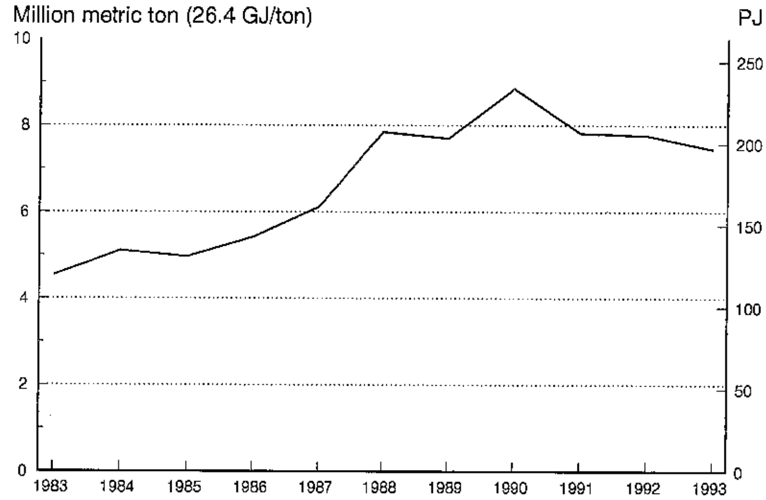

Figure 5.3 *Coal use for electricity generation in the Netherlands*
Source: [36]

The origin of steam coal is mainly determined by production capacities and prices of coal exporting countries. Sometimes political factors are at stake (South Africa until 1992). Some countries (China) have difficulty to supply high quality export coal. Also fluctuations in freight tariffs can cause shifts in the supply of coal. In recent years coal originated from Australia, the USA, Columbia, South Africa, Poland, and Indonesia [37] (Figure 5.4).

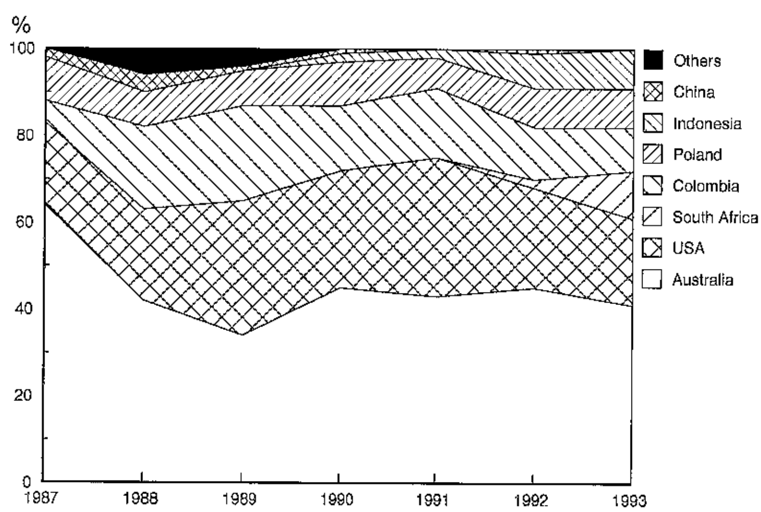

Figure 5.4 *Origin of steam coal for power plants in the Netherlands*
Source: [37]

Roughly half of coal demand is met by long term contracts. Yearly and spot or option contracts are the alternatives. Figure 5.5 gives an overview of volumes contracted under different forms in recent years [37].

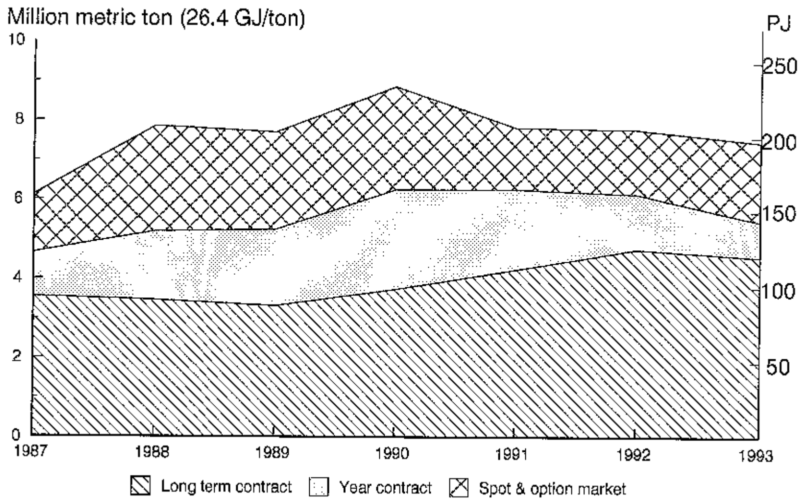

Figure 5.5 *Contract modes for coal imported for Dutch power plants*
Source: [37]

Differences in contract form can also influence coal prices. It proves that options and spot contracts are gaining importance. This could be caused by low fuel prices and expectations of stable fossil fuel prices in the years to come. In the Netherlands the stiff competition between natural gas and coal in the power generation market is a reason to give ample room for options and spot contracts instead of long term and yearly contracts [37].

Factors described above - country of origin, transport distance, freight rates, contract mode - influence coal prices. Also transport costs in the Netherlands - mostly by barge - and environmental taxes have to be considered. Figure 5.6 presents costs at the power plant site, based on FOB costs, transport costs, inland transport, and environmental taxes [34].

Coal prices in Figure 5.6 have not been discounted to the year 1993. It is evident that FOB coal prices decreased in real terms in the last few years. The same holds for ocean freight rates for steam coal. However, the suggestion that coal prices will keep on falling, is highly hypothetical.

An in-depth analysis has to focus on factors accounting for mining costs, inland transport costs, and marine transport costs. The effect of rising productivity - which has been spectacular indeed in most countries concerned - will ultimately be offset by the effects of depletion of coal from relatively cheap (and near-coast) resources in exporting countries. It is a matter of time when worldwide production costs for export coal will begin to rise. To predict this moment for each region and for each level of international steam coal demand is not easy or even impossible. Not only relatively expensive development of new (deeper or thinner) seams in existing mines and the opening of completely new mines are factors of concern, but also more stringent environmental regulation in some cases.

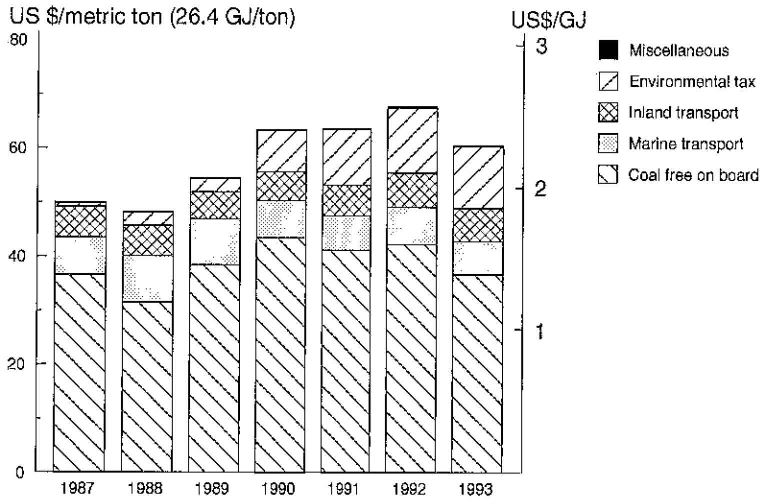

Figure 5.6 *Factors determining the coal price for electricity generation*
Source: [37]

5.3 Reserves - trends and prospects

World coal reserves are large by any standard. BP [6] presents a total figure of 1,040 billion metric tonnes, with a Reserve/Production (R/P) ratio of almost 240 years. Two points need attention:
- There is significant difference in R/P ratio for hard coal and lignite.
- Some countries have larger reserves than the BP review assumes.

For instance, in situ reserves of New Zealand have been estimated at 15 billion tonnes, more than half of which is potentially recoverable [38]. This potentially recoverable reserve has been split up in 2.5 billion tonnes of hard coal and 5.0 billion tonnes of lignite/subbituminous. The resulting world coal reserves and R/P ratios per country or region are presented in Table 5.2 [6,39]. The R/P ratio for world's hard coal reserves proves to be about 165 years, and for lignite even 500 years.

Reserves according to the international classification (Table 5.2) comprise:
- measured and indicated reserves; and
- inferred reserves.

Table 5.2 *World coal reserves, end 1993 [million tonnes]*

Country/region	*Hard coal (HC)*	*Lignite (LIG)*	*Total*	*Share [%]*	*R/P ratio (HC/ LIG)*
USA	112,668	127,892	240,560	23.0	203/426
Canada	4,509	4,114	8,623	0.8	84/407
Brazil	-	2,359	2,359	0.2	357
Columbia	4,240	299	4,539	0.4	190
Mexico	1,252	468	1,720	0.2	125/≥500
Venezuela	417	-	417	‰	107
Other LA[1]	991	1,404	2,395	0.2	135
France	178	32	210	‰	20/19
Germany	23,919	56,150	80,069	7.6	373/253
Greece	-	3,000	3,000	0.3	56
Turkey	162	6,986	7,148	0.7	32/140
UK	3,300	500	3,800	0.4	49/≥500
Other OECD[1]	1,774	993	2,767	0.3	125/57
Former SU	104,000	137,000	241,000	23.0	222/≥500
Poland	29,600	11,600	41,200	3.9	227/171
Other Europe	2,567	30,682	33,249	3.2	148/183
South Africa	55,333	-	55,333	5.3	304
Zimbabwe	734	-	734	0.1	≥500
Other Africa	4,744	1,267	6,011	0.6	≥500/≥500
Middle East	193	-	193	‰	143
Australia	45,340	45,600	90,940	8.7	249/≥500
New Zealand	≈ 2,500	≈ 5,000	≈ 7,500	0.7	≥500/≥500
China	62,200	52,300	114,500	10.9	59/≥500
India	60,648	1,900	62,548	6.0	261/112
Indonesia	962	31,101	32,063	3.1	35/≥500
Japan	827	17	844	0.1	115/≥500
South Korea	203	-	203	‰	21
Taiwan	100	-	100	‰	200
Other Asia	525	2,085	2,610	0.2	20/≥500
Total world	523,886	522,679	1,046,655	100	165/500

[1] LA: Latin America; Other OECD: Other OECD Europe.

With ongoing geological research, resources evolve from 'hypothetical' into 'proven'. For in situ resources of bituminous coal in South Africa a maximum depth of 300 and a minimum seam thickness of 1.2 m are specified [40]. In the USA the 'reserve base' is characterised by a distance of <1.2 km between points of observation, and the 'inferred reserve base' by a distance of 1.2-5 km. According to [41] proven reserves require boreholes with an intervening distance of 400 meter. Figure 5.7 shows measured & indicated resources on one hand, and inferred resources on the other hand, of New South Wales [42] based on total 89 billion metric ton.

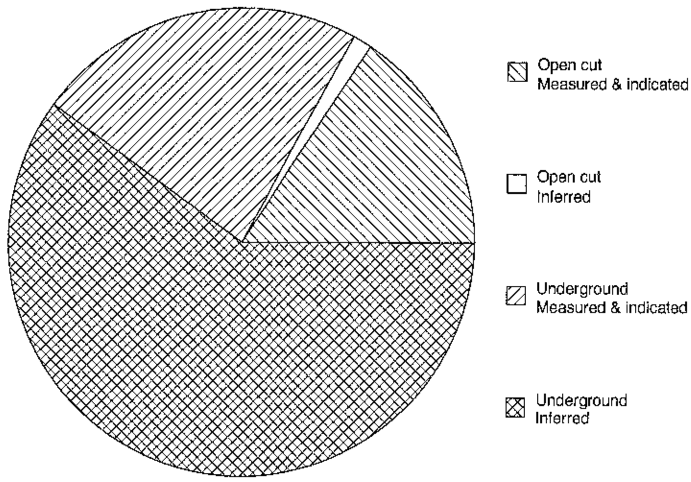

Figure 5.7 *Subdivision of coal resources in New South Wales (Australia)*
Source: [42]

Figure 5.7 shows that deep mineable resources are more abundant than those recoverable by surface mining, especially for inferred resources. The high R/P ratio (≈ 250 years for hard coal) of this scarcely populated continent, is a (partial) explanation for the predominance of surface mining.

5.4 Costs of mining and inland transport

5.4.1 Trends in FOB prices for Australia and the USA

The development of the Free On Board (FOB) of steam coal from Australia and the USA, is shown in Figure 5.8 [43]. The Australian steam coal price recovered from its lowest level in 1987. The US steam coal price has eroded constantly. FOB prices indexed at national currencies prove to be stable for Australian steam coal (due to depreciation of the A$ to the US$), and falling for US coal (Figure 5.9). Despite the price erosion, the USA lost much of its market share, mostly to South Africa: steam coal exports slumped from 38.5 million ton in 1992 to 22.1 million ton in 1993 [44].

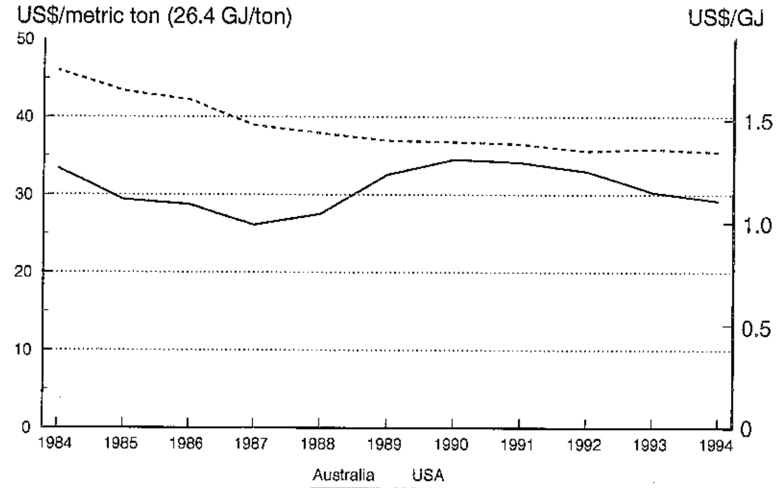

Figure 5.8 *FOB steam coal prices ex Australia and the USA, 1984-1994*

Source: [43]

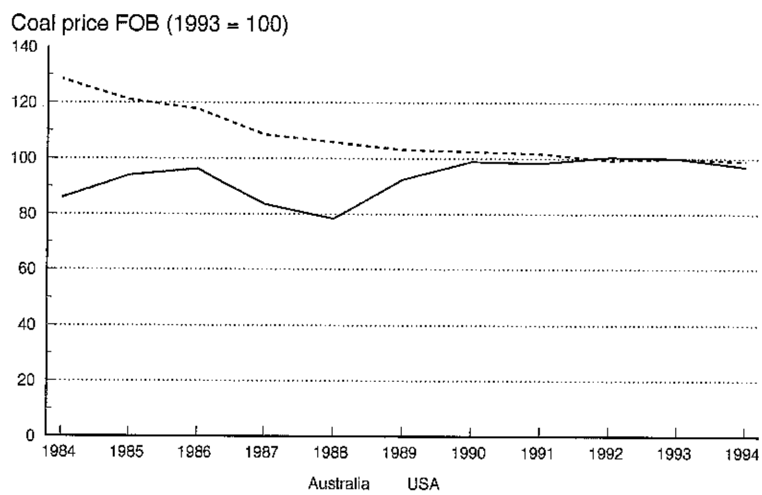

Figure 5.9 *Australian and US FOB steam coal prices (national currencies)*

Source: [43]

FOB prices of Australian and US steam coal eroded rapidly until 1987. Since then they have stabilised (however, not in real terms). The main cause of the price erosion is the stiff competition between fossil fuels at low price levels since about ten years. Improved coal mining technology, development of new productive mines and closure of marginal mines, have been implemented to remain competitive.

5.4.2 United States

The US coal industry is the second largest in the world after China, and the second largest exporter after Australia. Coal production amounted to 886 million tonnes in 1993. Coal exports totalled 67.2 million tonnes, worth $3.055 billion [44,45]. Coal production is mainly based on power generation demand: over 700 million t/y [41].

The three main coal basins are: the Appalachian Basin in the east, the Illinois Basin (mid-east), and the Powder River Basin (PRB) in the west. Coal output is based on 60% surface mining and 40% deep mining. Table 5.3 shows output and productivity of top surface mines in the western USA (>10 million t/y) [44,46,47].

Table 5.3 *Output [10^6 t/y] and productivity of top surface western mines*

Mine	State	1990	1992	1993	Productivity [ton/manhour]
Black Thunder	Wyoming	25.3	25.98	31.13	
Rochelle	Wyoming	10.9	14.42	19.22	
Jacobs Ranch	Wyoming	15.2	14.91	16.69	
Eagle Butte	Wyoming	14.0	12.38	15.28	
Belle Ayr	Wyoming	14.1	11.78	14.14	
Caballo	Wyoming	13.0	13.95	13.99	
Freedom	North Dakota	...	12.43	13.60	
Cordero	Wyoming	11.1	12.10	12.09	
Rosebud	Montana	11.6	13.33	11.07	
North Antelope	Wyoming	...	8.89	10.41	
Buckskin	Wyoming	...	8.25	10.14	
Total			148.5	167.7	≈ 27.5

Sources: [44,46,47]

In 1990 productivity of the twelve largest US mines, with an output over 9 million t/y, was 18.6 t/manhour [43]. In 1993 productivity of the PRB was even 26.03 t/manhour, varying from 16.33 t/manhour in Montana to 29.20 /manhour in Wyoming [41]. For the surface mines in Table 5.3 an average productivity of 27.5 t/manhour is assumed.

Similarly, Table 5.4 shows data of top underground mines, most them in the eastern USA [44,46]. In 1990 productivity of mines with an output of 4.5 to 9 million t/y was 10.7 t/manhour [31], and that of mines with an output of 0.9 to 4.5 million t/y was 3.7 t/manhour. These data refer to surface mines and deep mines. Productivity in the underground mines of Table 5.4 is estimated at 8 t/manhour on average. Average productivity across all US mines was 3.95 t/manhour in 1992 [44].

Table 5.4 *Output [10^6 t/y] and productivity of top US deep mines*

Mine	State	1990	1992	1993	Productivity [t/manhour]
Enlow Fork	Pennsylvania	...	4.81	6.71	
Bailey	Pennsylvania	5.1	5.53	6.26	
Skyline Utah	Utah	...	4.72	4.72	
Galatia	Illinois	...	3.44	3.81	
Powhatan 6	Ohio	...	3.12	3.63	
Wheatcroft	Kentucky	...	...	3.63	
Mountaineer	West Virginia	...	1.25	3.63	
Twentymile	Colorado	...	2.92	3.54	
Gary No.50	West Virginia	3.1	...	3.36	
Sufco	Utah	...	2.36	3.27	
Wabash	Illinois	2.9	2.64	3.08	
Total			37	45.6	≈ 8

Sources: [44,46]

The highest coal prices were noted in 1987: $25.4/tonne 'ex mine' (free of rail or barge). Since then, prices have slipped each year, down to $23.2/tonne 'ex mine' in 1993. For the next few years price increases below the inflation rate are expected [44].

In 1992 production costs of surface mines in Wyoming were equivalent to $8.75/tonne (1993 $, 26.4 GJ/ton), whereas production from these mines was 135 million tonnes. For deep mines in Utah corresponding figures were $24.75/tonne, and 21 million tonnes [48].

Transport costs are estimated at $17/tonne for the west coast and at $11/tonne for the east coast (Appalachian and Illinois basins), both at the lower end of IEA Coal Research estimates [46,49]. Competition between rail transport and transport by barge could be significant for European clients [49]. Table 5.5 shows approximate volumes and FOB steam coal prices for the west and east coast (1992 and 1993).

Table 5.5 *Export volumes and prices of US steam coal [$/tonne FOB]*[1]

Region	West		East		West		East	
Year	1992		1992		1993		1993	
	[E6 t/y]	[$/t]	[E6 t/y]	[$/t]	[E6 t/y]	[$/t]	[E6 t/y]	[$/t]
	7.0		31.5		6.1		16.0	
Mining		9		23		10		24
Transp.		17		11		17		11
Loading		3		3		3		3
FOB		29		37		30		38

[1] Heating value 26.4 GJ/tonne.

Sources: [42,44,45]

Figures for FOB prices of steam coal from western mines (Table 5.5) indicate that export can only be profitable, if based on surface mining.

It is without doubt that much more steam coal could be exported, if need would be. In the Appalachian basin, Ohio has substantial amounts of coal at depth, but these remain relatively unexplored, whilst strippable reserves are available. In Alabama, the Warrior and Plateau coalfields contain the majority of resources, although the seams are thinner and deeper than those in the central and northern Appalachians [46].

For the western USA production prospects for steam coal are almost as favourable. Figure 5.10 illustrates production and excess capacity in the Powder River Basin (PRB, eastern USA) over the years 1985-1993 [47].

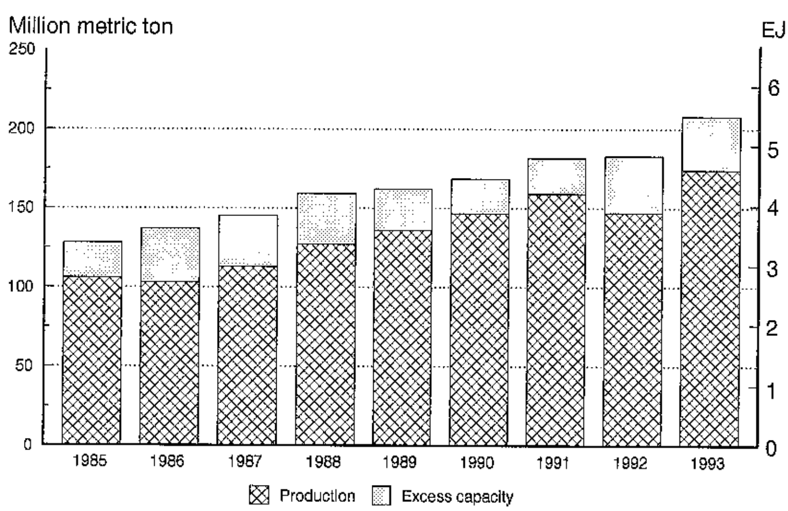

Figure 5.10 *Production and excess capacity of the PRB (based on [47])*

The western USA offers rather cheap excess capacity, possibly of the order of magnitude of 35 million t/y; however, not all of this capacity can be made available for export, e.g. for logistical reasons. The potential of the eastern USA has been noted; average production costs in the east are higher than in the PRB region. The average mine today is probably well into its originally projected life cycle; on average mines are believed to be at least 50% depleted. This will cause rising cost curve. Heavy investments in new mines could be necessary: a mine producing 2 million ton annually would require a capital investment in excess of $100 million [46].

At current low FOB steam coal prices, the export potential of the USA is limited, mainly because of the relatively high production costs of eastern mines. The National Coal Association projects a modest steam coal export (east and west) of 24.4 million tonne in 1994 [50]. Projections for 2000 range from 49 million t/y to as high as 96 million t/y [46].

Based on the foregoing analysis and earlier assessments (Koleninzetstudie, ECN Policy Studies, 1991) [51], steam coal supply curves for the USA (west and east) are shown in Figure 5.11.

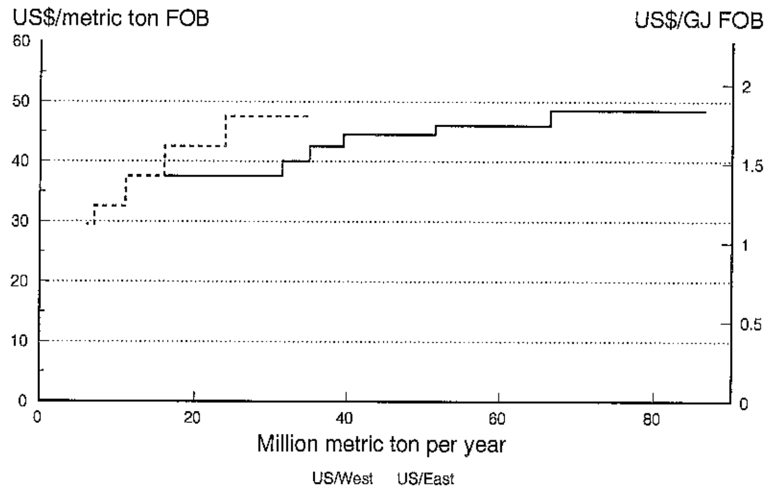

Figure 5.11 *Steam coal supply curves for the western and eastern USA*

Maximum export potential of western USA around 2010 could be 35 million t/y; limits or bottlenecks are railway capacity, loading ports and, to a lesser extent, production capacity. Maximum FOB costs are estimated at $47.5/tonne for more than 24 million t/y: $29.5/tonne production costs, $18/tonne transport & loading. Note that production costs of $29.5/tonne (26.4 GJ/ton) would be $19/tonne below *average* production costs of British Coal (£32.32/tonne ≈ $48.5/tonne) in 1993 [52]. Production costs in the UK are by far the lowest of EU countries.

The maximum FOB price for eastern US steam coal could be $48.5/tonne FOB for export volumes exceeding 66.5 million t/y ($36.5/tonne production costs, $12/tonne transport & loading). The margin between production costs and *average* British Coal's production costs (1993) would then be $12/tonne. In that case maximum FOB costs would equal *average* production costs in the UK, making export to the UK uneconomic.

The USA will probably remain the world's swing supplier of steam coal. If demand for steam coal would expand rapidly, 96 million tonnes could be exported in 2000. However, concern over global warming could affect coal use. A lower figure of 49 million t/y in 2000 seems more reasonable.

5.4.3 Australia

Australia has been the world's leading coal exporter since 1984. Total production reached 237 million ton in 1993. Export totalled 131.8 million tonnes [53]. Coal is the country's largest export earner; coal exports in 1992/1993 had a total worth of A$7.6 billion (US$5.5 billion) [42].

Australia's coal industry is concentrated on the eastern side of the continent: the Bowen Basin in Queensland, and the Sydney-Gunnedah basin in New South Wales. Victoria has a significant brown coal mining industry. Top Australian coal mines are listed in Table 5.6 [54].

Table 5.6 *Top ten coal mines (surface and deep mines) in Australia (1989)*

Mine	State	Raw output [10^6 t/y]	Saleable output [10^6 t/y]
Peak Downs	Queensland	9.54	5.74
Goonyella/Riverside	Queensland	8.35	5.85
Blair Athol	Queensland	7.71	7.71
Blackwater	Queensland	6.26	5.60
Meandu	Queensland	6.03	4.74
Hunter Valley No.1	NSW	5.86	4.27
Curragh	Queensland	5.79	4.93
Saraji	Queensland	5.34	4.03
Norwich Park	Queensland	5.28	4.10
Ulan	Queensland	5.27	3.00

Source: [54]

The proportion of deep to surface mined hard coal is 30% to 70% [30,31]. Average production costs of surface mines ranged from $12.40/tonne in Queensland and $21.70/tonne in NSW, to $28.40/tonne for deep mined NSW coal in 1991. In January and February 1992 the FOB steam coal price was $37.2/tonne on average; for steam coal soled to the Netherlands, the FOB price during these months was $35/tonne [55].

Rail charges in NSW have been high until some years ago, as evidenced by [42,56,57]. However, a state wide train and radio communication and tracking system using satellite based technology is being introduced in 1994 [49]. Besides, the NSW Minister for Mines has announced to open up competition in rail transport. Competition from non-government operators could represent savings of A$200 million [58]. Rail rates are assumed to come down to $6/tonne (A$8.5/tonne) for the line to Newcastle, to $6.5/tonne (≈ A$9/tonne) for Sydney, and to $8.0/tonne (≈ A$11/tonne) for Port Kembla. Note that Port Kembla's capacity should be enlarged from 16 to 20 million t/y [58].

Terminal improvements will also reduce turn around times from five days to three days per vessel [39], thereby reducing loading costs. Based on the throughput of these ports, rail charges in NSW could be $7/tonne on average, equal to a recent IEA Coal Research estimate [54].

Also in Queensland, rail charges were relatively high until recently [49]. It is assumed that charges could come down to US$9/metric ton. Loading costs could be $3/tonne, at the lower end of IEA Coal Research data [54]. Table 5.7 gives a breakdown of FOB steam coal prices for Queensland (QLD) and New South Wales (NSW).

Table 5.7 *Export volumes and prices of Australian steam coal [$/tonne FOB, 26.4 GJ/metric ton]*

State	QLD		NSW		QLD		NSW	
Year	91/92		91/92		92/93		92/93	
	[E6 t/y]	[$/t]	[E6 t/y]	[$/t]	[E6 t/y]	[$/t]	[E6 t/y]	[$/t]
	24.8		32.9		23.2		33.8	
Mining		21		23		18		20
Transp.		9		7		9		7
Loading		3		3		3		3
FOB		33		33		30		30

Sources: [42,43,54,55,58]

Export of steam coal has not been very profitable for many years. Selling steam coal into the European market would have entailed losses for 40% of coal producers in 1989 [54]. The NSW coal industry had an average return on shareholder's funds of only 1.9% over the past nine years; after tax operating profit in 1991/1992 averaged A$1.24/tonne [57], and 50% of respondents of a survey, representing 80% of the NSW coal industry, were unprofitable in 1991/1992 [42]. In the meantime, profitability has been improved somewhat, due to cost reductions in coal mining - higher productivity, closure of marginal mines - and in inland coal transport.

Export capacity of metallurgical and steam coal could rise to 176 million t/y in 1995, and to 225 million t/y in 2000 [42]. Export projections for steam coal range from 70 to 93 million t/y in 2000. A high export volume presumes a rapidly growing seaborne trade of 300 million tonnes in 2000, 50 percent more than in 1991. A lower volume seems more reasonable.

The data presented and the assessment for the 'Koleninzetstudie' (1991) [51], are used as evidence for a supply curve for Australian steam coal (Figure 5.12).

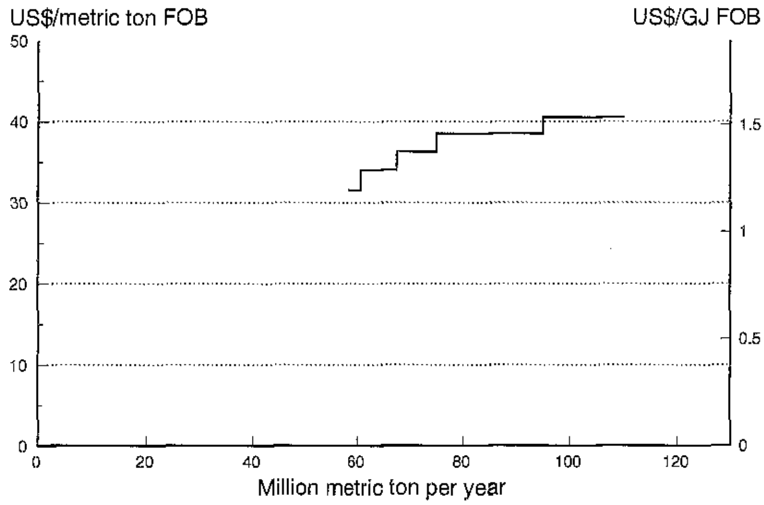

Figure 5.12 *Steam coal supply curve for Australia*

Production and inland transport costs are lower than for the eastern USA. Export capacity could amount to 110 million t/y. For volumes in excess of 95 million t/y, corresponding maximum FOB costs are estimated at $40.5/tonne ($30/ton production costs, $10.5/ton transport & loading). In that case the margin between Australian FOB costs and *average* British coal production costs (1993) would be $18.5/tonne, which would give Australian coal still some competitive edge in the UK market.

5.5.4 South Africa

South Africa is the third largest coal exporting nation of the world. In 1993 South Africa recovered much acceptability in coal markets. For instance, the largest single market decline of all US coal exports, the 3.1 million t/y drop in shipments to Denmark, was almost entirely taken over by shipments from South Africa. In 1993 exports of steam coal and anthracite rose by 1 million t/y to 51.2 million t/y. Coal is the second largest mineral export product for South Africa, worth US$1.34 billion in 1993 [59].

With a respectable R/P (Reserves/Production) ratio of about 300 years (Table 5.2), South Africa represents some 10% of total world known recoverable reserves of hard coal. Surface mining accounts for about 40% of total output, which is a comparatively low figure. For mines using conventional mining techniques (room and pillar instead of longwall mining), South Africa seems to have lower costs than the USA. South African mines have lower tax, land and regulatory costs. For surface mines with few-level, thick seams, South African mines are generally lowest in cost. US surface mines of the same characteristics are somewhat more expensive to exploit, and Australian mines even more expensive [59].

Just a few years ago South Africa, with minemouth costs of $10-25/tonne, was a very competitive producer [60]. However, nowadays the country has become a mid- to high cost steam coal supplier, as overall productivity levels are significantly lower than those of Australia and Indonesia. The latter countries have a larger share of surface mining than South Africa [59].

Volumes and prices for South African steam coal have been obtained from several publications, e.g. [61]. Rail charges are US$6/ton, which compares favourably with Australian charges, despite the long distance from Transvaal to Richards Bay: 560 km [62]. In South Africa unit trains have an average load per haul of 8,400 metric ton, compared to 1,630 metric ton in New South Wales in 1988 [56]. In the meantime, however, the NSW railways have been equipped with unit trains of 32 wagons or more (120 metric ton gross weight capacity per wagon), resulting in 3,840 metric ton per haul [58]. Table 5.8 gives approximate volumes and prices of South African steam coal over the last few years.

Table 5.8 *Approximate volumes and prices of South African steam coal [US$/ton FOB, 26.4 GJ/metric ton][1]*

Year	90/91		91/92		92/93		93/94	
	[E6 t/y]	[$/t]	[E6 t/y]	[$/t]	[E6 t/y]	[$/t]	[E6 t/y]	[$/t]
	43.10		44.17		45.23		48.33	
Mining		18		19		18		18
Transp.		6		6		6		6
Loading		3		3		3		3
FOB		27		28		27		27

[1] Net calorific value of South African export steam coal ≈ 25.75 GJ/metric ton.

Sources: [59-62]

Exports are developing favourably, due to the (still) competitive price of South African steam coal and the regained international confidence after the apartheid era. It is expected that South Africa will successfully recapture some of the market lost to competing exporters, by steadily expanding their export capacity and keeping the costs as low as possible.

Based on the foregoing analysis and earlier assessments, a steam coal supply curve for South Africa is presented in Figure 5.13.

An export level of 53 million t/y can be attained by extension of mines. A further 11 million t/y could be delivered within reasonable distance from existing mining areas. Although mining conditions are less favourable than for existing mines, production costs are only slightly higher. For the maximum level of 76 million t/y in 2000, relatively high investments are needed in new mechanised deep mines and adjacent infrastructure [63]. Also some expansion of terminals at Richards Bay will be necessary: its current capacity is 59 million t/y and could be easily expanded to 64 million t/y [64].

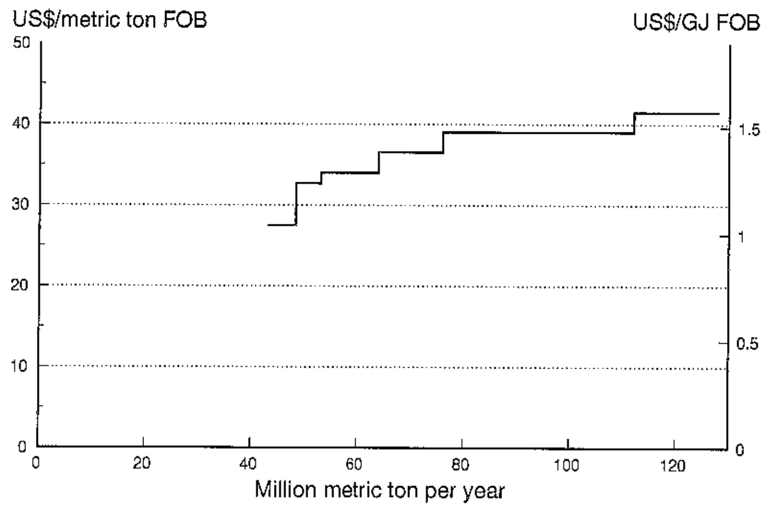

Figure 5.13 *Steam coal supply curve for South Africa*

Beyond the level of 76 million t/y in 2000, additional investments in more marginal mining areas and investments in railways and export terminals are needed. The ultimate level of steam coal exports considered is 128 million t/y. For the block from 112 to 128 million t/y, FOB costs are estimated at $45/tonne ($36/tonne production costs, $9/tonne transport and loading).

5.5.5 Indonesia and New Zealand

Indonesia has become a significant steam coal exporting nation. Coal resources were estimated at 34.2 billion tonnes (23 billion tones of which proven) in January 1992 [65]. Indonesia's resources consist of 58.6% lignite, 26.6% subbituminous coal, and 14.4% bituminous coal. The majority, 67%, are located in Sumatra and 32% in Kalimantan [66]. Production of the largest mine (East Kalimantan) started in 1991, and reached 8.4 million ton in 1993. It is a capital intensive mine, with an initial investment in excess of $550 million [67]. Indonesia's coal export rose from 5 million tonnes in 1991 to around 18 million tonnes in 1993.

Considering coal production capabilities and deposits, projections of coal production range from 71 million t/y in 1998/1999 to 55-60 million t/y by 2000 [68]. Coal from the large mine in East Kalimantan is suitable for injection as pulverised coal in blast furnaces of steel mills. The majority of coals is of steam coal quality. Considering that roughly half of future production will be for inland use, and some of the coal is of premium quality (blast furnaces), steam coal export could reach 25-30 million t/y in 2000, and even more in the next decade. A question mark is the R/P ratio, which stood at about 35 year for hard coal in 1993 (Table 5.2).

New Zealand is a new coal producing and exporting nation. Potentially recoverable resources are set at 7.5 billion tonnes; lignite reserves are deemed large (South Island), but also subbituminous as well as bituminous reserves are significant (South Island's west coast) [38]. Export could be boosted from 1 million tonne in 1993, to 2.7 million t/y in 1998 [38,69] and possibly to 10 million t/y around 2010.

Table 5.9 gives volumes and prices of Indonesian and New Zealand's steam coal over 1992 and 1993. Presumably, discounts have been larger than assumed in Table 5.9. However, such discounts will be insignificant, once these countries are accepted as reliable suppliers of steam coal. The distance from Europe is roughly the same for New Zealand and Australia. Both countries are more distant from Europe than Indonesia.

Table 5.9 *Export volumes and prices of Indonesian and New Zealand's steam coal [$/tonne FOB, 26.4 GJ/metric ton]*

Country	Indonesia		New Zealand		Indonesia		New Zealand	
Year	92		92		93		93	
	[E6 t/y]	[$/t]	[E6 t/y]	[$/t]	[E6 t/y]	[$/t]	[E6 t/y]	[$/t]
	16.0		-		17.5		≈1.0	
Mining		21		-		21		21.5
Transp.		7		-		6[1]		6[1]
Loading		3		-		3		3[1]
FOB		31		-		30		30.5

[1] Based on reduction of transport costs and full scale mining development (New Zealand).

Sources: [38,65,67,68]

Figure 5.14 shows an approximate steam coal supply curve for Indonesia and New Zealand.

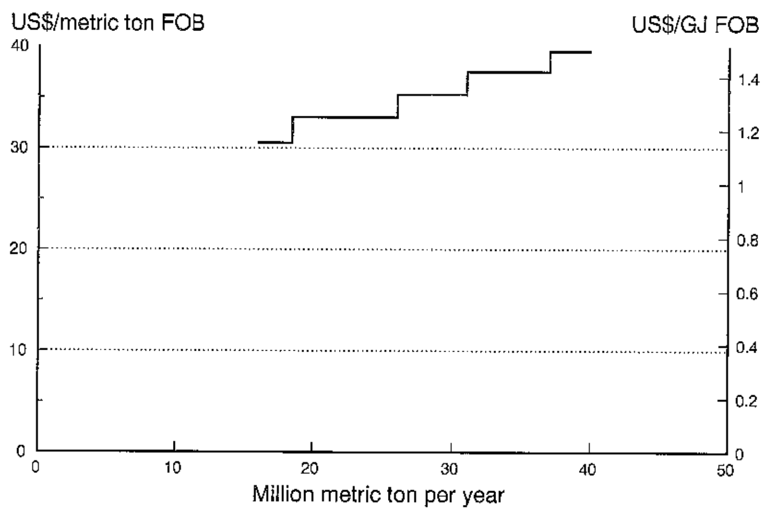

Figure 5.14 *Steam coal supply curve for Indonesia and New Zealand*

The combined export capacity could double to 40 million t/y. Maximum FOB costs are estimated at $39.5/tonne ($29 production costs, $8 transport & loading), for exports exceeding 37 million t/y.

5.5 Costs of ocean transport

Ocean freight rates for steam coal depend on the economic tide in world trade. Figure 5.15 shows freight rates for dry bulk transport from main exporting nations destined for Amsterdam/Rotterdam/Antwerp [70].

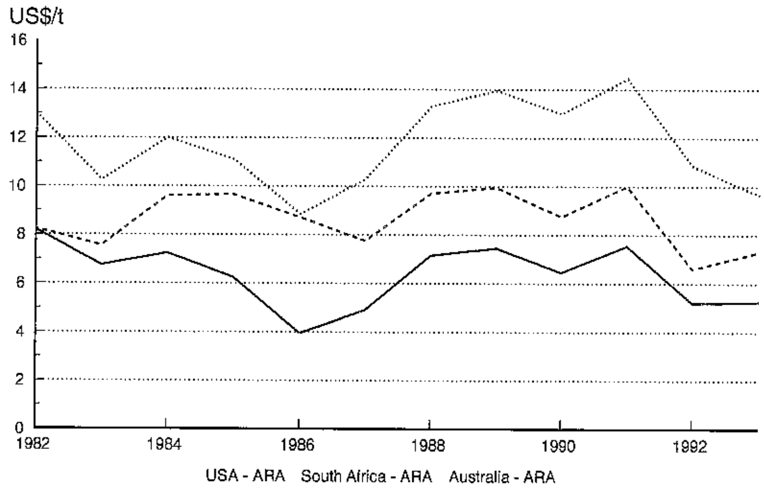

Figure 5.15 *Ocean freight rates for dry bulk transport from three main exporting nations to Amsterdam/Rotterdam/Antwerp (ARA)*

Source: [70]

Currently the ocean transport market seems to tighten, giving an upward trend in freight rates. Representative freight rates for steam coal with destination ARA are shown in Table 5.11 [70,71,72,73].

Table 5.11 *Representative ocean freight rates for steam coal exports to Amsterdam/Rotterdam/Antwerp (ARA)*

Origin	Distance [mile]	Volume [tonne]	Freight rate [$/tonne]
USA	3,600	≥100,000	7
Australia	12,500	≥140,000	12
South Africa	7,300	≥140,000	9
Indonesia/New Zealand	12,000/12,500	≥100,000	13

Sources: [70-73]

Freight rates presented here presume the largest vessels that are practible on the different routes. For Australia-Europe 58% of steam coal was transported in vessels larger than 100,000 ton DWT in 1990 [74]. The ports of interest in the USA (Hampton Roads), Australia (Gladstone, QLD, Port Kembla, NSW) and South Africa (Richards Bay) all can receive vessels of the largest tonnage.

In Indonesia the main port at south east Kalimantan gives access to vessels up to 150,000 ton DWT [75]. Freight rates for Indonesia are assumed to be slightly higher than for Australia. New Zealand is a minor steam coal supplier. Freight rates of

$13/ton could materialise, if coal export would be boosted to about 10 million t/y, which seems possible in the long run.

5.6 Price prospects

Based on the foregoing sections, the steam coal supply curves of the regions most of interest for the EU-12 countries are combined, and compared to two IPCC scenarios IS92a and IS92c.

With respect to seaborne steam coal demand in EU-12 countries, the following growth rates for IPCC scenarios IS92a and IS92c [1] are assumed:
Scenario IS92a: 3.5% annual growth 1990-2000, 2.5% after 2000;
Scenario IS92c: 3.5% annual growth 1990-2000, 0% to 2005, -1.5% thereafter.

The patterns of steam coal imports to the EU-12 from 1980 to 1990, and with projections for the period to 2020 are shown in Figure 5.16.

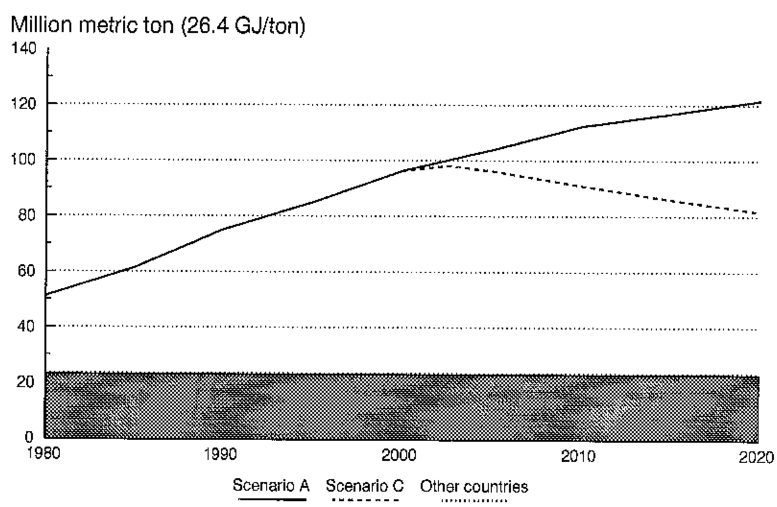

Figure 5.16 *Projected EU-12 seaborne steam coal import from all countries*

Table 5.12 gives a comparison of these projections with those of others [76,77]. Estimates of earlier date tend to overestimate EU-12 imports of steam coal, notably for the UK.

Table 5.12 *Seaborne steam coal demand by EU-12: comparison of IPPC-based coal demand projections and others for EU-12 [million t/y, 26.4 GJ/ton]*

Projection	1990	1995	2000	2005	2010	2010
Scenario IS92a (IPCC)	75.0	89.1	105.8	120.0	136.2	175.4
Scenario IS92c (IPCC)	75.0	89.1	105.8	105.8	105.8	84.6
IEA Coal Research '92 [54]	75.0		142			
Doyle (draft report '91)	75.0	112.6	132.4	151.5	151.5	157.7

Sources: [54,76,77]

In Figure 5.17 the results of the supply curves in section 5.4 are combined, assuming imports from third countries constant: only imports from the USA, Australasia and South Africa are varied.

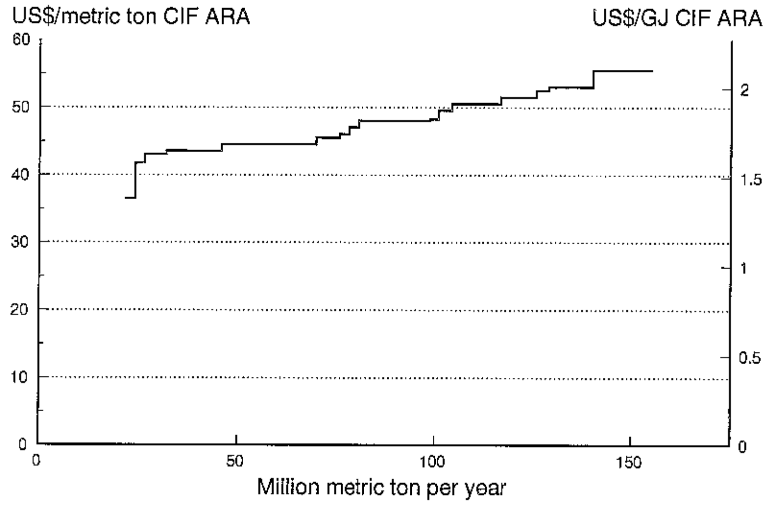

Figure 5.17 *Steam coal supply curve for EU-12 (CIF ARA[1]) from USA, Australasia and South Africa*

[1] Amsterdam/Rotterdam/Antwerp.

Confronting the estimates of steam coal demand from the three regions of interest - USA, Australasia and South Africa - with the supply curve (Figure 5.17) gives the following results.

Scenario independent development from 1990 till 2000

Based on the 3.5% growth rate for both scenarios, import from the USA, Australasia and South Africa will increase from 52 million t/y in 1990 to 83 million t/y in 2000. Total seaborne imports in 2010 are estimated at 106 million tonnes. Marginal CIF costs will increase by only a few $/tonne.

Scenario IS92a

Over period 2000-2020 the import of steam coal is assumed to grow with 2.5% annually. Under this scenario total import of seaborne steam coal would be at 175 million tonnes in 2020. Assuming that import from third countries remains constant at 23 million t/y, import from the three regions of interest amounts to slightly more than 150 million tonnes. The resulting marginal price for coal imported from these main export region is about $55/tonne CIF ARA.

Scenario IS92c

In the period 2005-2020 import of steam coal is assumed to fall with 1.5% annually. Total steam coal imports could be about 84 million tonnes in 2020. Accounting for the contribution from third countries, the import from the USA, Australasia and South Africa could be some 61 million t/y in 2020. The corresponding marginal import coal price is $47/tonne CIF ARA.

Marginal CIF costs of steam coal from the regions analysed show a rather significant difference for the two scenarios under consideration. The gap between the marginal

CIF costs (ARA) is estimated at about $11/ton (the difference between $8/ton and $47/ton).

The market of internationally traded steam coal is very competitive. Therefore, market prices are likely to exceed minimum required supply prices of incremental supplies by a very small margin if any margin at all. Considering the vast resources of coal and the relatively flat world demand for steam coal, depletion of the cheapest coal reserves will give a small upward pressure on coal prices. If present growth trends of seaborne steam coal demand will sustain, a price on the order of $55/tonne, CIF Europe, in 2020 is projected. Should this demand stagnate, e.g. as a result of implementation of CO_2 reduction policies a stable price on the order of $44/tonne, CIF Europe, in 2020 is anticipated. These projections are made on the supposition that for relevant marginal sources of supply for Western Europe future advances in production technology will be completely offset by real cost increases of major inputs such as labour.

6. SCENARIOS FOR FUTURE PRICES OF FOSSIL FUELS

6.1 Introduction

In this chapter projections will be presented of long-run marginal supply costs of fossil fuels over the period 1993-2020. At the request of VROM, demand projections for fossil fuels will be based on IPCC scenarios IS92a and IS92c. Year 2020 will be used as reference projection year and year 1993 as base year. Demand projections for fossil fuels are set out in section 6.2.

An integrated overview of the incremental supply curves for fossil fuels, developed in the previous three chapters is given in section 6.3. These curves provide a graphical representation, in ascending sequence, of the estimated today's minimum required prices (current long-run marginal costs) per unit of incremental supply to non-FSU European markets for a range of demand levels. As such these curves reflect estimated minimum long-run average market prices, based on current cost data. On certain assumptions the incremental supply curves valid for actual circumstances can be used to project the lower bound of possible long-run price trends. In section 6.3 the aforementioned supply curves are adapted for minimum required price projections and matched to demand projections, as already set out in section 6.2. This yields minimum required price projections for reference year 2020.

In section 6.4 prospects for market prices of oil, gas, and coal in year 2020 under scenarios IS92a and IS92c are set out. These prospects are presented especially to set out the differences between projecting minimum required prices and market prices for fossil fuels.

6.2 Demand scenarios for fossil fuels

In order to obtain projections of the demand for oil, natural gas and coal in reference projection year 2020, use will be made of IPCC greenhouse gas emission scenarios. A brief introduction to six IPCC scenarios has been given in section 2.7. At the request of VROM scenario IS92a will be interpreted for the purposes of this project as a 'business-as-usual scenario' and IS92c as an 'enhanced environmental policy scenario'. In other words, it will be assumed that IS92a provides 'most probable event' projections of demand for fossil fuels if no major changes in environmental policies occur, whilst IS92c would do so when environmental policies, especially CO_2 reduction policies would become more stringent. In line with this interpretation, IS92a and IS92c demand projections are considered here to represent upper bounds and lower bounds for plausible demand projections. It should be pointed out, though, that some oil market analysts expect even higher demand levels than the ones consistent with IS92a as a result of rapidly rising living standards in the developing world, especially in East and South Asia.

It is stressed that the interpretation above has been chosen to facilitate VROM's ongoing policy preparation exercises. As a matter of fact, it does not totally comply with the original scenario interpretation. For instance, it is assumed here that in scenario IS92a and IS92c world oil and gas reserves in the projection base year - 1993 in this study - are the same. This assumption differs from the original interpretation.

In the next three subsections a brief explanation is given of demand projections of relevance for the Western European market for oil, natural gas and coal respectively. The projections relate to projection year 2020 both under scenario IS92a and IS92c.

6.2.1 Oil

As set out in chapter 3 the oil market can be considered to designate a genuine world market with transport costs playing a relatively minor role. Hence, price formation in European markets have to be considered in perspective of world supply and demand conditions. Under the 'business-as-usual' scenario IS92a global demand for oil would increase to 79 mb/d, i.e. by 25% as compared to the 1990 level of 63 mb/d. Roughly three quarters of currently proved oil reserves would have been consumed by year 2020 under IS92a. Under scenario IS92c, worldwide oil demand is assumed to slightly decrease compared to the 1990 level to 59 mb/d in final projection year 2020.

6.2.2 Natural gas

In chapter 4 it has been set out that because of the high costs of gas transportation, at world level three main regional gas markets can be distinguished (North America; Europe; East Asia), each with distinctive features. Limited if somewhat increasing possibilities occur for arbitrating between these regional markets. For example, under tight market conditions Central Asian and Middle East producers may play off customers in East Asia against customers in non-FSU Europe. Nonetheless, the regional rather than the global level is appropriate to analyse price formation on the European gas market. A distinctive feature of the European gas market, as compared to North America, is the relatively limited sources of supply and the somewhat less well developed gas transport infrastructure. This, coupled with the huge upfront investments necessary for gas production and transportation, makes that to date the European gas market is still driven by long-term supply contracts. Therefore, prospective price developments will mainly be determined by incremental gas supplies that still have to be contracted. Reserves of natural gas are large compared to current world demand (R/P ratio about 66 years compared to 43 years for oil). At current demand levels proved conventional reserves are sufficient to meet demand well into the 21st century. Hence, in the foreseeable future there is scope for a larger share of gas in world energy demand.

Projections for gas demand in non-FSU Europe for the year 2020 amount to 324 bcm/y and 500 bcm/y for scenario IS92c and IS92a respectively. To date, long-run gas delivery contracts have been arranged that provide for annual gas supplies to European gas markets totalling 289 bcm by year 2020. Additional European gas demand has still to be contracted. Under scenarios IS92a and 1992c this leaves volumes of natural gas still to be contracted for European customers of 35 bcm and 211 bcm respectively (see table 4.9).

6.2.3 Coal

Similar to gas the high transport costs of coal impede the ready tradeability of the latter energy carrier, making that worldwide the lion's share of apparent coal consumption is procured from indigenous coal resources. Another underlying factor is that relative to oil and gas, low-cost coal resources are ubiquitous and occur fairly well dispersed. The latter factor renders the coal market quite competitive.

Labour costs constitute a quite important cost component for extraction of, notably deep mine, coal reserves. Especially the labour cost factor and increasing internalisation of environmental costs of coal production in Western Europe, weakens the competitiveness of coal mines in the latter region, both relative to low-cost extra regional coal and to competing fuels. Elsewhere, notably in the USA, a substantial increase in labour productivity is been achieved in coal extraction from opencast surface mines. This, in turn, makes that in meeting demand for coal in Western Europe increasing reliance has to be placed on extra-regional supplies of seaborne coal. Consequently, the coal price in Western Europe will be highly contingent on the marginal costs to meet the demand for seaborne steam coal in Western Europe. Major extra regional supplies are envisaged to originate from the USA, Australasia and South Africa. For these suppliers incremental supply cost curves have been presented in chapter 5.

Under business-as-usual scenario IS92a demand for coal in Western Europe has been projected to amount to 716 million tonnes (18.9 EJ). Of this amount 660 million tonnes can be apportioned to EU-12 countries. Seaborne steam coal in Western Europe (EU-12) under IS1992a would be 175 million tonnes by year 2020, as against 89 million tonnes in year 1995. If IS1992a conditions prevail, the main exporting regions (USA, Australasia, South Africa) are envisaged to deliver 150 million tonnes to EU-12 by 2020.

Under scenario IS92c demand for coal in Western Europe has been projected to amount to 561 million tonnes (14.8 EJ), of which 517 million tonnes would stem from EU-12 countries. Seaborne steam coal in Western Europe (EU-12) under IS1992c would be 85 million tonnes by year 2020. The main exporting regions (USA, Australasia, South Africa) are envisaged to deliver 61 million tonnes to EU-12 by 2020 under IS1992c.

6.3 Minimum required price projections

Hereafter, supply curves for oil, gas, and coal, developed in chapters 3 to 5 are matched with projected corresponding demand levels under scenarios IS92a and IS92c. In combination with assumptions on prospective cost developments, this exercise is to yield projections of minimum required prices of fossil fuels in projection year 2020, delivered at Western European markets. The resulting price projections provide a floor level for border prices (i.e. before inland distribution costs and taxes in importing countries) projected to prevail in Western Europe for crude oil, gas, and coal by the same year.

6.3.1 Oil

Oil reserves are large compared to world demand: the reserves to current production (R/P) ratio is about 43 years for proved conventional reserves. About 65% of the world's proved reserves are situated in the Middle East and could be produced at prices of $12/b or less. All of the world's projected demand up to 2020 in IS92c, and almost all the demand up to 2020 in IS92a, could be met with presently proved low-cost reserves of the Middle East. Under scenario IS92a resort to proved (higher-cost) resources in non-OAPEC countries (with production costs ranging from $/b 12-20 before government take but including $/b 1-1.5 interregional transport costs) cannot be avoided whatsoever.

Projections of minimum required oil prices in the year 2020 should account for future cost developments. Here it will be assumed that the negative effects of technological developments on prospective exploration, development, and transportation costs will fully offset upward price pressures resulting form resource depletion effects and other real cost increases.

The following conclusions for the order of magnitude for minimum required oil prices (CIF Western Europe) result from the considerations above. If conditions of scenario IS92a will prevail, a minimum required oil price on the order of $\$US_{1993}$/b 12-20 is projected for year 2020. Under scenario IS92c conditions a minimum required price around $\$US_{1993}$/b 10 is envisaged.

The price levels expected for each of the scenarios are shown in Table 6.1.

Table 6.1 *Oil demand and derived marginal costs CIF Rotterdam for the two IPCC scenarios considered; year 2020 [$\$US_{1993}$/b and $\$US_{1993}$/GJ]*

Scenario	World oil demand in 2020		Minimum required oil price CIF Rotterdam	
	[EJ/y]	[mb/d]	[$/b]	[$/GJ]
IS92a	164.8	79.0	12-20	2.1-3.5
IS92c	122.5	58.8	8-12	1.4-2.1

6.3.2 Natural gas

Reserves of natural gas are large compared to current world demand (R/P ratio about 66 years compared to 43 years for oil). At current demand levels proved conventional reserves are sufficient to meet demand well into the 21st century. From the perspective of natural resource endowments, over the projection period considered there is even scope for a gradually rising share of gas in world energy demand.

Because of the quite high transportation costs by pipeline or ship (LNG), there are several more or less separate regional gas markets rather than one global market with quite diverging price levels. Total cumulative demand till 2020 cannot be fully met by cheap, intra-EU gas resources, such as the Groningen field. Incremental supplies to the European gas market would have to come from Norway, the North Sea, Siberia, Algeria, the Middle East and probably Nigeria. Minimum required gas prices CIF

Western Europe by year 2020 will be contingent to a major extent on the costs of gas from Siberia's Yamal peninsula and the Middle East.

Projections for gas demand in non-FSU Europe for the year 2020 amount to 500 bcm/y and 324 bcm/y for scenario IS92a and IS92c respectively. Volumes of natural gas still to be contracted to meet these demand levels boil down to 211 bcm and 35 bcm respectively (See table 4.9). Application of the incremental European gas supply curve developed in chapter 4 (see figure 4.1), yields current minimum required prices pertinent to these volumes, i.e. 3.5 $US\$_{1993}$/mbtu and 5.0 $US\$_{1993}$/mbtu respectively. As already set out in section 4.4, as a result of ongoing technological developments a moderate downward net impact of underlying factors to minimum required prices for gas over the period 1995-2020 appears a likely possibility. Allowance has been made for a downward shift of the incremental supply curve with a margin up to 0.5 $/mbtu.

Table 6.2 *European gas demand and estimated border prices for the two IPCC scenarios; year 2020 [$/mbtu and $/GJ]*

Scenario	Additional import demand for Europe		Minimum required border price for gas	
	[EJ/y]	[bcm/y]	[$/mbtu]	[$/GJ]
IS92a	8.02	211	4.5-5.0	4.8-5.3
IS92c	1.33	35	3.0-3.5	3.2-3.7

6.3.3 Coal

Coal is the most abundant of all fossil fuels, in absolute quantities as well as R/P ratio. Current world requirements could be extracted from currently proved reserves for about 165 years in the case of hard coal and even over a period of 500 years ahead for subbituminous coal and lignite. Under 'normal' market conditions the market for internationally traded coal is quite competitive. As a result, seaborne coal demand is rather price elastic; suppliers tend to be price takers. Sudden world oil price hikes can have a notable upward impact on coal, though; be it that coal price oscillations are poised to be less wide in percentage points than is the case with oil prices.

For prices of coal imported by European countries the costs of mining, inland handling cum transport and ocean transport are essential. Both in production and in handling and transportation, some improvement of technology is to be expected. Yet it is envisaged by this report's authors that - if more so under scenario IS92a circumstances than under scenario IS92c - after year 2010 a slightly upward trend in minimum required prices is to be reckoned with. This as a result of technological improvements having gradually less effect than depletion of low-cost resources.

As set out in the previous section, demand for coal in Western Europe is projected to amount to 14.8 EJ and 18.9 EJ in 2020 for the IPCC scenarios IS92c en IS92a respectively. In order to determine the CIF import price, amounts of coal imported and minimum required coal prices are determined as shown in Table 6.3.

Table 6.3 *EU-12 coal demand and corresponding volumes and prices of coal imported from main coal exporting region; year 2020*

Scenario IS92a (IPCC)

Western Europe: 18.9 EJ, equalling:	716 million tonnes
• of which EU-12 coal demand:	660 million tonnes
- of which hard coal import 27%:	178 million tonnes
* from third countries:	23 million tonnes
* from main exporting regions:	155 million tonnes

Derived minimum required price (Figure 5.17): $55/tonne ($ 2.1/GJ)

Scenario IS92c (IPCC)

Western Europe: 14.8 EJ, equalling:	561 million tonnes
• of which EU-12 coal demand:	517 million tonnes
- of which hard coal import 27%:	140 million tonnes
* from third countries:	23 million tonnes
* from main exporting regions:	117 million tonnes

Derived minimum required price (Figure 5.17): $47/tonne ($ 1.8/GJ)

Under IS92a conditions coal from new and more remote mines in the main producing areas of the world would be needed to meet the growing demand. The effect of technological improvements would be offset by the depletion effect, resulting in relatively higher investment costs for deeper and more remote coal reserves. The minimum required coal price would rise to $ 55/tonne, i.e. $ 2.1/GJ, CIF ARA (Amsterdam/Rotterdam/Antwerp).

In case of scenario IS92c the international coal market would be able to absorb demand from EU-12 countries without any difficulty, and minimum required prices on a CIF ARA basis could be as low as $ 47/tonne ($ 1.8/GJ). Declining levels of hard coal production in European countries would cause an additional need for import of hard coal. However, it seems unlikely that under scenario IS92c the price of coal CIF ARA would exceed the level of $50/tonne.

6.4 On prospective market price developments for fossil fuels

In behalf of VROM this reports aims at projecting minimum required prices, rather than market prices, for fossil fuels in Western Europe over the period 1995-2020. Nonetheless, in order to put the projections of the previous section in proper perspective, in this section some preliminary observations are made concerning the prospects for market price developments over the next 25 years.

6.4.1 Oil

It is stressed that the minimum required price approach adopted in this report considers cost minimization from a global economic perspective. In doing so no account was made for economic rent components and so-called user cost for extraction of depletable resources. Yet exclusion of an economic rent component in the price for natural resources may not be realistic, especially not so when low-cost supplies are distributed quite indisparately over the world, as is the case with oil and, if to a somewhat lesser extent, natural gas. For instance, in the real world strategic considerations go a long way in explaining that a substantial part of world oil demand is met and will be met in the foreseeable future by higher-cost oil reserves. These considerations are not only 'politically' but also economically rational, considering the low number of countries with major low-cost oil reserves and the economic costs of unexpected supply interruptions for oil importing countries. It is quite conceivable that governments of major oil-importing countries and private oil producing and marketing agents in countries with high-cost oil reserves will co-opt to preclude lasting oil price dips below levels that will make development of oil reserves in the $\$US_{1993}$ 10-16 range financially unattractive. Furthermore, it has to be reckoned with that early in the next century (somewhere around year 2000 under scenario IS92a and around 2010 under scenario IS92c) the impact of depletion of low-cost oil reserves will be significantly perceived and anticipated by traders on the spot markets for crude oil. This awareness will prompt the latter to make much more explicit allowance of the user value of oil, i.e. the option value of not having to use substitutes for depletable low-cost oil resources, than is the case in the present buyers market. Evidently, the user value of oil reserves will be highly contingent on the anticipated remaining time period in which low-cost reserves are still available to meet world oil demand and price developments with respect to (broadly higher cost) backstop technologies such as renewable energy technologies. It is the contention of this report's authors that oil traders and the majority of professional oil market analysts are presently exaggerating the importance of the downward impact of current technological advances in oil prospecting and development cost on prospective price developments of fossil fuels as against rising user values.

Major oil-importing countries give high priority to decreasing their dependence on low-cost oil from OAPEC countries. The main reason is that a major part of internationally traded oil is supplied by just four or five countries in the Middle East, the political, social and economic stability of which are uncertain. As a result, notably in OECD member states strong political forces oppose a further increase in the dependence on oil from the Middle East. The pertinent governments have tended to apply trade and fiscal instruments to discriminate against extra regional low-cost oil producers so as to shield the operations of local higher cost producers. Therefore, should countries richly endowed with low-cost oil decide in favour of a strategy 'to buy market share' by flooding the market with their oil, these countries may at long last end up by giving away a higher share of the economic rent of their resource to the tax collectors in importing countries than this share before implementing the aggressive marketing strategy while making less inroads into oil export markets than might have been anticipated with a scenario of low prices on oil spot markets.

Checking production in the Middle East seems to be an important foreign policy objective of the USA to a growing dependence on imported oil. At present, Saudi Arabia and Kuwait are under strong political tutelage of the USA. The current, 'economically rational' governments of these countries do not wish to destabilise the world economy through sudden ruptures in oil supply, but are keen to sustain oil revenue cash flows at as high a level as possible over the long run. Sudden oil price hikes would stimulate supply from higher cost competitors, whilst at the same time invigorate the determination in major oil consuming countries to bring down the cost of oil substitutes through increased R&D efforts and selective market stimulation policies. Evidently, these developments would run counter to the long-run economic interest of OAPEC countries. Moreover, OAPEC countries and other oil producing countries are becoming more and more dependent on cooperation with western oil companies for technology and investment resources.

All in all, both major oil consuming countries and 'economically rational' oil producing countries seem to have a common interest in stimulating oil production at oil price levels that will not be:

- too low so as to provoke intensified use of discriminatory trade instruments against low-cost oil producers by governments of oil-importing countries;
- too high so as to put major export markets for low-cost oil in the balance through crowding out by local higher cost competitors and displacement by backstop energy resources.

It can be concluded that there are strong forces at work, to keep the oil price in the medium run at current levels, in a price band from $\$US_{1993}$ 16 through 20/b. Yet in the longer run, starting somewhere in the first decade of the next millennium depletion of lower cost oil is poised to bring about an upward pressure on oil prices. Especially under scenario IS92a, it is highly unlikely that improvement in exploration and production technology will sufficiently offset depletion of low-cost oil resources to prevent the world oil price from gradually rising.

Under the 'business-as-usual' scenario IS92a oil demand would increase by 25% compared to the 1990 level. If IS92a is to prevail, roughly three quarters of currently proved oil reserves will have been consumed by the year 2020. This is bound to put a clear upward pressure on oil prices within the projection period considered. For good or worse, under IS92a the market share of OAPEC countries is to substantially increase. To start with on oil spot markets, soon to be followed by similar movements on the futures markets for oil delivery contracts and administered prices, the moving average of oil prices will set out to rise on a sustained basis. Moreover, in order to counteract to some extent rising OAPEC monopolistic power EOR technology will have to be applied on a large scale. By application of EOR technology oil production from 'mature' oil fields can be prolonged over a longer period than without EOR. Moreover, under IS92a conditions a gap between oil supply from conventional and EOR production and demand for oil on the other hand unconventional oil from tar sands will have to be produced in significant quantities. In case of scenario IS92a oil prices would show a steadily growing trend, ending up in the range of $\$US_{1993}$ 25/b to \$ 35/b (\$ 4.4-6.1/GJ) in 2020. By contrast, upward price pressure under the IS92c are envisaged to be moderate. Border prices CIF Western Europe on the order of \$ 18-22/b (\$ 3.2-3.9/GJ) in year 2020 are projected under the IS92c scenario.

6.4.2 Gas

If scenario IS92a would materialize, a tremendous additional volume of gas would have to be contracted until the year 2020. Although world's gas reserves are rather plentiful, huge investments in additional gas supply would be needed. The relatively high demand would require timely development of such capital intensive projects as Yamal (Western Siberia) and pipeline or LNG import from Iran. Border prices CIF western Europe for gas are expected to rise steeply to a level on the order of $\$US_{1993}$ 5-7/mbtu (\$ 5.2-7.4/mbtu) by year 2020. These projections make explicit allowance for the expectations of this report's authors that in the short to medium run the European gas market will turn from a buyers' market into a market in which sellers can to some extent capitalize on preferences with gas customers in favour of gas. It is expected that gradually a certain price premium for gas, compared to oil and - more so - to coal can be imposed upon the market.

In case of scenario IS92c a market price on the order of \$ 4.0-5.5/mbtu (\$ 4.2-5.9/GJ) in year 2020 is envisaged. Because of stricter environmental policies, the relative premium in the gas price vis-à-vis competing fossil fuels is expected to become even more pronounced.

6.4.3 Coal

Under scenario IS92a the minimum required coal price CIF ARA would have to rise to \$US 55. As the market price for coal in Western Europe is primarily determined by the price of extra regional seaborne imports and these, in turn, are to some extent positively correlated to prices in the international oil market, it is anticipated that under IS92a coal market prices may rise in excess of minimum required prices to a level of \$ 65-90/t (\$ 2.5-3.4/GJ) by year 2020. Because of its innate inferior qualities as against gas and oil, a clear disagio in the market price of coal is anticipated.

Under environmentally enhanced scenario IS92c, the inferior qualities of coal will get even more attention. It is anticipated that under this scenario the market price for coal will be close to the minimum required price. Accordingly, a price band in year 2020 of \$ 45-50/t (\$ 1.7-1.9/GJ) is projected under IS92c. This would imply a huge disagio in the market price of coal as compared to gas and oil.

ANNEX A. ABBREVIATIONS

In this report the following abbreviations have been used (Table A.1).

Table A.1 *List of abbreviations*

	Signification
ARA	Amsterdam/Rotterdam/Antwerp
b or bbl	barrel
btu	British Thermal Unit (1.055 kJ)
cf	cubic foot (0.0283 m^3)
CIF	Costs Insurance Freight
CNG	Compressed Natural Gas
DWT	Dead Weight Tonnage
E&D	Exploration and Development
EE	Eastern Europe
EOR	Enhanced Oil Recovery
EU	European Union
FOB	Free On Board
FSU	Former Soviet Union
GDP	Gross Domestic Production
IEA	International Energy Agency
IGU	International Gas Union
IPCC	Intergovernmental Panel on Climate Change
LNG	Liquid Natural Gas
NLG	Natural Gas Liquids
NSW	New South Wales
OAPEC	Organ. of Arabic Oil Producing and Exporting Countries
OPEC	Organisation of Oil Producing and Exporting Countries
PRB	Powder River Basin
QLD	Queensland
R/P	Reserve/Production ratio
SI	Standard International units
toe	ton of oil equivalent
TPA	Third Party Access
UAE	United Arabic Emirates

ANNEX B. WORLD OIL, NATURAL GAS AND COAL RESERVES

Proved oil reserves are presented as a function of time in Table B.1. For oil, gas and coal reserves as a function of time for recent years are presented in the Figures B.1, B.2 and B.3 respectively, based on BP statistics [6] [17].

Table B.1 *Development of proved oil reserves [billion toe]*

	1968	1973	1978	1983	1988	1993
Middle East	36.3	47.3	49.6	50.3	77.3	89.6
Latin America	4.2	4.3	5.3	11.4	17.1	17.7
(Former) CPE's[1]	8.0	14.0	13.2	11.5	11.3	11.4
USA	5.3	5.1	4.3	4.4	4.4	4.0
Rest of world	9.7	14.6	15.2	14.4	13.7	14.0
Total	63.5	85.3	87.6	92.0	123.8	136.7

[1] Centrally Planned Economies.

Source: [6]

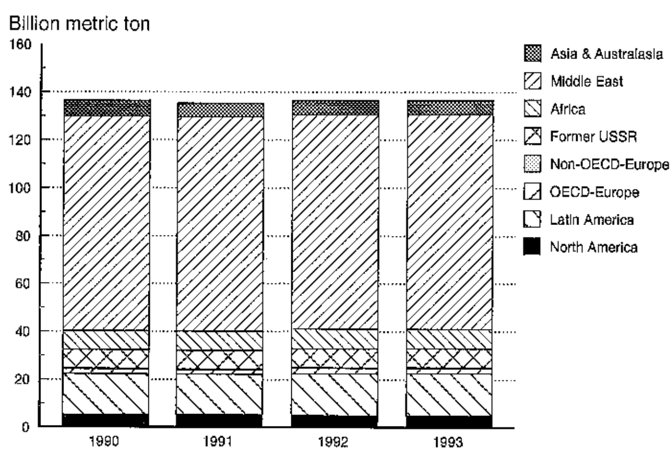

Figure B.1 *Proved oil reserves 1990-1993*

Source: [6]

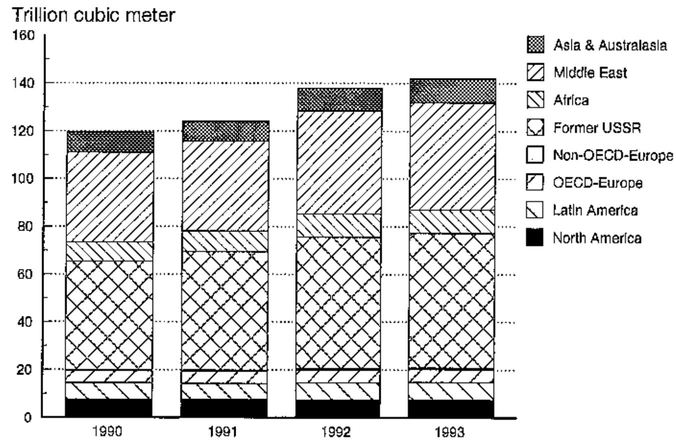

Figure B.2 *Proved gas reserves 1990-1993*

Source: [17]

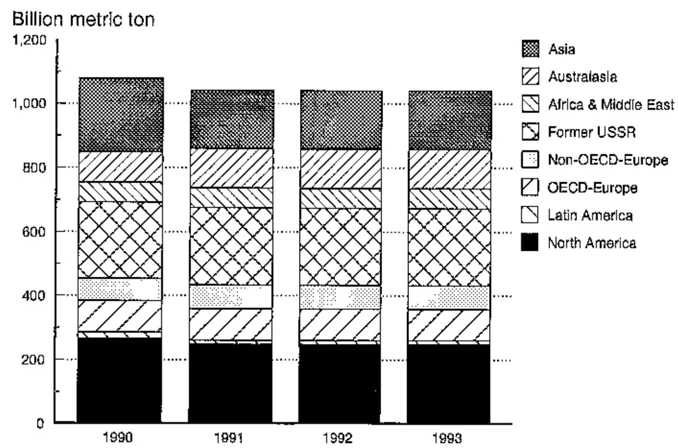

Figure B.3 *Measured, indicated and inferred ('proved') coal reserves 1990-1993*

Source: [6]

ANNEX C. DEMAND PROJECTIONS FROM IPCC SCENARIOS

Tables C.1 to C.3 give projections of oil, gas, and coal demand from the IPCC scenarios IS92a and IS92c (corresponding to Figure 2.1, Chapter 2). The 1990 data are from the last 'BP Statistical Review of World Energy' [7].

Table C.1 *Actual and projected world oil consumption by region; 1990-2020 [EJ]*

	1990	2000 IS92a	2000 IS92c	2020 IS92a	2020 IS92c
North America	38.8	40.0	34.0	37.1	29.5
Western Europe	26.3	24.4	20.6	21.7	17.5
Eastern Europe	3.5	2.1	1.8	2.2	1.5
FSU	17.6	17.3	14.2	18.1	12.1
OECD Pacific	11.9	14.1	11.8	12.7	10.2
Middle East	6.8	6.5	5.3	9.2	6.2
Africa	4.0	6.5	5.3	16.6	11.4
Latin America	7.0	10.6	8.5	14.3	10.6
Other Asia	15.5	17.7	14.2	32.9	23.6
Total world	131.4	140.3	116.7	164.8	122.5

Sources: [1,7]

Table C.2 *Actual and projected world gas consumption by region; 1990-2020 [EJ]*

	1990	2000 IS92a	2000 IS92c	2020 IS92a	2020 IS92c
North America	23.7	26.7	22.7	27.6	17.3
Western Europe	9.5	13.7	11.1	14.4	8.9
Eastern Europe	2.7	3.9	3.3	4.6	3.4
FSU	25.0	31.4	26.4	37.5	27.7
OECD Pacific	2.8	3.6	3.0	4.5	2.2
Middle East	3.6	6.6	5.5	15.6	8.5
Africa	1.3	2.4	1.9	6.1	3.7
Latin America	2.2	4.0	3.2	9.1	6.1
Other Asia	3.2	6.1	4.8	18.0	9.1
Total world	74.0	97.8	81.9	137.4	86.9

Source: [1,7]

Table C.3 *Actual and projected world coal consumption by region; 1990-2020 [EJ]*

	1990	2000 IS92a	2000 IS92c	2020 IS92a	2020 IS92c
North America	21.3	23.7	20.5	33.7	24.4
Western Europe	13.4	12.6	11.6	18.9	14.8
Eastern Europe	7.2	3.8	3.6	5.6	4.4
FSU	12.9	30.7	28.9	45.5	35.7
OECD Pacific	4.9	5.9	5.5	8.9	6.9
Middle East	0.2	0.0	0.0	0.0	0.1
Africa	3.3	2.8	2.5	7.3	4.9
Latin America	0.7	0.9	0.6	3.3	1.8
Other Asia	29.9	36.5	32.3	67.7	48.1
Total world	93.8	116.9	105.5	190.8	141.3

Source: [1,7]

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