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The Targets IMage Energy Regional (TIMER) Model

Technical Documentation

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Abstract

The Targets IMage Energy Regional simulation model, TIMER, is described in detail. This model was developed and used in close connection with the Integrated Model to Assess the Global Environment (IMAGE) 2.2. The system-dynamics TIMER model simulates the global energy system at an intermediate level of aggregation. The model can be used on a stand-alone basis or integrated within the framework of the integrated assessment model IMAGE 2.2. The model simulates the world on the basis of 17 regions. The main objectives of TIMER are to analyse the long-term dynamics of energy conservation and the transition to non-fossil fuels within an integrated modelling framework, and explore long-term trends for energy-related greenhouse gas emissions. Important components of the various submodels are: price-driven fuel and technology substitution processes, cost decrease as a consequence of accumulated production ('learning-by-doing'), resource depletion as a function of cumulated use (long-term supply cost curves) and price-driven fuel trade. The first chapter gives a brief overview of the model objective, set-up and calibration method. In subsequent chapters, the various submodels are discussed, with the introduction of introduciconcepts, equations, input assumptions and calibration results. Chapter 3 deals with the Energy Demand submodel, Chapter 4 with the Electric Power Generation submodel, and Chapters 5 and 6 with the Fuel Supply submodels. Chapter 7 describes fuel trade and technology transfer modelling; Chapter 8, the Emissions submodel. In the last chapter, a few generic concepts are discussed in some detail to improve the user's understanding of the model. The TIMER-model has played a role in the following: the Special Report on Emission Scenarios (SRES) for the Intergovernmental Panel on Climate Change (IPCC), the European AirClim-project, the construction of global mitigation scenarios, and the Policy Options for CO_2 Emission Mitigation in China project.

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Samenvatting

Dit rapport bevat een gedetailleerde beschrijving van het Targets IMage Energy Regional (TIMER) simulatiemodel. Het model is ontwikkeld en toegepast in nauwe relatie met het Integrated Model to Assess the Global Environment (IMAGE) 2.1-2.2. . Het TIMER model is een systeem-dynamisch simulatiemodel van het wereld-energiesysteem op een intermediair aggregatieniveau. Het model kan zowel als afzonderlijk model alsook geïntegreerd met het IMAGE 2.2 modelkader worden gebruikt. Het model simuleert de wereld op basis van 17 regio's. De belangrijkste doelstellingen van het TIMER model zijn het analyseren van de lange-termijn dynamica van energiebesparing en de overgang naar niet-fossiele brandstoffen in een geintegreerd modelkader, en het verkennen van de lange-termijn trends inzake energie-gelieerde broeikasgas-emissies. Belangrijke ingredienten van de diverse deelmodellen zijn: prijsgedreven brandstof en technologie substitutieprocessen, kostendaling als gevolg van accumulerende produktie ('learning-by-doing'), hulpbron uitputting als een functie van cumulatief gebruik (lange-termijn kosten-aanbodcurves) en prijsgedreven brandstofhandel. In het eerste hoofdstuk wordt een overzicht gegeven van modeldoel, opzet en calibratiemethode. In de navolgende hoofdstukken worden de diverse submodellen gepresenteerd waarbij concepten, vergelijkingen, invoerveronderstellingen en calibratieresultaten worden geïntroduceerd. Hoofdstuk 3 behandelt het Energievraagsubmodel, Hoofdstuk 4 het Electriceitssubmodel, en Hoofdstukken 5 en 6 de Brandstofaanbodsubmodellen. Hoofdstuk 7 behandelt brandstofhandel en technologie-overdracht; Hoofdstuk 8 bespreekt enkele generieke concepten om het modelgedrag te verduidelijken. Het TIMER-model is gebruikt in het Special Report on Emission Scenarios (SRES) voor het Intergovernmental Panel on Climate Change(IPCC), het Europese AirClim-project, de constructie van wereldwijde mitigatiescenarios en het Policy Options for CO_2 Emission Mitigation in China project.

1. Introduction

In this report, we present a detailed description of the energy model TIMER 1.0 (Targets IMage Energy Regional model[1]). The TIMER model consists of the TIMER energy demand and supply model and the TIMER emissions model (TEM). Hereafter we simply refer to the TIMER model. The TIMER model is a system-dynamics, simulation model of the global energy system at an intermediate level of aggregation. The model can be used both as a stand-alone model, or integrated within the framework of the integrated assessment model IMAGE 2.2. In IMAGE 2.2 the TIMER model replaces the Energy-Industry System (EIS) of IMAGE 2.1. The main objectives of TIMER are to analyse the long-term dynamics of energy conservation and the transition to non-fossil fuels within an integrated modelling framework, and explore long-term trends with regard to energy related emissions of greenhouse gases and other gases. TIMER is a simulation model; it does not optimise scenario results over a complete modelling period on the basis of perfect foresight. Instead, TIMER simulates year-to-year investment decisions based on a combination of bottom-up engineering information and specific rules on investment behaviour, fuel substitution and technology.

The framework IMAGE 2.2 (Integrated Model to Assess the Global Environment) has been developed to study the long-term dynamics of global environmental change, in particular changes related to climate change (IMAGE team, 2001). In the IMAGE 2.2 framework the general equilibrium economy model WorldScan and the population model Phoenix feed information into two systems of models, i.e. the Energy-Industry System (EIS) and the Terrestrial Environment System (TES). The Energy-Industry System (EIS) consists largely of the TIMER 1.0 model described in this report. Together with the Terrestrial Environment System (TES), the land use changes, as well as the anthropogenic emissions of greenhouse gases and other gases are calculated. These form the input of the Atmosphere-Ocean System (AOS) (including the oceanic carbon models, the atmospheric chemistry model and the climate model. The Atmosphere-Ocean System (AOS) calculates the atmospheric concentrations of these gases, as well as climate change and sea level rise.

The TIMER 1.0 model builds upon several sectoral system dynamics energy models (Sterman, 1981; Naill, 1977; Davidsen, 1988). ; The model is based on the earlier TIME model that was been developed and implemented for the world at large (Vries, 1995; Vries, 1996; Bollen, 1995). An earlier TIMER version has been implemented for 13 world regions (Vries, 2000). The model version presented in this report is implemented for 17 world regions that are shown in *Figure 1.2* [2]. The model has been carefully calibrated to reproduce the major world energy trends in the period 1971-1995.

In this report, we describe the main elements of the TIMER model, the underlying concepts and technical formulation and we indicate how the model has been calibrated to reproduce historical energy trends. In Chapter 2 a general overview of the model is given and the way in which the model is calibrated is discussed. In the subsequent Chapters, the Energy Demand (ED) model, the Electric Power Generation (EPG) model and the supply models of liquid, solid and gaseous

[1] The model is called Targets IMage Energy Regional model (TIMER) because it has originally been developed as part of the IMAGE 2.1 model (Alcamo *et al.* 1994, 1998) and the TARGETS model (Rotmans and De Vries, 1997).

[2] Within the IMAGE 2.2 modeling framework a total of 19 global regions are the basis of analysis. For energy use, however, the regions Antarctica and Greenland can be neglected so that a set of 17 regions remains.

fuels are discussed. Chapter 7 describes the regional interactions in the model (trade and technology transfers). Chapter 8 describes the emission module of TIMER. Finally chapter 9 describes generic model building blocks such as learning-by-doing and substitution dynamics. The Appendices contain information on the emission module and the sources of data used to calibrate the model.

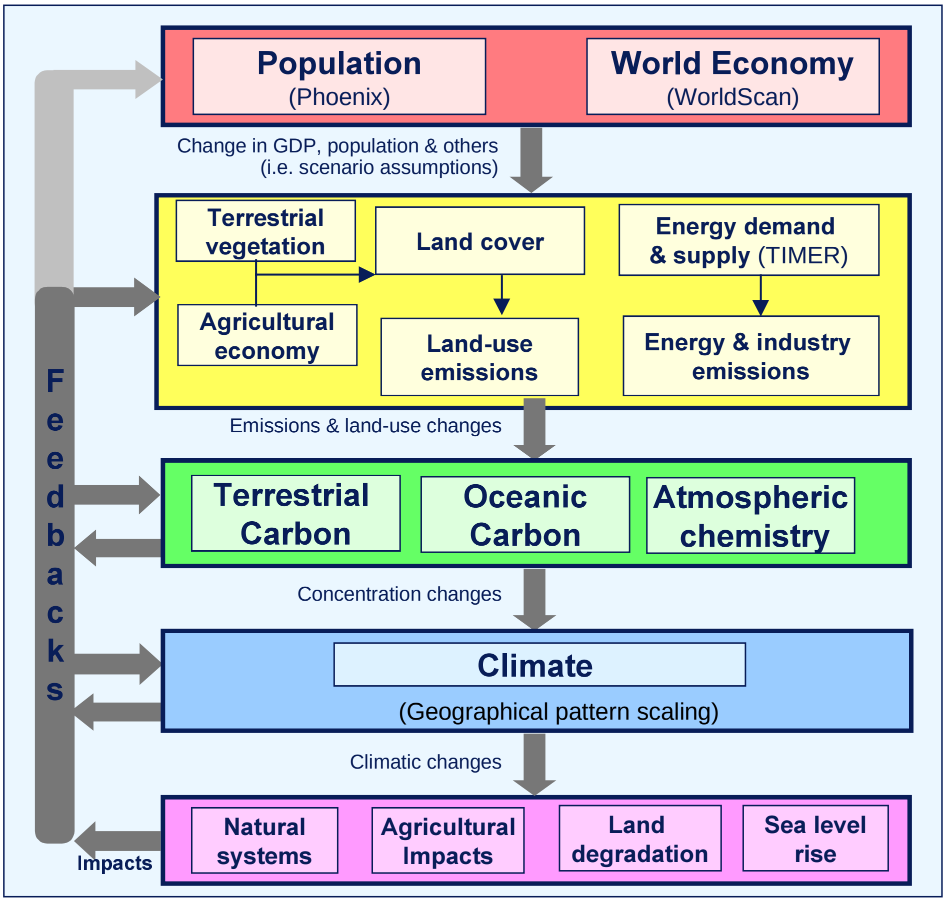

Figure 1.1: Model structure of IMAGE 2.2

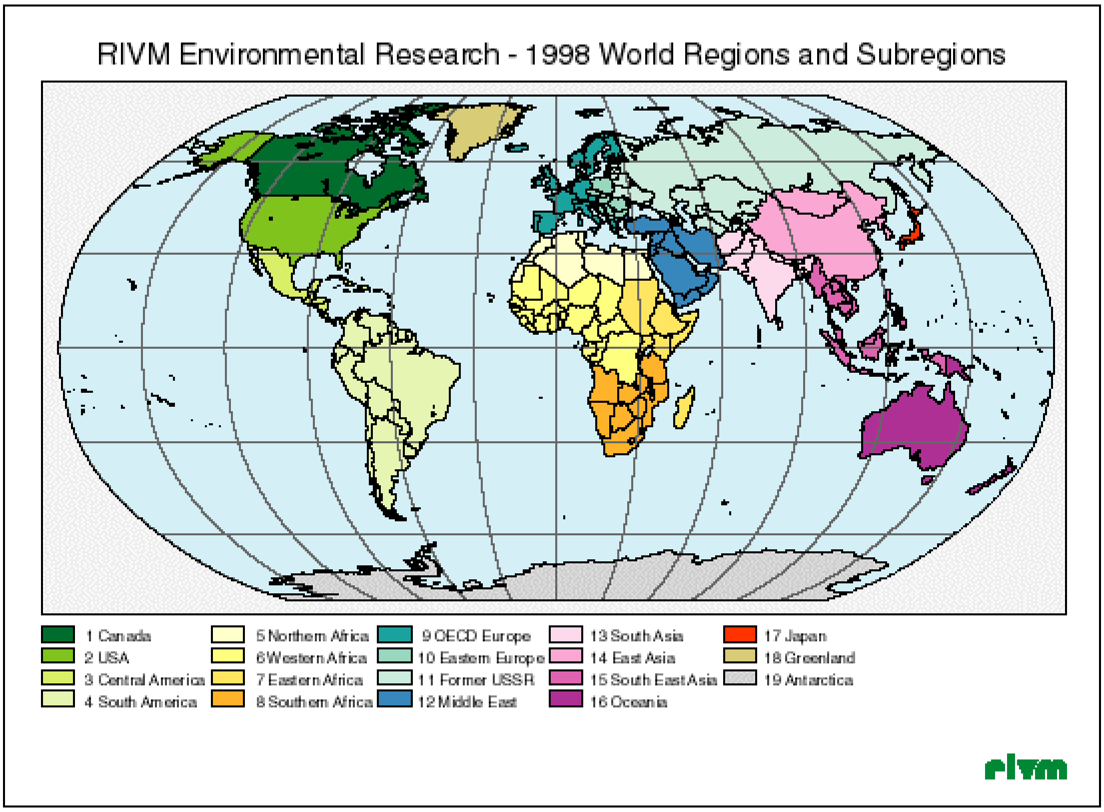

Figure 1.2: IMAGE 2.2 Regions

2. Model overview and methodological aspects

2.1 Overview and objective

Energy is a necessary and vital component of almost all-human activities. Historically, energy policies have been mainly concerned with increasing the supply of energy. However, currently we know that some of the most challenging environmental problems that mankind faces in the 21st century are directly linked with the production, transport, storage and use of energy. Of these problems, the issue of climate change is the one most directly connected to the use of fossil fuels, but also, for instance, acidification and oil spills are largely caused by fossil fuel combustion.

Trends occurring within the energy system are therefore extremely important – both for the economy and the environment. Fortunately, research has shown that within the energy system a large number of options are available to steer developments in more sustainable directions such as the use of alternative energy sources and improvements in energy efficiency. However, large controversies still exist on the costs and potential of these options. This is understandable, given the complexity of the energy system and the many links with other parts of society. Hence, it is important to examine the dynamics of this system by means of integrated models to understand current trends in energy consumption and production and its evolution in the future.

In the TIMER-model, a combination of bottom-up engineering information and specific rules and mechanisms about investment behaviour and technology is used to simulate the energy system. The output is a rather detailed picture of how energy intensity, fuel costs and competing non-fossil supply technologies develop over time. Most macro-economic models currently used deal with the same developments in the form of one or a few highly aggregated production functions and a single backstop technology that supplies non-fossil energy at a fixed cost level (Janssen, 2000; IPCC, 1999). In our view, the two approaches are complementary: the macro-economic models provide consistent links with the rest of the economy, the TIMER-model gives bottom-up process and system insights [3].

The main objectives of TIMER are:

- to analyse the long-term dynamics of the energy system within an integrated modelling framework, in particular with regard to energy conservation and the transition to non-fossil fuels, and
- to explore long-term energy-related and industrial greenhouse gas emissions scenarios which are used in other submodels of IMAGE 2.2.

The TIMER model includes the following main features:

- activity-related demand for useful energy (2 forms: non-electricity and electricity) in 5 sectors, incorporating structural (economic) change due to inter- and intrasectoral shifts;
- autonomous and price-induced changes in energy-intensity, covering what is referred to as energy conservation, energy efficiency improvement or energy productivity increase;
- fossil fuel exploration and exploitation, including the dynamics of depletion and learning;
- biomass-derived substitutes for oil and gas, penetrating the market based on relative costs and learning;

[3] A model which is in various aspects similar to the TIMER-model is the POLES-model, developed at Institut d'Economie et de Politique d'Energie (IEPE) in Grenoble (EU 1997; Criqui 1999).

- electric power generation in thermal power plants and in alternative options (nuclear, wind, solar), penetrating the market based on relative costs and learning;
- trade of fossil fuels and biofuels between the 17 world regions.

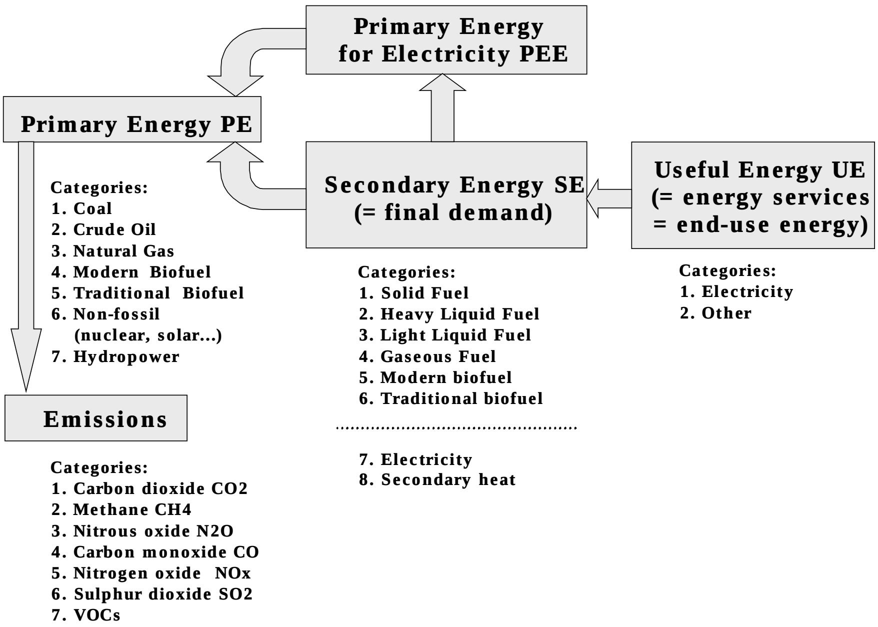

Figure 2.1 Overview of the submodels of the TIMER-model. Regional population and per capita activity levels are from exogenous inputs. The TIMER Emissions Model connects the TIMER-model with the other parts of the IMAGE-model.

Table 2.1: Main exogenous inputs, assumptions, outputs and key aspects not dealt with in the TIMER-model.

Main exogenous inputs	– regional population – regional macro-economic activity levels (GDP, Value Added in Industry and Services, and Private Consumption)
Submodel assumptions	– energy intensity development (structural change, autonomous energy efficiency improvement, response to prices) – technology development (learning curves) – resource availability, fuel preferences and constraints on fuel trade – end-of-pipe control techniques for gas emissions
Model output	– use of primary and secondary energy carriers and feedstocks – production of energy carriers – energy-related and industrial emissions of greenhouse gases, sulphur dioxide, ozone precursors and halocarbons (CFCs etc.) – demand for modern and traditional biofuels
Aspects not incorporated	– feedback from energy system investments and fuel trade patterns on macro-economic activity levels – feedback from possible, temporary energy shortages on macro-economic activity levels – feedback from energy price on macro-economic activity levels – interaction of (carbon)tax related money flows with macro-economic activity levels – feedback from actual emissions on emission policies and measures – institutional aspects such as the consequences of privatisation and liberalisation of electricity markets

The model consists of 6 submodels, which are described briefly in the remainder of this section. The interactions between regions in the form of fuel trade and technology transfer are described separately in chapter 7. In each submodel some generic formulations are used to describe certain processes, such as the sequence of energy-intensity reduction steps; substitution dynamics between competing fuels c.q. options; the process of learning-by-doing as a function of cumulated output; and the resource depletion dynamics. These are discussed separately too, in chapter 8. *Table 2.1* indicates the main exogenous inputs and some key aspects, which may be important but are not dealt with in the TIMER-model simulations – at least not explicitly.

The Energy Demand (ED) submodel

In the Energy Demand model the demand for final energy is modelled as a function of changes in population, economic activity and energy efficiency improvement. The energy demand is calculated for five different sectors, and for eight different types of energy carriers. Changes in population and economic activity drive the demand for energy services (or useful energy). It is assumed that the sectoral energy-intensity (in energy unit per monetary unit) is a bell-shaped function of the per capita activity level. This reflects the empirical observation of 'intra-sectoral' structural change: with rising activity levels a changing mix of activities within each macro-sector leads to an initial increase, then a decrease in energy-intensity. The actual shape of this function (which varies per sector - and to some degree also per region) is a major determinant of the demand for energy services and is considered as an important scenario parameter related to the scenario narrative. This formulation implicitly contains a value of the income elasticity (measures as change in energy services per unit of change in activity), the usual parameter in energy economics. Next, the calculated demand for energy services/useful energy is first multiplied by the Autonomous Energy Efficiency Increase (AEEI) multiplier. The AEEI accounts for observed historical trends of decreasing energy intensity in most sectors, even with decreasing energy prices. The AEEI is assumed to decline exponentially to some lower bound and is linked to the turnover rate of sectoral capital stocks.

Subsequently, the resulting useful energy demand is multiplied by the Price-Induced Energy Efficiency Improvement (PIEEI) to include the effect of rising energy costs for consumers. This is calculated from a sectoral energy conservation supply cost curve and end-use energy costs. The supply cost is assumed to decline with cumulated energy efficiency investments as a consequence of innovations. This reflects the dynamics of learning-by-doing and its rate is determined by the so-called progress ratio, i.e. the fractional decline per doubling of cumulated investments. Next, the demand for secondary energy carriers (see above) is determined on the basis of their relative prices in combination with premium values (the latter reflecting non-price factors determining market shares, such as preferences, environmental policies, strategic considerations etc.). The energy prices are incorporate both the fuel prices (after international trade), taxes and assumptions about conversion costs and efficiencies The absolute values of the conversion efficiencies (from final energy into useful energy) is largely a matter of system choice, but their relative (future) course is an important model parameter. The secondary fuel allocation mechanism itself is described for most fuels with a multinomial logit formulation that sets market shares as a function of aforementioned prices and preference levels. For traditional biomass and secondary heat alternative approaches are used. The market share of traditional biomass is assumed to be mainly driven by per capita income (higher per capita income leads to lower per capita consumption of traditional biomass). The market share of secondary heat is set by an exogenous scenario parameter.

The Electric Power Generation (EPG) submodel

The Electric Power Generation (EPG) submodel simulates investments in various forms of electricity production in response to electricity demand, based on changes in the relative fuels prices and changes in relative generation costs of thermal and non-thermal power plants. The model focuses on the overall long-term dynamics of regional electricity production. First, demand for electricity, an input from the Energy Demand submodel, is converted into demand for required installed generating capacity, using assumption on the base-load peak-load division and the required reserve factor. Given the depreciation rate, the investments in new generating capacity can be in one of the four electricity producing capital stocks distinguished: hydropower, thermal, nuclear and renewables (wind, water, biofuels).

Expansion of hydropower capacity is based on an exogenous scenario. The remaining electricity demand is fulfilled by either thermal power plants (combustion in fossil or biomass-derived fuels) or nuclear and renewable power plants (in presentation sometimes taken together as non-thermal electricity or NTE). For the thermal plants, an exogenous increase in conversion efficiency and change in specific investments costs are assumed. For the nuclear and renewable options, it is assumed that the specific investment costs decline with cumulated production. This reflects learning-by-doing and its rate is determined by the so-called progress ratio, i.e. the fractional decline per doubling of cumulated investments. The penetration dynamics of NTE-technology is based on the difference in generation costs between thermal and non-thermal options. As in the Energy-Demand model, the allocation process (in terms of investments) is described by a multinomial logit formulation - in which in additional to generation costs also a premium factor is used which include non-costs based considerations (preferences based on for instance environmental policies). Within the thermal electric stock several fuels can be used i.e. coal, oil, natural gas and modern biofuels. Also their allocation is based on corresponding generation costs (based on fuel prices from the fuel supply submodel) using a multinomial logit equation. For all investments a certain construction time is assumed before operation starts.

The Fossil Fuel (FF) submodels

TIMER includes three fossil-fuel production submodels for respectively solid, liquid and gaseous fuels. These submodels start from the regional demand in secondary energy carriers, the demand for fuels for electricity generation, the demand for fuels for international transport (bunkers) and the demand for non-energy use and feedstocks. For each fuel type, these fuels are increased by an additional factor reflecting losses (e.g. refining and conversion) and own energy use within the energy system. In a next step, demand is confronted with possible supply - both within the region and, by means of the international trade model, within other regions. The submodels for solid, liquid and gaseous fuels have several aspects in common:

- An important element in the submodels for liquid and gaseous fuels is the possibility of market penetration of non-carbon based alternative fuel. In the current version of TIMER this alternative is confined to a biomass-derived liquid/gaseous fuel alternative. The production of these biofuels requires agricultural land, which is accounted for in the land-cover model (part of the TES system). Other conversion routes, e.g. coal liquefaction or hydrogen from biomass or solar electricity, are not been modelled explicitly in the current TIMER version. The penetration of biomass derived fuels are described by a multinomial logit formulation, allocating market shares on the basis of production costs. The production costs of biofuels are assumed to decline with cumulated production, but to increase with the annual production level. The former reflects learning-by-doing and its rate is determined by the so-called progress ratio, i.e. the fractional decline per doubling of cumulated investments. The latter reflects depletion dynamics, in terms of suitable land availability and land-use competition.

- Exploration and exploitation of fossil fuel reserves are also governed by a depletion-multiplier and a learning-parameter. The depletion multiplier reflects the rising cost of discovering and exploiting occurrences when cumulated production increases. This is based on long-term supply curves of fossil fuels - which could be derived from resource estimates. The learning parameter reflects declining capital-output ratios with increasing cumulated production due to technical progress as a result of learning-by-doing.
- In total four international fuel trade markets exists within the model for coal, crude oil, natural gas and modern biomass. In the fuel production submodels, trade modules are used that simulate interregional fuel trade. Here, it is assumed that each region desires to import fuel from another region depending on the ratio between the production costs in that other region plus transport costs, and the production costs in the importing region. Transport costs are the product of the representative interregional distances and time and fuel dependent estimates of the costs per GJ per km. To reflect geographical, political and other constraints in the interregional fuel trade, an additional parameter is used to simulate the existence of trade barriers between regions. Market allocation is done using multinomial logit-equations.

The Energy-Industry Emissions submodel

The last submodel, the TIMER Emissions Model (TEM) calculates the emissions into the atmosphere from energy- and industry-related processes. Together with the previous four submodels, it forms the Energy-Industry Emissions model of IMAGE 2.2. It replaces the original energy-industry emission model of the EIS model of IMAGE 2.1 (Alcamo, 1996; Bollen, 1995). In this model, the regional energy-and industrial related emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), nitrogen oxides (NO_x), carbon monoxide (CO), non-methane volatile organic compounds (NMVOC), and sulphur dioxide (SO_2) are computed. In addition the model calculates the emissions of the halocarbons (CFCs, HCFCs, HFCs etc.). The model consists of two modules: the energy-emission- and the industry-emission module. In each, time-dependent emission coefficients are applied on the primary energy use fluxes and industrial activity levels, representing technological improvements and end-of-pipe control techniques for CO, NMVOC, NO_x and SO_2 (FGD in power plants, fuel specification standards for transport, clean-coal technologies industry etc.)

2.2 Model calibration

2.2.1 General procedure

In order to show the relevance of the model and to find estimates for many of the model parameters, TIMER has been calibrated by comparing simulation results to historical data from 1971 to 1995[4]. Calibration is defined here as the procedure for comparing the model results with results of the real system as represented by measured variables and its direct derivatives. Validation is not done yet, although the failure to reproduce certain historical trends and the comparison with model results from other researchers enhance our understanding of model

[4] The historical data themselves are discussed in Appendix B. These historical data are not the outcome of exact measurements as in a scientific laboratory; they have all kinds of uncertainties – but as our objective is not an exact reproduction of past trends, they serve our purpose.

domain and validity. It should be noted that complex model structures such as in the TIMER model make it impossible to pursue a rigorous calibration and validation. Instead, one has to be satisfied with a reasonable reproduction of available data about a few key observables, which are meaningful in the modelling context. Such a reproduction is not unambiguous: several sets of assumptions may give satisfactory results. Each of these sets may be plausible in the absence of sufficient understanding of the system, although such sets may be mutually contradictory.

In this section, we discuss the calibration procedure, which is used to calibrate the model and to verify the validity of the model structure and the variables involved. A detailed account for the world version of the model (TIME) is given elsewhere (Vries, 1995; Vries, 1996; Vries, 2000).

The general calibration procedure for TIMER consists of the following steps, performed for each region over the calibration period 1971-1995:

1. First, the Energy Demand (ED) submodel is calibrated using historical sectoral activity levels and sectoral secondary fuel and electricity prices. This yields the demand for secondary fuels (coal, oil(products), gas, traditional, electricity) which should be in fair agreement with the historical data (if not, possible explanations are discussed).
2. Next, the Electric Power Generation (EPG) submodel is calibrated using historical sectoral electricity demand and inputs in electricity generation (coal, oil/HLF, gas, hydro, nuclear). This is repeated with the simulated sectoral electricity demand to explore the discrepancies between simulated and historical time-series. This exercise yields fossil fuel and non-fossil (hydro, nuclear) inputs into electricity generation and installed capacities, which should be in fair agreement with the historical estimates. The simulated electricity costs c.q. prices are compared with the (scarce) historical data and used to do additional fine-tuning of cost parameters. Regional imports/exports of electricity have been included only as exogenous time-series – as they have been relatively small so far.
3. From the two previous steps, we calculate the simulated demand for coal, oil (HLF/LLF) and gas and compare them with historical data. Both the historical and the simulated time-series are used to calibrate the Solid Fuel (SF), Liquid Fuel (LF) and Gaseous Fuel (GF) submodels. This yields calculated fuel prices which are then, in combination with premium factors, used as inputs for the Energy Demand model. For traditional biomass we use exogenous time-series; modern biofuel use is in nearly all regions small enough to be neglected.
4. In first instance, the previous step is performed with exogenous time-series for regional fuel imports and exports. Once the regional fossil fuel submodels show more or less correct behaviour, the fuel trade dynamics is included. This generates fuel imports and export flows based on relative production costs and transport costs and barriers. The latter are used to reproduce the historical trade flows within 5-10% accuracy, which is fairly good in view of the many non-price based interacting factors determining fuel trade.

In the process, the submodels generate auxiliary results which are not influencing other submodel behaviour but which can be helpful in calibration and validation. For instance, in the EPG- and the SF-, LF- and GF-model the requirements for capital (investments), for labour (underground coal mining, biofuels) and land (biofuels) are calculated and then compared with available regional statistics. Using fuel-specific emission coefficients, the emissions of various gases can be calculated and compared with other estimates.

2.2.2 Classification of variables for calibration purposes

A division has been made into five categories of model variables, each one with its distinct characteristics. This makes it easier to see which variables should be compared with historical data and which are to be estimated from expert literature and/or sensitivity analyses. The categories are:

- exogenous drivers, which are determined by mechanisms outside the scope of the (sub)model and need to be entered exogenously, based either on historical facts or on assumptions about future developments. The major ones are regional population and sectoral activity levels (*Table 2.1*).
- calibration observables are those variables chosen from the available statistics to be reproduced by the simulation. Sometimes, these are exogenous drivers for one of the submodels during the iterative calibration procedure. Examples are secondary fuel demand and electricity use.
- exogenous model parameters based on historical observables are variables that are not endogenously calculated or explained but estimated from literature. They may or may not be time-dependent. Examples are the efficiency and specific investment costs of thermal electric power plants or the ratio of exploration and exploitation costs in oil and gas supply.
- model variables are parameters that are calculated in the model, and of which the outcome should be checked against historical data, literature estimates and results from other energy analyses, whenever available. Examples are the labour force in underground coal mining operations and the energy system investments.
- other model parameters, which are partly based on historical data or on system-related assumptions, and are subjected to sensitivity analysis as part of the calibration procedure. Examples are the autonomous rate of energy efficiency improvement (AEEI), the secondary fuel cross-price elasticity and the associated premium factors, and the learning coefficients for surface coal mining and non-thermal electric power generation.

In section 2.1, we indicated the general procedure of the calibration. In terms of variables, first, the exogenous drivers are introduced into the model. These are for the calibration period 1971-1995 and the scenario period 1995-2100:

- population size (per region), and
- activity level (per region and sector: GDP, $VA_{industry}$, $VA_{services}$, Private Consumption).

For the emissions submodel, the important drivers are outputs from the Energy model: secondary fuel use and fuel input for electricity generation. For some relations, population and income are used. Emissions of halocarbons, i.e. CFCs, HCFCs, halons, carbon tetrachloride and methyl chloroform, hydrofluorocarbon (HFCs), perfluorocarbon (PFCs) and sulphur hexafluoride (SF_6) are introduced from exogenous series.

Secondly, the calibration observables are introduced. The important ones are (for each region and for 1971-1995):

- secondary fuel use (per sector and fuel type)
- electricity use (per sector)
- secondary fuel prices (per sector and fuel type)
- electricity prices (per sector)
- electric power transmission and own use losses
- electric power capacity
- fuel inputs for thermal electric power generation (per fuel type)

- electricity generation costs
- fossil fuel (coal, crude oil, natural gas) production
- surface and underground coal mine production
- modern biomass use and production
- traditional biofuel use

In the calibration of the 17 region TIMER model, we have started using the parameter values from the world version of the TIMER-model (Vries, 1995; Vries, 1996). Then, for each region we compared the simulated and the historical values of the above-listed variables. Starting with the exogenous model parameters, we make changes to see whether the simulated values can be brought to closer match the historical values. These parameters usually represent system characteristics that can be derived from literature. Often, their regional values differ for obvious reasons from the world averages, e.g. the base-load factor for hydropower or the coal costs as a function of depth. The parameters in TIMER are discussed in the separate chapters.

In the emission submodel, the calibration observables are the regional emissions as registered in various databases. For CO_2 and SO_2, calibration has happened for the full 1971-1995 period. For all other gases – N_2O, CH_4, CO, VOC, and NO_x – calibration has only been applied for the year 1995 as reliable estimates for earlier years are lacking. Model outcome variables: energy and industry related greenhouse gas and acidifying emissions and some other emissions (other ozone precursors, halocarbons) are inputs for the IMAGE-model, i.e. the atmospheric chemistry model of AOS.

3 Energy Demand (ED) submodel description

3.1 Introduction

The TIMER-Energy Demand (ED) submodel simulates the demand for final energy on the basis of assumed trends in a variety of factors, of which the most important are economic output and structure, technological progress, energy prices and assumptions with regard to lifestyles and energy and environmental policies. In its formulation, the submodel is based on insights and model items that have gained acceptance among many energy-economy researchers (see e.g. IEA, 1997; Johansson, 1989; Schipper, 1993) [5]. This, for instance, includes the decomposition of trends into activity related factors and changes in energy efficiency.

The model distinguishes four dynamic factors: structural change, autonomous energy efficiency improvement, price-induced energy efficiency improvement and price-based fuel substitution. The demand for useful energy per unit of activity often increases in the first stages of (economic) development after which it tends to decrease as a result of intersectoral and intrasectoral shifts in economic activities (agriculture, industry, services). Due to differences in development stages and due to regional interactions, the regions of the world show this bell-shaped trend in widely diverging forms (see e.g. Goldemberg, 1988; LeBel, 1982). The notion of structural change attempts to capture this phenomenon and its consequences for energy demand. Secondly, historical information indicates energy efficiency improvements for many energy-intensive industrial products even in periods of declining energy prices, at rates between 0.5 and 1 %/yr. (see for instance Molag, 1979). This is captured in the Autonomous Energy Efficiency Improvement (AEEI) multiplier which causes energy-demand intensity to decline autonomously as a consequence of continuous technical innovations and capital turnover rates [6]. Thirdly, the model takes into account that energy prices have an impact on the efficiency of energy use [7]. The actual response is difficult to measure and differs for different sectors; the model we have opted for an approach intermediate between a bottom-up engineering analysis and a top-down macro-economic approach, using a time-dependent energy conservation supply cost curve. The fourth factor considered is the substitution among secondary fuels. This is described in the model with a multinomial logit formulation through which relative prices in a part of the market determine the actual secondary fuel market shares.

An overview of the Energy Demand model is given in *Figure 3.1*. It shows how exogenous time-series for (sectoral) activity determine the demand for useful energy demand at the initial (1971) state of technology and prices (‘frozen technology’). Due to autonomous and price-induced energy efficiency improvement, the actual demand is lower and equal to use if no constraints are operating. Heat demand is satisfied by a price-determined mix of solid, liquid and gaseous fuels. This final demand for secondary fuels and electricity is calculated by incorporating (the changes in) the efficiency in converting secondary fuels and electricity into useful energy. Electricity demand is met by electric power generation (Chapter 5). The model is

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5 The main elements have been developed first as part of the ESCAPE- and the IMAGE2.0 project and, in its present form, the IMAGE2.1 and TARGETS-project. For detailed descriptions of earlier and present versions, we refer to (Toet, 1994; Bollen, 1995).

6 The dynamics behind it can only be understood in the context of mostly qualitative and speculative theories of long-term technology and economy dynamics (see e.g. Grübler, 1990; Grübler, 1999; Sterman, 1981; Tylecote, 1992.

7 Because energy is partly a complement to capital and a substitute for labour, relative factor prices may actually be the relevant variable.

implemented for 17 regions, 2 energy functions (heat and electricity) and 5 economic sectors (residential, industrial, commercial, transport, other).

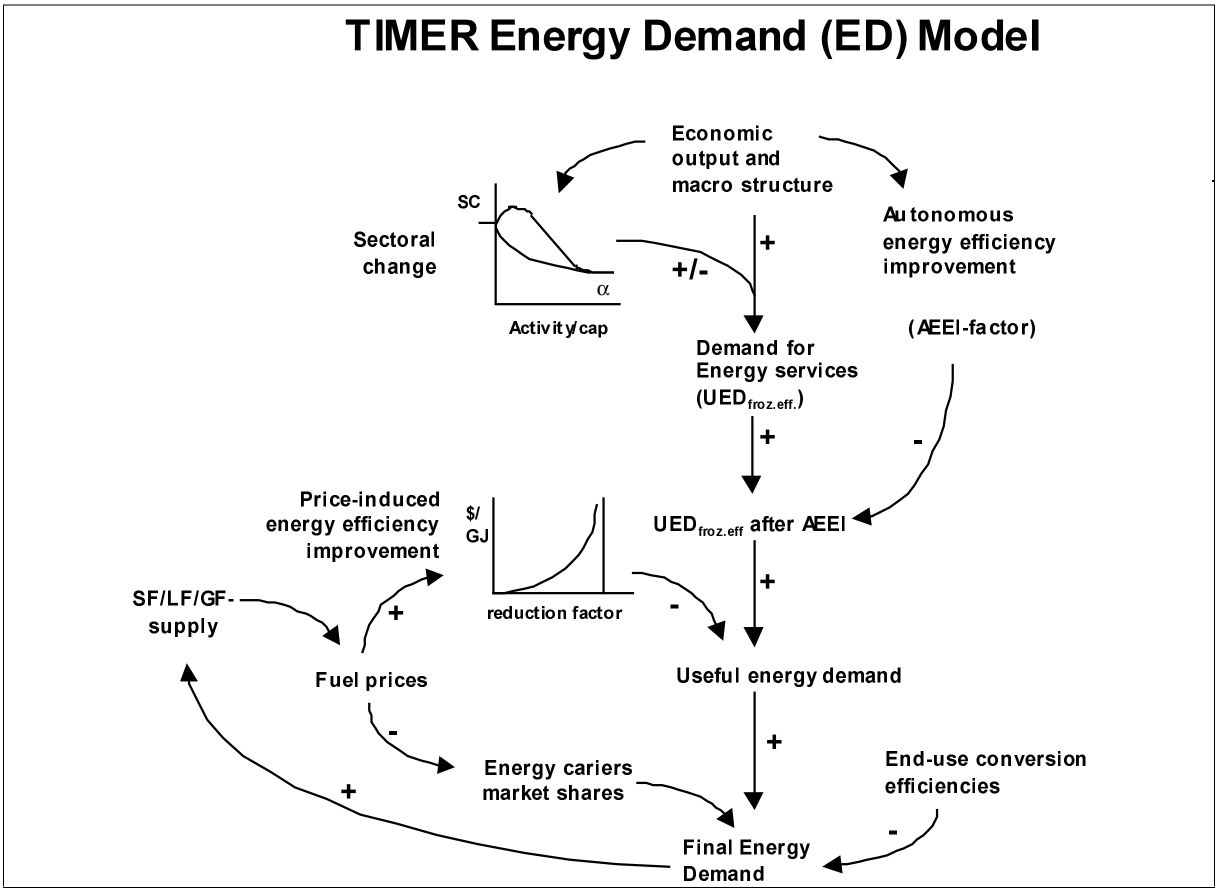

Figure 3.1: Overview of the ED-submodel

The formal definitions of the variables used in TIMER to distinguish the role of the different factors on energy demand can be found in *Box 3.1*. For each sector, we use one indicator for the level of activity (Act), which in all cases is a monetary indicator. The energy-intensity is, thus, defined as the ratio between the energy consumption and this activity indicator. It should be noted that the use of aggregated, monetary indicators leads to rather limited notion of energy efficiency (IEA, 1997; Norgard, 1995; Phylipsen, 1997). Reasons include: i) monetary indicators do not capture all activities demanding energy (much household work, but also informal activities are not included); ii) it is difficult to capture structural changes within sectors in these indicators; and iii) price changes and differences in price levels make it difficult to compare these indicators in time and among different regions. Part of these short-coming are taken care off in TIMER-ED, in particular by using Purchasing Power Parity (PPP, or International) dollars (Summers and Heston, 1991), modelling at sector level, and explicitly capturing structural change. *Figure 3.2* gives an overview of the various categories used in the calculation chain.

Box 3.1: Key-terms
*Primary energy consumption: Total p*rimary energy consumption is the sum of all energy consumed by a process or industrial sector, including losses at various stages of energy production (upgrading and harvesting processing).
Final energy consumption: The energy consumed directly by end users in the form of solid, liquid and gaseous fuels and electricity. It does not include the energy lost in the production and delivery of these fuels and electricity. It is thus equal to the use of secondary fuels and electricity, indicated in the statistics also as *secondary energy consumption.*
Useful energy: Final energy minus estimated conversion losses at the site of final use. It is sometimes also referred to as end-use energy.
Energy services: Energy used for given services in a specified reference year, measured in energy required using the technology of a given year ('frozen technology', here as of 1971). It is in the present context, given our choice of system boundaries, by definition equal to useful energy.
(Final/Primary) Energy intensity: The amount of (final/primary) energy consumed per financial unit of activity or output. In the present context, with activity levels expressed in monetary units, energy intensity is in GJ per 1995 US $.
Energy efficiency: Energy actually consumed per unit of activity or output compared to the energy consumption for the same activity or output in the reference year. The term energy efficiency is used preferably referring to real improvement in the ratio between final energy consumption and the energy services provided.
Structure: Structure refers to the proportion of different activities within each sector. For the manufacturing sector, for instance, structure refers to the share of total manufacturing value-added produced within the individual subsectors.

Source: partly based on Schipper, 1993

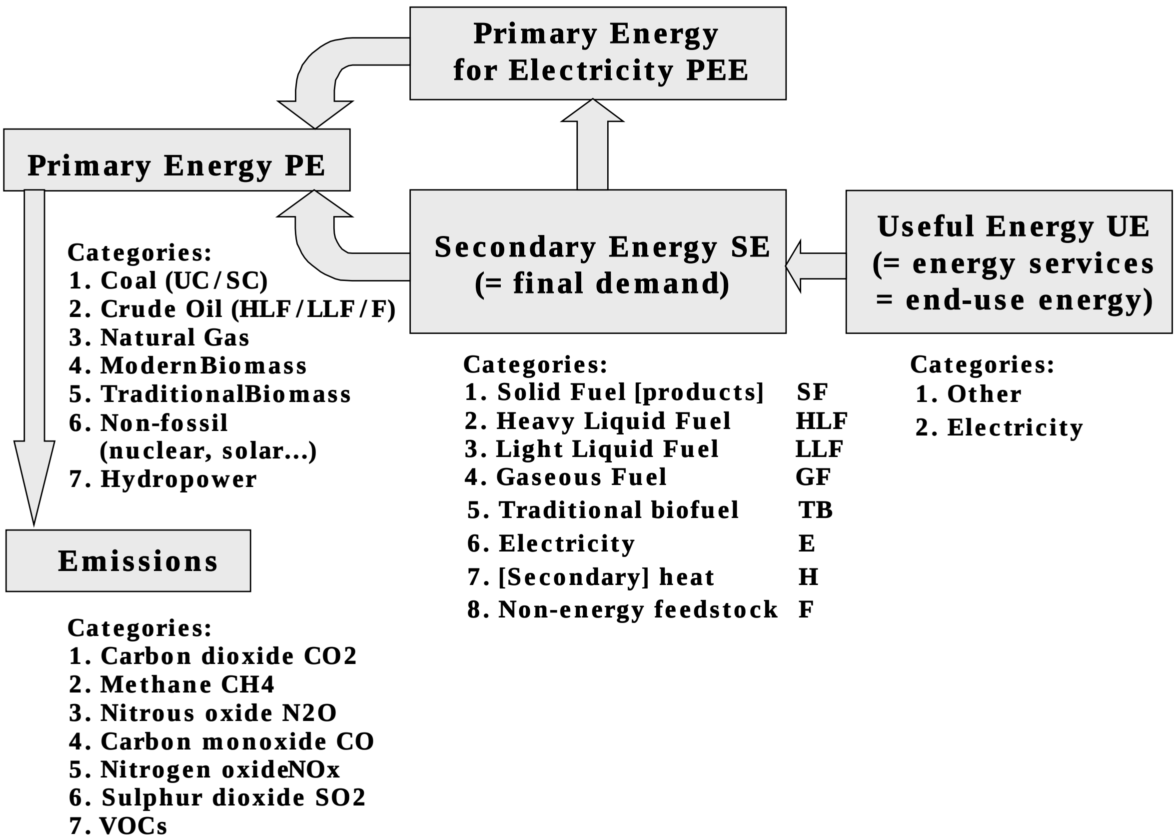

Figure 3.2: Categories in the ED-submodel in relation to the rest of TIMER.

The total ED-submodel can be summarised in two formulas:

$$UED_{trsi} = ActPC_{trs} * POP_{tr} * UEI_{1971,rsi} * AEEI_{trsi} * PIEEI_{trsi} \quad \text{GJ/yr.} \quad (3.1)$$

$$SED_{trsji} = UED_{trsi} * \mu_{trsj} / \eta_{trsj} \quad \text{GJ/yr.}^{8} \quad (3.2)$$

The first equation says that in any year t, Useful Energy Demand in the form of other than electricity forms (i=1) and electricity (i=2) in sector s in region r, UED_{trsi}, equals the product of per caput activity level $ActPC_{trs}$, the population POP_{tr}, the Useful Energy Intensity $UEI_{1971,rsi}$ at the technology and price levels in the initial year (1971; 'frozen efficiency'), and two factors accounting for the autonomous and price-induced improvements in energy efficiency after the initial year. The factors are referred to as Autonomous Energy Efficiency Improvement factor $AEEI_{t,r,s}$ and Price-Induced Energy Efficiency Improvement factor $PIEEI_{trs}$.

The second equation says that in any year t, the use of secondary fuel (j=1..5; see *Figure 3.2*) and electricity (j=6; see *Figure 3.2*) respectively in sector s in region r, SED_{trsji}, equals the Useful Energy Demand UED_{trsi} needed in the form of non-electricity (i=1) and electricity (i=2) and the market share of fuel j in sector s in region r, μ_{trsj} , divided by the efficiency with which this fuel is converted to useful energy, η_{trsj} The value of $UED_{1971,rsi}$ in eqn. 3.1 is calculated from the historical data on secondary fuel and electricity and estimated conversion efficiencies $\eta_{1971,rsj}$.

The running indices are for:	
t	time (1971-1995, 1995-2100)
r	region (see Figure 1.2)
s	sectors (industry, transport, residential, services, other)
j	energy form (non-electricity, electricity)
j	secondary fuel (SF, HLF, LLF, GF, heat H, electricity E; see Figure 3.2)

In *Eqn. 3.1* different indicators are used for the activities within each sector (ActPC). *Eqn. 3.1* can directly be applied for the energy function heat; for the energy function electricity the term $\mu_{t,r,s,j}$ / $\eta_{r,j}$ is set equal to 1 as there is only one energy carrier with market share 1 and an assumed conversion efficiency of 1 (the losses in electricity generation are calculated in the EPG-model (cf. *Chapter 4*)). *Eqn. 3.1* and *3.2* can be seen as a specific form of the well-known IPAT formula, stating that Impact = Population * Activity/caput * Technology. In the remainder of this paper, we omit the indices t (time) and r (region) unless there is specific reason to include it.

In our demand formulation, the focus is on the amount of energy services provided. Obviously, this concept should only be used in relation to well-defined system boundaries. The amount of energy services is in TIMER equated to Useful Energy Demand UED and its evolution over time is derived from its value at *frozen efficiency*[9] (*Eqn 3.1)*. This allows comparing changes in energy demand due to structural changes and efficiency improvements separately. It is important to realise that the Useful Energy Demand UED – and the derived Useful Energy Intensity UEI - are non-observable quantities. It is an estimate of the amount of heat or power that is used to perform the energy service, that is, useful energy using 1971 technology. An

[8] The common unit for energy fluxes is GJ/yr. 1 GJ/yr = 31.71 Watt = 0.0239 toe/yr.
[9] In the model, the term 'frozen efficiency' refers to end-use technology as used in a region in 1971.

interesting quantity in this respect is the Useful Energy intensity UEI: it represents the component of energy demand changes which is solely due to changing inter- and intrasectoral activity patterns. It is expressed as:

$$UEI_{froz.eff,rsi} = {UED_{froz.eff,rsi}} \big/ {Act_{rs}} \qquad \text{GJ/unit} \qquad (3.3)$$

3.2 Structural change: relating energy services and economic activity

Economic activity levels including the manufacturing and use of energy-using capital goods, and population size are usually seen as the most important driving force behind the demand for energy. As explained in the previous section, the focus on energy demand is, in first instance, on useful energy at frozen efficiency - also referred to as energy services. *Table 3.1* indicates the kind of energy services provided by secondary fuels and electricity, and associated equipment - that is, energy-using capital goods.

Table 3.1 Energy service categories

Energy service:	*Comments*	*associated appliances*
Pumping	all sectors; mainly electricity-driven	Pumps
Ventilation	all sectors (buildings, cars); mainly electricity- driven	Ventilators
Refrigeration	all sectors; mainly electricity-driven	Refrigerators
other motors	electricity-driven: all sectors; transport: mainly oil-based fuels	Electro-motors (trains); motors (cars, trucks, planes)
Lighting	all sectors; mainly electricity-driven	incandescent, TL etc.
Electronics	all sectors; mainly electricity-driven	audio-video, tv, pc, telephone etc.
space cooling	all sectors (buildings, cars); mainly electricity- driven	air-conditioners
low-temp space heating	Residential and services sector (buildings); mainly based on fuels	stoves, central heating, elec-heater, heat-pump
low-temp process heat	Industrial sector; mainly based on fuels	steam boilers
high-temp process heat	Industrial sector; mainly based on fuels	steam boiler; ovens; electric heating
Miscellaneous	-	-

As economies develop, the type of activities performed within the economy and the amount and type of energy services needed tend to change (intersectoral shift). The structural change of an economy over time is reflected in the shifting shares of the aggregated sectors agriculture, industry and services in total value added (*Figure 3.3)* and employment. These structural changes alone can influence the energy consumption of an economy significantly. At the level of sectors, for instance, increases of industrial activities in total GDP at the expense of agricultural activities or services tend to increase energy consumption. One important reason for this is that the production of energy-intensive products, for instance non-ferrous metals, requires 10 to 100 times more (direct) energy per unit of GDP than one unit of GDP produced by bank services.

Within sectors, the same dynamics can be observed (intrasectoral shift). A shift within the industrial sector from energy-intensive activities, such as aluminium production, to less energy-intensive activities, such as meat packing, will decrease energy consumption per unit of GDP, all else being equal. Conceptually, this can be phrased as a shift from products with large resource and low labour inputs to products with low resource and high labour/knowledge /service inputs per physical/monetary unit of output [10]. It should be noted that any measurement

[10] Much analysis based on Input-Output tables has been done. However, the relationship between energy-intensity in terms of physical and of monetary units is a complex one.

of (economic) activity levels is itself problematic, one issue being the role of informal (non-monetarised) activities and another the comparison of activity levels between regions.

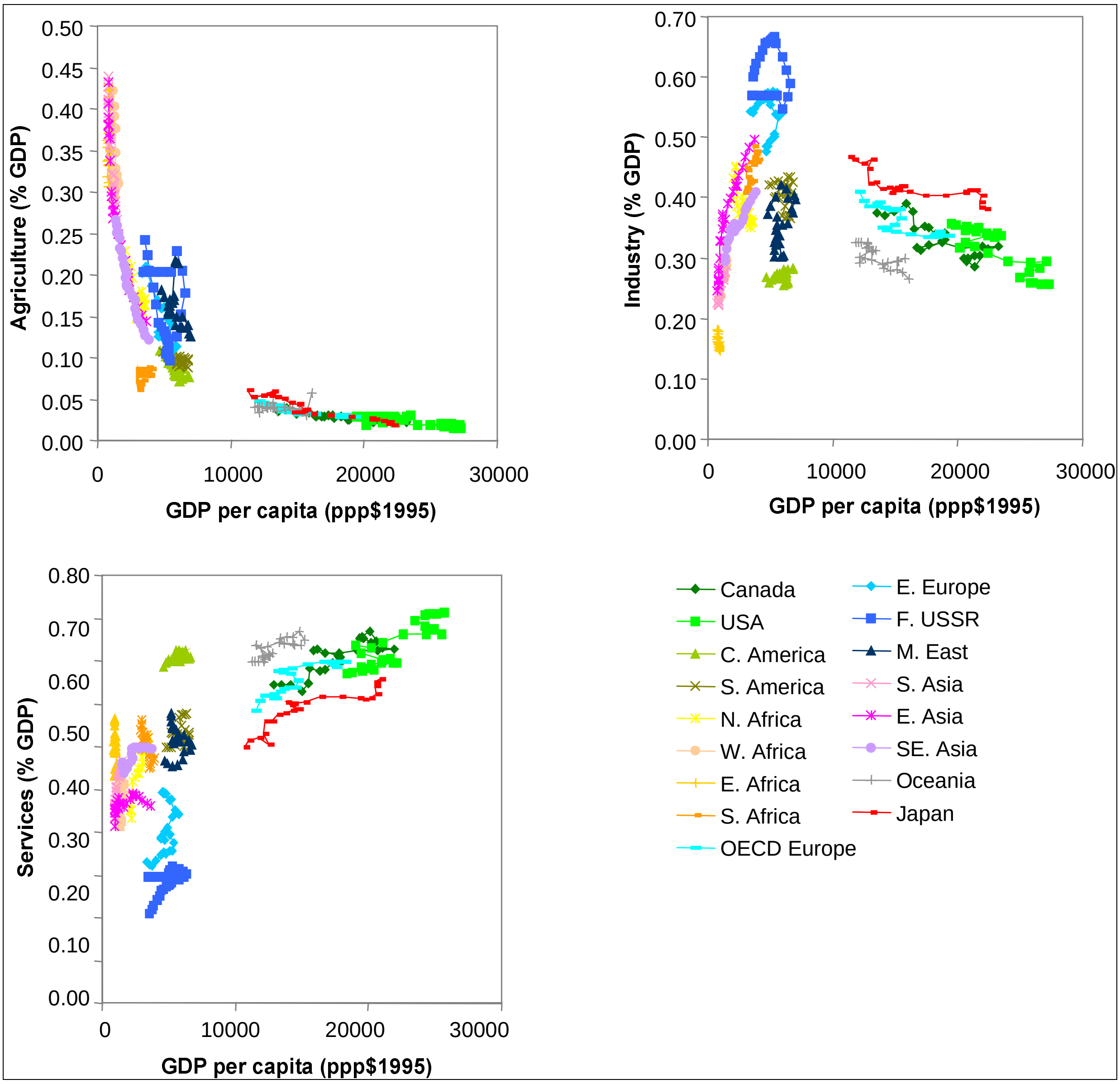

Figure 3.3: Share of agriculture, industry and services in total value added between 1970 and 1995 for the 17 IMAGE regions (World-Bank, 1998).

In the ED model, two mechanisms are assumed to incorporate the effects of sectoral changes on the demand for energy services (Useful Energy Demand at frozen efficiency, UED_{frozen}):

- *intersectoral* structural changes: shifts in economic activities from agricultural to industrial and from industrial to service sector activities (measured in monetary units), and
- *intrasectoral* structural changes: shifts in economic activities within a sector, e.g. from heavy to light industry.

The first type of structural change is implemented in the model by disaggregating total energy use in the model into five separate sectors, for which energy use is related to specifically chosen activity indicators. These indicators are valued added for the industrial sector (VA_{ind}), valued added for the services sector (Va_{serv}), private consumption for the residential sector (PC) and Gross Domestic Product (GDP)[11] per capita for the transport and 'other' sector. Within the IMAGE 2.2 framework, the exogenous scenarios used for changes in these activity indicators are based on the WorldScan-model (CPB, 1999b). This ensures a certain consistency, not only between the different sectors but also between the different regions.

Box 3.2: Trends in 'dematerialisation'

In the industrialised regions there is clear evidence of the role of structural change in trends in energy- and material-intensities. For instance, between 1973 and 1994 aggregated structural changes in the mix of sectoral activities drove up energy use between 0.1 – 0.7% per year for selected OECD countries (Unander, 1999). These aggregated changes can be the result of various underlying trends. A major factor behind the decrease in energy use per unit of GDP is, as indicated above, 'a gradual transition of the output mix in the direction of information- and value-intensive, but material-extensive, products and the availability of higher-quality and lighter substitutes in the form of advanced materials' (Grübler, 1990).

However, there are also other, more equivocal factors at work. Demographic factors such as decreasing household size and ageing may lead to higher energy-intensity[12]. The growing importance of energy-intensive transport modes and the ongoing electrification of offices, on the other hand, tend to increase energy-intensity, as do life-style related changes such as the increasing size/weight of new cars and the purchase of electric waterbeds and garden lights. Yet, one may also think of life-style changes which result in lower energy-intensity. For instance, if people in the developed regions feel a widening gap between economic activity and well-being, a reduced emphasis on activity-growth and increasing support for 'green' technologies and investments may emerge. Such a 'greening' or 'dematerialization' of the economy is usually thought to bring down the energy use per unit of GDP. Finally, changes in the regional import and export flows and the dynamics of technology transfer may also cause significant changes in the energy intensity. There is evidence that part of the energy-intensity reduction in the OECD has been realised by a shift from energy-intensive production to import of energy-intensive materials (Schipper, 1997).

Due to lack of data and different and less well understood dynamics, the picture for the less industrialised countries is at least as complex. It is often assumed that with industrialisation the energy-intensity in the less industrialised countries will strongly rise, following the historical development trajectories of currently industrialised countries. This, however, may not or only partly happen, because late-comers have important catching-up possibilities and countries are quite heterogeneous with regard to process and product saturation levels. This argument clearly makes sense for much of manufacturing. In transport, canals and railways may never reach the densities they reached in Europe but the preferred automobile-road system may actually lead to a more energy- and material-intensive development pattern than Europe's historical trajectory. More generally speaking, a key question is whether the industrialising countries will follow current European and North-American life-styles.

To simulate the second type of structural changes, the intensity of energy use in each sector (*Eqn. 3.3*) is modelled as function of a selected 'driver of change', also indicated as Driving Force per caput DFpc (see *Table 3.2*). Available data suggest that the resource intensity in physical units per monetary unit can be represented by a bell-shaped function of the caput activity level DFpc (Vuuren, 2000). Energy intensity starts at low levels, in a stage in which fuels and electricity are minor inputs. If activity levels rise, producers and consumers will start to purchase capital goods which require commercial fuels and electricity to operate - ovens, machinery, cars and trucks, stoves, heating and air-conditioning installations, washing

[11] Although we use regions, we still use Gross Domestic Product, GDP.

[12] (Ironmonger, 1995) projects an increase of 2.4% of residential energy use per caput due to the expected further decline in Australian households.

machines etc. In the next stage, often less energy-intensive activities start to dominate sectoral energy consumption at the margin. As a result, the activities within the sector grow faster than energy use, and thus intensity declines. There are still large uncertainties about what actually happens and further research is needed.

In *Figure 3.4*, the demand for useful energy is shown in a stylised form as a function of the driving force DFpc. If energy-intensity is expressed per unit of DFpc, the hyperboles represent constant useful energy demand per capita isolines [13]. As *Table 3.2* shows, this is the case for all sectors but the industrial sector. This is because at higher GDP/cap levels the share of $VA_{industry}$ tends to decline and one has to introduce some form of irreversibility to avoid energy-intensity going up again as income increases. Therefore, for this sector we use GDP per capita as driver of change. Using this curve assumes that certain phenomena are universal in nature, such as the transition from energy- and materials-intensive bulk products towards knowledge-intensive processed goods within industry, the increase of the size of dwellings and of office spaces and the add-on luxuries in cars if people become materially more affluent. To be sure: these are life-style related developments, not natural laws. The present-day emergence of a global consumer culture tends to affirm these trends, but other courses of (political and consumer) action might lead to quite different trends.

Table 3.2: Sectoral indicators used in the structural change formulation

Sector	*Intensity indicator (UEI_{frozen})*	*Driver of change (DF_{pc})*
Industry	$UE_{frozen, industry}$ / $VA_{industry}$	GDP per capita
Transport	$UE_{frozen, transport}$ / GDP	GDP per capita
Residential sector	$UE_{frozen, residential}$ / Priv. Cons	Private consumption per capita
Services	$UE_{frozen, services}$ / $VA_{services}$	Value added services per capita
Other	$UE_{frozen, other}$ / GDP	GDP per capita

We express the stylised curve of *Figure 3.3* for the intensity UEI_{frozen} (see also *Eqn. 3.3)* as a function of PPP-corrected values for sectoral activity indicators:

$$UEI_{rsi} = UEIbase_{rsi} + 1/(\alpha_{rsi} + \beta_{rsi} * DFpc_{rs} + \gamma * DFpc_{rs}^{\ \delta}) \qquad \text{GJ/\$} \qquad (3.4)$$

By choosing certain values of the parameters α, β, γ, and δ (based on historical trends) *Eqn. 3.3* can take a form in which the intensity initially rises, goes through a maximum for a value of $DFpc = (-1/\gamma\delta)^{1/(\delta-1)}$, approaching asymptotically a fixed per capita level, $UEIbase_{rsi} + 1/\alpha_{r,s,i}$ which is region- and sector-dependent. Hence, at high activity levels the UED-intensity follows an isoline of constant GJ/cap of the magnitude $1/\alpha_{r,s,i}$. In *Chapter 9,* the dynamics of *Eqn. 3.4* are analysed in more detail. Note that this curve is for UEI_{frozen}, that is, for the 1971-level of technology and prices.

An important aspect of this formulation is the possibility to introduce physical data into the energy demand simulation. Regions differ in climate, in the stage of their techno-economic development etc. Such information can be introduced in the assessment of the regional saturation levels by gauging the regional curves to account for differences in climate (residential and services, but also industry), population density (transport, but also residential), primary sector self-sufficiency (industry) and traditional fuel use for cooking (residential). In

[13] All converted to PPP 1995 $, also indicated as international dollars, I$.

general, the differences can be given a sensible interpretation and can be linked to similar analyses done by others (E.g. Sorensen, 1998).

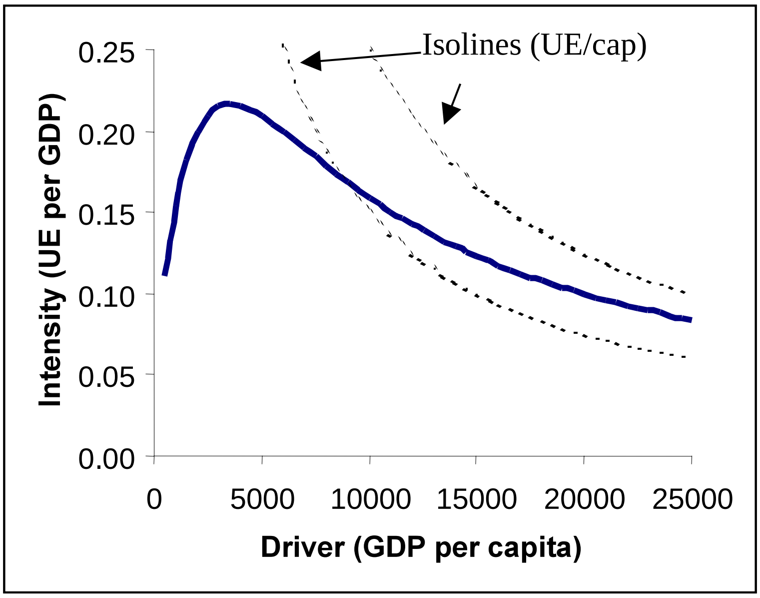

Figure 3.4: General shape of the intra-sectoral structural change Eqn.3.4

A more advanced approach would be to use intermediate explaining variables such as office floor space, number and size of trucks etc. We hope to do this in future work, bridging monetary top-down with process-based bottom-up approaches (Price, 1999; Groenenberg, 1999). Still, one may miss important explaining variables in this way, for instance a supply push in the case of electric power overcapacity or heavily subsidised pricing. On top of this is the (un)reliability of the sectoral data, including changes in sectoral definition.

It should be reiterated that UED_{frozen} is a non-observable quantity. The parameterisation is done by gauging the curve to the 1971-1995 historical data, entering reasonable estimates from the literature on conversion efficiencies and the role of autonomous and price-induced efficiency improvements. We have constructed a new and consistent database from IEA and other sources to this purpose (see Appendix A). For the scenario part, we assume regional per capita saturation level trying to account for differences in:

- industry: the product/process mix and the state of technology;
- transport: population density, mobility patterns, and the state of infrastructure and technology;
- residences: climate, building practices and cooking and heating/cooling habits;
- services: climate, building practices, heating/cooling habits and the nature of the service/commercial sector;
- other: no special considerations have been applied; the main activity in this category is agriculture. This category is often small and/or a statistical artefact which tends to diminish as the energy statistics are improving.

An additional consideration is that the demand for useful energy is not always met - there may be an unmet, or latent, demand that cannot be satisfied due to lack of purchasing power or supply capacity. For the calibration, this phenomenon is not accounted for.

As it turned out, the calibration for the period 1971-1995 yielded for some sectors/regions disturbing results. One question mark relates to behaviour under decreasing activity levels, such as occurred in the Former Soviet-Union after 1990. The functional we use (eqn. 3.4) suggests that the energy-intensity would then fall back in the pre-maximum early industrialisation phase and increase again in the post-maximum period. The latter is what actually happened in the Former Soviet-Union, which can be explained because of fixed base energy requirements and falling activity. However, one might as well see the opposite happen when the decline leads to (industry) rationalisation or (behavioural) adjustments. More research is needed to get a better understanding of the issue of (ir)reversibility at this aggregation level.

Another point is that an independent estimate of useful demand for electricity and for other, non-electricity forms of energy is not always giving satisfactory results. Therefore, it was decided to link the demand for electricity to the demand for other energy forms for the sectors industry, transport and other via the time-dependent heat-to-power ratio. In this way, one can make the evolution of this ratio part of the scenario, which seems more meaningful in view of the complex factors governing the competition of electricity with other energy forms.

3.3 Energy conservation: AEEI and PIEEI

For selected OECD countries in the 1973-1995 period, it has been found that energy conservation has reduced the energy consumption in different countries and sectors at rates typically between 0 and 2.5% per year (Schipper, 1992). Within TIMER-ED two main types of useful energy demand reduction are distinguished (*Eqn. 3.5*) [14], Autonomous Energy Efficiency Improvement (AEEI) and Price Induced Energy Efficiency Improvement (PIEEI):

$$UED_{rsi} = UED_{froz.eff,rsi} * AEEI_{rsi} * PIEEI_{rsi} \qquad \text{GJ/yr} \qquad (3.5)$$

Autonomous Energy Efficiency Improvement (AEEI)

The innovations underlying autonomous efficiency improvements are introduced mostly in new capital goods as retrofit options are often less effective and more expensive. Therefore, the ED-model distinguishes for all sectors old and new capital equipment and applies a purely exogenous ‘technological progress’ to new capital goods. In this two-vintage approach, the energy-intensity will drop slightly faster for higher activity growth[15]. The AEEI-factor is calculated in the following way:

$$AEEI_{t,rsi} = AEEI_{t-1,rsi} * \left\lfloor AvInt_{t,rsi} / AvInt_{t-1,rsi} \right\rfloor \qquad - \qquad (3.6)$$

Here, AvInt is the average energy intensity. This is evaluated by applying the marginal energy intensity, MargInt, to new capital:

$$AvInt_{t,rsi} = \frac{AvInt_{t-1,rsi} * OldCap_{t,rsi} + MargInt_{t,rsi} * NewCap_{t,rsi}}{OldCap_{t,rsi} + NewCap_{t,rsi}} \qquad \text{GJ/\$} \qquad (3.7)$$

[14] In fact, also a third type of energy conservation exists which is the change in time of the conversion efficiency from final energy to useful energy (mostly using coal, oil and natural gas boilers but also biomass). Due to our focus on useful energy, this type of energy conservation exists as a separate category – and is modeled by an exogenously determined scenario parameter.

[15] It remains constant with zero or negative activity growth.

In this formula, OldCap and NewCap are indexed variables which represent the old and new capital equipment installed in year t. The total capital stock is the sum of old and new capital equipment. To keep things simple, it is assumed to grow at the same rate as the activity. We assume that regions differ with regard to the MargInt in the initial year 1970. MargInt is calculated as:

$$MargInt_{t,rsi} = \exp[LMI_{si,(t-1970+TL)}] \qquad \text{GJ/\$} \qquad (3.8)$$

with LMI a curve which represents a global technology progress curve (as a function of time) and TL the location of a region in time along this curve. Choosing TL >0 makes it possible to position regions ahead of other regions with regard to past learning which is only of any consequence if the LMI-curve is non-linear. The rate at which regions move along the LMI curve can also be varied. In this way, faster ‘autonomous’ decline in energy efficiency be modelled – for instance as result of technology transfer.

From these equations it is seen that the real force behind a decrease of the AEEI-factor is the decline in MargInt: if it remains constant, the AEEI-factor remains constant. A lower bound is introduced through the learning curve: if the LMI-curve becomes flat, LMI_{lim}, the MargInt no longer decreases. In our formulation, the rate of capital stock, (dNewCap/dt/dTotalCap/dt), also influences the rate of AEEI. However, simulation experiments indicate that incorporation of the capital stock turnover rate is only significant in case of negative activity growth rates, as have happened for instance in Eastern Europe and the Former Soviet-Union since 1990.

Price-induced Energy Efficiency Improvement (PIEEI)

A second category of energy conservation is caused by investments made in response to energy price changes, the so-called Price-Induced Energy Efficiency Improvement (PIEEI). Many of these investments will have a retrofit character, i.e. they are added to operating capital stocks.

Starting point for the calculation of the optimal conservation for energy-using equipment, EEopt, is that the marginal investment costs to conserve an additional unit of useful energy are increasing: the energy conservation cost curve. The value of EEopt is derived from the assumption that energy consumers maximise the difference of the costs to take energy conservation measures on the one hand and the revenues from lower fuel or electricity costs on the other hand. In other words: they invest up to an economically optimal level of energy-intensity reduction. This optimal level is defined as the point up to which the average of all measures still yields a net revenue; at the margin there can still be conservation measures available that generate net revenues. Taking the derivative of the cost curve, the optimal energy efficiency for a desired payback time PBT_{des} [16] and sectoral energy costs CostUE is given by:

$$EEopt_{rsi} = CC\max_{rsi} - 1/[\sqrt{CC\max_{rsi}^{-2} + CostUE_{rsi} * PBT_{rsi} / (CCS_{rsi} * CCI_{rsi})} \qquad - \qquad (3.9)$$

with CC_{max} a maximum on the achievable price-induced reduction factor, CCS the steepness parameter of the conservation cost supply curve and CCI the factor with which the cost curve declines (Vries, 1995). CC_{max}, PBT_{des} and CCS are exogenous inputs. CostUE is the weighted average price of consumed fuels and thus depends on fuel prices and market shares. CCI is

[16] Because only part of the energy efficiency investments simulated are the object of rational decisionmaking by energy end-users, it is adequate to think of the PBT as the apparent payback time used.

determined either by an exogenous time-series of annual decline percentages or, as part of a learning-by-doing process, related to the cumulated conservation investments. Note that 0 < EEopt < CC_{max} and that EEopt is the factor with which UED is to be multiplied to get the optimal UED. Formula 3.9 can be rewritten into an expression for the marginal investment costs IC_{marg} (Vries, 1995):

$$IC_{m\arg} = CCS_{rsi} * CCI_{rsi} * \left[(1-\zeta)^{-2} - 1 \right] / CC\max_{rsi} \qquad \$/GJ_{saved} \qquad (3.10)$$

Here, ζ is the degree to which the maximum has been achieved, EEopt/CCmax. If ζ–> 1 then IC_{marg} –> oo and if ζ–> 0 then IC_{marg} –> 0. The factor CCS*CCI/ CC_{max} can be interpreted as the total investment costs associated with a reduction of the energy intensity with a factor (V5 - 1)/2 ~ 0.62 for CC_{max} = 0.9. Thus, a rule of thumb is that the choice of CCS*CCI/ CC_{max} indicates the level of the average investment costs per GJ_{saved} at which a total reduction in energy-intensity of 62 % is realised. Chapter 9 illustrates these equations in more detail.

Two things should be noted here. In our implementation, we assume that all regions have the same (sectoral) conservation cost curve in terms of CCS and CC_{max}. We then use historical energy prices and assumed payback times to normalise this curve for each region in such a way that in each region the conservation cost curve has its origin at the point where no additional energy efficiency measures are taken (PIEEI = 0). In this way the simulation reflects the phenomenon of differences in marginal costs of energy conservation.

Secondly, our formulation implies the use of a price-elasticity which depends on the degree of conservation c.q. the energy cost and on time. The price-elasticity is defined as the ratio of percentage change in energy use before and after PIEEI and the percentage change in energy costs CostUE. This formulation implies a price-elasticity tending towards zero if a large share of the maximum conservation is implemented, reflecting the phenomenon that price changes induce less conservation investments once the cheapest options are introduced.

After a fuel or electricity price change, the effect of conservation investments is only applied for new capital equipment. Although many energy conservation investments will have a retrofit-character, we account for a diffusion period of price-induced energy savings: in a period of declining end-use energy prices, the model generates a slowly declining PIEEI to represent gradually less effective energy management practices. In formula form:

$$PIEEI_{t,rsi} = \frac{PIEEI_{t-1,rsi} * OldCap_{t,rsi} + EEopt_{t,rsi} * NewCap_{t,rsi}}{OldCap_{t,rsi} + NewCap_{t,rsi}} \qquad - \qquad (3.11)$$

with EEopt the previously defined factor with which the energy-intensity of newly installed capital goods (factories, dwellings, offices, cars, etc.) has declined because of a rise in fuel or electricity prices. OldCap and NewCap are calculated as in the previous formula for the AvInt.

For model calibration, the key parameter is the steepness of the conservation cost curve, CCS. The empirical basis for the conservation investment cost curve which represents the cumulative investments as a function of the price-induced reduction in energy intensity, consists of the curves published in the literature over the past 15 years (Vries, 1995; Beer, 1994; Blok, 1990;

Vries, 1986). As shown by Te Velde (1997) this notion can also be compared to price elasticities of energy demand – opening another set of available literature to calibrate CCS [17].

Another important assumption relates to CCI, representing the decline over time as a result of innovations, mass production and economies of scale. For instance, regulation and mass production will tend to make many energy efficiency measures cheaper and new technology will be developed [18]. In TIMER, CCI is implemented in the form of a loglinear learning curve (cf. *Chapter 9):*

$$CCI = CumInv_{PIEEI}{}^{-\pi} \qquad \text{\%/yr} \qquad (3.12)$$

with π the learning coefficient which has to be inferred from case-studies. Based on an extensive database of existing and future conservation measures in the Netherlands, (Beer, 1994) have estimated the potential value of CCI in different sectors between 1990 and 2010. We have used these values as the basis for implementation in TIMER.

Assumptions with regard to the desired payback time PBT obviously have a large influence on the PIEEI: the shorter it is, the less responsive consumers will be to an increase in fuel or electricity prices. In the past, the payback time for energy conservation probably have varied on the basis of information, available investment capital and other factors.

Finally, the actual investments in energy efficiency in response to (perceived) energy price changes take time to be implemented across various market segments. This is represented with a constant time delay, CCdelay - another exogenous input. Because it is known that price-induced energy efficiency improvements are only partially undone if prices fall again (Haas, 1998), we have the option to keep the value of PIEEI at its minimum value- or to slow down the response to falling prices.

From the above formulation (Formulas *3.4, 3.8 and 3.10*), it is seen that the sectoral useful energy-intensity tends towards a lower limit of $(1/\alpha_{r,s,i})$ * LMI_{lim} * (1-CCmax). With the default settings, this lower bound could theoretically come down to 100*0.1*0.1=1 GJ/cap/yr - or about 30 Watt - for all sectors together which is to be compared with 1990-values in the order of 100-200 GJ/cap/yr - or 3 à 6 kW - in industrialised regions. These numbers can be compared with a recent analysis by (Sorensen, 1998).

From this formulation it is seen that changes in fuel prices induce, besides changes in fuel market shares, a decline in the marginal intensity. This decline is the faster, the higher the activity growth and the faster the innovation. It should be noted that thus far we have not introduced any explicit interaction c.q. competition between non-electricity and electricity (in the industrial, transport and other sector the shares of electricity and non-electricity are determined by a scenario parameter; in the other two sectors electricity and non-electricity are modelled independently). Decentralised options such as solar heating, small-scale photovoltaics and wind and electricity from cogeneration can often only be modelled within a system context

[17] They propose a putty-semi-putty production function; the energy-price elasticity becomes greater in the long than in the short run – which is consistent with certain parameterizations in TIMER.

[18] This often happens because the new energy efficiency measures become part of the design phase and hence an ever more integrated part of the construction or device.

including grid and storage systems; in the present TIMER-model we assume that such options are part of the AEEI/PIEEI developments.

3.4 Fuel prices and market shares : premium factors and constraints

After the calculation of the demand for useful energy, UED (cf. Eqn. 3.5), the next question is which secondary fuels (coal, liquid fuels, gas, traditional biofuel) are satisfying this demand. Here, the following considerations have guided the model formulation:

- traditional fuel use is only partly governed by market dynamics; for example, an important determinant is the availability of traditional fuels such as fuelwood and dung which are related to land-use, population density and (rural) income;
- only part of useful energy demand can be satisfied by a given fuel according to price-based market processes, due to e.g. the impossibility to use oil for transport before the advent of the Otto-engine and the corresponding oil refinery developments or to use gas before the infrastructure is available;
- there is often a difference between the actual (regional) market price and the price as perceived by the users. This discrepancy reflects non-market considerations which influence consumer choice, e.g. convenience, availability and reliability, limitations in supporting technologies and (expected) environmental problems (see for instance Renou-Maissant, 1999;
- heat from combined heat-and-power plants is governed to some extent by market processes but also by complex interactions with the electric power sector.

We have attempted to deal with these observations in the following way. The cost of fuels are calculated according to:

$$CF_{rsi} = (a_{rs} * ISP_{rsj} * const * LF_{rs} + FPEnd_{rsj} * PF_{rsj}) / \eta_{rsj} + OMC_{rsj} \qquad \$/GJ \qquad (3.13)$$

with ISP the specific investment cost of the fuel conversion equipment, FPEnd the Fuel Price in different end-use sectors, PF the Premium Factor, LF its average load factor, η its conversion efficiency and OMC the Operation and Maintenance Cost [19]. Of the two constants included in *Eqn. 3.1*3, a is the annuity factor, and const a conversion constant [20]. The end-use fuel price FPEnd is based on the fuel price from the Fuel Supply submodels FPSup and the Electric Power Generation submodel for electricity (see next chapters) and augmented with (carbon)taxes:

$$FPEnd_{rsj} = FPSup_{rsj} + Tax_{rsj} + CTfac_{j} * CarbonTax_{rs} \qquad \$/GJ \qquad (3.14)$$

The general tax Tax represents all kinds of fuel taxes; they are only implemented if historical changes have taken place or as scenario parameter. CTfac is a factor correcting for the fuel-specific carbon content if a carbon tax (in $/GJ) is applied.

The next step is to calculate the market shares for each secondary fuel. The market share for traditional biofuels is exogenously determined from a relationship with per caput income (described in *Chapter 5*). For the other fuels it is assumed that the market is not completely

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19 In calculating the useful energy cost to determine the PIEEI, the premium factor is not included, i.e. set equal to one.

20 $a = r/(1-(1+r)^{-ELT}$ with r the interest rate and ELT the economic lifetime. The conversion factor const equals $10^6/(365*24*60*60)$.

open for substitution among all fuels (mainly due to lack of infrastructure). In the remaining market segment, the relative fuel shares (coal, liquid fuels and gas) are determined by a multinomial logit formulation with fuel prices corrected with the premium-factors PF. In formula form, the use of secondary fuel SE is calculated from the UED after AEEI and PIEEI, UEDAP, for heat (i=1) and for secondary fuel category j:

$$SE_{rsj} = \lfloor UEDAP_{rsi} / \eta_{rsij} \rfloor * (1-\mu_{rs,i=1,j=4}) * (1-NAMS_{rsij}) * \mu_{rsj} \qquad \text{GJ/yr} \qquad (3.15)$$

Here, η is the end-use conversion efficiency from fuel to useful heat and μ the market shares (cf. Eqn. 3.1). NAMS is the Not Allowed Market Share, equal to that share of the market assigned to one specific fuel only [21]. The exogenously determined fraction of traditional fuels (j=4) is also excluded. The values of η and NAMS are exogenous, time-dependent inputs. The value of μ is calculated from the multinomial logit expression (cf. Chapter 9):

$$\mu_{rsj} = \frac{(P+CF_{rsj})^{-\lambda}}{\sum_{j=1}^{n}(P+CF_{rsj})^{-\lambda}} \qquad (3.16)$$

with CF the product of costs of different fuels (*Eqn. 3.13*) and λ the cross-price elasticity between the five secondary fuels. Premium factors (P) are used to represent non-price related considerations such as lack of infrastructure, environmental disadvantages, supply uncertainties and the like. Earlier research for seven OECD countries indicated that prices could only partly explain interfuel competition (Renou-Maissant, 1999). Because the model does consider transport and distribution costs in an aggregated way only, part of the premium factor can be interpreted as real add-on costs.

The market shares derived from *Eqn. 3.16* are only for new capital vintages in the same way as for the AEEI and PIEEI, to represent a time-lag in fuel-switching processes. Hence the actual market shares in any year t are:

$$\mu_{t,rsi} = \frac{\mu_{t-1,rsi} * OldCap_{t,rsi} + \mu_{t,rsi} * NewCap_{t,rsi}}{OldCap_{t,rsi} + NewCap_{t,rsi}} \qquad (3.17)$$

OldCap and NewCap are calculated as in the previous formula for the AvInt. Because of this formulation, the value of the cross-price elasticity λ (*Eqn. 3.16*) is rather large because at the margin fuel switches can be rather fast. This model formulation results in changing shares for fuels if their relative prices - or perceived prices, i.e. corrected with the premium factor - change. The switch is faster in a period of high activity growth. In a situation of declining activity, the average energy-intensity remains constant.

It should be noted that our approach of excluding a part of the market from price-driven substitution as a way of taking technological systems, affects the estimates of cross-price elasticities and of the premium factors PF. Also the omission of any explicit coupling between the prices of the various fuels is implicitly influencing these estimates. Furthermore, changes in

[21] Currently, the parameter NAMS has only be used in the 1971-1995 period to assign a larger share of energy use in transport sector to liquid fuels in order to prevent gaseous fuels to penetrate this market too fast in regions with a cheap supply of gaseous fuels.

the composition of each sector (for instance, decline of heavy manufacturing and low-technology industries and expansion of high-technology industries) also lead to shifts towards other fuels – which is not covered explicitly in our model.

3.5 ED model implementation and model calibration 1971-1995

In the implementation of the TIMER-ED model for the 17 regions, we have compared historical data from statistical sources to the corresponding output variables shown in *Table 3.3*. Most model parameters/variables varied to improve the fit with historical data or to (re)construct scenarios are shown in *Table 3.4*. *Table 3.5* lists some additional parameters/variables which are of less importance in the model calibration and/or have been kept constant.

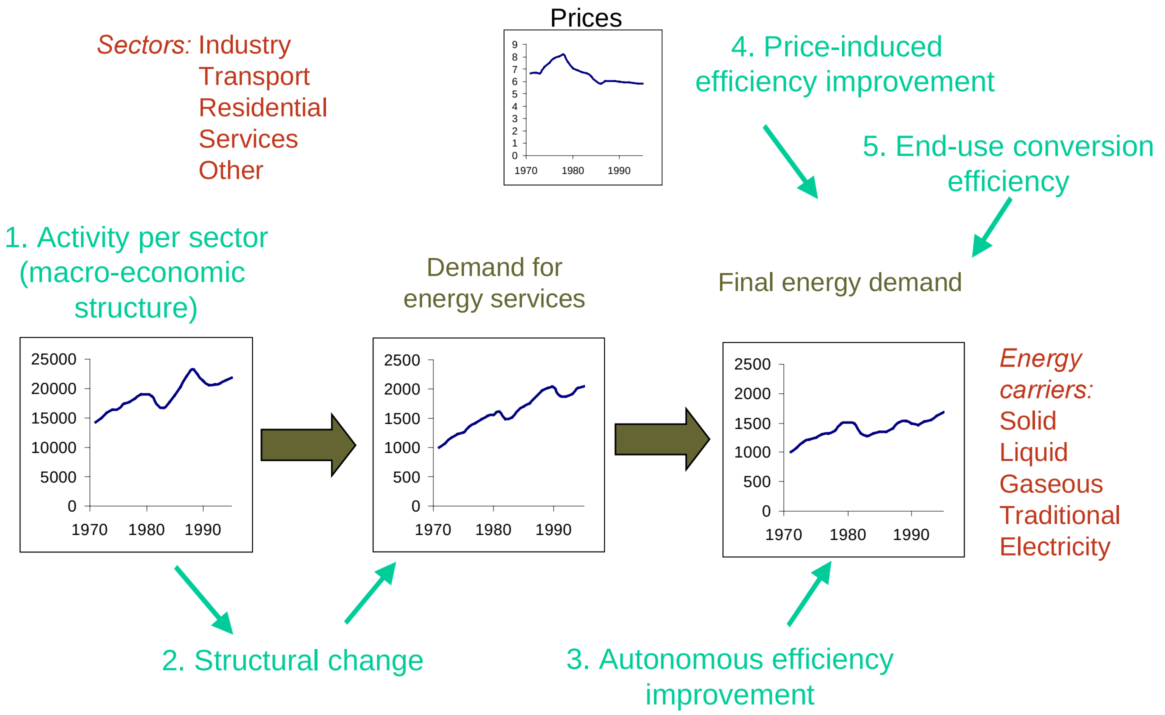

Figure 3.5: The calibration procedure: from activity level to final energy demand.

The model calibration of the TIMER-ED model is a cyclic process (cf. Chapter 2). We started by tuning the autonomous energy efficiency improvements, the decline in energy efficiency investment costs and the price elasticity to gauge model parameters to parameters in the literature. Next, we have calibrated the structural change formulation, based on the assumption with regard to position of the maximum intensity and saturation levels (see further in the section). Finally, all main parameters influencing structural change and efficiency improvement were changed from their starting values to optimise the calibration (measured in terms of Coefficient of Variation and the regression coefficient – cf. Chapter 9).

Figure 3.5 shows the calibration procedure for a particular region and sector in the simulation: the activity level is translated into useful energy (energy service) demand, which is then reduced by the effects of energy efficiency improvements and finally converted into secondary fuels and electricity.

Table 3.3: Model variables used for historical calibration for ED-model. Model parameters (see Table 3.4) are varied to get the best fit between simulated and historical time-series. See Appendix A for data sources).

Variable	**Subscripts**	**Description**	**Unit/domain**
SE	rsj	Use of secondary fuels	GJ/yr
FP	rsj	Prices of secondary fuels	1995$/GJ

r=region, s=sector, i=energy function (heat,elec), j=secondary fuel type

Table 3.4 Model parameters used for historical calibration and, if in bold, also for scenario (re)construction for ED-model. Parameters are varied around a default value within a certain domain.

Variable	**Subscripts**	**Description**	**Unit/domain**
$1/\alpha$	rsi	GJ/cap value to which UEI approaches for high DFpc	0-200 GJ/cap
UEIbase β,γ,δ	rsi	SC-parameters, such that the maximum A_{max} occurs at DFpc=$(-1/\gamma\delta)^{-1/(\delta-1)}$	$\delta<0$
LMI_{lim}	si	Lower limit on AEEI-induced fall in energy-intensity within 100 years	log(LMI)~LMI_{lim} + constant*(t-1970); 0.01<LMI_{lim}<0.5
TL	rsi	AEEI-learning position of region relative to world curve	T>0 year, depending on interpretation of regional for/backwardness
CCmax	rsi	Maximum intensity-reduction resulting from price changes	0.1-0.9, depending on sector and function
PBT	rsi	PayBack Time used by consumers in evaluating en-efficiency investments	0.5-15 year
CCS	rsi	Steepness of the Conservation Cost Supply curve; its value indicates the level at which ~60% savings are economically optimal	10-300 $/GJ
CCI	rsi	Annual fractional decline of the Conservation Cost Supply curve (exogenous or from learning-by-doing)	CCI<1, 0-3%/yr
η	rsij	Conversion efficiency from secondary fuel j to useful energy of function i	(historical)(0-1)
NAMS	rsij	Not Allowable Market Share: the part of the market (function i) which cannot be penetrated by a fuel (j)	(historical)(0-1)
Carbon tax	rsj	(carbon)tax in $/GJ applied as price-adder on sec fuels for non-electricity demand	Based on historical data and scenario assumptions; affects PIEEI and Market Shares
PF	rsj	PremiumFactor as multiplicator on UECost (sec fuels for non-elec demand)	>0; affects Market Shares

r=region, s=sector, i=energy function (heat,elec), j=secondary fuel type

Table 3.5 Model parameters for which historical values and/or fixed assumptions are used. Parameters are given a default value based on exogenous input time-series or on literature.

Variable	Subscripts	Description	Unit/domain
DFpc	rs	Driving Force in the form of $/cap activity level	(historical)(0-150000$/cap)
ConsDelay	rsi	Delay between economically indicated and actual energy conservation investment	0-10 year
ConsRevers		(ir)reversibility of energy conservation measures	-1(1)=completely reversible (irreversible) 0=partly revers
λ	rs	Cross-price elasticity; if λ=0 no price-induced fuel switch	0-10
$E/TL_{end\text{-}use\ cap}$	rsi	Economic/Technical Lifetime of energy-using capital goods; effects AEEI-rate	10-15 years
$E/TL_{conserv\ cap}$	rsi	Economic/Technical Lifetime of capital goods; effects PIEEI-learning rate	PBT for EL; 10-15 years for TL
Interest	rsi	Interest rate used for annuity	0-0.5
LoadFactor end-use	rsi	Average load factor to calculate Useful Energy cost (CostUE)	<1
OMC	rsj	Operation & Maintenance cost to calculate Useful Energy cost (CostUE)	$/GJ

r=region, s=sector, i=energy function (heat,elec), j=secondary fuel type

3.5.1 Calibrating the structural change parameters

In our calibration we have used the drivers and intensity measures as indicated in Table 3.2. It is important to realise that intensity refers here to the demand for useful energy at frozen efficiency (thus before AEEI and PIEEI) so it is a virtual, unobservable quantity. We have applied the following procedure:

- collect time-series[22] with empirical data on secondary commercial and traditional fuel use, SE_{rsj} (see Appendix A for data sources);
- convert these into useful energy demand at frozen efficiency by multiplying them with a time-dependent conversion efficiency, $UED_{frozen.r,s,j} = \eta_j * SE_{r,s,j}$; estimates for these efficiencies are taken from the literature (Schipper, 1992, Boonekamp, 1998) and are shown in *Figure 3.6* further on in this section;
- estimate from historical data and trial simulations reasonable values for AEEI and PIEEI as of 1995 (see further in the section), to reflect the change in intensity due to these factors; this allows an interpretation of the UED as '1971 frozen technology and prices';
- for the sectors industry, transport and other, useful energy demand is aggregated across the forms non-electricity (heat) and electricity and multiplied with a sectoral heat-to-power ratio to calculate the electricity demand[23];
- define a structural change relation for the resulting 7 (3*1+ 2*2) sector-function combinations, which is the basic representation of how the energy-intensity changes as a function of the activity indicator - we have chosen the function given by *Eqn. 3.4*. Estimating the constants in this function is done by choosing the value of A_{max} and c_0 in such a way that the coefficient of variation (CVY) has the lowest possible value.

[22] The number of data series are 170, i.e. for 17 regions, 5 sectors and 2 types of energy (electricity and fuels).
[23] We assume that for these sectors formulation of energy demand at the level of total useful energy demand is preferable as it allows for linking fuel and electricity use. In the sectors 'residential' and 'services', in contrast, electricity is used more for specific functions – and modelling electricity and fuel use as separate energy functions is assumed to better represent the dynamics of energy use in these sectors.

- if this gives not a satisfying result, the curve is shifted upward or downward as a way to give more weight to other historical data than the 1995-data and/or the value of Y_0 is given a non-zero value.

Choosing a value for α, β, γ, δ and UEIbase implies the choice for an isoline of energy use par caput per year to which the curve approaches at high activity levels and a hypothesis about the dynamics of technological change in and among regions (cf. Vuuren, 2000) for a discussion on the dynamics of metal demand).

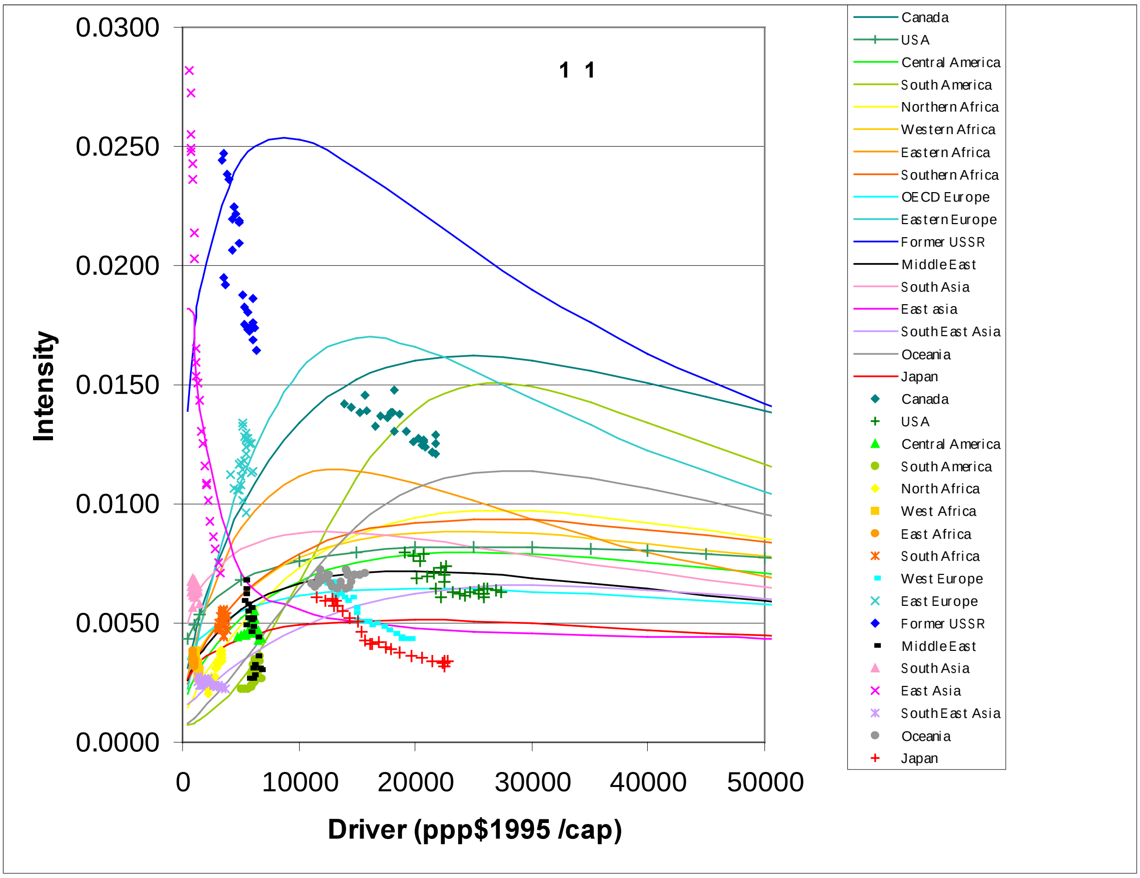

Figure 3.6: Historical regional energy-intensity and the model relationship as a function of the DFpc (in PPP-corrected 1995 US$/cap) for non-electricity and electricity end-use in the industrial sector

Figure 3.6 shows the results of this procedure for the industrial sector for some selected regions. The upper graph shows the trajectory of the sectoral Useful Energy Intensity at frozen efficiency UEI_{frozen} as a function of GDP/cap (solid curve) and the 1971-1995 data – while the lower graph shows the corresponding trajectory of sectoral Useful Energy at frozen efficiency per capita defined as UEI_{frozen} * GDP/cap [24]. In both graphs the dots represent historical data for useful energy. It is important to realise that the difference between the solid curve and the historical data is the part which is to be explained by the various factors behind changes in the energy-intensity (AEEI, PIEEI, fuel substitution).

[24] It should be noted that for the sector Industry energy-intensity is expressed in GJ/$VA (Value Added), hence constant per capita energy consumption does not show directly up as isolines in the intensity-driver plot, but the data has to be multiplied with the corresponding fraction of Value Added in GDP.

These graphs represent the currently selected implementation, but this is certainly not the only implementation possible. In fact, the structural change formulation will be varied in different scenarios. In doing the calibrations, we have been led by the following considerations:

- in the industrial heat sector, the degree of autarchy, resources availability and technology transfer possibilities all are determinants of the regional differences. Here, too, the curves have been gauged by assuming that regions cluster around isolines of constant unabated useful energy demand per capita at very high activity levels;
- in the transport sector, we assume a regional differentiation on the basis of population density as a proxy for life-style c.q. mobility patterns.
- in the residential heat sector, climate is causing regional differences. Hence, we have gauged the curve to isolines of constant unabated useful energy demand per capita based on the assumed heating demand;
- for the service sector, we assume that climate here, too, is one of the determinants but less important than in the residential sector [25]. Hence we apply the same clustering but less divergence in the energy-intensity at very high activity levels. More research is needed to better understand the factors behind energy-intensity in this sector.

For the remaining sectors and forms (residential electricity, services electricity and other), we use the principle of parsimony: parameters for regions/sectors are only taken different if we had reasonable arguments to explain it. The heat-to-power ratio has been used for calibration in those sectors where electricity demand is coupled to demand for other energy forms.

For most sectors and regions, the results of this procedure is satisfactory; in some cases not. One can think of two explanations. First, it is possible that the empirical data base is weak, e.g. because time-series on regional economic activities are weak. A second explanation is that our modelling framework does not capture some important dynamic determinants, e.g. the change in relative shares of energy-intensive and energy-extensive industry or in the modal split in transport. This is also related to the fact that for each sector, we use only one, monetary indicator to represent activities. It might well be possible that using more, physical indicators could improve our results. In case of the Middle East, for instance, GDP per capita is for a large share related to revenues from oil sales. However, energy consumption in this region is largely unrelated to oil production – explaining the relatively poor results for this region. Another possibility is that the representation chosen by *Eqn. 3.4* is not correct. Further research should shed more light on this.

In addition, the following observations can be made from the results of the calibration of structural change formula for heat (non-electric energy):

- the data for most industrialising regions are in too narrow a domain to yield satisfactory calibration results;
- at present industrial energy consumption per capita in the industrialised regions is still much higher than in less-developed regions; the shift towards more knowledge-intensive and energy-extensive products may have a large influence in the less-developed regions but only after an initial rise towards higher energy-intensity levels
- residential and service heat demand appear to follow a flat path until levels are reached which reflect the climatic differences; saturation effects start to operate at levels below

[25] Unfortunately, the service sector is ill-defined in the statistics In some regions it may actually be very similar to residential - and often informal - activities, think of tourism and schools (excluding transport). In other regions it may be quite different, think of large hospitals and computerized offices. This problem may be even worse for the sector 'other'.

10000 I$/cap. Yet, the maximum for the service sector in less-developed regions may not be reached within a couple of decades, albeit at a much lower level than the present one in industrialised regions;
- residential and service electricity demand do show no or much less signs of saturation;
- the energy-intensity in the transport sector can be expected to rise for less-developed regions as the car system expands, with maxima in energy-intensity being reached well into the century. At higher income levels, energy-intensity slowly declines reflecting saturation effects.
- for the sector other, interpretation is hardly possible in view of the different and changing sector definition. We simply assume a gradual decline to an isoline of 3 GJ/cap/yr, partly as a result of better statistics.

Electricity use has separately been calibrated for the residential and service sectors only. The difference with non-electricity use is that the intensity continues to rise to higher per caput activity levels although at lower GJe/$-values. The pattern is obscured by, we assume, differences in climate, life-style, available equipment etc.[26]. The high-income regions may have passed a maximum and their electricity-intensity may have started to decline. In combination with the relatively large decline in non-electricity-intensity, there will be a gradual increase in the share of electricity in final energy use and the saturation levels of 30-90 GJe/cap are higher than for non-electricity. The UEI-curves for the low-income regions differ significantly from those for the presently high-income regions. This is partly explained by the fact that regions like China and India have a much larger latent demand for electricity than the OECD-regions 50-80 years ago due to, amongst others, the availability of many electric appliances and the use of air-conditioning in their relative warm climate. We assume some convergence in per caput levels at very high per caput activity levels but the empirical basis for these estimates is weak [27].

The values chosen for the structural change variables α, β, γ, δ and UEIbase in Eqn. 3.4 also define where the structural change formula reaches its maximum. In the calibration procedure, we have chosen the value of the maximum and the saturation level derived the other parameters accordingly [28]. *Table 3.6* indicates the choice of the maximum, for all regions and sectors.

In general, the following characteristics can be seen (as result of our model calibration):
- the maximum in the structural change formula is reached at a lower value for industry and the sector 'other' than for the other sectors; the maximum for transport is reached at relatively high values.
- in general, low-income regions reach their maximum at lower values for the respective driving forces than the high-income regions.
- maxima in the structural change formulation are reached at lower values for non-electricity than for electricity.

These features reflect the empirical findings discussed in the previous paragraphs.

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[26] Other factors are that regions differ with respect to the use of electric heating, safety and health regulation, mechanization and automation and heat conservation which all require [electric] power.

[27] The regions Middle-East and South America follow a strange path for the residential and service sector: electricity use keeps strongly increasing in a period of declining activity. Also Eastern Europe and CIS show rather strange trajectories, which is undoubtedly related to statistical misinterpretations and errors in both the fuel use data and the activity indicators..

[28] The parameter δ has also been set in advance but not been analysed for regional/sectotal differences. The parameter UEIBase has been used for the 1971 calibration and is close to zero.

Table 3.6: Values chosen for the position of the maximum in the structural change formulation (cf. Eqn. 3.4 and Figure 3.3).

		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	
		Position of maximum in 1995ppp$/yr.								
Industry	All	18439	18640	19041	19242	19242	19242	13473	20892	
Transport	All	34307	34307	24000	27000	27000	24000	20000	26000	
Other	All	24164	24856	15861	13093	8942	16899	14131	5482	
Residential	Oth	2107	4365	8129	4365	4333	1887	1775	3942	
	Elec	23935	35978	30950	18907	14903	20758	17263	20172	
Services	Oth	6920	3613	23161	23935	9755	13669	7768	15475	
	Elec	23903	32214	21617	15294	27036	27750	22520	12886	
		9	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**
Industry	All	18037	15865	8580	19494	12371	12172	20032	25150	19118
Transport	All	43000	24000	17000	22000	27000	39000	26000	26000	45000
Other	All	24929	6174	3060	7212	2500	1330	8942	18628	29007
Residential	Oth	6000	4727	1189	4456	1705	1641	1415	7996	9762
	Elec	35978	12886	5118	11380	14903	26193	20758	27698	40494
Services	Oth	12645	5660	3285	6623	12645	4802	25832	11140	5155
	Elec	35767	11079	7979	12216	18924	16453	18571	25632	25985

Note: Numbers refer to region numbers as indicated in Chapter 1.

3.5.2 Calibrating the AEEI and PIEEI parameters

Given the above assumptions about the development of useful energy demand at frozen efficiency, $UED_{frozen,rsj}$, the calibration focuses on the parameters which determine the rate of autonomous and price-induced efficiency improvements. Using historical sectoral activity levels and fuel prices, and using the structural change assumptions discussed above, the following assumptions have been implemented based on historical calibration.

Changes in end-use conversion efficiency

- The parameter η, the conversion efficiency from secondary to useful energy energy, is dependent on one's system boundary choice. In TIMER-ED, it is the change over time which matters, however, because it drives energy demand and fuel substitution dynamics. For transport and electricity, we have set the conversion efficiencies to 1. *Figure 3.7* gives the regional values used for non-electricity in the non-transport sectors as of 1995. The data on conversion efficiencies for previous years have been taken from various sources, including (Boonekamp, 1998).

Autonomous Energy Efficiency Improvement

- The global technology progress curve used in TIMER-ED is taken the same for all regions and sectors but different for heat and electricity. *Figure 3.8* shows the curve used in TIMER for industry (left-hand side).
- the TL (Energy Efficiency Technology Level, Eqn. 3.8) indicates what the position of a region is on the global technology curve; the leading industrialised regions are positioned in the interval of 60-100 years, that is, they are near the inflection point in the global technology curve. The low-income regions are mostly positioned between 20 and 50 years which presumes the opportunity for rather fast catching-up in the coming decades.

In addition, the rate at which regions move along the 'time' axis can also be varied. Assuming the default progress rate of 1 year / year – the resulting AEEI progress rate is indicated in *Figure 3.8* (right-hand side). In the calibration progress for all regions this default progress rate has been used. In scenarios, higher progress rates are sometimes used to simulate, for instance, the impacts of technology transfer.

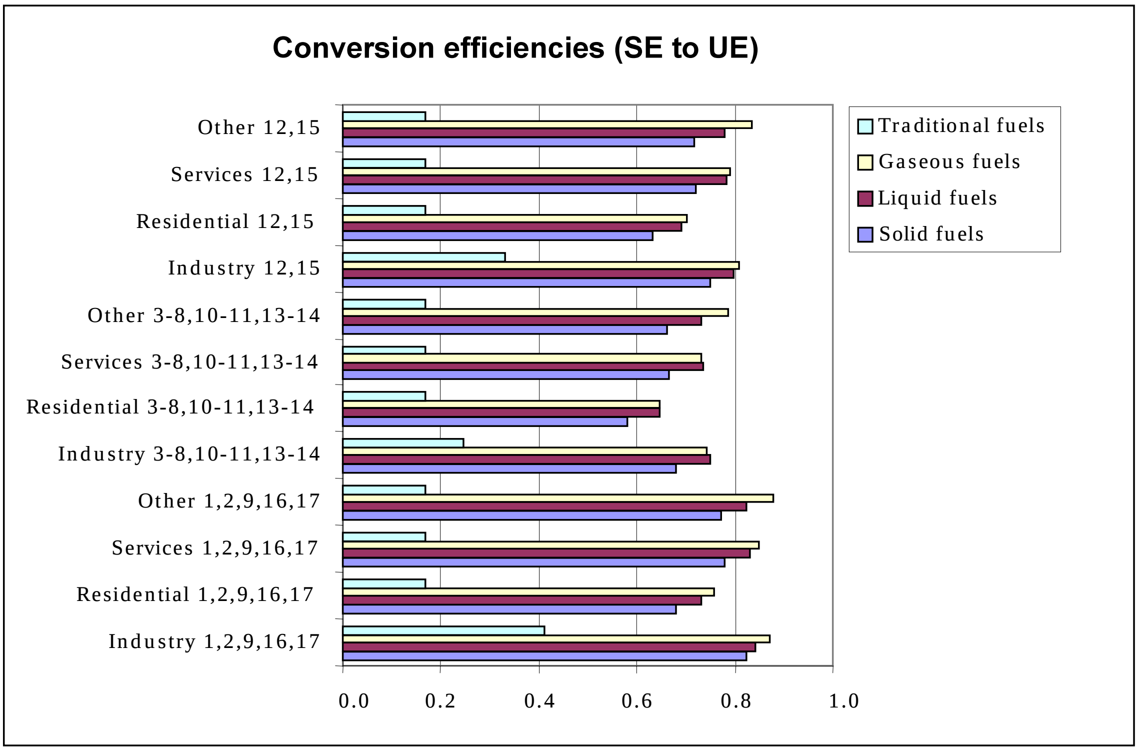


Figure 3.7: Regional and sectoral values for end-use fuel conversion efficiency in 1995 (η).
Note: Numbers refer to region numbers as indicated in Chapter 1.

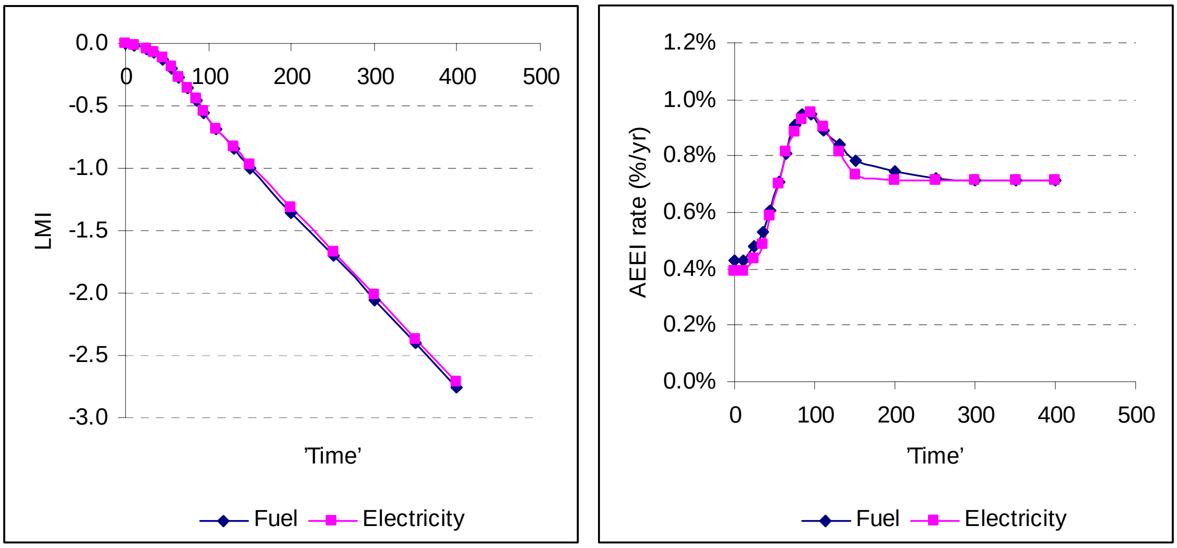


Figure 3.8: The LMI curve used in TIMER for the industrial sector (left-hand side) and the corresponding annual progress rate for AEEI (right-hand side).

Price-induced Energy Efficiency Improvement

The inclusion of the PIEEI-factor makes the picture more complicated, because the fuel and electricity prices become an integral part of the simulation. In first instance, we have used historical prices; in a second round we have used prices calculated in the fossil fuel supply and electric power modules. In the calibration of TIMER-ED the following choices have been made:

- In the calibration procedure, for prices a data set has been used that has been constructed from historical data (see Appendix A). The data set contains separate data for all energy carriers and all different sectors. Average values have been indicated in *Figure 3.9.* After calibration of all submodels, instead of the historical data the prices as calculated by different TIMER submodels have been used. This means that at that stage, the market shares the model has been re-calibrated.
- the upper limit on price-induced energy efficiency improvements, CC_{max} (Eqn. 3.9/3.10), is set at 0.8 for all regions, sectors and energy forms; this is equivalent to 80% reduction;
- the desired payback time PBT_{des} (Eqn. 3.9) indicates the number of years in which an energy efficiency investments has to be earned back; the higher the less myopic. We use values ranging from <1 year for most sectors in the low-income regions up to 3 years for industry in the high-income regions. The values change during the period 1970-1995, a requirement for calibration. For a few selected regions, the 1995 values are shown in *Figure 3.10*. We assume only minor differences between non-electricity and electricity;
- the parameter CCS (Conservation Cost curve Steepness, Eqn. 3.9/3.10) indicates how much investments are required per GJ_{saved}. In combination with prevailing energy prices and payback times, this parameter determines the energy use price elasticity. The CCS have been chosen so that the resulting elasticities reflect available data on elasticities (e.g. Te Velde, 1997). The same values are used for all regions (*Table 3.7*).
- the parameter CCI (Conservation Cost curve decline through learning, Eqn. 3.9/3.10) indicates the rate of loglinear learning if the energy efficiency capital stock builds up - it induces a decline in the conservation cost curve, and hence cheaper energy efficiency improvements. We use a progress ratio of 0.81 for all regions, sectors and energy functions, which means a 19% cost reduction on doubling of cumulative investments. In the next step, the initial capital stock (the second determinant of decline in the conversation cost curve), has been set at such a level that the decline rate complies to available data for Western Europe (Te Velde, 1997; based on Vuuren, 1996):

Table 3.7: Values chosen for the steepness parameter of the Conservation Cost curve (cf. Eqn. 3.9 and 3.10).

	Heat	Electricity
	$/GJ	*$/GJe*
Industry	30	125
Transport	17	60
Residential	25	95
Services	25	95
Other	25	95

- The PIEEI implementation of TIMER-ED can have different responses to falling energy prices. Efficiency measures can become ineffective as energy prices go down, that is, the dynamics are fully reversible, or that they are kept at or near their optimum level implying some degree of irreversibility. Empirical research suggests at least partial irreversibility (Haas, 1998). In the calibration, we opt for a slow response to falling energy prices – and limit reversibility to only 30-40%% of the improvements made;

- the parameter CD (Conservation Delay) indicates how many years it takes before actual energy efficiency measures have been fully taken according to their economic optimum; it is set at 4 years.

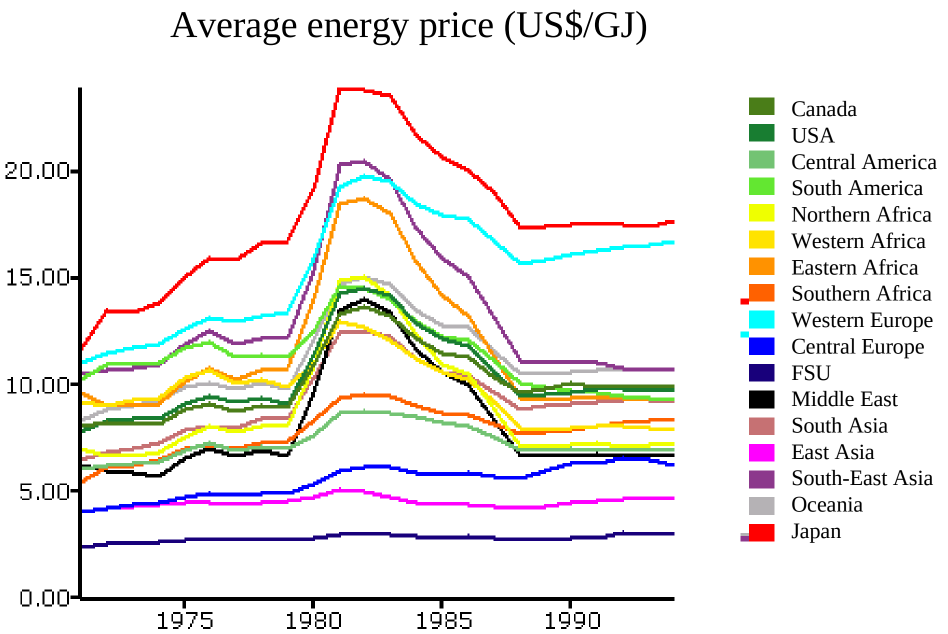


Figure 3.9: Average energy price (for all sectors and energy carriers, including electricity) according to the historical data set used for calibration (cf. Table 3.3).

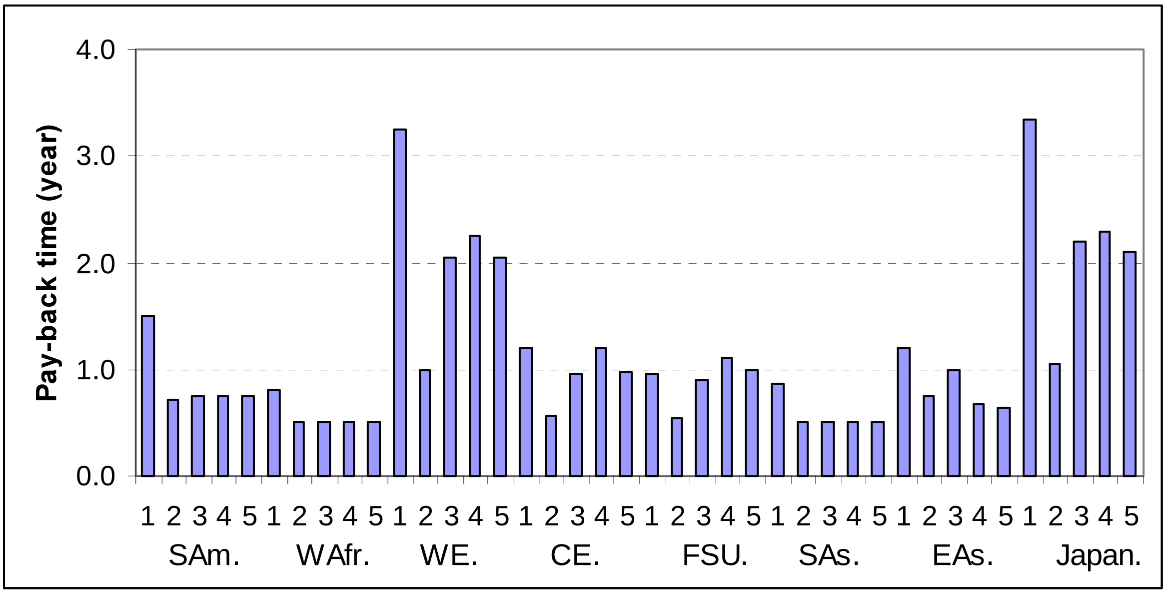


Figure 3.10: Desired Pay-back Time used in TIMER in a few selected regions, in the 5 different sectors (industry, transport, residential, services and other) (cf. Eqn. 3.9).

3.5.3 Calibrating fuel market shares

The fuel market shares are calibrated on the basis of assumption with regard to the non-price based market share, the cross-price-elasticity and the premium factors:

- The non-price-based market shares, NAMS (Eqn. 3.15), reflect technological impediments such as the absence of a gas infrastructure or the penetration of a new and competitive technology which overrules fuel price considerations – as the case of electric rail transport. It only has been used for coal in industry (coke in steel production) and oil in transport (to avoid too fast a penetration of natural gas);

- The value of λ (Eqn. 3.16), the cross-price-elasticity between secondary fuels, is set at 2 for all regions and sectors – this implies a relatively strong response to changing prices;
- the premium factor, PF (Eqn. 3.13), reflects discrepancies between market price and perceived price. We use this variable to calibrate the historical market shares of the various fuels. It turned out to be most important for coal in the non-industry sectors, where its decline can only be explained by a high price-adder, and for natural gas for which a price-adder is used to represent the long lead-times for infrastructure (see *Figure 3.11* and *Figure 3.12*). The high premium values for coal in the residential sector are in particular important in the high-income regions. The high values in the residential sector indicate the additional distribution costs not taken into account in the model and the perceived costs associated with environmental and supply security and comfort considerations.

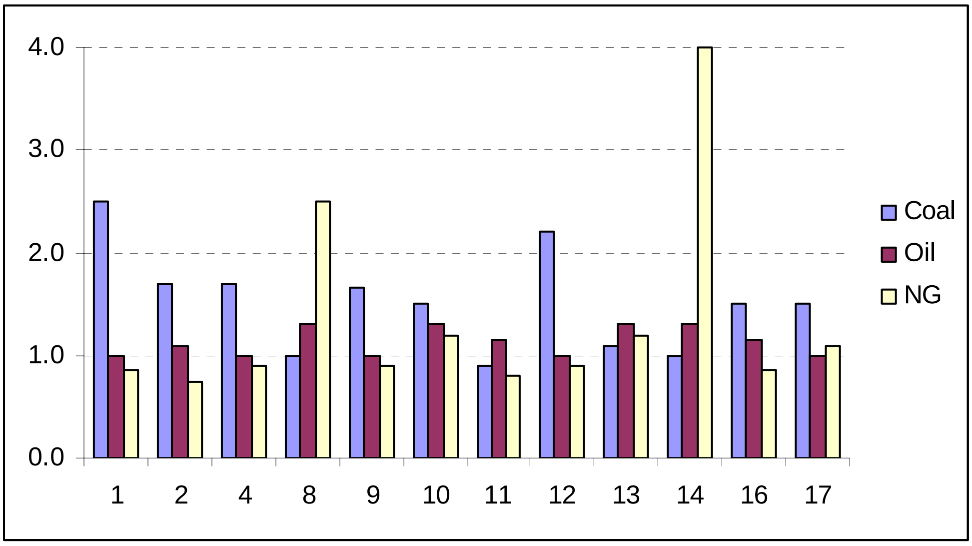


Figure 3.11: Premium factors in industry for selected regions. Note: Numbers refer to region numbers as indicated in Chapter 1.

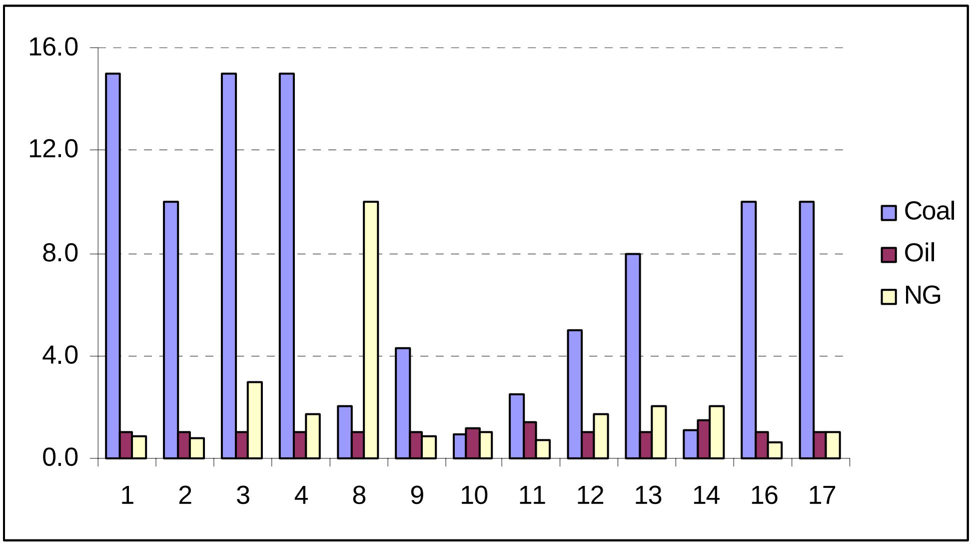


Figure 3.12: Premium factors in the residential sector for selected regions. Note: Numbers refer to region numbers as indicated in Chapter 1.

3.5.4 Ambiguities in the model calibration

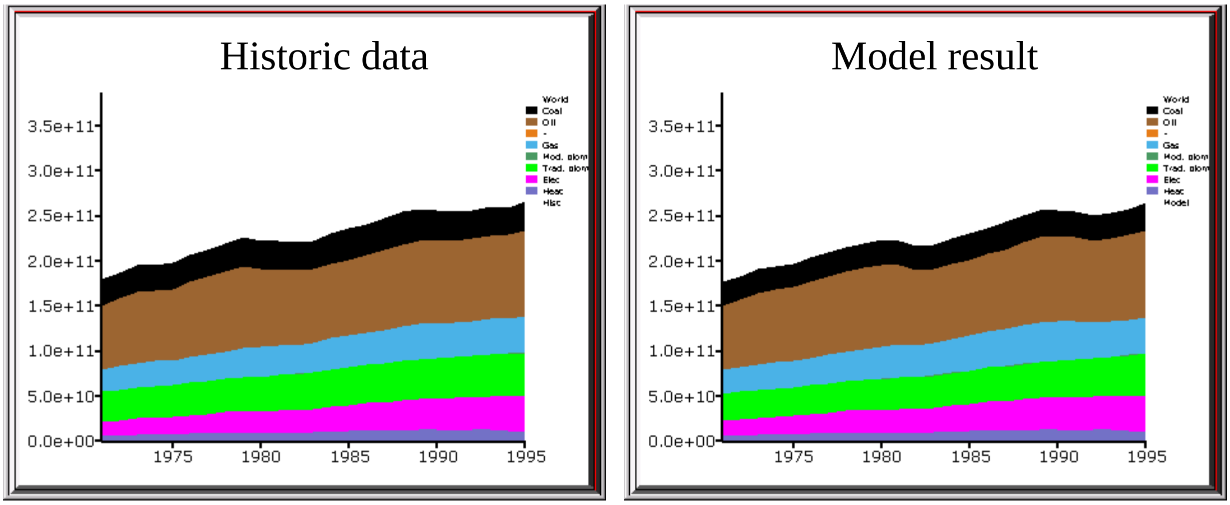
The calibration experiments indicate that the trends can be reproduced quite well, but there is not an unambiguous ‘best’ calibration. Given the structural change relation and the resulting time-path for useful energy demand, one can still emphasise the role of technology (AEEI) or of prices (PIEEI). In reality, it is a mix in which cultural, political and economic factors all play a role. In performing the calibration for the energy demand module, divergent but possibly equally valid choices can be made. These depend on one’s interpretation of the past. For example:

- The role of governments has been quite different and can be influential. Regions like Western Europe and Japan were well aware of their oil dependence and have stimulated energy conservation; this can work out through technology programs (AEEI, CCI) or through subsidies (higher PBT_{des}).
- Regions differ with regard to the strength of market mechanisms. Whereas in regions like the USA one would expect an important role for price changes (PIEEI), regions like India and China may have relied much more on state-controlled planning. In still other regions consumers may have coped with price increases by adjusting their behaviour.
- In some sectors, notably industry and transport, one may expect an important role for technology transfer, especially since liberalisation has resulted in much larger capital flows between regions. This would be in favour of rather high autonomous changes in regions which are industrialising on the basis of foreign industrial plants and cars.
- A flat conservation cost curve may reflect a wasteful energy-use pattern but it can also indicate technical backwardness or behavioural changes due to low income. Hence, the parameter settings are only a first plausible choice - it is not a rigorous result.

For example, historical data on transport energy use are well reproduced for the industrialised regions (Canada, Western Europe, Japan) in two different ways. Either one assumes a strong increase in energy demand in the past by structural change, in that case high energy conservation rates are explained by strong response to fuel price increases (PIEEI). Alternatively, a much smaller increase resulting from structural change is assumed, and thus fuel price increases explain only a minor part of the efficiency improvements (PIEEI). These quite different implementations both give a fairly good fit. However, they give quite different values for long-term energy use. In the first case, a, we would expect a continuing strong increase of energy demand, certainly in case of constant or declining fuel prices. In the second case, b, slower increases a result of structural change may well result in stabilising sectoral energy consumption. In a similar way one can come up with quite different explanations of the gradual phasing out of traditional fuels. More detailed submodels in combination with more detailed and better data are needed to diminish these ambiguities.

3.6 Calibration results 1971-1995

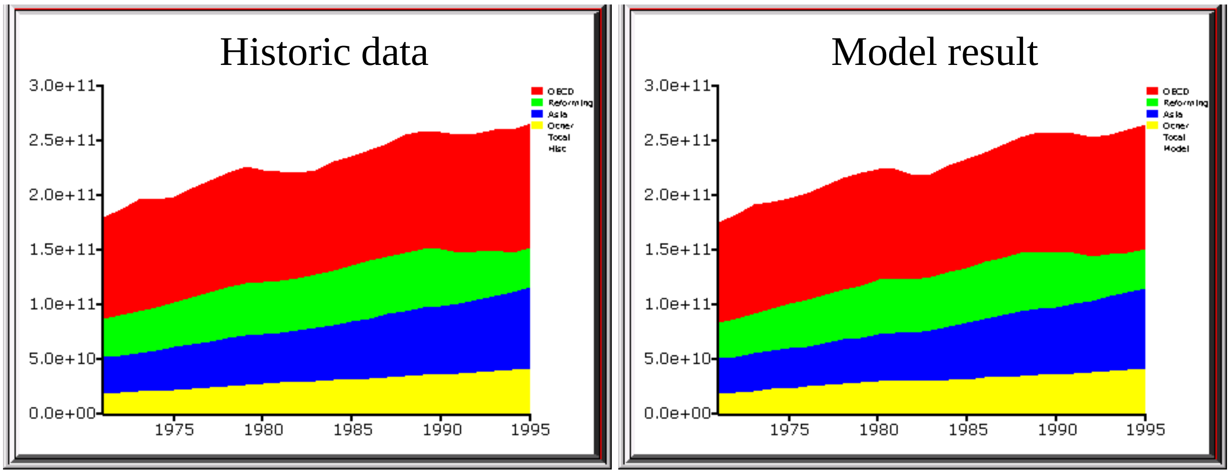
Figure 3.13 shows the resulting global final energy demand by energy carrier, both according to our historic data set and the model result. *Figure 3.14* shows the same variable, but now by IPCC region. The figures clearly show that at this aggregated level the model is very well able to reproduce the historic trends, based on our calibration.



Coal Modern biomass Sec. heat
Oil Traditional fuels
Natural gas Electricity

Figure 3.13: Comparison of model results, aggregated for the world, for final energy demand per carrier compared to historical data – before including a correction factor.

While the model seems to be able to reproduce historic trends well in most regions and sectors, this is not the case for all of them. We will discuss the model results for one example where the model reproduces historical trends very well, and one example for which the model produces poor results.



OECD Asia
East. Europe/FSU Africa, Latin America, Middle East

Figure 3.14: Comparison of model results, aggregated for the world, for final energy demand per IPCC-region compared to historic data – before including a correction factor.

Figure 3.15 shows for the transport sector in Western Europe the determinants of secondary energy use. It indicates historical final energy use as reported by the IEA, the simulated final energy demand, and the energy use as it would have been without AEEI and PIEEI. It is seen that the growth elasticity with respect to energy services is significantly above unity, but that especially the AEEI - in this implementation – has contributed to a lower fuel use. The attribution to AEEI instead of PIEEI is somewhat ambiguous, as has been discussed before. Certainly in this case, the AEEI has been so effective because the oil crises of the 1970s and 1980s initiated a consumer demand for more fuel-efficient cars and wave of innovations with manufacturers. Thus, it was actually a price-induced response, one could argue. Also fuel substitution has played a – minor – role. The curves on the right-hand side show that fuel use for transport in Western Europe has fallen with some 20% between 1971 and 1995, instead of an increase with 35%. Curves like these are quite region-specific.

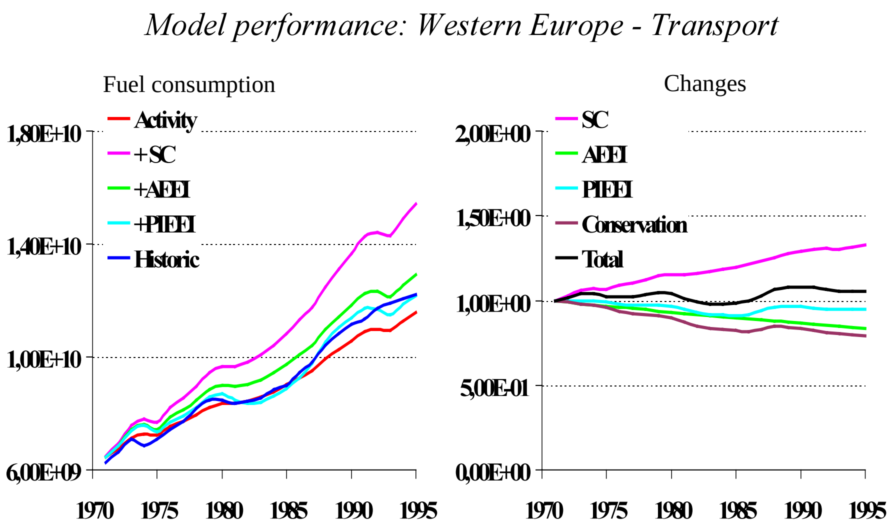


Figure 3.15: Model results for transport fuel demand in Western Europe. Note: the figure shows the simulated secondary fuel demand in GJ in and the subsequent calculation steps on the transport sector (largely LLF) in Western Europe. Activity data, taking into account intrasectoral structural change, lead to useful energy demand (upper curve). The curve drops as AEEI is included, drops further after inclusion of PIEEI – which now should closely resemble the historical data. The right hand graph shows the trends normalised to 1971=1.

A second example is given in *Figure 3.16.* Industrial final energy demand across all fuels for the Middle East region is shown, simulated and historical. There is a serious mismatch which cannot be removed by changing the values of calibration variables within an acceptable domain. The main reason for this is that the presumed relationship between industrial energy use and GDP is, in the Middle East region, absent. This is understandable: income in the oil-rich countries in this region is strongly tied to the oil export revenues, hence the simulated outcome reflects the decline in GDP after the oil price fall in the mid-1980s. However, industrial activity did not follow this fluctuation as it had other determinants – so the actual energy use in industry kept rising.

For those regions/sectors for which the current model formalism seems to produce unsatisfactory results, a correction factor has been introduced. The reason to introduce this correction factor is that the TIMER model is also used for policy analysis. For these purposes historic trajectories can be very relevant (e.g. the 1990 base year of the Kyoto protocol). *Figure 3.17* shows the average value of these correction factors per region. The regions have been divided into 2 groups: those with a correction value higher or lower than 5% - and the other regions. The Figure shows that the regions for which the correction value has indeed a value significantly different from 1.0 are East Asia, Middle East and the Former USSR. For East Asia in 1970, the value is even 2.5. On the other hand, the values for most industrialised region are simply 1.0.

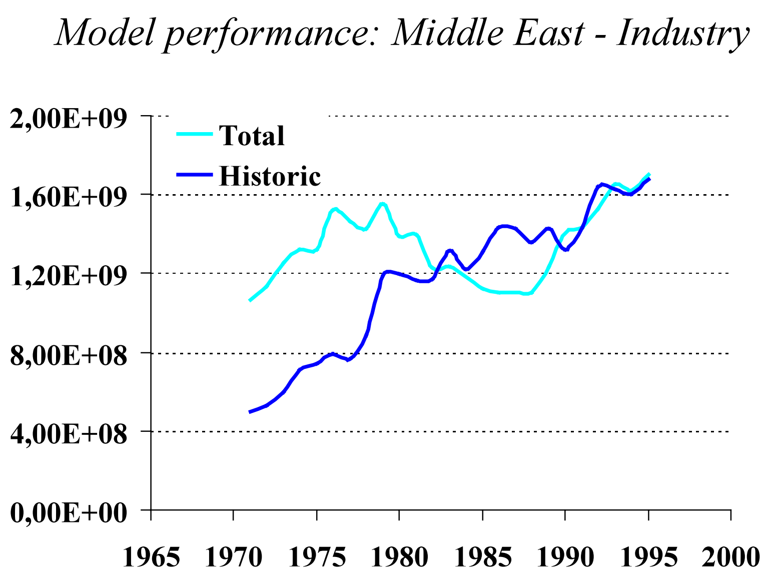


Figure 3.16: Industrial secondary fuel use in the Middle East region (IEA-statistics and as simulated).

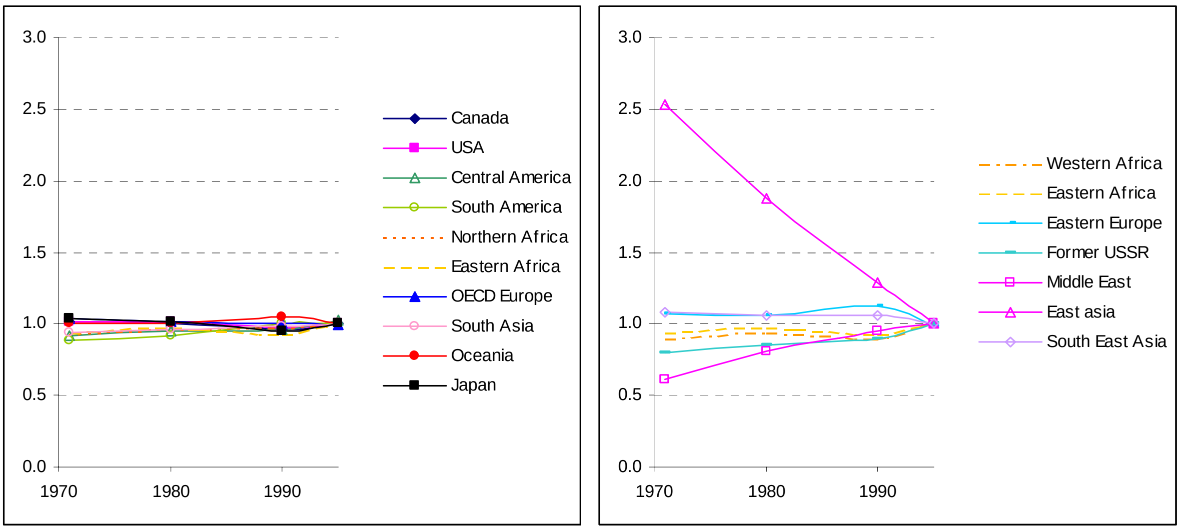


Figure 3.17: The value of the correction value used in TIMER 1.0 to improve reproduction of historical trends.

These mismatches with historical time-series have been used to explore the model dynamics in more detail. In South and Central America, the high inflation rate casts doubt on the validity of the activity levels as measured in constant 1995 US $. The large discrepancy for the industrial sector in the Middle East has been discussed above. The more serious calibration problems for the Former USSR probably represent the quality of historical data – for instance, differently defined activity indicators have been used – and the phenomenon that, in a situation of declining economic activity, energy use may not decline proportionately. Energy-intensity has been observed to rise in some cases because rationalisation is blocked or delayed and in the meantime a large part of energy use may be fixed (capacity effect) or installations may become less efficient due to part-load losses and inadequate operation and maintenance. There are signs that such events did occur in the Former USSR in the 1990s.

A relatively large mismatch between modelling results and historical data occurs in East Asia. There are several reasons for this. First of all, the East Asia region as defined in IMAGE 2.2 is very diverse in energy terms: it contains countries such as Taiwan and South Korea, with relatively high income levels and relatively modern industries, and countries such as China and Northern Korea, with relatively low incomes. The heterogeneity of the region can lead to different trends than the trends that can be observed in other regions. In addition, the historical GDP growth rates (around 8-10% per year) for China are thought to be overestimated, which implies that energy intensity might not have fallen so dramatically as suggested in our current historic database. Finally, China clearly has followed a different development trend than most regions with already at fairly low per capita income levels a strong orientation on (inefficient) heavy industry – more so probably than the Former USSR. These three factors at least partly explain why the model fails to reproduce the historical trends in the East Asia region (see also Vuuren *et al.*, 2001).

3.7 Directions for future research

Obviously, there are many directions for model improvements. Based on our present modelling experiences we suggest the following modifications and extensions as high-priority ones:

- There is a general mismatch in empirical connection and theoretical understanding of the linkages between the bottom-up engineering analyses (both about past and future) on the one hand and top-down dynamics of aggregate variables on the other. A high research priority is to use formalisms such as dynamic economic input-output analysis to connect past and possible future trends in physical indicators such as energy use per m^2 surface area or ton-km with monetary indicators such as service sector activity (Wilting, 2001). A first step could be to single out the high-energy/material-intensive industry as a separate sector and link the transport sector dynamics to a simple transport model with modal split, travel time etc. as parameters.
- A related topic of research is to get a better understanding of the nature and size of changes in the energy-intensity (energy use per unit of activity) at the margin, i.e. in the newly emerging activities as represented in the aggregate monetary indicators.
- A better understanding is needed about the process of substitution of traditional fuels for commercial fuels. We will discuss this issue in more detail in *Chapter 5,* but it could very well influence some of the energy demand trends discussed under this Chapter.
- There are indications that new final energy carriers could play an important role in future (mitigation) scenarios, in particular hydrogen. In TIMER, hydrogen could be modelled as an alternative to other energy carriers – but this would also mean that a hydrogen supply model needs to be developed.
- The Autonomous and Price-induced energy efficiency improvement are currently formulated as two independent processes. In reality, these two processes for a large part use the same potential for improvement (although driven by different processes). An alternative formulation that could be considered is modelling autonomous energy efficiency improvement based on the turn-over of capital (as is already done) and the decreasing investments costs in the PIEEI curve.

- The multinomial logit equation which is used in the energy-demand model, but also in several other places of TIMER, captures the idea that fuel costs and benefits are not equal for each individual decision-maker. While the equation seems to be perfect in introducing a distribution in different fuel choices, the distribution in costs itself are not taken into account in TIMER. This might lead to underestimation of costs for mitigation strategies. An alternative formulation to estimate fuel costs can be based on CES production functions.
- Finally, the relationship between sectoral activity and energy use can be improved by investigating and simulating in more detail the effects of (ir)reversibility of energy use for lower or declining activity growth rate, the diffusion of energy efficiency technologies in and across regions, the substitutable and non-substitutable parts of electricity use, and the role of decentralised demand-reducing supply options.

4. Electric Power Generation (EPG) submodel description

4.1 Introduction

Electric power generation is an important and growing part of the energy-supply system. In the industrialised countries, the share of electricity in total secondary energy demand rose from less than 7% around 1950 to around 20% in 1995 (IEA, 1998a). In developing regions, electricity still constitutes a much smaller share of demand, ranging from 10-15% in the Latin American regions, North Africa, South Africa and the Middle East to only 1% in East Africa[29] (IEA, 1998a). Construction of power plants and transmission and distribution networks absorb a sizeable portion of national investments, especially in the early stages of establishing power supplies. Annual investments in electricity generation in the 1990s in the developing countries are estimated to be 12% of total domestic investments.

Generation of electricity is currently for the largest share based on fossil fuel fired power plants - world-wide 85% (*Figure 4.1*). The current efficiency of these plants is, on average, 35-40% in developed regions and 30-35% in most developing regions. There are good prospects for achieving efficiencies of 60-70% in the longer term (Johansson, 1989). Large efficiency gains can also be achieved by replacing separate production of heat and power by combined heat and power (CHP) and cogeneration technologies. This could mitigate greenhouse gas emissions. Further penetration of non-fossil-fuel-based based electricity and hydropower could mitigate emissions even more. Expansion of hydropower is, however, limited to a maximum potential in the region. Expansion of non-fossil options in particular depends on cost developments which are largely determined by the interactions between markets and innovations.

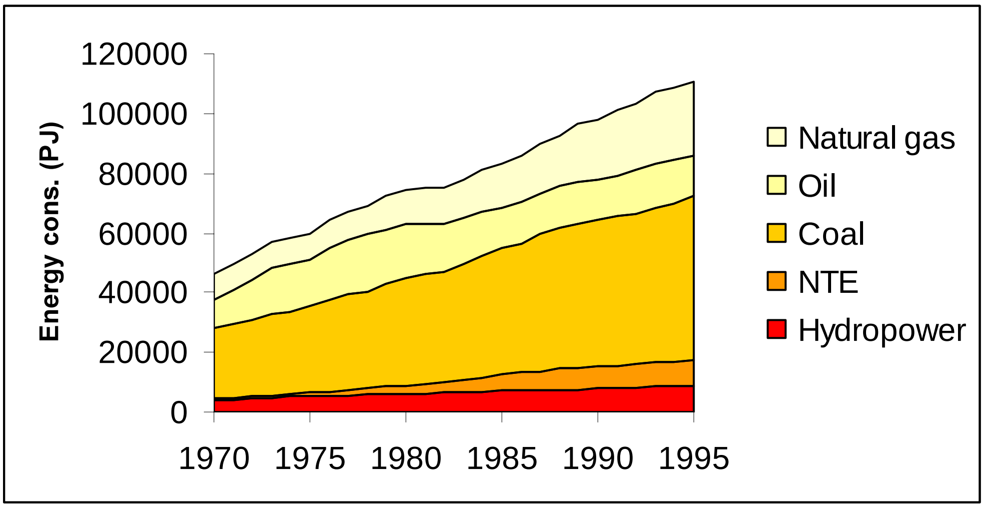


Figure 4.1: Inputs in electricity generation world-wide (NTE refers to all non-fossil-fuel-based options except hydropower)(Source: IEA, 1998; efficiencies for NTE and hydropower are according to IEA definitions, that is, on the basis of thermal fuel input equivalent).

[29] In secondary energy demand, estimates for consumption of traditional biomass have been included (see Annex A).

4.2 Overview of the EPG model

The EPG model of TIMER simulates the electricity generation by distinguishing four capital stocks associated with one or more out of five alternative inputs. The capital stocks represent electric power generating capacity: hydropower (H), fuel-combustion based (referred to as Thermal, T) with either solid, liquid or gaseous fuels, and two different capital stocks for non-thermal electricity, i.e. nuclear energy (NU) and renewables (NR). Combined Heat Power (CHP) is currently not modelled separately. Instead the heat demand is added to electricity demand, assuming higher possible generation efficiencies. The model takes into account the limitations of each fuel type - for instance with regard to its ability to function as base and peak load supply. *Figure 4.2* gives an overview of the model. Electricity demand is an input from the TIMER ED model and used to calculate the required production. For each capital stock, costs are calculated; the investment and fuel use decisions are governed by a small set of operating rules. The resulting required solid fuel, liquid fuel and gaseous fuel inputs are inputs for the respective supply models.

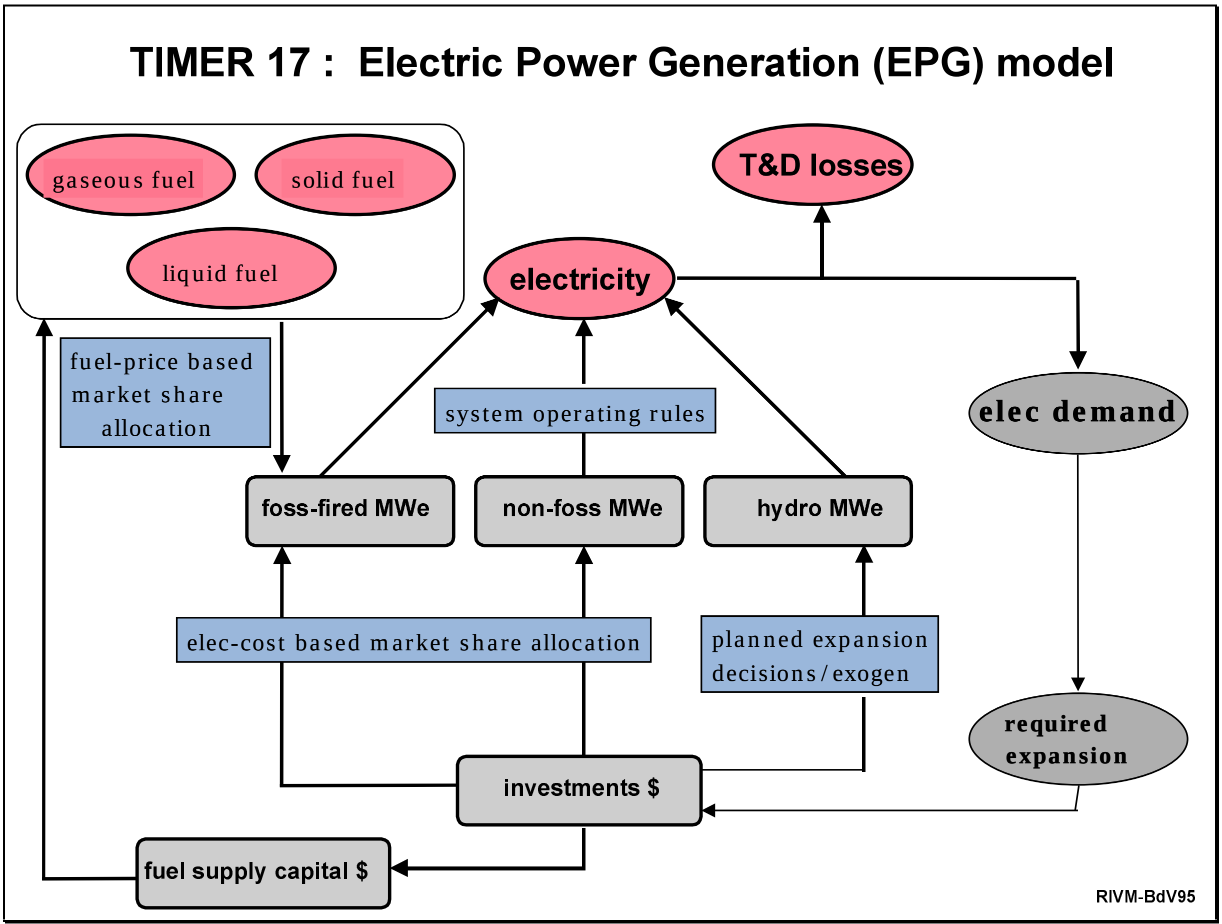


Figure 4.2: Overview of the EPG-model

4.2.1 Electricity generation and capacity

In the ED-model the secondary electricity demand SElD is calculated for region r and sector s (cf. Eqn. 3.1, j=elec). The net electricity demand is converted into Gross Electricity Demand GElD:

$$GElD = \sum_{s} SED_{s2} * (1 + TDLF) * (1 + OULF) * FCF + NTS \qquad \text{GJe/yr} \qquad (4.1)$$

Here, TDLF is the Transmission & Distribution Loss Factor, OULF the Own Use Loss Factor, FCF the Financial Constraint Factor. NTS is the net trade flow, i.e. import minus export and read as an exogenous scenario. The FCF allows the simulation of the system if less capital is available than is required. The TDLF and OULF are estimated from historical time-series. The NTS is based on historic data in 1970-1995 period[30]. We have simplified the short-term operation of the system by assuming that gross demand is generated in two fractions : base-load and peak-load, i.e. a two-block load duration curve representation. The fraction of gross demand generated in base-load is an exogenous input (indicated with FracBL).

Four categories of electricity producing capital stock are distinguished to generate electricity [31]:

- hydro-electric (H), which is installed according to an exogenous time-path towards a finite hydropower potential;
- thermal electric (T), which can be fuelled by solid, liquid or gaseous fuels, assuming fuel-specific conversion efficiencies and investment cost time-paths for each fuel;
- nuclear electric (NU), based nuclear fission/fusion heat assuming specific investment costs to be related to cumulated output (in terms of technology development and depletion); and
- non-thermal renewable electric (NR) which represents solar, wind, geothermal and other renewable electricity generation modes, and for which we assume specific investment costs to be related to cumulated output (in terms of technology development) and annual production (depletion).

It should be noted here that the index T for thermal refers to all options based on combustion of either fossil or biomass-derived fuel. In TIMER model results, the results for nuclear and non-thermal renewables are not always shown separately but aggregated as non-thermal electricity (N). No distinction is made between centrally and decentrally operated power stations.
The total producing stock ECap is given by the sum of the different capital forms ($ECap_H$ + $ECap_T$ + $ECap_{NU}$ + $ECap_{NR}$). Each of the four capital stocks is assumed to depreciate at a rate of $ECap_k/TLT_k$ with TLT_k the technical lifetime of stock k, and to produce a certain output of electricity (in GJe) per unit of capacity (MWe). This output is determined by how the system is operated and is expressed in the load factor of stock i, LF_i. This load factor is defined analogously to the system load factor : $LF_k = EProd_k /(ß * ECap_k)$ and $EProd_i$ the actual production of stock k and ß=8760 * 3.6 GJe/MWe.yr [32]. Total annual electricity production equals $EProd = \Sigma_k EProd_k$ (k=H, T, NU, NR).

We assume that hydro-electric and non-thermal capacity (NU + NR) will mostly operate in base-load. For hydro, a scenario parameter determines how much of the capacity can be used for peakload (using storage facilities); for non-thermal capacity, the share of capacity used for peak-load depends on the actual demand for peakload electricity – and the available supply by means of thermal capacity[33]. The baseload production of hydro and non-thermal capacity is determined by the time-dependent load factors BLF_H, BLF_{NU} and BLF_{NR}. Assuming that

[30] Regional electricity trade is, at least at present, only an important factor between the regions Canada and USA. Therefore, we decided not to incorporate an explicit trade model, as for solid, liquid and gaseous fuels but simply base electricity trade on exogeneous scenarios.
[31] Combined-heat-and-power (CHP) units are discussed in the Appendix to this chapter; it is not yet implemented in TIMER.
[32] One year has 8760 hours; 1 MWe producing during 1 hour generates 1 MWhe or 3.6 GJe.
[33] For the world at large, this is not unrealistic; for smaller regions resources like hydro- and windpower with seasonal variations cannot be simulated accurately in this way.

thermal capacity in base-load operation runs with an average load-factor BLF_T, the required thermal capacity to generate the base-load demand, $ECap_{bT}$, is :

$$ECap_{bT} = \frac{GElD * FracBL - \beta * (ECap_{bH} * BLF_H + ECap_{bNU} * BLF_{NU} + ECap_{bNR} * BLF_{NR})}{\beta * BLF_T}$$

MWe (4.2)

The total required base-load capacity is calculated as $ECap_b = ECap_H + ECap_{NU} + ECap_{NR} + ECap_{bT}$. It is possible that $ECap_{bT} < 0$. In this case $ECap_{bT}$ is taken zero and the excess non-thermal capacity, $ECap_{exc,N}$, is assumed to be operated in peak-load. The capacity available for peak-load, $ECap_p$, equals $ECap_{inst}$ - $ECap_b$. Its load factor is calculated as:

$$PLF = MIN\lfloor GElD * (1 - FracBL)/(ECap_p * \beta), PLF_{\max} \rfloor \qquad (4.3)$$

with PLF_{max} an assumed upper limit for the load factor of peak-load capacity.

The choice of FracBL, BLF and PLF can be calibrated to the historical value of the (regional) over-all system load factor. In first instance, FracBF and BLF are kept constant over time, whereas PLF is calculated to gauge demand and production under the condition $PLF < PLF_{max}$, as described above. One may wish to simulate measures to increase the over-all system load factor (e.g. load management) by increasing PLF_{max}. Alternatively, one may incorporate other characteristics for N-options by a change of BLF over time (e.g. lower values if photovoltaics have a larger share).

This formulation takes into account that a capacity shortage may develop. If this occurs, it generates demand for additional capacity to be built according to the equation for required capacity expansion (k=H, T, NU, NR):

$$ECap_{ord} = (ECap_b + E\Pr od_p /(PLF_{\max} * \beta) - ECap_{inst} + \sum_k ECap_k / TLT_k) \qquad \text{MWe} \qquad (4.4)$$

in which the last term accounts for depreciated capacity. In the actual calculation, an extrapolated demand GElD for the calculation of $ECap_b$[34] is used and a construction time CT_k is taken into account. For the calculation of the electricity produced in the peak-load, it is assumed that the excess non-thermal-capacity (NU or NR) is used at the PLF-value and the remainder is supplied with T-capacity. A desired reserve margin factor is used to ensure an adequate level of system reliability - neither too high nor too low.

4.2.2 Fuel use and capacity expansion

What type of capacity will be ordered? This is determined by the following allocation rules:

- For *hydro power*, capacity is exogenously prescribed on the basis of a desired fraction of the estimated technical hydropower potential in the region;

[34] Demand is anticipated over a time horizon of TH years on the basis of a trend factor of the form $(1+r)^{TH}$ with r the annual growth rate in the past TH years.

- The remaining demand for capacity is allocated to *thermal power, nuclear power and renewables*. The substitution process between these generation forms actually occurs in terms of the allocation of the required c.q. available investments.

Hydro power

Usually, hydropower expansion is part of a set of broader issues such as food production and population migration and is in the case of large-scale dams centrally planned. For this reason we use exogenous scenarios formulated in terms of the fraction of the estimated technical potential being installed in any given year. When hydrocapacity is ordered, it is assumed to have a construction delay before it starts producing electricity. As said before, this hydropower capacity is assumed to be operated at a certain number of hours per year: the Base Load Factor (BLF_H), derived from actual experience in the region.

Competition between thermal power, nuclear power and renewables

For thermal power (T), nuclear power (NU) and renewables (NR), investments are allocated according to a multinomial logit model (cf. Chapter 9), allocating shares in investments on the basis of generation costs. The indicated fraction of investments allocated to non-thermal electric power capacity $IMSE_k$ is given by (k=T, NU, NR):

$$IMSE_k = \frac{PF_{elec} * ElCost_k^{-\lambda_{T-NT}}}{\sum_k PF_{elec} * ElCost_k^{-\lambda_{T-NT}}} \tag{4.5}$$

with ElCost the generation cost, λ_{T-NT} the substitution elasticity and PF_{elec} premium values describe non-price factors that determine the allocation shares of the various generation forms (e.g. environmental constraints). From this, the actual market share μ_{NT} is calculated by applying a delay which reflects the time needed to penetrate various market segments. Consequently, the ratio of the generating cost ElCost of thermal and non-thermal capacity determines this investment allocation. The generation cost for each option, ElCost, are discussed in the next section.

Allocation among different types of thermal electricity production

From the equations described in the previous paragraph, it is seen that the total electricity produced in fuel-based thermal capacity, $EProd_T$, equals:

$$EProd_T = [ECap_{bT} * BLF_T + ECap_p * PLF * (1 - ECap_{exc,N})] * \beta \quad \text{GJe/yr} \tag{4.6}$$

Which fuels will be used? We distinguish 3 categories of fuels: solid (that is, hard coal, lignite etc. either direct combustion or in integrated gasification or liquefaction units), liquid (either from oil and/or biomass-derived BLF) and gaseous (natural gas and/or biomass-derived biofuel BGF). The market penetration dynamics for these fuels is again based on a multinomial logit function which determines the indicated market share of fuel m, $IMSFE_m$, for the thermal electricity generating capital stock T (m=SF, LF, GF) :

$$IMSFE_m = \frac{\left(FEPrice_m * PFE_m / \eta_m\right)^{-\lambda_{SF-LF-GF}}}{\sum_m \left(FEPrice_m * PFE_m / \eta_m\right)^{-\lambda_{SF-LF-GF}}} \tag{4.7}$$

with $FEPrice_m$ the fuel price, η_m the average efficiency with which the fuel is converted into electricity, PFE_m the premium factor as estimated for utilities and $\lambda_{SF-LF-GF}$ the cross-price elasticity. Fuel prices are the driving force for this substitution process and are coming in from the Fuel Supply models.

Because actual market prices are not the only factors that determine utility preferences, we have again introduced premium factors PFE_m. These represent e.g. the environmental and legislative aspects of coal handling and storing, the perception of shortages, the protection of the (coal) industry for reason of employment and the lack of a (natural gas) infrastructure – leading to PFE_{coal} in the range of 0.7-0.9. By including the estimated efficiency for the particular fuel, we single out at least one factor which determines the premium value of that fuel. With a delay, the actual market share μ_m becomes equal to the indicated market share. This delay is represented by an adjustment time ADJ. In this way, the entire capital stock can switch to other fuels albeit slowly. Dual-firing options are implicit in this formulation.

4.2.3 Costing rules and investments

The driving force for the penetration of various forms of generation capacity thus depends on its generating costs relative to the other available options. How are these costs to be calculated ? There are a few widely used rules in calculating the costs of electricity produced (see e.g. Kahn, 1988). Basically, two cost elements have to be considered:

- investment costs for generation and for transmission and distribution, derived from the costs of capital and the rate of capital depreciation; and
- operation and maintenance costs which include fuel inputs as the major item but include also labour, materials etc.

Specific investment costs, Isp, are dependent on the power generation technologies which are used e.g. low-investment diesel-engines vs. high-investment solar cells, and on the availability of capital. Operational costs are also quite different for the various generation technologies : for an inefficient coal-fired power plant they may amount to 70% of total costs whereas for nuclear power plants it may be less than 20%. Operational costs other than fuel costs are usually quite small and are included in the specific investment costs.

Thermal power

In the EPG-submodel we use a general cost formula which converts the costs of the existing capital stocks into annual capital costs with the annuity formula and which calculates fuel costs from thermal efficiencies and fuel prices. The costs of electricity produced with thermal capacity are (m=SF, LF, GF):

$$E\cos t_T = \left[a * Isp_T * ECap_T + E\Pr od_T * \sum_m FE\Pr ice_m * \mu_m / \eta_m \right] / E\Pr od_T \qquad \$/GJe \quad (4.8)$$

with a the annuity factor [35], Isp_T the specific investment costs (including a fixed add-on term for operation and maintenance costs), and FEPrice the price and μ the actual market share for each fuel. For the thermal capacity we assume an exogenous improvement in thermal efficiency over time as well as an exogenous change in the specific investment costs; both can be used to

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[35] Defined in the usual way as a = r/(1-(1+r)**(-ELT)) with r the discount rate c.q. interest rate and ELT the economic lifetime of the investment.

simulate innovations as well as add-on equipment such as flue-gas desulphurisation. The fuel price, FEPrice, is taken from the fuel supply modules, with the option to add taxes.

Similar equation are used for the cost of hydro-, nuclear and renewable capacity, but in each reflecting the different underlying dynamics.

Hydro power
For hydro, the specific investment costs are a nonlinearly increasing function of the utilisation rate of this potential:

$$Isp_H = \left\lfloor Isp_{H,t=1990} * (e^{0.7*ECap_r / ECap_{H,t=1990} - 0.7} \right\rfloor \quad \$/MWe \quad (4.9)$$

As is seen, in the reference year 1990, it equals the value in the input file $Isp_{H,t=1990}$. The fuel price for hydro is assumed to be zero.

Nuclear and renewables
For both nuclear and renewable capacity, the trend in Isp is interplay of both learning-by-doing and depletion.

The first factor, learning-by-doing reflect technology development and the rate at which specific investment costs decrease is assumed to be a linear function of the cumulative production:

$$Isp_k = Isp_{TSL_N} * (CumEProd_k / CumNTEProd_{k,t=TSL_N})^{\pi} * Depl_k \quad \$/MWe \quad (4.10)$$

with k = NU, NR; π the learning coefficient; Isp_{TSL} the specific investments costs in the reference year and Depl the factor taken into account the impact of depletion.

For both nuclear and renewables also depletion is taken into account. For nuclear, depletion is assumed to work via scarcity cheaply exploitable fuel resources (uranium etc). For renewables, depletion works via the fact that the most attractive sites for production will be produced first. Higher production rates means that new, less attractive sites need to be developed – or other, more expensive renewable options (shift from wind to solar) need to be used. For both nuclear and renewables, depletion is assumed to have a negative impact on Isp (for nuclear, depletion should actually have an impact on fuel costs – but to simplify the necessary equations, this has been taken into account via Isp).
For nuclear power, the impact of depletion increases with cumulative production.

$$Depl_{NU} = f(CumEProd_{NU} / Resource_{NU}) \quad (4.11)$$

with Resource being the ultimately extractable fuel resources. It should be noted that by choosing a the technology rate and the size of the resources, the role of depletion can be overruled. For renewables, the impact of depletion increases with annual production:

$$Depl_{NR} = f(EProd_{NR} / MaxProd_{NR}) \quad (4.12)$$

with MaxProd being maximum level of electricity that can be realistically produced from renewables each year. Again, also for renewables depletion can be offset by technology development.

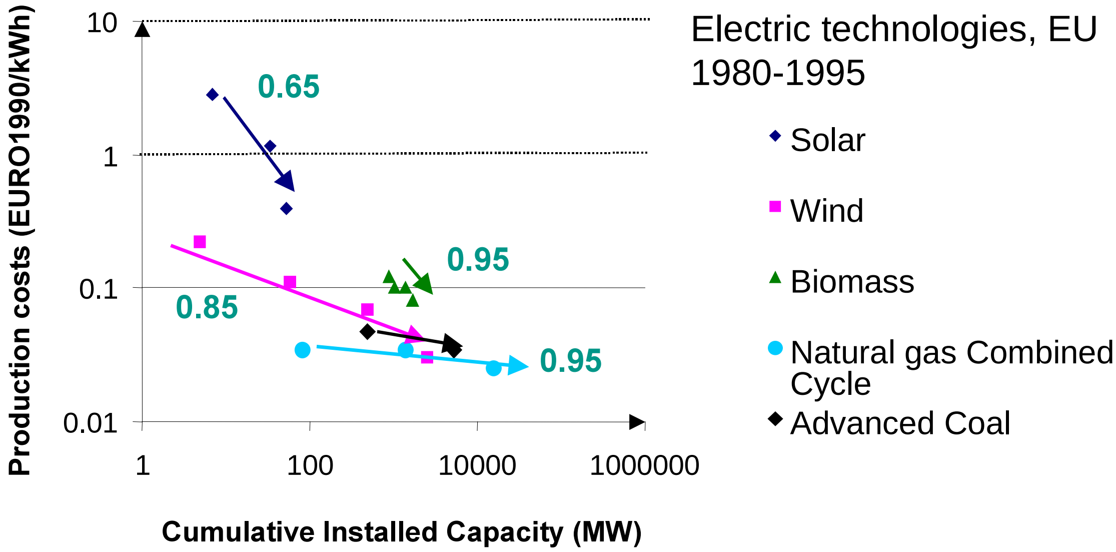

Figure 4.3: Examples of learning curves for electric technologies in the EU

In addition, to depletion and learning, on the short-term also capacity constraints can play a role in the generation costs of nuclear and renewables. The load factor for thermal and non-thermal capacity decreases if their share in total capacity increases. As soon as the sum of H- and NT-capacity exceeds the required base-load capacity, NT-capacity will start operating in the peak-load regime whenever T-capacity is less than the required peak-load capacity [36]. As a consequence the NT-load factor will drop which in turn increases its cost and thus slows down its penetration rate. This is a negative loop, whereas the learning-by-doing is a positive loop.

Using the economic lifetime ELT and not the technical lifetime TLT (ELT<TLT) for the calculation of the annuity and annuitising the total capital stock tends to overestimate the capital costs, especially in periods of low or negative capacity growth. Use of the investment costs as of time t tends to overestimate capital costs in a situation of declining specific investment costs - which is the expectation for both NT- and T-capacity (see Vries, 1995).

The price of electricity is set equal to the average generation cost plus the capital cost of transmission and distribution, multiplied by some pricing factor χ which may depend on the category of consumers as indicated by the sector s:

$$Eprice = \chi_{rs} * \left[\sum_k E\cos t_k * E\Pr od_k / E\Pr od \;\; + a_{TD} * Isp_{TD} * ECap / E\Pr od \right]$$

$/GJe (4.13)

[36] It is assumed that hydropower will never exceed the required base-load capacity. For some regions (Canada, Latin America) this gives some complications in the calibration period.

with a_{TD} the annuity factor applied for the transmission and distribution capital stock and Isp_{TD} the required transmission and distribution capital per unit of generating capacity[37]. In first instance we assume that the value of Isp_{TD} is constant, irrespective of system reliability and transmission and distribution losses - which is not the case in the real world (see e.g. Munasinghe, 1979).

The total annual investment flow which is required within the EPG-model is given by (k=H, T, NU, NR) :

$$ElInv = \sum_k \left[MAX(dECap_k / dt, 0) * Isp_k + (dECap / dt) * Isp_{TD} \right] \qquad \$/yr \qquad (4.14)$$

In various parts of the world, there is a large capacity shortage. A major reason for capacity shortages and a resulting unmet demand for electricity is a shortage of capital, often in combination with extremely high demand growth rates. Estimates for India and China indicate that this may be in the order of 5-15% in the present situation (see e.g. Audinet, 1998). Also, construction times longer than expected, caused for instance by environmental objections against hydropower expansion, and a sometimes low reliability of power stations and transport systems contribute to capacity shortages and unserved electricity.

The ratio between the actually installed and the required system capacity is in the model used as a feedback signal. If this ratio drops below one, the anticipated required electricity capacity is divided by this ratio [38]. Such a shortfall in electricity affects industrial and agricultural production, and also in more indirect ways the residential and commercial sector. So far, we have not included these feedbacks on economy and welfare in our model. Implicitly, it is assumed that the shortage in transmission and distribution is proportional to the shortage in generation capacity, as will be discussed later.

4.3 EPG model implementation and model calibration 1971-1995

We compared historical data from statistical sources with the corresponding output variables as shown in *Table 4.1*, to implement the model for the 17 regions. The model parameters/ variables which can be varied to improve the fit with historical data or to (re)construct scenarios are shown in *Table 4.2*. *Table 4.3* lists some additional parameters/variables which are usually not varied because they are fairly constant or insignificant. The code is regions r=1..17, sectors s=1..5, fuel category m=1..3 and capacity category k=H, T, N and NR.

Electricity demand

For electricity demand, first the electricity demand as determined by ED model is multiplied with Transmission & Distribution Loss Factor (TDLF) which also includes own use. The values for TDLF has been determined from the IEA database and are indicated in *Figure 4.4*. The share of peakload versus baseload is in a next step determined by the FracDemBL. This factor is set independently of the region and time-independent at 90% baseload.

[37] We apply a value for TD separately because the economic lifetime for TD-equipment, ELT_{TD}, is assumed to be quite long (30 years).

[38] This assumption may introduce errors in case of rationing schemes e.g. non-delivery to industrial consumers during certain days of the week. See e.g. Thukral (1991).

Table 4.1 Model variables used for historical calibration for EPG-model. Model parameters (see Table 3.4) are varied to get the best fit between simulated and historical time-series. See Appendix A for data sources).

Variable	Subscript	Description	Unit/Domain
ElProd	r	(Gross) Electricity Production	GJe/yr
ECap	r,H/T/N	Electric power generating capacity	MWe
TEFuel	r,m	Fuel for Electricity generation	GJ/yr
ElCost/Price	r	Cost/Price of electricity	$/GJ
CH	r,CHP	Heat delivered by Combined Heat Power schemes	GJ/yr

Table 4.2 Model parameterss used for historical calibration and, if in bold, also for scenario (re)construction for EPG-model. Parameters are varied around a default value within a certain domain.

Variable	Subscript	Description	Unit/Domain
GElD	r	Gross Electricity Demand	(historical)
TDLF+OULF	r	Transmission & Distribution Loss Factor + Own Use Loss Factor; for CHP function of penetration	(historical) $0.0<TDLF<0.5$
η	rm	thermal efficiency of T-capacity using fuel category m	(historical) $(0.1<\eta<0.9)$
PT	rm	Premium Factor for fuel category m for Electricity from T-capacity	
Isp	rH, rT, rN, rCHP	specific Investment cost for power plant type k; for CHP function of penetration	$/kWe
χ	rs	pricing factor between generation plus TD cost and sectoral price	
θ	r	share of N-capacity that can be used for heat supply	(INDIRECT)

Table 4.3 Model parameters for which historical values and/or fixed assumptions are used. Parameters are given a default value based on exogenous input time-series or on literature.

Variable	Subscript	Description	Unit/Domain
PLF_{max}	r	maximum Peak Load Factor for non-base-load capacity	$0.3<BLF<1.0$
FracBL	r	Fraction of electricity use in base-load operation	
BLF	r,H/T/N/CHP	Base Load Factor for power plant type k; for CHP function of penetration	$0.3<BLF<1.0$
$\lambda_{SF-LF-GF}$	r	cross-price elasticity in fuel use for T-capacity	$0<\lambda<10$; if 0, equal shares
λ_{T-NT}	r	cross-cost elasticity for T- vs. N-capacity	$0<\lambda<10$; if 0, equal shares
TLT	r,H/T/N/CHP/TD	Technical Lifetime which effects depreciation rate	yr
ELT	r,H/T/N/CHP/TD	Economic Lifetime which effects capital costs (annuity)	yr
I_v	r	required TD-investment per unit of installed generating capacity	$/kWe

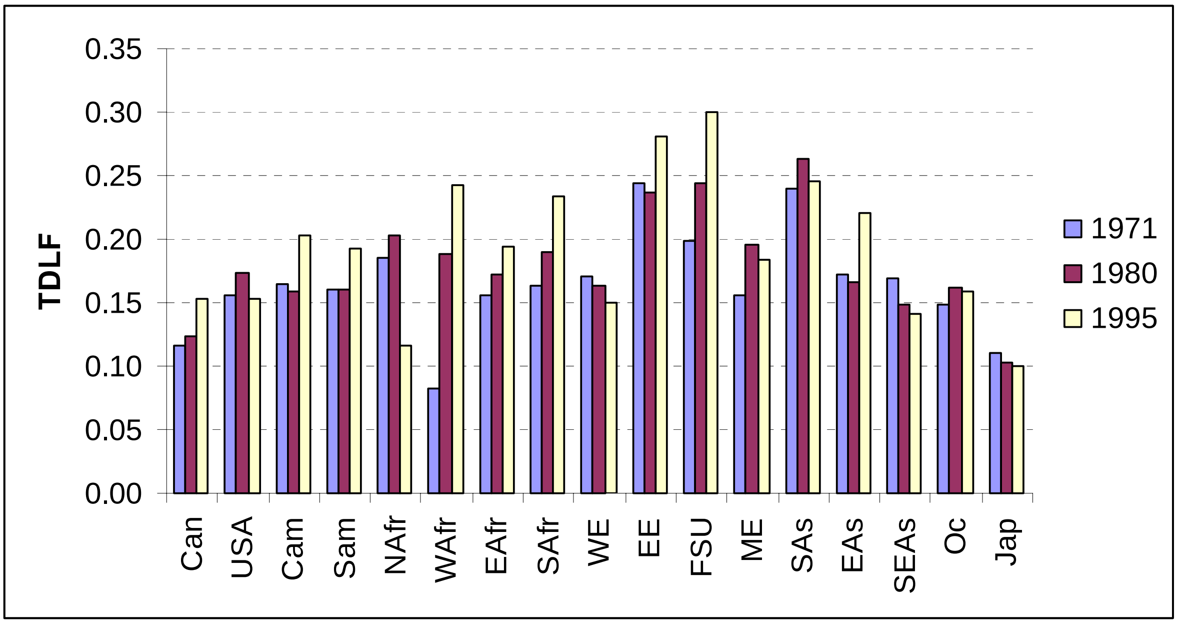

Figure 4.4: The Transmission and Distribution Loss and Own Use factor TDLF(1+OULF) (Eqn. 4.1).*

Hydropower

Calibrating the formulation for hydropower generation is rather simple. First, the potential hydropower capacity is assigned to each region (*Table 4.4*). Historical capacity c.q. scenario values are introduced as a fraction of this potential - thus, an exogenous time-path for installed hydropower capacity is introduced. This fraction is the variable used for calibration. Each MWe produces with a load-factor which may vary from year to year; its historical value is used to calculate electricity generation.

Table 4.4 gives an overview of the potential hydropower capacity and hydropower generation (Moreira and Poole, in Johansson, 1993). Available data on actual capacity indicates that the average load factor is in the range of 0.3-0.6. *Table 4.4* also indicates the potential capacity used in TIMER. For all regions we assume a technical lifetime of 100 years, whereas the specific investment costs range from 1500 to 3000 $/kWe (*Table 4.4*). The differences reflect different endowments and utilisation rates.

Non-fuel based Non-Thermal (NU and NR) power generation

Calibration for electricity from nuclear (NU) and renewable (NR) capacity is derived from the product of installed capacity and the load factor. Installed capacity on its turn results from the parameter settings for each region: i.e. 1) an exogenous RD&D program (that can force shares in investments above the shares set by the market formulation) and 2) changes in electricity generation costs that influence the cost-based competition. The latter is influenced by 1) a time-dependent learning factor π and 2) depletion dynamics (insignificant for the calibration period but important in future simulations). The calibration has to be done in an iterative way.

Table 4.4 Data on hydropower generation and technical potential (Eqns. 4.4 and 4.9)

	Potential	Production			Capacity in use	Load factor	Investments
		1971	1980	1995	1995	1995	Initial value
	GWe	PJ	PJ	PJ	Fraction	Fraction	$/kWe
Can	164	585	904	1207	0.37	0.62	3000
USA	173	949	1004	1131	0.54	0.40	3000
Cam	56	63	85	156	0.33	0.30	2000
Sam	509	248	692	1621	0.18	0.60	2000
NAfr	23	25	42	42	0.20	0.32	2000
WAfr	253	33	55	84	0.04	0.30	2000
EAfr	101	3	8	19	0.02	0.30	2000
SAfr	101	18	104	47	0.05	0.30	2000
WE	365	1140	1429	1625	0.45	0.35	3500
EE	48	99	197	191	0.54	0.25	3000
FSU	278	454	665	861	0.25	0.41	1500
ME	18	23	76	184	0.64	0.63	10000
SAs	190	118	207	365	0.15	0.47	2000
EAs	481	166	308	811	0.13	0.48	2000
SEAs	163	27	35	142	0.08	0.33	2000
Oc	20	89	115	155	0.68	0.39	3500
Jap	40	303	318	296	0.98	0.30	3500

Source: Resources are based on the UNDP (2000); in combination with (Moreira, 1993). Production data from IEA (1998).

Table 4.5 Implementation for some key time-dependent system variables (Eqns. 4.4-4.10)

EPG-Model	*Thermal T*	*Hydro H*	*NonThermal NT*	*T&D*
Economic LifeTime (yr)	12	12	12	30
Technical LifeTime (yr)	25	50	25	40
Interest Rate (%)	10	10	10	10
Construction delay (yr)	3	5	8	na
TE-NTE logit parameter	4			
TE fuels logit parameter	2			

Learning starts up with an initial value of the specific investment costs, $Isp_{N,init}$. An additional problem is that the 'NR' technology used in the model, is in reality a combination of all kind of renewables, which means that somehow data for solar, wind etc needs to be combined. The first step is to gauge π_{NT} to more-or-less the scarcely available time-series for generation costs of nuclear and a combination of solar/wind. Based on the data from various sources (IEA, 2000, WEA, 2000) we have decided to use a learning rate for NR of 0.8. For NU, we have a historic learning rate of 1.0 (a result of technology development on one hand, and stricter regulation on the other). Choices for some other important parameters are shown in *Table 4.6.*

Available data on current generation costs based on nuclear power typically varies between 2000-3000 US$/kW, making nuclear slightly more expensive than coal-based and natural gas based alternatives in almost all countries (IEA, 1998a). For solar, wind and other renewables considerable ranges for generation costs can be found – depending, for instance, on the site, country and technologies applied. Generation costs for PV typically vary around 5000-10000

US$/kW and for wind between 1000 and 2000 US$/kW. Based on the assumed model settings, *Figure 4.5* shows the results for NR technology in the USA compared to the data for PV and windmills as indicated in the WEA (it should be noted that the WEA data indicates cutting-edge technology, while the model results indicated average production costs).

Table 4.6: Data on nuclear and renewable generation capacity (cf. Eqn. 4.11)

	Investments ($Isp_{N,init}$)		Learning ratio (π_{NT})		Load factor		Forced fraction in total investments	
	$/kWe Initial	$/kWe Initial	Fraction 1995	Fraction 1995	Fraction 1995	Fraction 1995	Fraction 1995	Fraction 1995
	NU	NR	NU	NR	NU	NR	NU	NR
Can	3500	7800	1	0.8	0.65	0.53	0.15	0.00
USA	3500	7800	1	0.8	0.65	0.53	0.18	0.01
Cam	3800	7800	1	0.8	0.65	0.53	0.03	0.04
Sam	3800	7800	1	0.8	0.65	0.53	0.26	0.00
NAfr	3800	7800	1	0.8	0.65	0.53	0.00	0.00
WAfr	3800	7800	1	0.8	0.65	0.53	0.00	0.00
EAfr	3800	7800	1	0.8	0.65	0.53	0.00	0.45
SAfr	3800	7800	1	0.8	0.65	0.53	0.08	0.00
WE	3500	7800	1	0.8	0.65	0.53	0.43	0.00
EE	3500	7800	1	0.8	0.65	0.53	0.26	0.00
FSU	3500	7800	1	0.8	0.65	0.53	0.40	0.00
ME	3800	7800	1	0.8	0.65	0.53	0.00	0.00
SAs	3800	7800	1	0.8	0.65	0.53	0.07	0.00
EAs	3800	7800	1	0.8	0.65	0.53	0.30	0.00
SEAs	3800	7800	1	0.8	0.65	0.53	0.00	0.05
Oc	3800	7800	1	0.8	0.65	0.53	0.00	0.02
Jap	3500	7800	1	0.8	0.65	0.53	0.32	0.00

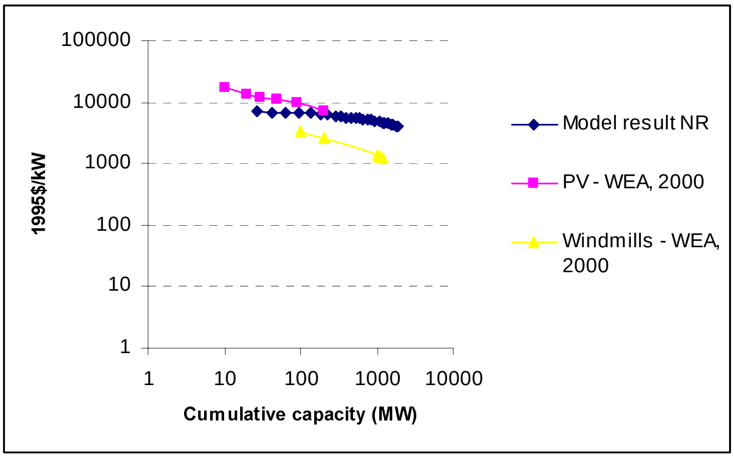

Figure 4.5: Generation costs for NR-technology in the USA compared to historical data (cf. Eqn. 4.12).

Historically both NU and NR technologies are used for electricity generation even when their costs are higher than the competitive thermal plants (T) for each region we have introduced an RD&D program (as fraction of total investments in electric power capacity). The required values are also indicated in *Table 4.5*. The values for NU vary between 0 and 40% (indicating government support for nuclear power programmes); for NU the values are typically between 0 and 5% (with the exception of East Africa – where almost no electricity is produced, but using a relatively large share of renewables).

For depletion of nuclear power, we have used the available information from the World Energy Assessment (WEA, 2000; Vries, 1989b) on uranium reserves, including extraction from oceans (combining it with assumptions on recycling and efficiencies of nuclear power plants). Only one, global, depletion curve is used. The curve as indicated below is used as default in TIMER. Based on assumption on development of alternative nuclear technologies (e.g. fusion) – alternative curves can be used.

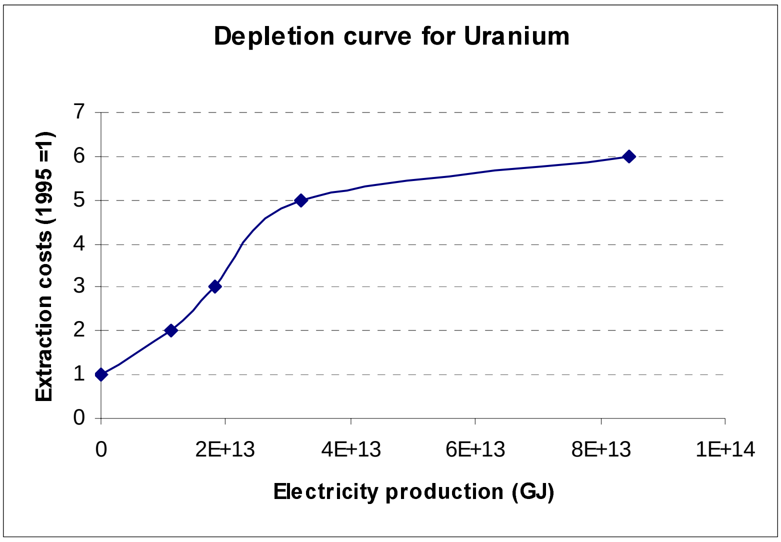

Figure 4.6: Depletion curve for NU technology as used in TIMER (Eqn. 4.11)

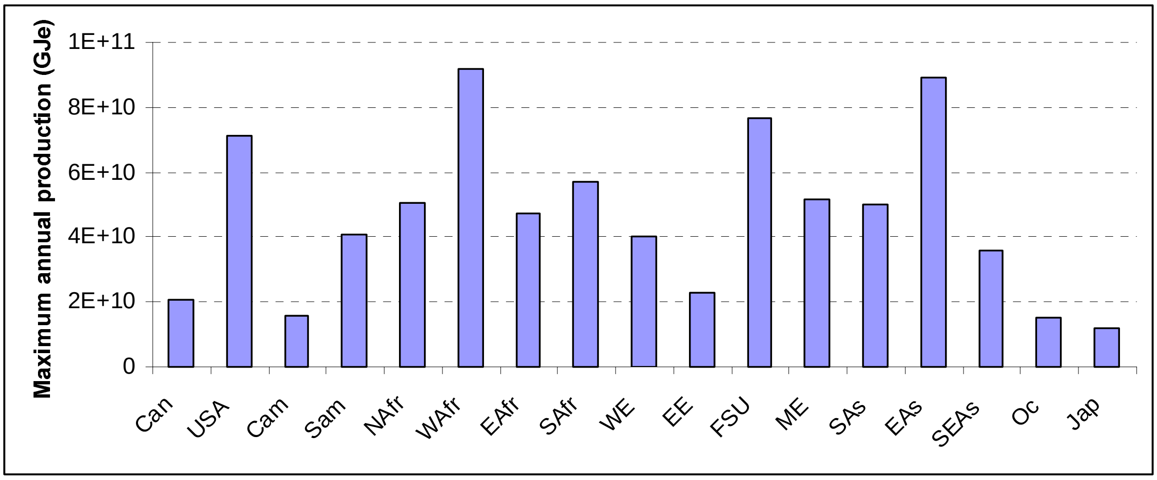

Figure 4.7: Maximum production of NR per region.

For NR, we have used the potentials as indicated in the WEA to construct our depletion curves. For wind, the underlying data are based on Grubb and Meyer (1993) and WEC (1994). For solar, we have used the minimum estimates as indicated in WEA. The assumption is that the larger share of the maximum potential is used, the higher the generation costs are (less attractive sites).

Fuel-based thermal (T) power generation
The simulation of T-production hinges on several region-dependent variables:

- the fraction of demand which is considered base-load, FracBL (see earlier in this paragraph);
- the maximum load factor for peak-load capacity, PLF_{max};
- the time-dependent load factor for base-load T capacity, BLF_T;
- the time-dependent efficiencies of thermal plants (per fuel type) (η);
- the time-dependent investments costs of thermal plants (Isp_T);
- the time-dependent fuels costs (as calculated in other submodels of TIMER);
- the time-dependent premium values (PT);

Using historical time-series for T-capacity and T-generation, we have varied the first two variables in such a way that simulated and historical data give a good match. If this did not succeed with a constant BLF_T, its value has been adjusted. This procedure turned out to be fairly straightforward.

We have used historical data of the thermal efficiency η (based on IEA data) and estimates on investments costs (IEA, 1998), fuel prices for the electricity sector, and performed the calibration by varying the fuel premium factors, PF.

Table 4.7: Specific investment costs and average efficiencies for power plants for solid, liquid and gaseous fuels (Eqns. 4.8 and 4.15)

	1971			1980			1995		
	Coal	Oil	NG	Coal	Oil	NG	Coal	Oil	NG
Specific investment costs ($/kWe)									
	1600	1470	930	1550	1420	860	1475	1350	750
Average efficiencies (-)									
Can	0.33	0.33	0.34	0.34	0.37	0.34	0.37	0.40	0.39
USA	0.33	0.36	0.37	0.37	0.37	0.37	0.36	0.38	0.39
Cam	0.26	0.31	0.30	0.26	0.30	0.34	0.30	0.34	0.36
Sam	0.26	0.27	0.30	0.28	0.28	0.35	0.30	0.30	0.33
NAfr	0.28	0.27	0.25	0.26	0.27	0.30	0.30	0.35	0.35
WAfr	0.28	0.26	0.25	0.24	0.25	0.30	0.30	0.30	0.33
EAfr	0.28	0.25	0.25	0.24	0.25	0.30	0.30	0.31	0.33
SAfr	0.33	0.29	0.25	0.34	0.32	0.33	0.36	0.32	0.35
WE	0.34	0.35	0.38	0.35	0.36	0.39	0.37	0.38	0.38
EE	0.30	0.30	0.27	0.32	0.33	0.30	0.31	0.33	0.34
FSU	0.30	0.30	0.33	0.31	0.33	0.32	0.29	0.30	0.29
ME	0.22	0.30	0.25	0.29	0.38	0.28	0.34	0.40	0.38
SAs	0.27	0.26	0.28	0.27	0.27	0.28	0.26	0.33	0.32
EAs	0.26	0.26	0.28	0.27	0.30	0.29	0.30	0.35	0.34
SEAs	0.28	0.30	0.28	0.26	0.31	0.30	0.33	0.34	0.36
Oc	0.26	0.33	0.35	0.29	0.33	0.38	0.37	0.36	0.37
Jap	0.30	0.40	0.42	0.39	0.40	0.44	0.44	0.42	0.46

Source: IEA, 1998

For the adjustment time in fuel substitution we use 6-8 years; for the substitution dynamics between thermal (T) and non-thermal (NT) capacity we use 20 years. Choices for the important parameters are shown in *Table 4.7* and *Table 4.8*.

Table 4.8: Baseload factor for thermal plants and the maximum peak load factor per region (Eqns. 4.2 and 4.3)

	Baseload factor			Maximum peak load factor
	1971	1980	1990	
Can	0.63	0.82	0.72	0.30
USA	0.65	0.65	0.53	0.20
Cam	0.54	0.53	0.55	0.20
Sam	0.70	0.70	0.70	0.30
NAfr	0.62	0.60	0.61	0.20
WAfr	0.62	0.60	0.61	0.20
EAfr	0.62	0.60	0.61	0.20
SAfr	0.62	0.60	0.61	0.20
WE	0.63	0.62	0.62	0.20
EE	0.63	0.62	0.58	0.20
FSU	0.64	0.65	0.65	0.20
ME	0.63	0.56	0.58	0.20
SAs	0.60	0.58	0.64	0.20
EAs	0.86	0.78	0.68	0.20
SEAs	0.63	0.63	0.60	0.20
Oc	0.55	0.63	0.63	0.20
Jap	0.80	0.67	0.63	0.20

Fuel premium factors

Using only fuel costs is not enough to model the market shares of the different fuels in electricity generation for the different regions; a premium factor needs to be added. From this one may infer some explanations for the non-unity premium factors, i.e. the difference between perceived and actual fuel prices. First, there may be no infrastructure for coal or gas which gives high premium factors. Secondly, strategic issues may affect perceived prices in the sense that coal and gas became substitutes for an undesirable dependence on OPEC-oil - which would bring premium factors down. Thirdly, utilities may realise the comparative advantage of gas (low specific investment costs, high efficiency of STAG-units, no storage costs) and disadvantages of coal (high specific investment costs - especially with strict environmental regulations, low thermal efficiency, environmental constraints). This would decrease the premium factor for gas and increase it for coal. In all regions outside the OECD, the premium factor for gas declines from (very) high values towards a multiplier value of 1-2, which probably signifies the gradual build-up of a gas infrastructure in these regions after which natural gas could become a competitor.

Competition between thermal, nuclear and renewables

The logit-value has been set a relatively sensitive value of 4-5 for all regions. The actual shares of the different generation forms has been calibrated by changing their generation costs (see further in this section) and introducing premium factors. In most regions, we have assumed that there is a small premium value (aversion) against nuclear power based on lack of technology and the public awareness of possible nuclear risks.

4.4 Calibration results 1971-1995

Figure 4.8 shows the historical and simulated fuel inputs for the electricity generation in the world at large for the period 1971-1995. It is seen that both the total electricity production and the distribution of the various options/fuels in the input is reproduced quite well.

Table 4.9: Premium factors used for different fuels in thermal plants (Eqn. 4.8)

	1971			1980			1995		
	Coal	Oil	Natural gas	Coal	Oil	Natural gas	Coal	Oil	Natural gas
Can	0.9	0.7	1.0	0.5	0.9	3.0	0.6	1.1	1.0
USA	1.1	0.8	4.0	0.8	1.6	1.7	0.6	1.8	0.9
Cam	40.0	1.1	4.0	15.0	1.1	4.0	2.0	1.2	2.0
Sam	4.0	1.5	1.0	2.0	1.5	1.0	1.8	1.3	1.0
NAfr	3.0	1.0	2.5	4.5	1.1	1.8	3.0	1.2	1.0
WAfr	8.0	1.0	1.0	8.0	1.0	1.0	8.0	1.0	1.1
EAfr	20.0	0.9	12.0	20.0	0.9	12.0	20.0	0.9	12.0
SAfr	0.6	2.0	8.0	0.6	2.0	7.9	0.6	2.0	7.9
WE	1.2	1.2	2.5	0.9	1.2	3.0	1.2	1.5	1.0
EE	1.3	1.3	1.7	1.3	1.0	1.7	0.8	1.3	1.6
FSU	1.2	0.7	2.8	1.2	0.7	1.3	0.9	1.0	0.9
ME	4.0	1.0	0.9	2.5	1.0	0.9	1.0	1.3	0.8
SAs	2.0	1.1	1.8	2.0	1.1	1.8	0.9	1.5	1.6
EAs	3.5	0.7	45.0	1.7	0.7	27.0	1.0	1.0	2.0
SEAs	7.0	1.0	4.0	7.0	1.0	3.0	1.7	1.1	0.7
Oc	1.3	1.5	3.0	1.2	1.5	1.1	0.8	2.0	1.4
Jap	1.7	0.9	1.6	1.2	1.0	1.6	0.7	1.2	1.4

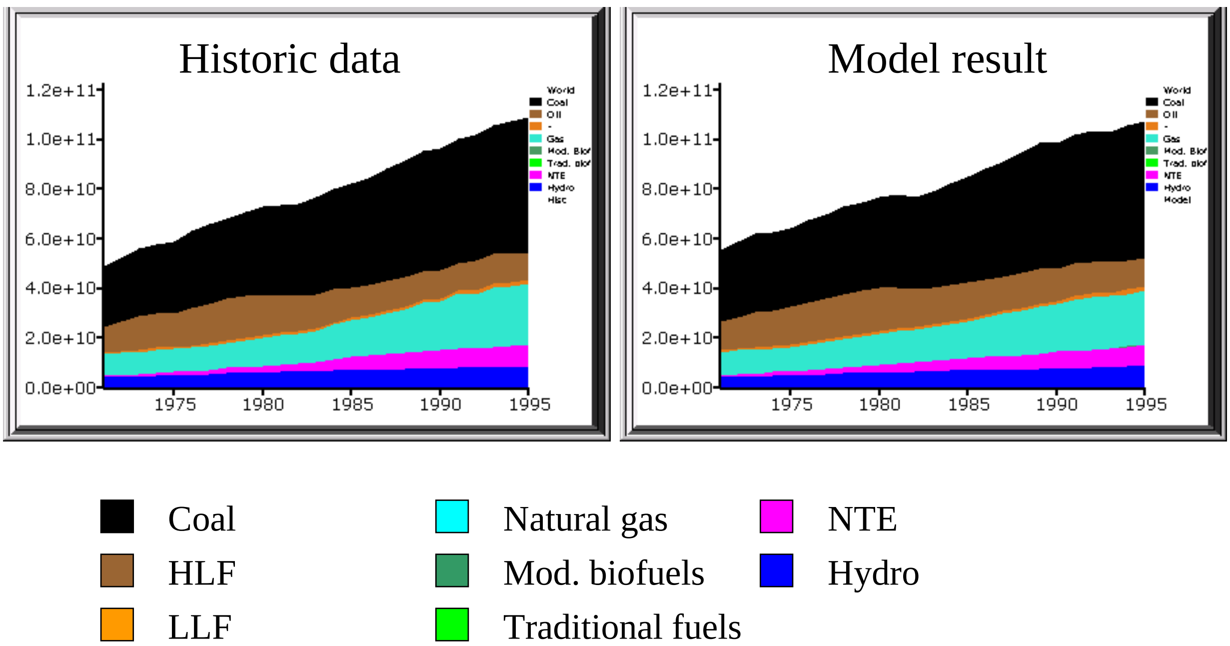

Figure 4.8: Global electricity production by fuel type; model compared to historical data

Obviously, at the regional level the results do diverge slightly more from the historical data set – but also here the overall results are quite good. *Figure 4.9* gives an example of results at the regional level by comparing the total installed capacity for electricity generation for Western Europe and South Asia against historical data. The expansion of electric generation capacity in both regions is reproduced very well.

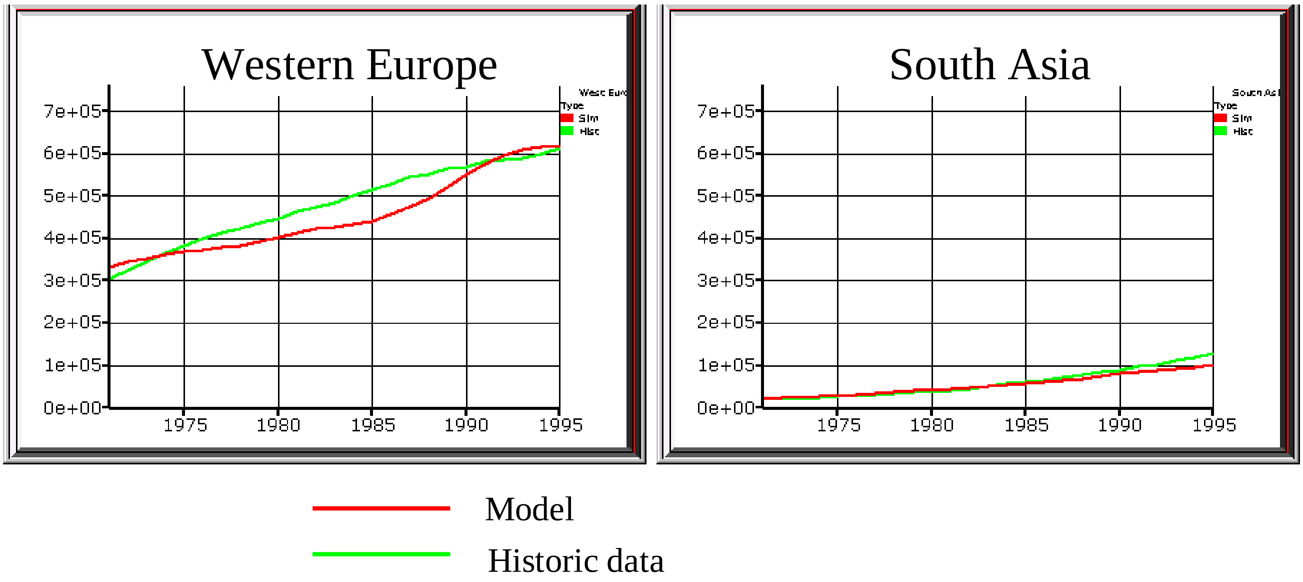

Figure 4.9: Expansion of capacity in Western Europe and South Asia

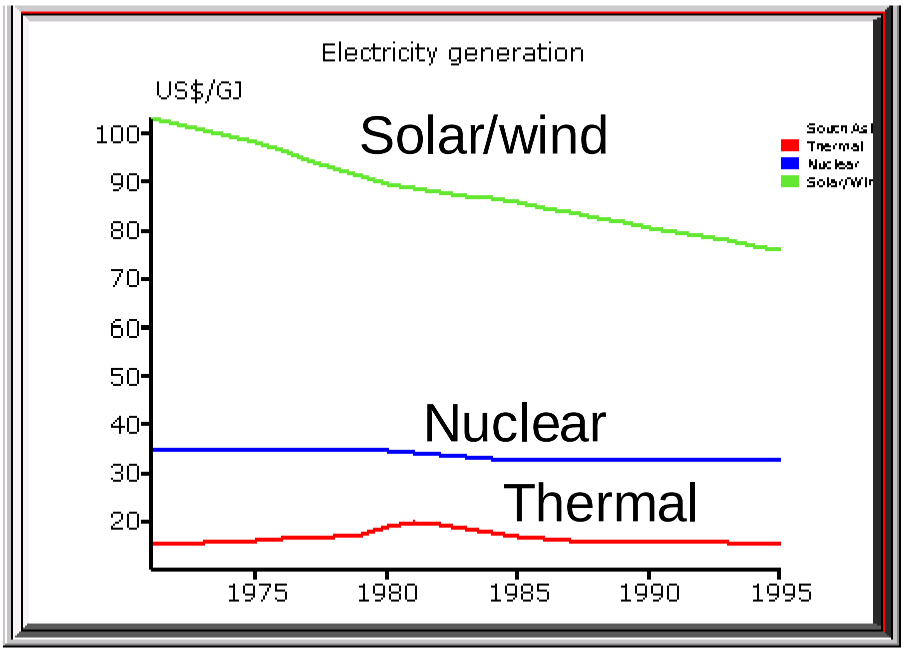

Figure 4.10: Electricity generation costs for various options in the USA

Finally, *Figure 4.10* shows the generation costs of the three competing generation options for the USA. By far, thermal power is the cheapest producing option. However, in time solar/wind has considerably gone down in costs.

4.5 Directions for future research

Obviously, there are several possibilities for model improvements. Based on our present modelling experiences we suggest the following modifications and extensions as high-priority ones:

- The modelling of the new, renewable electric power options is still relatively simple with only limited connections with bottom-up data. For solar and wind, we intend to improve our modelling capabilities by relating the current formulation to a more bottom-up oriented approach, in which potentials for different options are determined on factors such solar radiation, available wind energy, technological development.

- Improving the modelling of renewable options will also require a (slightly) more detailed formulation of the main operational rules in electricity supply. This concerns for instance the amount of base and peakload electricity demand and the options for storage within the system.
- Although earlier we have developed a Combined Heat and Power submodel, the module is not yet operational (see Appendix below). It will be an important priority to re-integrate this submodel, which means that a better balance can be made in supply and demand for heat.
- The efficiency of electric power plants is currently driven by exogenous scenarios. This is based on practical considerations, but it means that no 'learning-by-doing' formulations is used, as for other technologies, and that thermal efficiency is not influenced by pressure on the system (e.g. a carbon tax). An alternative formulation might be considered.
- In the 1990s the management of electric utilities has been changing due to the political pressures for privatisation. Recent examples – such as the experiences with privatisation in the UK and the electricity crisis in California – suggest that some of the rules as modelled in TIMER have become less valid. More in particular, it is needed to assess the dynamics behind profit-oriented capacity operation and extension and such initiatives as 'green electricity'. Limited experience so far makes it hard to formulate the new rules of the game.

The fraction of decentralised generating capacity, both in the form of small- to medium-sized cogeneration units and small-scale renewables-based capacity, is on the rise. Recent evaluations suggest that market liberalisation tendencies may lead to quite unexpected directions for such distributed/embedded generation schemes. This will be one of the research priorities. This will be improved in the extended model of renewable energy options.

5. The Traditional and Solid Fuel Supply submodels

5.1 Introduction

This chapter describes the supply submodels for traditional fuels, mainly biomass, and solid fuels, which cover the coal range from anthracite and coke to lignite. The IEA estimates that about a third of the developing countries' final energy need is met by biomass (firewood, agricultural residues, animal wastes, charcoal and other derived fuels). In specific countries and regions, this share can be as high as 80-90%. At world level, biomass accounts for an estimated 15% of the global final energy use. Unfortunately, in spite of its significance, data on traditional biomass are scarce and biomass fuels are excluded in most global energy demand models and analyses. Omitting biomass from the analysis of future trends, however, means that fuel substitution processes and related land use cannot be fully captured.

The solid fuel coal is a relatively abundant resource in comparison with the liquid and gaseous carbon occurrences. Its exploration has a long history. Therefore, and for geological reasons, not many new discoveries have been made in the last decades or are expected in the future. Coal production rates have exponentially risen since the Industrial Revolution. It soared in Britain soon to be followed by France, Germany, the United States and Russia. Since the middle of the 20th century, coal's share in the commercial energy market has been declining, mainly because of the penetration of cheaper and more convenient oil and gas and more efficient energy use especially in steelmaking (scrap use). Still, in absolute numbers coal production continued to increase and the coal industry remains one of the major industries in the world. The most important users of coal are electric power stations and heavy industries such as iron-steel and cement. The most important coal producing regions currently are the USA and East Asia (*Figure 5.1*).

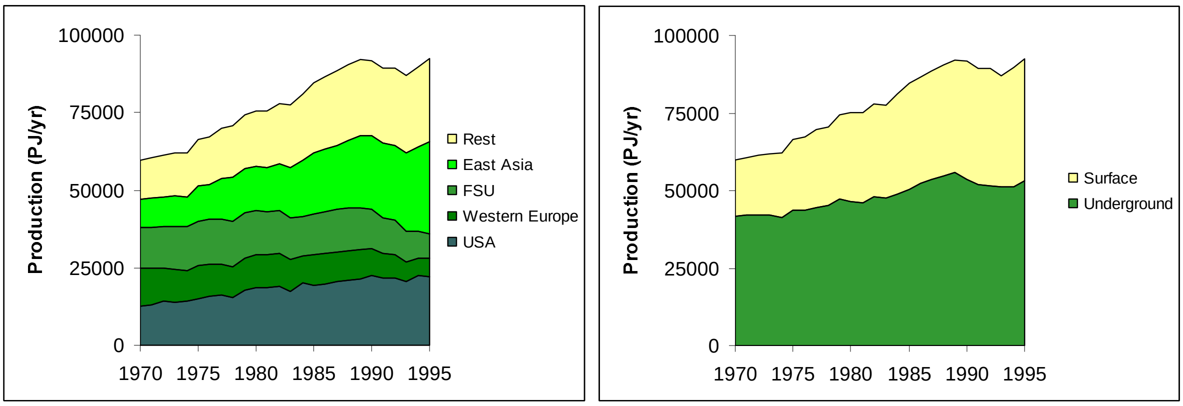

Figure 5.1: Coal production between 1970 and 1995 (Source: IEA 1998b)

5.2 Traditional fuel use

Traditional fuels are an important source of energy, certainly in many developing countries. Based on its low status as the 'poor man's fuel', it is generally expected to disappear along with development. However, the World Energy Outlook of the IEA in 1998 (IEA, 1998b) indicated that biomass energy will still be a major energy source for at least several decades.

In TIMER, only a simple description of traditional fuels has been included. The reasons for this are the limited availability and reliability of data and relatively large uncertainties regarding the dynamics of traditional fuel use[39].

By far the largest share of traditional biomass is consumed in the residential sector. The model focuses on this sector. Consumption in other sectors has been described exogenously by scenario files. We have used the work of Birol and Lambert D'Apote (1999) and slightly adapted their equations. We calculate the consumption of traditional biomass TFCons in the residential sector as a function of changes in population POP, per capita income GDPpc and the regional price of oil Oilprice:

$$TFCons = (TFConsPC + TFConsPC\_sat) * POP \qquad \text{GJ/yr} \qquad (5.1)$$

In which, TFCons is the per capita consumption of biofuels – and TFConsPC_sat the amount of biofuels consumption that is supposed to be unsubstitutable. The latter is based on the observation that in high income countries a certain amount of traditional biofuels (e.g. fireplaces) remains being used, apparently independent of further income increases.

$$TFConsPC = TFConsPC_{t-1} * \left[1 + \varepsilon_1 * (\Delta GDPpc / GDPpc)\right] * \left[1 + \varepsilon_3 (\Delta Oilprice / Oil\,\mathrm{Pr}\,ice)\right] * \left[1 + \varepsilon_2 * (\Delta Urban\_pop / Urban\_pop)\right] \qquad \text{GJ/cap} \qquad (5.2)$$

The elasticities ε_1 and ε_3 are also based on Birol and Lambert D'Apote (1999) and model calibration. ε_1 is negative for all regions, but its value varies between –0.1 and –1.5. Birol and Lambert D'Apote determined the values of ε_1 based on analysis of historic trends. In TIMER, we assumed future development ε_1 is a function of actual per capita consumption: at lower consumption rates the elasticity declines. ε_3 is positive but has only a very small value, as research indicates that the consumption of traditional biomass is hardly influenced by price changes. ε_2 has been determined based on historic data – and covers the assumption that traditional fuel use is higher in rural areas that in urban areas.

The equations 5.1 and 5.2 are only used after 1995. Before 1995, historic traditional fuel use is read into the model based only IEA data.

5.3 The Solid Fuel (SF) submodel

5.3.1 Overview

The solid fuel (SF) submodel of TIMER describes the production of coal in different regions and the corresponding prices. The formulation has used parts of the Coal-model as described in (Naill, 1977) which is also a part of the Fossil-2 model used for the U.S.A. by the Department of Energy (AES, 1990). An overview of the model is given in *Figure 5.2*. In the model, the production of coal depends upon the desired demand for coal, which leads to investments in

[39] The data on traditional fuel consumption have been taken from EDGAR (Olivier *et al.*, 1998) and IEA (1998a). It should be noted that most sources do distinguish between modern (commercial) biomass and traditional biomass. As modern biomass still represents a very small share of all biomass use, we have assumed that in statistics only consumption in the transport sector refers to modern biomass use.

coal-producing capital stock. In fact, two capital stocks are distinguished based on their different dynamics, which are underground coal (UC) and surface coal (SC) production capital. The share of investments in UC and SC mining depends on the relative costs, which are affected by labour costs and changes in specific costs due to technological learning[40] and depletion[41] and, in the case of UC-mining, capital-labour substitution[42]. These costs determine, together with a certain revenue, the coal price. The coal price in turn influences the investments in coal production.

In principle, in the model only one generic type of coal is considered, at 29 GJ/ton, also referred to as solid fuel. Thus, no distinction is made between various types and grades of coal, in terms of calorific content or ash-content. Nevertheless, one quality parameter, the sulphur content of the coal, has been included to determine the potential sulphur emissions from coal produced in different regions.

Two important parameters in the model are the reserves and resources. Coal reserves depend on exploration which converts resources into identified reserves and production which depletes the reserves. Over the last 80 years extensive assessments of coal reserves have been made (see e.g. (Fettweiss, 1979) for a detailed discussion). Several elaborate classification schemes have been worked out. The key axes are :

- probability of occurrence (proven, probable/indicated, possible/inferred);
- geological characteristics, mainly seam thickness and depth;
- physical-chemical characteristics, mainly quality in terms of the content of inorganic material (ash, sulphur) and of C-H-ratio (anthracite, bituminous, subbituminous, lignite).

Any reserve estimate has to be explicit on the probability that the coal is actually in place, on which fraction can be mined technically and/or economically, and on the need for and cost of upgrading/benefaction of coal in view of market requirements.

Coal reserves can be mined in various ways. Traditional ways are underground mining with room-and-pillar methods (50-60% recoverable) and with mechanised long- and shortwall-mining (60-90% recoverable) (see *Figure 5.1*, indicated as underground). Surface (or opencast) coal mining has become more important due to technological progress, lower labour requirements and economies of scale in surface mining techniques. Recoverability is high (>90%). However, without proper restoration after exploitation, environmental impacts are severe. Between 1970 and 1995, world-wide the share of surface mining increased from 30% to 42%. This trend is found in almost all regions, for instance, in the USA and the FSU the share went from respectively 45% and 30% to 60% and 50% (Fettweiss, 1979) and EDGAR-database). Astakhov (1984) show that the penetration of opencast mining in the former USSR follows the logistic substitution pattern between 1940 and 1985. The largest share of underground mining is currently in East Asia, where it still covers 90% of total production.

The present model version does not allow for the conversion of coal to liquid or gaseous fuels. Several technologies for liquefaction and gasification have been developed in the past, mostly during periods with restricted supply (for instance the second world-war). After the oil crises in

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[40] The increase of capital productivity in opencast mining leads to a cheaper way of exploiting reserves less than 400-600 m below the surface.

[41] With increasing cumulative coal output, the reserves which are economically recoverable tend to require more capital and labour per unit of output because they are deeper, have thinner layers etc.

[42] The substitution of labour by capital increases the labour productivity and mitigates the costs increase as labour wages rise.

1970s, the prospects for these conversions processes were thought to be good[43]. However, the cost estimates for them tended to rise over time while the world oil prices have been falling. It also became evident that coal conversion processes have large negative environmental impacts, which will further drive up costs. Apparently, only integrated systems of coal gasification and combined-cycle electric power generation offer prospects for large-scale introduction within the next few decades. This is dealt with in the electric power generation (EPG) submodel.

Not all environmental consequences of coal production can be dealt with in the present TIMER-model. Carbon-dioxide emissions and other coal-related environmental pressures such as emission of sulphur- and nitrogen-oxides are incorporated in the emissions module. Requirements for and degradation of land and water, however, are not included. As these may increase significantly in the future, they may become the topic of further study.

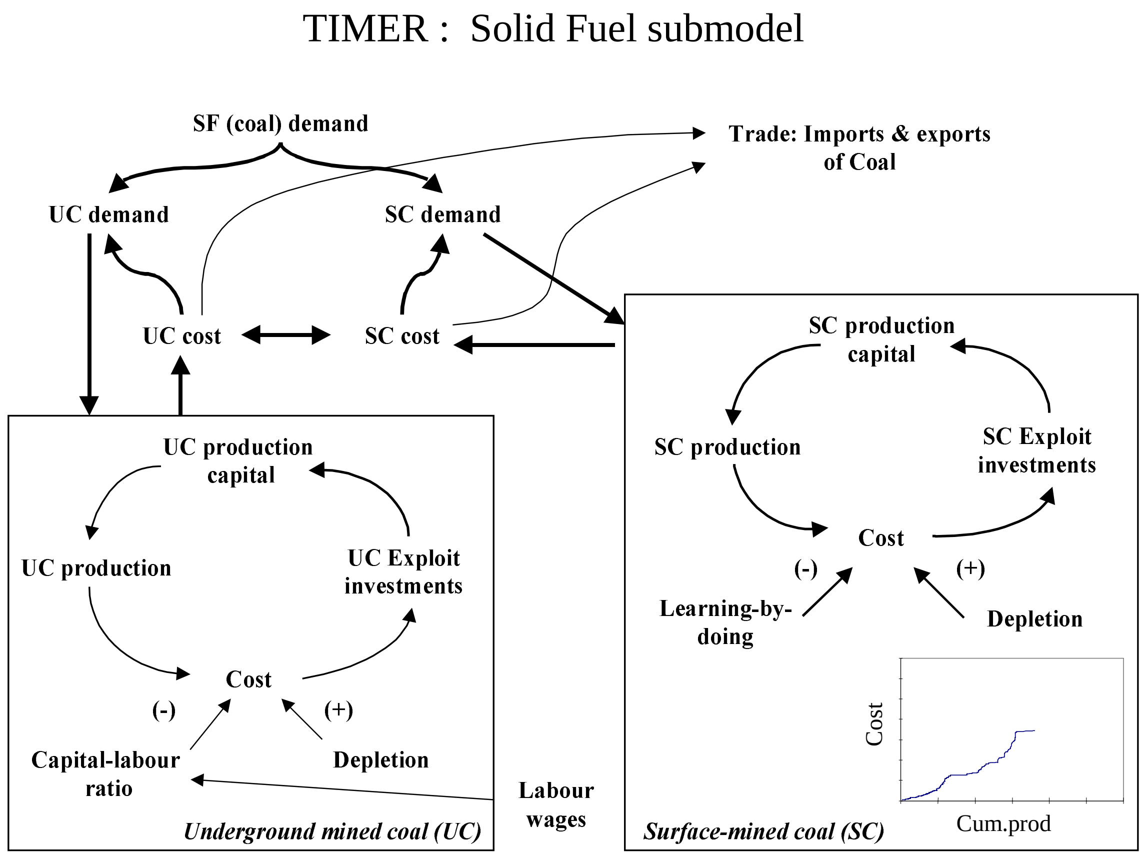

Figure 5.2: Overview of the solid fuel submodel

5.3.2 Solid fuel demand and trade

The demand for solid fuel in TIMER is determined on the basis of secondary coal demand (ED-submodel, *Chapter 3*), the need for solid fuel in electricity production (EPG-submodel, *Chapter 4*), the demand for coal for energy conversion purposes (e.g. to produce synfuels) and an additional factor to account for losses and energy sector consumption [44].

[43] It was claimed that at oil prices in the order of 30-40 1979-US $/bbl would allow commercial coal liquefaction; gas from coal might become available at prices of 8-9 $/GJ if coal is available at mine-mouth cost of about 1 $/GJ (Edmonds, 1985).

[44] Demand for fuels is information which generates action in the supply models such that demand can be met – with a few possible exceptions – and is met by supply. For this reason we use demand and use interchangeably.

$$CoalDem = (1+\tau 1)*(SE + FE + EC) \qquad \text{GJ/yr} \qquad (5.3)$$

with CoalDem the total domestic demand for coal, SE secondary coal demand including for non-energy purposes, FE coal for electricity production, EC the amount of coal used in energy conversion processes[45] and the factor τ1 represents transformation losses between these distribution nodes and domestic end-use.

On the basis of anticipated demand, coal companies decide to invest in coal producing capacity[46]. This planning is based on the Desired Coal Production, DesCP, which equals domestic coal demand but now including net trade, multiplied with an overhead factor τ1 and then extrapolated over a time horizon of TH years of the form $(1+z)^{TH}$ with z the annual growth rate in the past 5-10 years. In equation form:

$$DesCP = (CoalDem + CNTrade)*(1+z)^{TH} \qquad \text{GJ/yr} \qquad (5.4)$$

and CNTrade the regional expected coal export minus coal import. Coal trade is modelled in a simplified way. All regions compare the price of coal produced in their region – the Domestic Coal Price, DCPrice – with the price of imported coal from other regions – the Coal Import Price, CIPrice. The latter is calculated from that region's indigenous supply price plus additional transport costs derived from a regional distance matrix and a ton-km cost. A detailed description of the trade model is given in *Chapter 7*.

5.3.3 Solid fuel supply

The supply model model distinguishes between the resource base, CRB, and identified reserves, CRI. The first represents the ultimately recoverable coal at the technology and price levels throughout the simulation period. The second represents those parts of the resource base that have been discovered as part of the exploration process and are identified by the industry as technically recoverable.

For coal exploration, two alternative formulations are included in the model. The first formulation is used to reproduce the historic development of reserves. In this case, the exploration rate of the resource base, CDR, is simply based on an exogenous time-series. The alternative formulation, used both for historic simulations and the future, is to use the desired Reserve Production Ratio, RPR_{des}, which is an indicator widely used in industry. If RPR_{des} exceeds RPR_{act}, exploration efforts are accelerated.

Next, the amount of investment needed in regional coal production is determined. This is based on the Desired Coal Production and the assumedly constant rate at which existing capacity is taken out of production. Given the production cost of underground- and surface-mined produced coal – the calculation of which is described below, a multinomial logit function is used to determine which part of the additionally required capacity is invested into underground mining. The market share of the two different coal production modes are based on the expected

[45] The amount of coal used for energy conversion is simply given by scenario files. EC has to be included in historic calibration of certain regions (e.g Southern Africa).

[46] Oil, gas and electric power use purchased by the coal industry are not accounted for c.q. included in the energy use of the industrial sector.

production costs, assuming that in additional 5% of the totally available resources is used [47]. Normally, these expected costs will be very close to the actual production costs; divergence only occurs in case of sudden change in the long-term supply costs curve (depletion of cheap resources).

$$IMSC_{uc} = \frac{CCost_{\exp,uc}^{\;-\lambda_{uc-sc}}}{CCost_{\exp,uc}^{\;-\lambda_{uc-sc}} + CCost_{\exp,sc}^{\;-\lambda_{uc-sc}}} \qquad (5.5)$$

Capacity is first ordered, then constructed, which represents a delay of 3-5 years for capacity expansion. The cost of underground-mined coal, $CCost_{uc}$, and surface mined coal costs, $CCost_{sc}$, are discussed below. Using the capital-output ratio, the required investments can be calculated [48].

Underground Coal (UC) mining

The investments add, with a delay, to the coal producing capacity CPC_{und} – partly to replace the depreciated capital. In underground coal mining we use a Cobb-Douglas production function in capital and labour. The coal production $Cprod_{uc}$ equals the product of the installed production capacity, UCPC, and a Capacity Utilization Multiplier CUM which is a function of the ratio of total coal demand, CoalDem, and total coal production capacity, CPC. The actual coal production equals coal production capacity, unless the ratio between coal demand and coal production capacity exceeds 0.9 in which case the coal capital utilisation rate increases to 1.0 for a capacity shortage of 20%. Thus, capacity shortage allows a further production increase up to a certain point, reflecting short-term equilibration processes. The resulting equation for the underground coal production is:

$$UC\mathrm{Pr}od = UCPC * CoalCapacUtilFrac(CoalDem / CPC) \qquad \text{GJ/yr} \qquad (5.6)$$

This is produced unless the identified reserve falls short in which case price signals will cause additional exploration and/or imports.

In calculating the production costs, we postulate a Cobb-Douglas production function with a substitution coefficient between capital and labour θ and a depletion multiplier which is a function of the fraction of cumulative production, CumCProd, plus identified reserve, UCRI, on the one hand and the initial coal resource base, UCRB, on the other hand. Given the relative factor prices (GDP/cap related labour wages and annuity rate[49]), the optimal or required capital-labour ratio, RCLR, is calculated. With a delay this leads to adjustment in the labour force. This response ensures lowest-cost production in the longer run by adjustments in the form of mine mechanisation. The Required Labour Supply, RLabS, then becomes:

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[47] Expected production costs are used instead of real production costs to simulate that investors do have some knowledge about the regional long-term supply costs curve.

[48] In an earlier version, we used a formulation in which capacity expansion depended nonlinearly on the rate of return on investments as calculated from the difference between coal revenues and coal costs (Vries, 2000; Vries, 1999; Berg, 1994). This formulation turned out to give instabilities in some regions, probably reflecting the limited validity of this US-based approach..

[49] The annuity factor is defined in the usual way as a = r/(1-(1+r)**(-ELT)) with r the discount rate c.q. interest rate and ELT the economic lifetime of the investment.

$$RLabS = LabS_{1971} * (\frac{UCPC}{UCPC_{1971}}) * (\frac{RCLR}{RCLR_{t=1971}})^{-\theta} * (\frac{UCDeplM[1-(CumC\Pr od_{und,t}+UCRI)/UCRB_{1971}]}{UCDeplM[1-(CumC\Pr od_{und,1971}+UCRI_{1971})/CRB_{1971}]})^{1/(1-\theta)} \quad \text{man yr/yr} \quad (5.7)$$

The associated capital costs is set equal to the annuitised Capital Output Ratio COR_{und} which can be derived from the Required Capital Labour Ratio RCLR. This results for the coal production costs of underground mining operations in:

$$UCCost = (UCWages + a * RCLR) * RLabS / UCPC \quad \text{\$/GJ} \quad (5.8)$$

The coal companies are assumed to anticipate the rise in capital-output ratio as a consequence of depletion, using a time horizon of 10-20 years. This avoids overshoot behaviour in regions with limited low-cost resources.

Surface Coal (SC) mining

In the case of surface coal mining, labour costs are assumed to be a fixed and small fraction of the capital costs. The increase in the fraction of resources produced, CPCum/CRB_i, will tend to increase the capital-output ratio for surface coal mining, COR. At the same time, we assume that learning-by-doing tends to reduce the capital-output ratio due to innovations and economies of scale. Consequently, coal production from surface coal mining capital is:

$$SC\Pr od = SC\Pr odCapac * CoalCapacUtilFrac(CoalDem / CPC_{tot}) \quad \text{GJ/yr} \quad (5.9a)$$

$$COR_{surf,t} = COR_{1971} * SCDepl_{surf}[1-(CumC\Pr od_{surf,t}+SCRI)/SCRB_{1971}] * (\frac{CumC\Pr od_{surf,t}}{CumC\Pr od_{surf,1971}})^{-\pi})$$

$$\text{\$/GJ/yr} \quad (5.10a)$$

$$\text{SCCost} = \text{a} * COR_{surf,t} \quad \text{\$/GJ} \quad (5.10b)$$

with π the learning coefficient (cf. Chapter 9), and CoalCapacUtilFrac and SCPC respectively the Capital Capacity Utilization Multiplier and the Surface Coal Production Capacity. $COR_{surf,1971}$ is the initial output capital ratio. The function SCDepl is the surface coal equivalent of the depletion multiplier for underground mining (cf. Eqn. 5.7). Mining costs are equated to annuitised capital costs, that is, As with underground coal, the coal companies are assumed to anticipate rising costs due to depletion.

Solid fuel costs and prices

The capital costs of coal are calculated as an annuity factor times the production capital stock, divided by the annual production. As is clear from the previous discussion, in underground mining the labour costs are included and the wage rate is set equal to a fixed fraction of per caput income which is an exogenous driver. The cost of underground-mined coal are then calculated as the sum of annuitised capital costs and the product of labour force and wage rate. For surface-mined coal, labour costs are included as a fraction of capital costs. Given the cost of underground and surface coal, UCCost and SCCost, the Average Coal Cost ACC is determined as a weighted average.

The next step is to incorporate the capital requirements and resulting add-on costs for transport and upgrading of coal. This is modelled in a very simple way in the form of a fixed multiplier Coal Processing Factor CPF. Conversion losses e.g. due to assumed gasification/ liquefaction schemes, can be accounted for by this same factor. It is assumed that 90% of these additional costs are in the form of annuity payments for investments.

The resulting domestic price of coal depends on the weighed average of underground- and surface-mined coal, a Desired Gross Margin DGM, an overhead factor set at 1.1 and PriceCapacityUtilMult PCUM which increases nonlinearly above one if demand exceeds capacity and reflects the difference between a ‘buyers market’ and a ‘sellers market’. This results in:

$$DomCPrice = (1 + DGM) * 1.1 * PCUM\left[\frac{CoalDem}{CPC_{und,r} + CPC_{surf,r}}\right] * CPF * ACC \quad \$/GJ \qquad (5.11)$$

with CPC the Coal Producing Capacity and ACC the Average Coal Cost. The value of DGM is set at 1.3 to 1.4, representing an industry average marking up rate. The additional factor 1.1 represents additional costs; in future work we hope to expand this factor to include explicitly processes related to coal washing, environmental and safety measures etc.

As described in the beginning of this chapter, in case the domestic coal price DCP is higher than the price of imported coal from other regions, part of the demand will be met by imports. The resulting market price is defined as the market share of imports and domestic production times their respective prices.

5.4 Traditional fuel model implementation and model calibration 1971-1995

Based on historical calibration the following values are used within the traditional fuel formulation for 1995 (cf. Eqn. 5.1 and 5.2). In all regions, a minimum traditional biofuel consumption of 0.3 GJ per capita is assumed (except for Japan). The influence of changes in the prices of alternatives (oil) is assumed to be very small. The model equations are only used from 1995 onwards – until 1995 the model simply uses scenario files.

Figure 5.3 shows the results for one scenario from 1995 onwards. In the 1971-1995, data suggests that there might have been a small decline in per capita consumption of traditional biofuels (due to substitution to commercial fuels). In our current model setting, this trend is slightly accelerated after 1995. The trend seems, however, to be in line with the projections of other modelling and scenario groups.

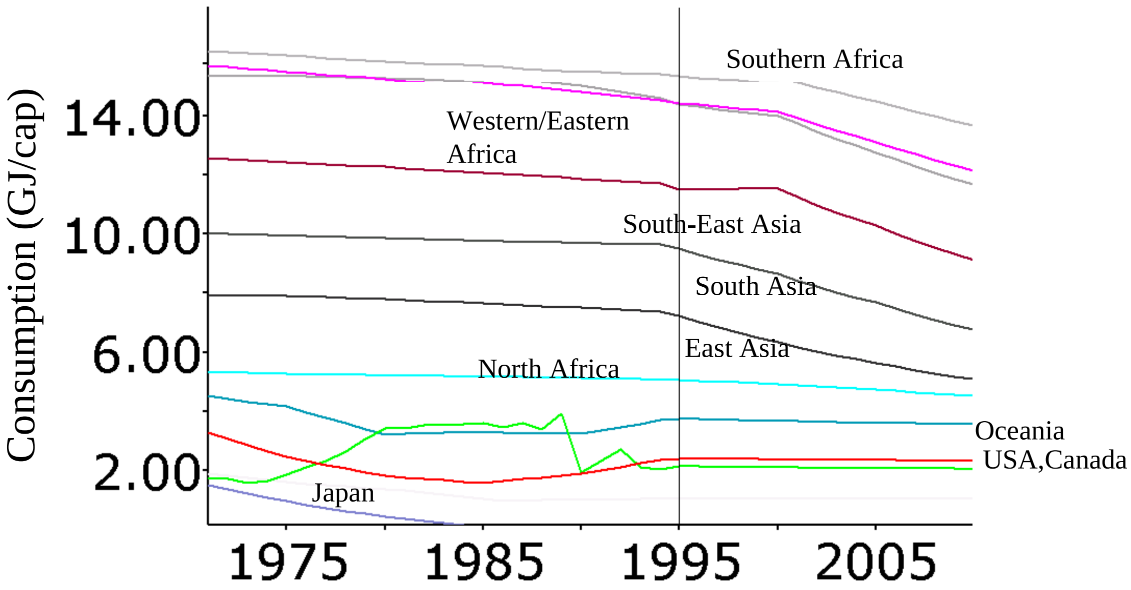


Figure 5.3: Results of residential use of traditional biofuels.

Table 5.1 Values for traditional fuel model

	TFConspc_sat (GJ/capita)	Income elasticity ε1	Urbanisation factor ε2	Price alternative ε3
Can	0.3	-0.2	-0.20	0.02
USA	0.3	-0.2	-0.20	0.02
Cam	0.3	-1.3	-0.40	0.02
Sam	0.3	-2.5	-0.50	0.02
NAfr	0.3	-0.2	-0.30	0.02
WAfr	0.3	-0.2	-0.24	0.02
EAfr	0.3	-0.2	-0.24	0.02
SAfr	0.3	-0.2	-0.24	0.02
WE	0.3	-0.4	-0.20	0.02
EE	0.3	-0.2	-0.20	0.02
FSU	0.3	-0.2	-0.20	0.02
ME	0.3	-0.3	-0.30	0.02
SAs	0.3	-0.1	-0.16	0.02
EAs	0.3	0.0	-0.12	0.02
SEAs	0.3	0.0	-0.11	0.02
Oc	0.3	-0.2	-0.20	0.02
Jap	0	-3.0	-0.20	0.02

5.5 Solid fuel model implementation and model calibration 1971-1995

We compared historical data from statistical sources with the corresponding output variables shown in *Table 5.2*, to implement the model for the 17 regions. The model parameters/ variables which can be varied to improve the fit with historical data or to (re)construct scenarios are shown in *Table 5.3*. *Table 5.4* lists some additional parameters/variables which are usually not varied because they are fairly constant or insignificant. There is also a set of initialisation parameters which have also been, directly or indirectly, derived from historical data. These relate largely to the initial (1971) capital-output ratio, labour and production capacity.

In first instance, the calibration of the coal module is done with historical data on regional coal production. This is equated to demand for coal; this demand generates investments into underground and surface coal (UC/SC) mines. If there is a capacity shortage, prices go up and capacity will expand. The cross-price elasticity $\lambda_{sc\text{-}uc}$ determines which fraction of available investments goes into surface mines. This in turn depends on surface-mined coal costs which change with depletion and innovations. It also depends on the underground-mined coal costs; these are a function of the cost increase from underground depletion UCDeplM, on the UCRelLabCost and on the capital-labour ratio CLR. Both the depletion multipliers are derived from the - scarce – information on available estimates of recoverable coal resources.

A detailed model calibration for the USA has provided most of the parameter values and relationships (AES, 1990; Berg, 1994; Naill, 1977). It turned out that the fraction of revenues re-invested had to be increased, in combination with the possibility to produce 110% of rated output capacity, to avoid capacity shortages. The initial capital-output ratio for surface coal mining is set relatively high, possibly reflecting the longer history or other effects. Also for Canada a rather detailed calibration has been performed, which indicates that production and cost trends can be reproduced quite well with assumptions based on the literature. However, there was a persistent tendency to have a capacity shortage in the demand surges in the 1980s. This has been corrected by lifting the fraction of revenues re-invested with respect to the original US-based curve (Naill, 1977) and by assuming that existing mines can produce up to 110% of their rated output capacity. A typical trade-off in the calibration is that higher learning-by-doing and lower initial capital-output ratios for surface coal mining has the same effect as an increase in the relative labour cost for underground mining. For the other regions model calibration was confronted with a paucity of data. Moreover, in several regions coal industry has been subject to stringent central planning which our model can only cope with in an indirect fashion. In similar fashion we have been performing sensitivity analyses to make adjustments for other important coal producing regions such as the Former Soviet Union, OECD and Eastern Europe, India and China.

Table 5.2 Model variables used for historical calibration for SF-model. Model parameters (see Table 5.1) are varied to get the best fit between simulated and historical time-series. See Appendix A for data sources).

Variable	Subscript	Description	Unit/Domain
UCProd	rt	Coal Production (total of saleable coal, at minemouth)	GJ/yr
SCProd	rt, und/surf	Coal Production from Underground Coal (UC) or Surface Coal (SC) mining	GJ/yr
CPrice	rt	Price of coal (both domestic and international)	$/GJ
CRI	rt	Identified coal Reserves	GJ

r=region, t=time

It should be stressed that the procedure of using the historical time-series on coal production and coal prices to change the parameters in order to reduce the difference between simulated and historical data is not unambiguous (cf. Chapter 4 on the ED-submodel). For example, an increasing proportion of surface-mined coal costs can result from shallow, i.e. cheap reserves, from fast learning, from high responsiveness to competition from underground-mined coal, or a combination of all three. Rising costs of underground-mined coal are due to a combination of depletion and labour-cost reducing mechanisation.

Table 5.3 Model parameterss used for historical calibration and, if in bold, also for scenario (re)construction for SF-model. Parameters are varied around a default value within a certain domain.

Variable	Subscript	Description	Unit/Domain
λ		elasticity between investing in UC or SC mining (if λ_{UCSC} =0 cost difference between UC and SC plays no role)	0-10
CDR	Rt, und/surf	Coal Discovery Rate indicates how much coal is discovered	GJ/yr
UCRelLabCost	r	ratio between labour cost in UC mines and average per caput consumption	0-5
UCDeplM	r	UC depletion multiplier reflects rise in capital-output ratio in UC mining with increasing depletion (Y/R)	0-1
COR	r, t=1970	initial output-capital ratio in SC mining	0-10 GJ/$
π	r,oil/blf	learning coefficient in SC mining	0.8-1
TCsp	r	Specific Transport cost	$/ton-km
TrPDiffFactor	r	Factor with which distance between regions is multiplied to represent trade barriers	0.5-5
ImpConstr	r	Exogenous constraint on fraction of OilDemand met by imports	0-1
ExpConstr	r	Exogenous constraint on how many times domestic production can be exported	>0

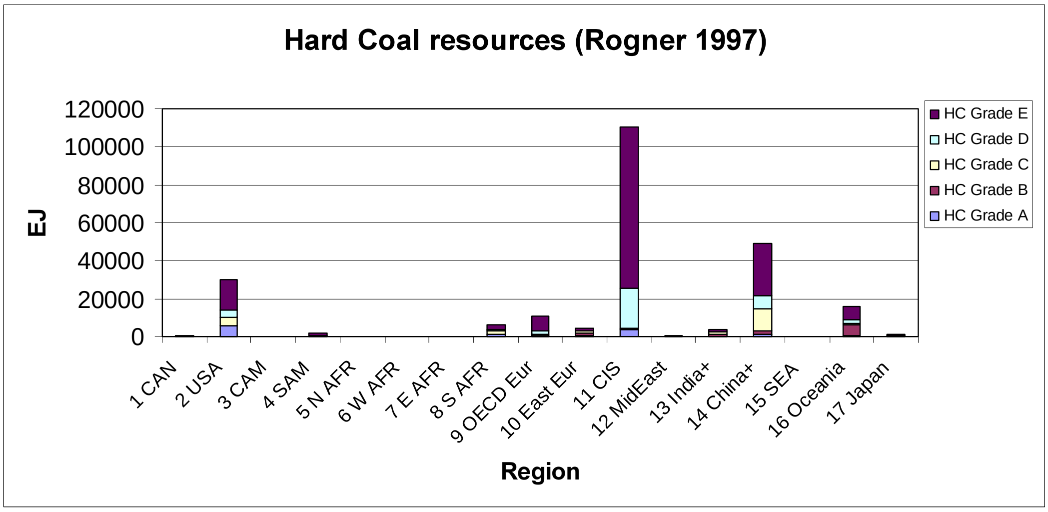
r=region, t=time

Table 5.4 Model parameters for which historical values and/or fixed assumptions are used. Parameters are given a default value based on exogenous input time-series or on literature.

Variable	Subscript	Description	Unit/Domain
PCUM	r	Price Capacitry Utilization Multiplier gives response of price to surplus/ shortage of capacity	(fixed)
CUM	r	Capacity Utilization Multiplier	
TLT	r,und/surf	Technical LifeTime for capital stocks	10 yr
CPC	r, t=1971, und/surf	Coal Producing Capacity in initial year 1971	$, partly from literature, partly from calibration
CRB	R,und/surf	Ultimately recoverable coal (conventional and unconventional)	GJ
OilDeplM	r	Functional of Capital-Output ratio for Crude Oil production as function of (ORB+ORI)/ORB	(cf. Figure 6.1)
θ	r	substitution elasticity capital-labour in UC mining	0.53 (fixed)
CPF	r	Coal Processing Factor accounting for additional cost in conversion and transport	>1 (default 1.4)
$\tau1$, $\tau2$	r	factors with which demand are multiplied to account for conversion and transport losses	>1 (default 1.1)
UCPH	r	UC Planning Horizon for demand forecast	2-10 yr (default 10 yr)
SCCT	r	SC Construction Time for new mines	2-10 yr (default 3 yr)

r=region, t=time

Resources.
Resource data for the 17 regions can be derived from a variety of literature sources but most of them are aggregate and give hardly any estimate of recovery costs (Rogner, 1997; Edmonds, 1985; Fettweiss, 1979; ECN, 1995; Kassler, 1994; Kaya, 1993; Matsuoka, 1994; McLaren, 1987; WEC, 1989). We mainly used Rogner's estimates. He distinguishes hard coal and brown coal and within each of these five different grades (A-E). We use the total sum of all these which adds up to a total of 6246 Gtoe. *Figure 5.4* gives the resources of hard coal (bitumenous) and brown coal (subbitumenous and lignite) for 5 categories and 17 regions. The subdistribition in as far as needed from the Rogner-data has been based on the 1988-proved reserve distribution (WEC, 1989). It is seen that the largest amount of coal reserves and resources are hard coal and that they are concentrated in a few regions.



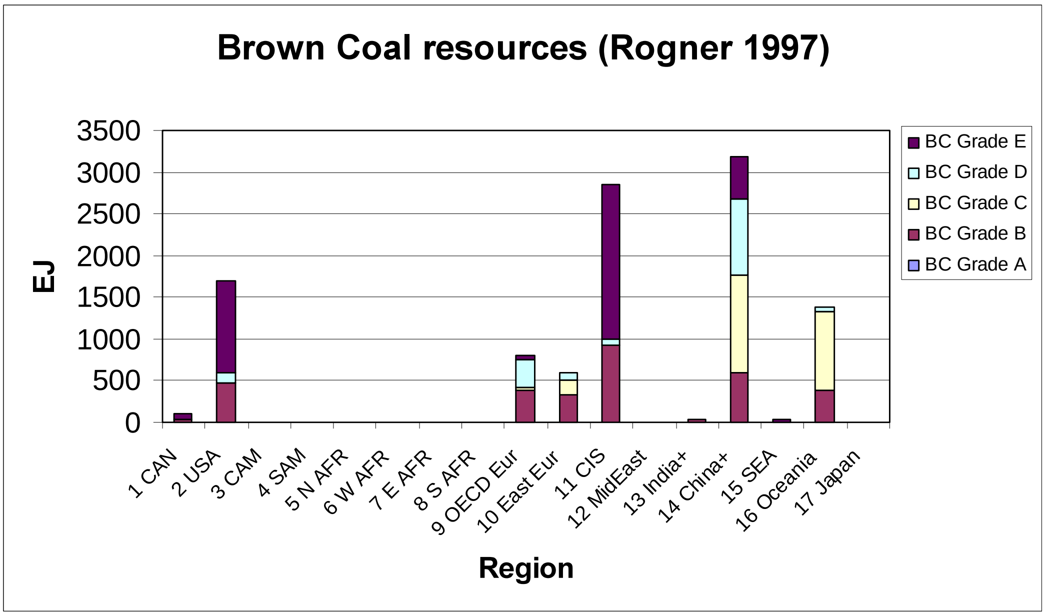


Figure 5.4: Hard coal (upper) and brown coal (lower) ultimately recoverable resources per region and grade (Source: Rogner 1997). Note the difference in scale.

If we assume that there is a 10% increase in production cost going from the category BC A – HC A – BC B – HC B … BC E – HC E, it is seen that the major potential suppliers of large amounts of coal at only slowly rising marginal cost (respective to present levels) are USA, CIS, China and Oceania. Generally speaking, brown coal can more easily – and only profitably – be mined in opencast mining. The assumptions on the total resource base (HC+BC, all Grades) are used to derive the depletion multipliers DeplM from *Figure 5.5a-b*, which show the factor with which the COR is multiplied vs. the fraction of the initial resource left. The depletion equivalent for surface mining is estimated from the share of brown coal in the total resource base and, in a similar way as for underground coal, from the grade classification (cf. *Table 5.4*). It is also based on a crude correlation between the 1995-share of surface mining in production and the share of brown coal in the total resource base. However, this part of the model needs better data for a more accurate assessment of coal use dynamics.

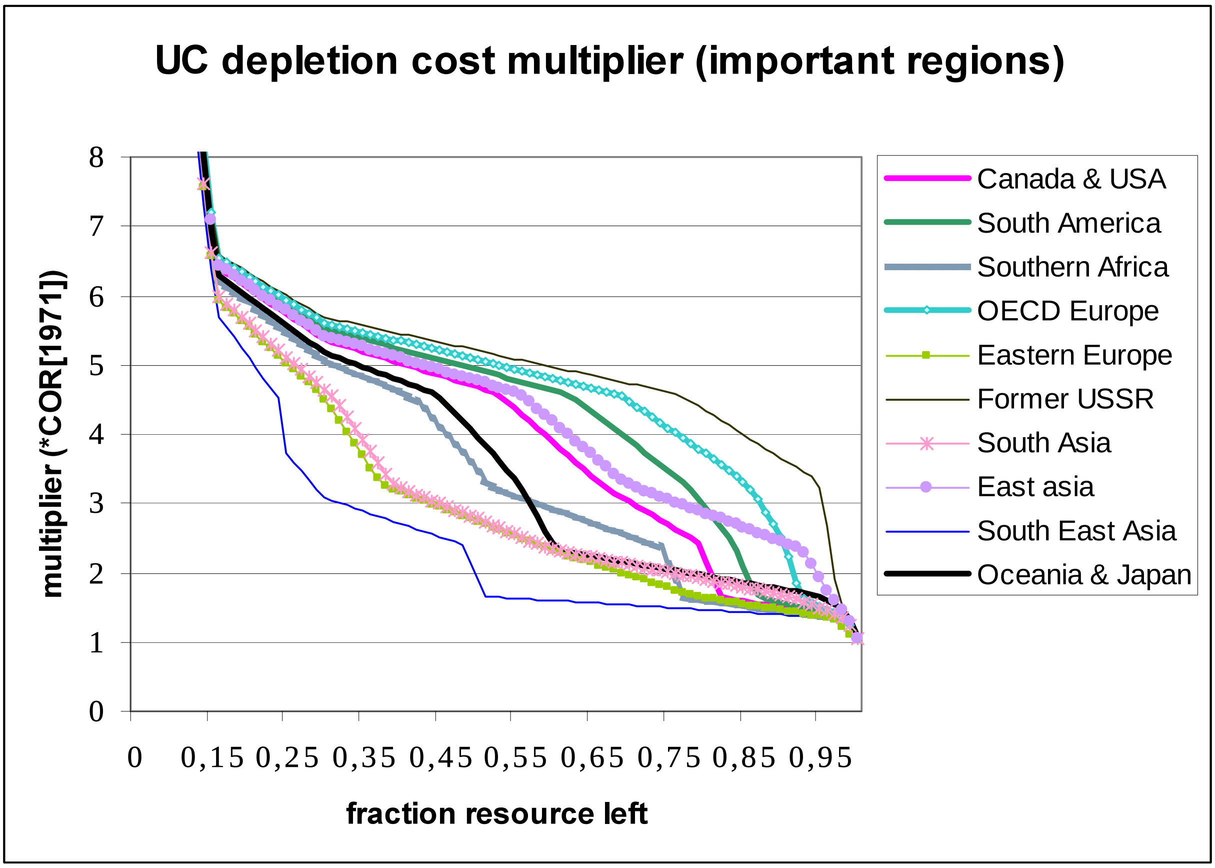


Figure 5.5a: Underground coal (UC) depletion multiplier: factor by which Capital-Output Ratio is divided as the fraction of remaining resource and initial resource base declines. Regions with very small coal resources are omitted..

Costs.

Costs depend mainly on the capital-output ratio's as a function of depletion, capital-labour substitution – and hence labour wages – and learning-by-doing. More research is needed on this parameter which reflects the way in which coal mines are operated. Labour wages are determined by multiplication of the exogenous factor UCRelLabCost.

The initial Capital-Output Ratio's for SC-mining, COR, as of 1971 are also given in *Table 5.5*. The learning coefficient for SC-mining, π, is a function of time and varies between 0.84 and 0.98 and is, for 1971, shown in *Table 5.5.* As cumulated production increases, the COR(1971) will start falling, the faster the lower π. In the previous model version, the fraction available for investments was related to coal revenues; this appeared to give unstable results (cf. Naill, 1977). Investments in underground and surface coal mining are now based on their relative costs by way of a multinomial logit parameter, λ, and it is assumed that the required capacity will be installed. The value of λ is a medium value of about 3 for all regions, partly because there was no data available to make better estimates. Delivery costs are also influenced by the losses in processing (upgrading, transport etc.) which is incorporated with the overhead factor CPF. Note that the time-dependency of several of these variables (UCRelLabCost, π, CPF) is based on the calibration experience and allows implementation of (aspects of) scenarios.

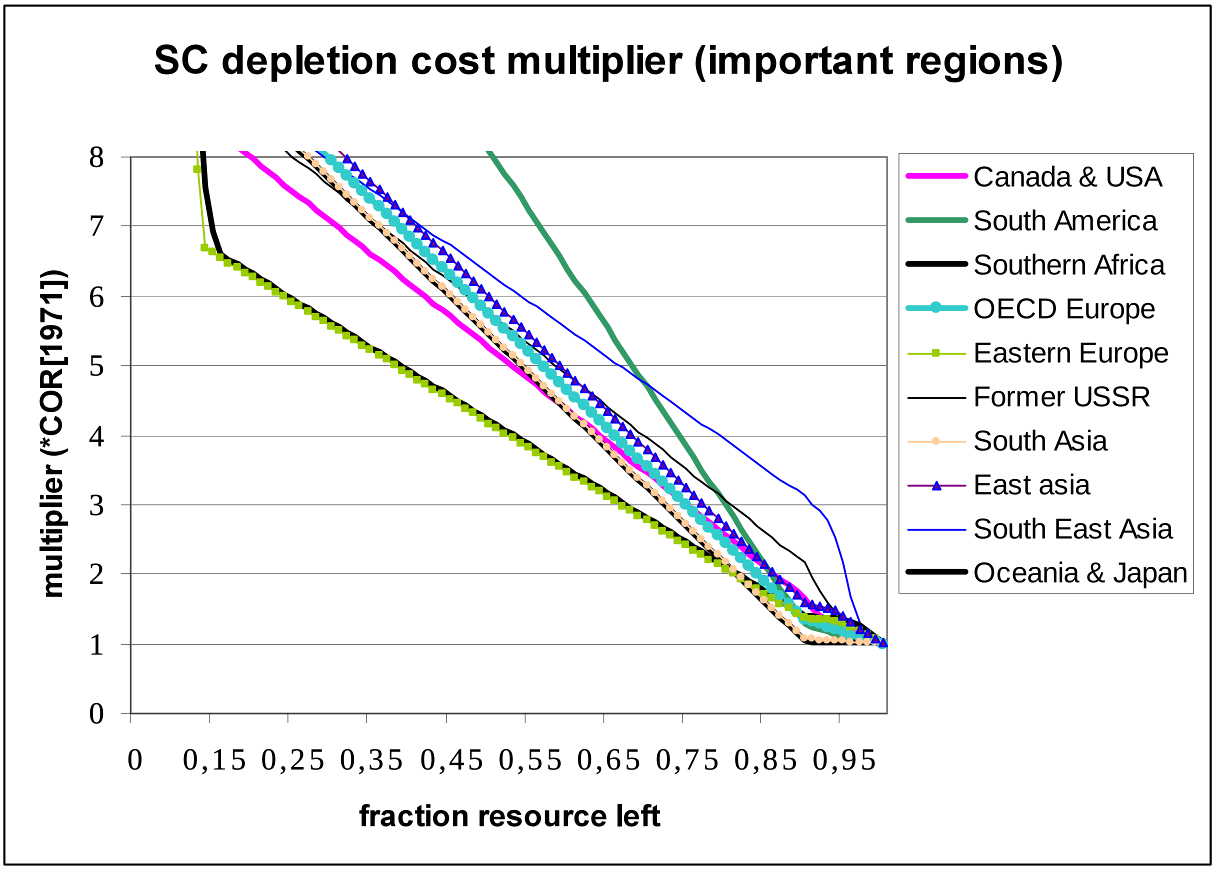


Figure 5.5b: Surface coal (SC) depletion multiplier: factor by which Capital-Output Ratio is multiplied as the fraction of remaining resource and initial resource base declines (Eqn. 5.10). Regions with very small coal resources are omitted.

In the calibration we have also used information on (world) market prices. Data from IEA Coal Information (IEA, 1991) suggest the following price range for coal, in $/GJ (*Table 5.6*). The costs at the mine include operating and capital charges (15% rate of return). Cost at export harbour include rail/barge costs and loading. All cost estimates are for a representative mine/route; the price ranges are up to 25% around these values. Price for coking coal may be significantly higher than for steam coal. Other important parameters, such as in the coal trade formulation, are discussed in *Chapter 7*.

5.6 Calibration results 1971-1995

In combination with calibration of the coal trade model, the solid fuel supply model is quite well able to reproduce the main historical trends. *Figure 5.6* shows the coal production in the 17 regions, both for historical and simulated data– and there are only minor differences. Obviously, the (dis)agreement is crucially dependent upon the model reproduction of coal demand (cf. Chapter 3) as it is assumed in the model simulations that demand is supplied at (almost) all times.

Table 5.5 Parameter values for SF-model calibration

	Underground coal		Surface coal		General	
Region	Initial labour supply	UCRelLabCost (2000)	Intial COR (1971)	Learning coeff (π)	Mult log par (λ)	Coal processing factor CPF (2000)
Can	4000	1	4.0	0.88	3	0.1
USA	110000	1	3.5	0.92	3	0.1
Cam	9000	1.1	5.0	0.90	3	0.3
Sam	16000	1.1	6.7	0.90	3	0.3
NAfr	13500	1	150	0.94	3	0.4
WAfr	3600	1	10	0.94	3	0.4
EAfr	90	1	150	0.94	3	0.4
SAfr	150000	1.1	5.1	0.90	3	0.1
WE	230000	1	9.0	0.92	3	0.3
EE	300000	1.1	3.0	0.94	3	0.3
FSU	600000	1.1	3.25	0.94	2.5	0.3
ME	28000	1.1	4.8	0.90	3	0.7
SAs	445000	1.2	3.5	0.90	3	0.7
EAs	2400000	1.3	5.75	0.88	2	0.7
SEAs	300	1.1	4.0	0.90	3	0.5
Oc	57500	1	4.9	0.96	3	0.1
Jap	25000	1.1	10	0.98	3	0.3

Table 5.6: Indicative coal prices (IEA, 1991)

Producing region	*Cost at mine*	*Cost at export harbour*	*Ocean transport cost*
AUS surface Q'l	0.43	1.25	0.25 (JAP) 0.45 (WEU)
AUS surface NSW	0.97	1.65	0.3 (JAP) 0.45 (WEU)
AUS underground NSW	0.76	1.57	0.3 (JAP) 0.45 (WEU)
US surface Appal	0.97-1.11	1.31-1.51	0.44 (JAP) 0.29 (WEU)
US underground Appal	0.71	1.49	0.48 (JAP) 0.22 (WEU)
US surface Wyoming	0.31	1.43	0.45 (WEU)
US underground Utah	0.82	1.73	0.30 (JAP)
Canada surface West	0.75	1.52	0.30 (JAP) 0.42 (WEU)
South Africa surface	0.35	0.86	0.36 (JAP) 0.32 (WEU)
Colombia surface	0.87	1.76	0.23 (WEU)

Obviously, at the regional level the divergences are somewhat larger. In the discussion here we concentrate on the USA and Southern Africa. The former is a region for which the current calibration of the model seems to work very well. *Figure 5.7* shows the results for both USA coal domestic demand and coal production. For both the historical and the simulated data, production is slightly higher than demand – indicating that the USA is a coal exporting region. The main trend discrepancy is in the period 1978-1988 which probably reflects the difficulty of reproducing the complex events in this period on the world oil market and its impacts on coal demand and trade.

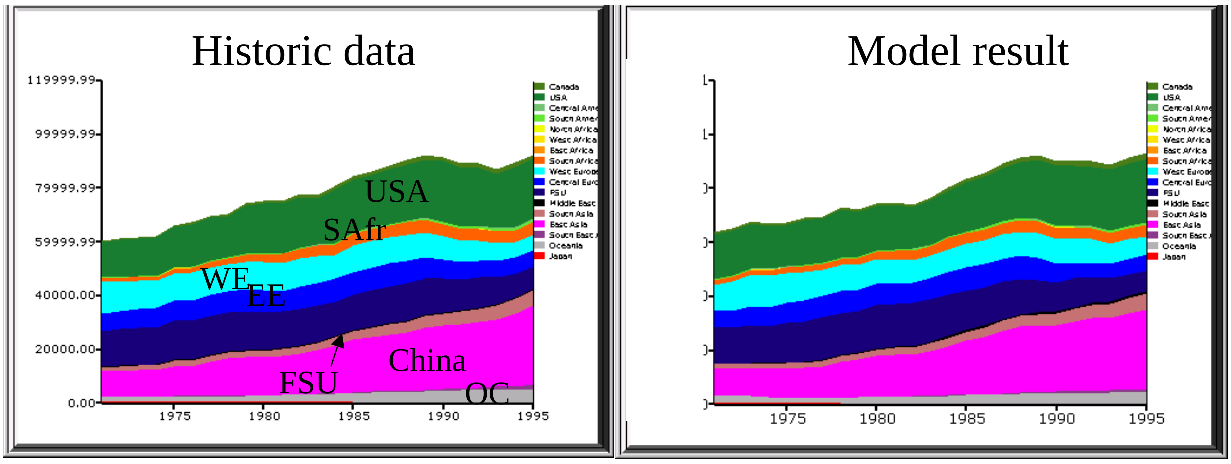


Figure 5.6: Comparison of historical coal production by region with modelling results

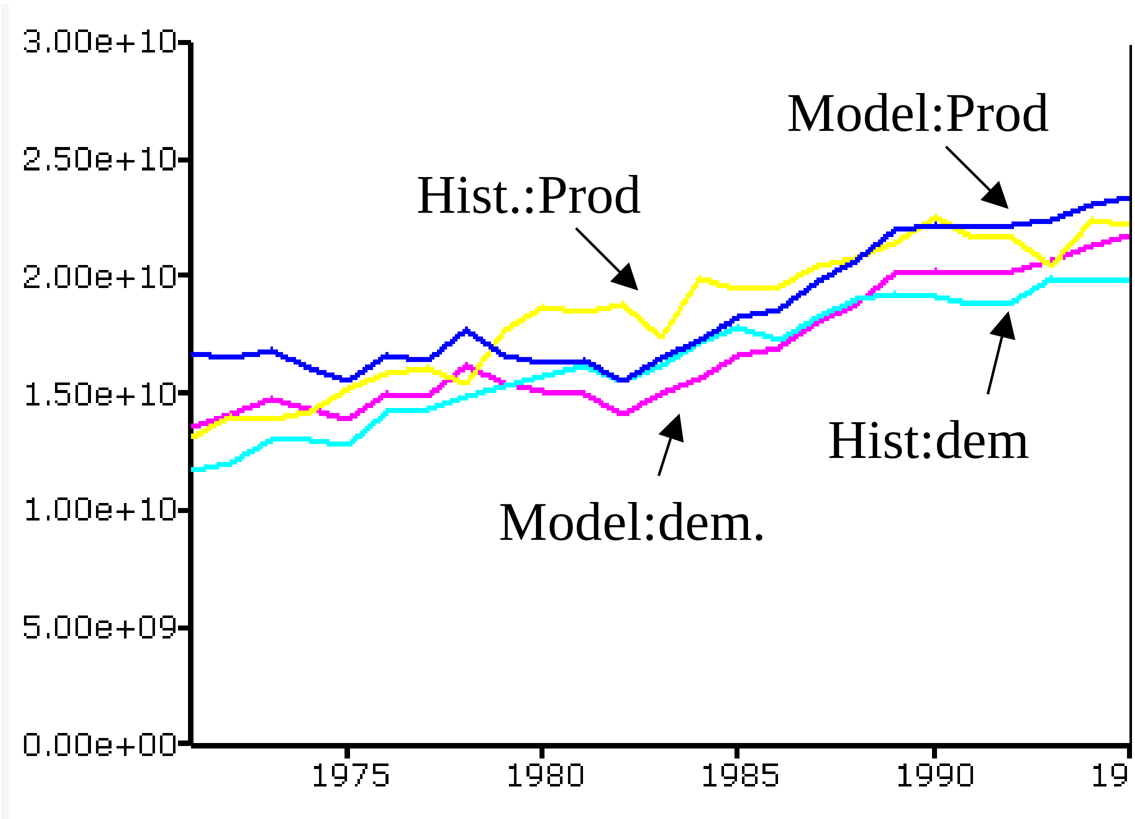


Figure 5.7: Coal demand and production in the USA; historical data and model result

Figure 5.8 shows coal production in both surface and underground coal mining for the USA. In many regions the share of these two modes of coal production are relatively hard to calibrate. They turn out to be relatively sensitive to small changes in their production cost ratio, which in turn need to be tuned in order to reproduce the international coal trade. Nevertheless, for the USA, the shares of underground and surface coal are reproduced quite well. For Southern Africa (*Figure 5.9*) the results are amongst the worst, with far too low surface coal output. Besides the limited reliability and definitional issues about historical time-series, we believe a major obstacle in getting a better fit was the interaction with the historical trade flows which also had to be close to historical data. One explanation for these findings is that the situation of

South African coal was exceptional both in terms of wage rates and export opportunities in the period before apartheid was abolished. Moreover, as in other regions, the empirical basis for separating underground mineable from surface mineable coal are rather weak.

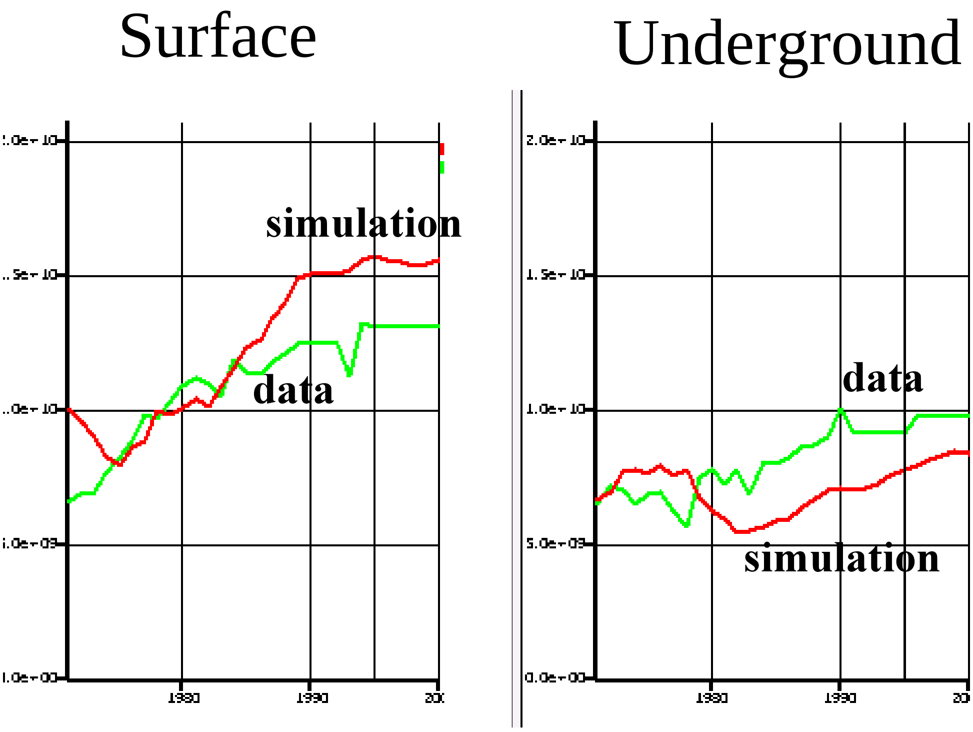


Figure 5.8: USA surface and underground coal production

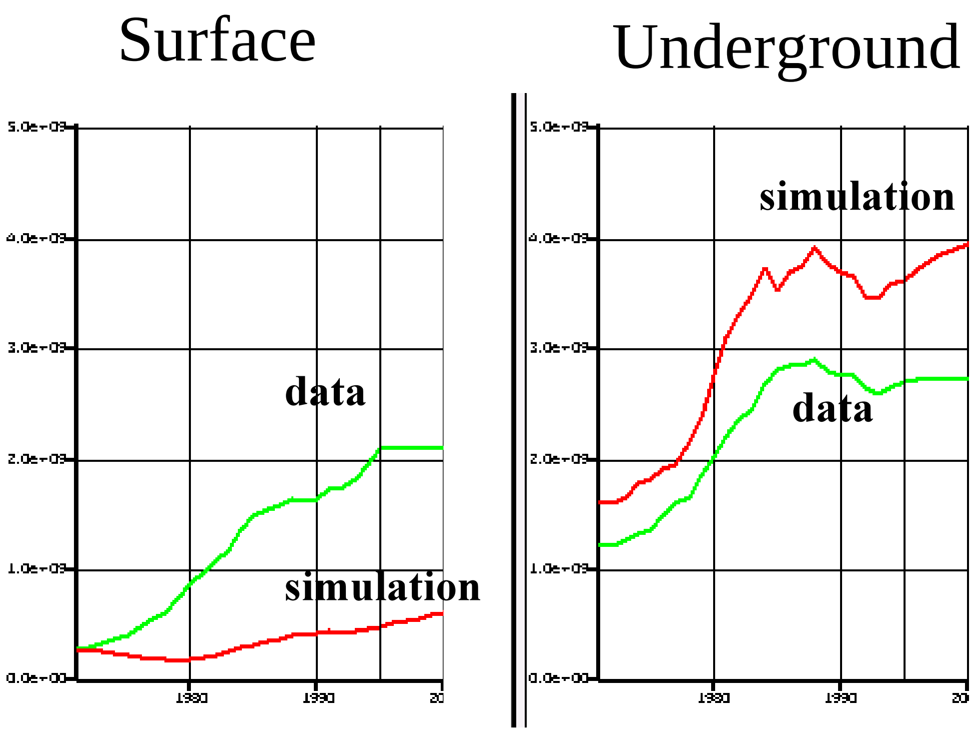


Figure 5.9: Southern Africa surface and underground coal production

In terms of prices, the trends in coal prices are reproduced fairly well in both regions (*Figure 5.10*). This suggests that the larger part of the demand-supply-trade dynamics is performing rather well and that the failure to reproduce surface mining output also has to do with our modelling of the investment decision.

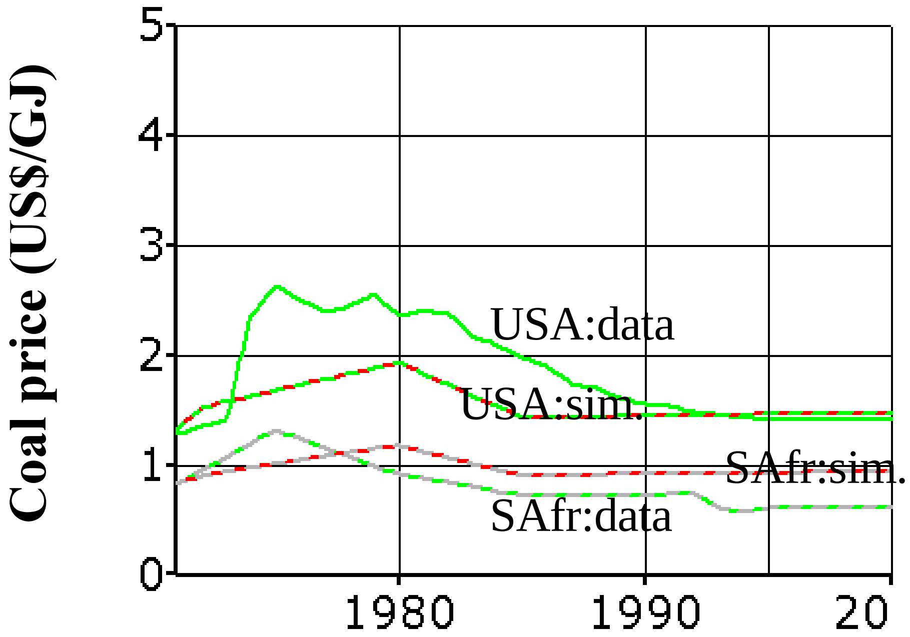


Figure 5.10 Coal prices in the USA and Southern Africa

5.7 Directions for future research

- We have introduced a distinction between surface and underground coal based on the relevance for emissions and the different dynamics for production costs. As it turns out, this formulation in combination with the coal trade module easily gives instabilities, for instance in a situation that the assumedly hard coal (underground) or brown coal (surface) gets depleted and a region has to switch from one coal production method to the other. Possible improvements are the dynamic transition from underground to surface coal mineable resources as a function of geological characteristics (thickness and depth of layers) and technology (digging machinery).
- In TIMER, coal is currently mainly used to produce solid fuels. However, coal can also be used to produce synfuels or other alternatives, possible in combination with clean coal technologies. Currently, we model 'synfuels' by a time-dependent exogenous scenario file – but it might be considered to more explicitly model these options. For instance, it can be desirable to construct a long-term supply cost curve on more parameters than estimated production costs only: distance to user or trade centres, special products or techniques as with coking coal or coal-bed methane etc.
- The modelling of traditional biofuels – and in particular the substitution with commercial biofuels – can be improved. Obviously, this is driven as much by the local resource situation – simulated to some extent in the IMAGE Terrestrial Environment System (TES) model – as by rational-choice market dynamics. The processes of urbanisation, of opening up of higher-income strata for commercial fuels such as kerosene and the informal exchange processes among the low-income segments in low-consumption regions should be better understood.

6. The Liquid Fuel and Gaseous Fuel supply submodels

6.1 Introduction

This chapter describes the supply models for liquid and gaseous fuels. These two submodels have basically the same structure, and describe how demand for liquid and gaseous fuels is met by fossil and biomass-based alternative fuels.

During this century, crude oil and a variety of fuels derived from oil have provided an increasing proportion of the world's energy needs. Oil and oil products are among the most widely traded commodities in the world with 80% of all oil produced being traded internationally (Subroto, 1993). During its exploitation there have been several warnings of impending oil scarcity, but – and possibly in response to such warning – new oil finds have always been enough to keep a rather steady ratio of 10-15 years between identified reserves and annual production. For the future, several (potential) alternatives exist, such as coal-based liquid fuels, biomass-derived fuels such as ethanol and deposits of non-conventional oil (oil shales and tar sands) which could become a viable large-scale alternative in the more distant future.

The production of liquid fuels requires a large and steady investment flow. Given the domination of private capital in the industry, oil business is dominated by market-oriented dynamics[50]. However, as the past has shown, national governments are important co-actors if only because in many countries, oil production and/or oil taxes are a large or even dominant source of government and export income (Gupta, 1995). From the perspective of energy demand, oil (products] is of special importance for the transport sector which is nowadays almost universally dominated by gasoline-, diesel- en kerosene-based combustion engines and turbines and which is growing relentlessly. Other important consumers of oil (products) are electric power plants (cf. EPG-model in Chapter 4) and industry.

Since the 1930s natural gas has become an important commercial fuel, first in the USA later in Europe and Russia. Its use was, among others, stimulated by discoveries of large reserves, foremost the giant fields in northwestern Europe and northern Russia. Convenience of use gives it a clear premium value. As result of increasing demand, flaring of natural gas is becoming less common but still accounts for an estimated 10% of world production. The reserve base of natural gas has grown faster than for crude oil: at present there is an abundance of low-cost natural gas fields. The main impediment for further introduction are the high transport costs and the need for large-scale and capital-intensive distribution networks. As with oil, there may be vast additional resources in the form of among others clathrates in deep reservoirs (Lee, 1988; Vries, 1989a).

Various alternatives exist for both liquid and gaseous fuels. Coal liquefaction is often mentioned as alternative for oil-based products, but up to now it has not become a commercially viable option at today's energy prices. A more attractive option apparently is conversion of coal into Synthetic Natural Gas (SNG) to be burnt in integrated systems for

[50] The combined annual sales of four multinationals in the oil-system: Exxon, Royal Dutch/Shell, General Motors and Ford in the early 1990s - about 450 10^9 $ - exceeded the GDP of the 1.1 billion people living in India and Indonesia.

[51] This is not only true for OPEC-countries like the Arab countries, Venezuela, Nigeria, Mexico and Indonesia, but also [for oil and gas] for countries like Norway, Britain and The Netherlands.

large-scale electric power generation. Another potential source of liquid and gaseous fuels is biomass. At the moment, the most important case is the sugar-cane derived ethanol which has reached a sizeable market penetration in Brazil. Both ethanol and methanol are also being used in the United States in a mixture with gasoline. In the present LF- and GF submodel, we consider biomass-derived fuels as alternative. This implies that land will be an important production factor if biofuels are going to penetrate the market.

6.2 The Liquid Fuel (LF) submodel

The Liquid Fuel (LF) model describes the way in which demand for liquid fuels is satisfied by crude oil and derived products or by alternative biofuels. It resembles the Solid Fuel (SF) submodel in several ways and is almost identical to the Gaseous Fuel (GF) submodel. In all three Fuel Supply submodels, there are exploration and exploitation processes with depletion and learning-by-doing and a capacity-related price mechanism. The LF- and GF-models also have an alternative, biomass-based fuel referred to as bio-liquid fuel (BLF) and bio-gaseous fuel (BGF). We discuss the LF-model in detail, whereas the description of the GF-model is confined to the last paragraph. *Figure 6.1* gives an overview of the model structure of the LF model. The basic loop simulates the demand for liquid fuels, the subsequent investments in crude oil production and exploration, and the increase in costs and prices as soon as technical innovations no longer offset the depletion effects. In the process, biomass-derived fuels become more competitive and attract an increasing fraction of the investments which further accelerates their competitiveness. Interregional trade in oil is dealt by using the same kind of equations as for coal, natural gas and biofuels. Regions compare the price of oil produced in their region – the Domestic Oil Price – with the price of imported oil from other regions – the Oil Import Price. The latter is calculated from that region's indigenous supply price plus additional transport costs derived from a regional distance matrix and a ton-km cost. On top of this, a simplified mechanism of oligopolistic price formation is included. A detailed description of the trade model is given in Chapter 7.

Parts of the Liquid Fuel (LF) model are based on previous energy models, especially on descriptions of the Fossil-2 model (AES, 1990; Naill, 1977), on a detailed systems dynamics model of the US petroleum sector by (Davidsen, 1988) and on research by Sterman (Sterman, 1981; Sterman, 1983; Sterman, 1988).

6.2.1 LF demand and trade

The demand for liquid fuels is modelled in the ED (*Chapter 3)* and EPG *(Chapter 4)* submodels and consists of 1) secondary liquid fuel demand SE_{rsj}, 2) fuel demand for non-energy use (e.g feedstocks), 3) liquid fuel demand for electricity generation FE_{rj}, 4) bunker oil fuel demand and 5) the net result of energy conversion processes (input and products from processes such as synfuel production from coal). The total liquid fuel demand can be divided into demand of Light Liquid Fuels (LLF) and Heavy Liquid Fuels (HLF); the former are the light oil products such as gasoline and kerosene, the latter the heavy fuel oils (see *Table 6.1*)[53]. The demand for HLF is assumed to occur mainly in the sectors industry, other and electric power generation. HLF-demand is calculated to be an assumed time-dependent fraction of demand for total liquid fuels per sector (*Chapter 3*). Total demand for liquid fuel, LFDem, is now (cf. Eqn. 3.15 and 4.13):

[52] Labour may be an important input, especially in low-labour-productivity regions. In fact, biofuels may initially only gain a competitive advantage - apart from strategic considerations - because it can absorb large amounts of cheap labour.

[53] In the transport sector, also the fraction of diesel and gasoline (both LLF) are recorded separately as this is relevant in our emission calculations.

$$LFDem = (1+\tau 1)(\sum_s (SE_s) + FE_{m=2} + BO + EC + NE) \qquad \text{GJ/yr} \qquad (6.1)$$

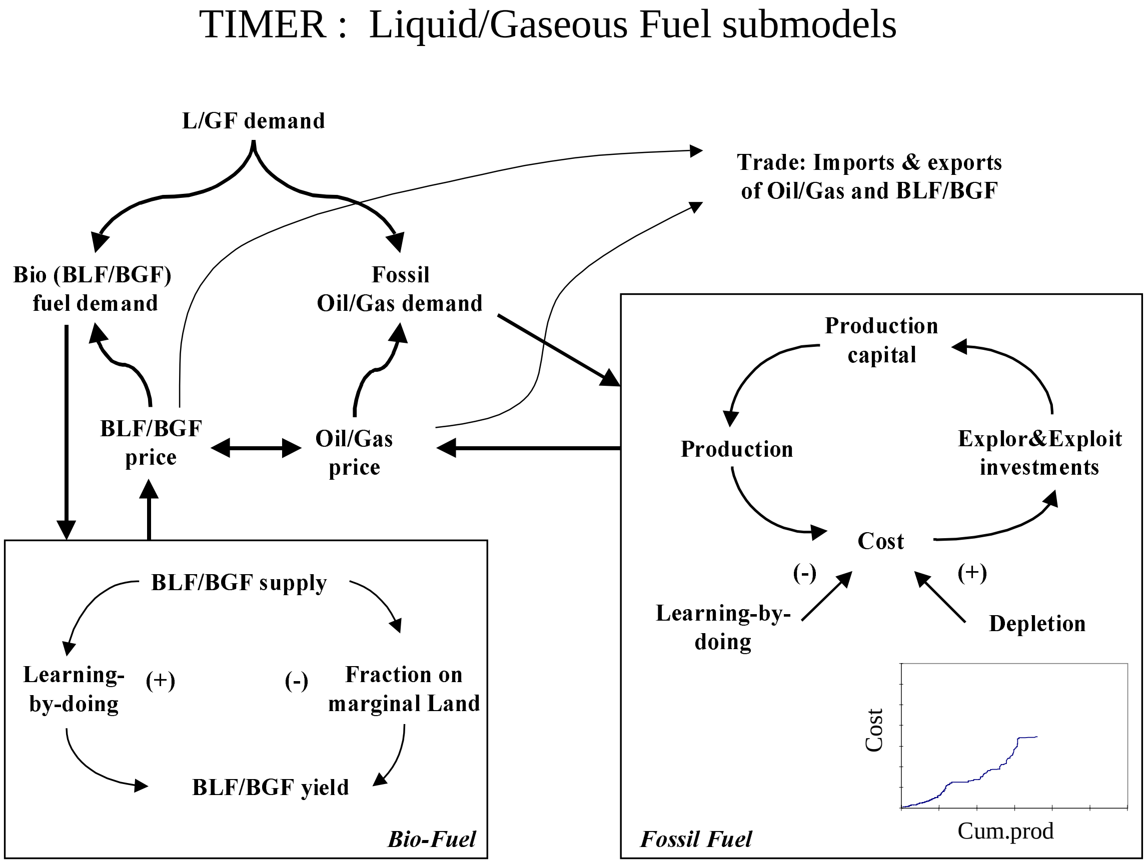


Figure 6.1 Overview of the Liquid Fuel (LF) submodel

with SE secondary LF demand, FE LF demand for electricity production, BO the demand for bunker oil, EC the net consumption/production of oil in energy conversion and NE the non-energy use of liquid fuels. The factor 1+τ1 accounts for transformation losses between production and end-use and losses between crude oil and oil products. The amount of bunker-oil per region has been modelled as a function of changes in industrial value-added and the amount of oil trade in a region. Energy conversion (for oil mainly relevant for regions with large synfuel production) is given by a time-dependent scenario. On the basis of anticipated demand for oil, oil companies decide to invest in oil exploration and oil producing capacity. This is done using the Desired (crude) Oil Production, DesOP, which equals crude oil demand within regions including im- and exports and extrapolated over a time horizon of TH years of the form $(1+r)^{TH}$ with r the annual growth rate in the past 5-10 years. In equation form:

$$DesOP = (LFDem * (1-\mu) + ONTrade) * (1+r)^{TH} \qquad \text{GJ/yr} \qquad (6.2)$$

and ONTrade the Crude Oil net trade, that is, the regional expected crude oil export minus import. .The market share of the alternative BioLiquidFuel, μ, is subtracted from total demand.

This alternative fuel (BLF) is discussed further on. Impacts on demand from competing fuels and from price changes are dealt with in the Energy Demand submodel.

Crude oil trade has modelled in a simplified way, similar to coal and with the assumption that only crude oil and not oil products are traded. All regions compare the price of crude oil produced in their region – the Domestic Crude Oil Price, DCOP - with the price of imported crude oil from other regions – import price. The latter is calculated from that region's indigenous supply price plus additional transport costs derived from a regional distance matrix and a ton-km cost. This part is similar as for coal and is dealt with in detail in *Chapter 7*.

Table 6.1: Distinction between light and heavy liquid fuels

Fuel type	(Petroleum) products included (IEA)
Light liquid fuels	Refinery gas, LPG, aviation gasoline, motor gasoline, jet fuel, kerosene, naphta, bio-liquid fuels
Heavy liquid fuels	Gas/diesel oil, residual fuel oil, other products

Source: IEA, 1998a

6.2.2 LF supply from fossil fuel resources

The life-cycle of (crude) oil is based on the distinction between the resource base OilRB, identified reserves OilRI and cumulated production OilPCum. OilRB represents the ultimately recoverable oil at the technology and price levels throughout the simulation period. The identified reserves OilRI represents those parts of the resource base that have been discovered as part of the exploration process and are identified by the industry as technically recoverable. Oil from tar sands and oil shales are assumed to be part of the higher-cost oil deposits. In the model, the cumulated production OilPCum is not only relevant for CO_2 emissions but is also the driving force behind the depletion and learning formulation.

Investment in oil exploration and exploitation

On the basis of anticipated demand for crude oil, expressed as DesOP, oil companies decide to invest in crude oil producing capacity and, if the reserve-production ratio (RPR) is below a desired level (RPR_{des}), in crude oil exploration. The exploration rate (P_{expl}) is based on the rule that investors in oil production try to find at least the amount of DesOP multiplied by a factor that is a function of RPR_{des} and RPR. .

$$P_{expl} = DesOP * (RPR_{des} / RPR_{act})^2 < Oil\,\mathrm{Re}\,source \qquad \text{GJ/yr} \qquad (6.3)$$

Obviously, the exploration rate can not be larger than the ultimately available resource per region. Related to the exploration rate are the exploration investments. The are apart from the desired production also determined by the Capital Output Ratio for exploration. This ratio is, on its turn, coupled to the overall Capital Output Ratio for oil production (but in terms of depletion not only taking the cumulative production but also the existing reserves into account). The dynamics of recovery technology is not explicitly taken into account (compare Davidsen, 1988). In a number of simulations, we have experimented with a lognormal distribution of the

[54] Unlike Davidsen, 1988 we do not include explicitly the dynamics of exploration and exploitation due to which an increasing fraction of the identified reserves become technically recoverable over time. It is assumed to be implicit in the learning-by-doing process.

size of the oil reservoirs which are discovered; this gives a much more realistic picture of real-world reserve developments.

Oil production

A key step in the simulation is how much is invested in oil production capacity. The oil producing capital stock, OilPCap, with its capital-output ratio, COR_{prod}, has the potential to produce OilPCap/COR_{prod} GJ/yr. The investments into production are determined by the depreciation of this existing capital stock plus the required additional capacity. The latter is derived from the wish to satisfy the desired production DesOP (Eq 6.2) with the constraint that at most a fraction m of the reserves can produced in any year. The multiplier EPIP (Expected Profit from Investments in Production) is used to express the fact that actual investments are less than indicated if the regional production costs exceeds the market price for liquid fuel. The investments in oil production are now equated to:

$$I_{prod} = EPIP * COR_{prod} * DesOP - OilPCap + OilPCap / TLT \qquad \$/yr \qquad (6.4)$$

with TLT the technical lifetime of the capital stock. The first term, EPIP * COR_{prod} * DesOP , equals the desired capital stock for crude oil production in the near (~ 3 year) future, given the profitability requirements of the investors. Both for exploration and exploitation investments, it takes some years before investments generate new reserves c.q. produce oil. In a normal situation, production equal the DesOP. However, the actual production can be limited by either the available production capital or the oil reserves. Total investments I_t can now be expressed as :

$$I_t = I_{expl} + I_{prod} \qquad \$/yr \qquad (6.5)$$

The investments maintains a capital stock with a production capacity (or potential production) OilPC = OilCap /COR_{prod}.

It is assumed that transport and refining of crude oil (products) also requires capital. It is calculated from the COR_{tr}, which is related to the degree of 'whitening the barrel' in refineries i.e. to the fraction of LLF in the total LF (product) demand. The implicit assumption is that only crude oil is transported between regions.

Depletion and learning dynamics in oil exploitation

The key factor in the cost of crude oil, OilCost, is the capital-output ratio, both for production, COR_{prod} , and exploration, COR_{expl} . The change over time of these ratios should represent two trends :

a) additionally discovered oil deposits tend to be of lower quality i.e. deeper, smaller and more distant or offshore . This is represented by a depletion cost multiplier which rises as a function of the ratio between cumulative production plus identified reserves, and the initial resource base;
b) over time, (capital) costs to find and produce one unit of oil tend to decline due to technical progress of all forms. This is represented by a learning-by-doing cost multiplier which falls with the logarithm of cumulated production (compare the learning-by-doing section in Chapter 9).

[55] For large areas and longer time periods the trends are quite plausible, but real-world data will show large fluctuations reflecting among others the lognormal size distribution of oil and gas fields (see e.g. Vries, 1989a).

These hypotheses are clearly approximations of the real world, shown valid for some regions in some periods and vindicated for other regions in other periods. The most obvious violation of the first hypothesis was the discovery of the giant low-cost oil fields in the Middle East (see e.g. Yergin, 1991). The strong centralisation of geological and technological expertise within the industry and the ever wider use of advanced exploration techniques, however, may make the above hypotheses for the future more, not less accurate.

In formula form, the above hypotheses are expressed as follows :

$$COR_{prod} = COR_{prod,tL} * OilDeplM\left((OilPCum)/OilRB_{tL,CO}\right) * (OilPCum/OilPCum_{tL})^{-\pi} \qquad \$/GJ \qquad (6.6)$$

In this formula, OilDeplM is the depletion multiplier for oil production, tL the year in which depletion and learning dynamics start and π the learning coefficient. The depletion multiplier is causing the capital-output ratio of oil exploitation to rise and is the capital-component of what is known in economic literature as the long-term supply cost curve.

For oil exploration we assume similar depletion and learning cost multipliers. The only difference is that we use the sum of the cumulative oil production and the actual reserves instead of OilPCum in the depletion multiplier. For both the depletion and the learning factor, alternatively a measure like cumulative footage drilled could be used (see e.g. Norgaard, 1972) but at present the data are lacking except for the USA.

6.2.3 LF costs and prices

The capital costs of crude oil are calculated as an annuity factor times the capital-output ratio of oil exploration and production capital. On top of this, it is assumed that the crude oil price is also affected by the ratio between demand and supply. This Supply Demand Multiplier (SDM), generating a cobweb-like dynamics, expresses the fact that the price increases when the ratio between demand and potential production, i.e., the capacity utilization factor, approaches or exceeds one. As we assume that there is a global market for oil, we determine this SDM at the global level and use it for all regions. For regions with isolated markets, this assumption is obviously incorrect but the influence of SDM is not important for long-term trends. The resulting expression for the Domestic crude Oil Price, DomOilPrice, in any given year is :

$$DomOil\,\mathrm{Pr}\,ice = SDM * a * (COR_{prod} + COR_{\exp l}) * (1 + DGM) \qquad \$/GJ \qquad (6.7)$$

In Eq. 6.11 a is the annuity factor and DGM the Desired Gross Margin. In comparison with the previously discussed depletion and learning dynamics, the SDM-generated fluctuations are short-term. Of course, this price has to be corrected for oil imports (see *Chapter 7*).

The next step is to incorporate the capital requirements and resulting add-on costs for transport and refining of crude oil. This is modelled in a simple way. It is assumed that these processes have the same capital-output ratio as the oil production capital stock but without the depletion multiplier, and that this ratio increases with an increasing LLF-fraction to account for additional cost of ‘whitening the barrel’. Conversion losses are accounted for by the constant loss factor in Eqn. 6.2. These (capital) costs are then allocated as add-on costs to the heavy and the light oil products. This has been done on the basis of a fixed price ratio between LLF and HLF and the assumption that transport and refining capital costs, multiplied by a desired margin, have to be recovered from selling the fuels. We assume that $COR_{tr\&ref} = COR_{prod}$ / OilDeplM. The resulting expression for the price of HLF in any given year is:

$$HLF\,Price = \frac{Oil\,Price + (1+DGM)*PRLH*OilCOR_{prod}}{\left((1-\delta)+PRLH(1-\mu)\delta\right)*OilDeplM} \qquad \$/GJ \qquad (6.8)$$

with PRLH the price ratio between LLF and HLF. The price of LLF is now given by :

$$LLF\,Price = a(HLF\,Price - Oil\,Price) + Oil\,Price \qquad \$/GJ \qquad (6.9)$$

The prices for LLF and HLF determine the demand for Liquid Fuels (in the ED-model and the EPG-model) and the penetration of alternative BLF.

6.2.4 LF supply from biomass (BLF)

The use of traditional biomass has been dealt with in *Chapter 5*. In the LF (and GF) submodel, biomass-based fuels refer to modern biomass as an alternative to conventional oil based liquid (or natural gas based gaseous) fuels. Bio-liquid fuels can be substitutes for gasoline, as ethanol in Brazil, or be used in electric power generation (see e.g. Johansson, 1989; Johansson, 1993). From the CO_2-perspective this is an attractive option of satisfying the large demand for especially transport fuels. It will require land as a production factor, as well as labour and capital inputs. In the production of biofuels, two steps can be recognised: 1) the production of biomass, 2) the upgrading of biomass into biofuels. For the first step, the production of bio-liquid fuels (BLF) and bio-gaseous fuels (BGF) cannot be seen independently – and here only one depletion/learning formulation is used. The second step is modelled independently for BLF and BGF.

In total, we assume a production function which is based on three elements :

- A capital output ratio for the production of biomass that are subject to learning;

- a land-output ratio, LOR, which decreases due to learning dynamics (see Chapter 9) and increases as result of depletion of suitable land until an exogenously set supply potential, BioPotSup, is reached.
- A capital-output-ratio for upgrading that is as well subject to learning.

In an earlier version, biofuels were modelled using a Cobb-Douglas equation also including labour costs, included to reflect the transition towards less labour-intensive techniques. However, the available evidence and information was too weak at present to warrant such a formulation.

Given the production cost of BLF, BLFCost, its penetration into the market for LightLiquidFuels (LLF) is modelled with a multinomial logit equation (see *Chapter 9*). The economically indicated market share for biofuels, IMSBLF, is given by :

$$IMSBLF = \left[\frac{BLFCost}{(BLFCost + OilLLFCost)}\right]^{-\lambda} \qquad (6.10)$$

Here, λ is the multinomial logit constant, being a measure of the cross-price elasticity – at high values minor cost differences generate already large shifts, and vice versa. With a delay, the actual market share μ will grow towards the indicated value which allows the calculation of bioliquid fuel production BLFProd = μ LLFDem. It is assumed that investors, either private or government, decide to invest with a delay into BLF-producing plantations, at the rate of the indicated supply times the capital-output ratio. The resulting equation for the annual investments is, similar to eqn. 6.4 for oil:

$$I_{BLF} = IMSBLF * LLFDem * COR_{BLF} - BLFCap + BLFCap / TLT_{BLF} \qquad \$/yr \qquad (6.11)$$

In a similar way, we account for the investments and capital costs of fuel conversion with a capital output ratio for conversion, $COR_{BLFconv}$, from which the required conversion capital, $BLFCap_{conv}$, is calculated.

This means that the production costs can be estimated as:

$$BLFCost = a * (BLFCOR + BLFCOR_{conv}) + LandPrice * Yield_{Bio} \qquad \$/GJ \qquad (6.12)$$

In Eqn. 6.12 a is the annuity factor, LandPrice an estimate of the price of land and Yield is the final amount of upgraded biofuel that can be produced per hectare. Land prices are estimated in TIMER based on an initial estimated and increase as a function of population and GDP growth. The average yield is assumed to decrease as more land is being used, reflecting the increasing use of marginal land and competition with food production. The formulation is:

$$Yield_{Bio} = Yield_{tL,Bio} * f_{Bio}(BioProd / BioPotSup) * (BLFCumLearn_{t-tL} / BLFCumLearn_{tL})^{-\pi} \qquad GJ/ha \qquad (6.13)$$

In Eqn. 6.13, the factors related to depletion are calculated for all biofuels – thus both bioliquid and biogaseous fuels. The index tL the year in which learning is assumed to start and f_{Bio} the depletion function. BLFCumLearn is the cumulative BLF production. The thus determined BLF-price - equated to BLF-costs plus a fixed profit margin - in relation to the LLF-price influences its future market share. The BLF-penetration can be accelerated by prescribing the market-shares and thus accelerating learning-by-doing, which can be seen to simulate RD&D programs (see *Chapter 9*).

6.3 LF model implementation and calibration 1971-1995

The LF-model has been implemented by assigning parameter values based on the available literature. However, there is only limited data on the size and especially the cost of regional oil deposits; their reliability is difficult to assess. Moreover, there is the aggregation problem: intensive variables such as costs, prices and taxes can never adequately be aggregated from country to regional level. *Table 6.2-6.4* show the variables used for empirical model calibration.

Table 6.2: Model variables used for historical calibration for LF-model. Model parameters (see Table 3.4) are varied to get the best fit between simulated and historical time-series. See Appendix A for data sources).

Variable	Subscript	Description	Unit/Domain
OilProd	rt	Crude Oil Production	GJ/yr
BLFProd	rt	(Commercial) Production of BioLiquidFuels	GJ/yr
OilCost, OilPrice	rt	Crude Oil Cost / Price	$/GJ
OilRI	rt	Identified crude Oil Reserves	GJ

r=region, t=time

Table 6.3: Model parameterss used for historical calibration and, if in bold, also for scenario (re)construction for ED-model. Parameters are varied around a default value within a certain domain. Trade related parameters are discussed in Chapter 7.

Variable	Subscript	Description	Unit/Domain
OilCOR	r,prod/expl	Initial Capital-Output ratio in Crude Oil production and exploration	1-5 $/GJ/yr (prod)
I	r,prod/expl	Initial Investments in Crude Oil production and exploration	$/yr (via 1971 production and initial COR)
SDM	r	supply-demand multiplier (response of crude oil price to ratio of desired and potential production)	(fixed)
π	r,oil/blf	learning coefficient in Crude Oil and BLF production	0.8-1
TCsp	r	Specific Transport cost	$/ton-km
TrPDiffFactor	r	Factor with which distance between regions is multiplied to represent trade barriers	0.5-5
ImpConstr	r	Exogenous constraint on fraction of OilDemand met by imports	0-1
ExpConstr	r	Exogenous constraint on how many times domestic production can be exported	>0
PrDCProd		Preference factor for Domestically produced crude oil	0-5

r=region, t=time

Table 6.4: Model parameters for which historical values and/or fixed assumptions are used. Parameters are given a default value based on exogenous input time-series or on literature.

Variable	**Subscript**	**Description**	**Unit/Domain**
δ	r	Share of LLF in total LF-demand	(historical)(0-1)
τ	r	Transformation loss factor	1-1.5
OilPC	r, t=1970	Crude Oil Producing Capacity in initial year 1970	$, partly from literature, partly from calibration
ORB	r	Ultimately recoverable crude oil (conventional and unconventional)	GJ
OilDeplM	r	Functional of Capital-Output ratio for Crude Oil production as function of (ORB+ORI)/ORB	(cf. Figure 6.1)
m	r	Technically maximum fraction of reserve which can annually be withdrawn	<0.2
TH	r	Time Horizon in anticipating Crude Oil production	<10 yr
TLT	r,oil/blf	Technical LiteTime for capital stocks	10 yr
ELT	r,oil/blf	Economic LifeTime for capital stocks, determines annuity factor with interest rate r	5 yr
OilTransfFrac	rt	factor with which (crude oil) demand is multiplied to account for conversion and transport/distribution losses	(historical)
OilExplFac	r	Factor determining the effectiveness of investments in Oil Exploration	=1(>1)
CapRatioTR	r	Initial Ratio of investments in Transport and Refinery Capital and investments in oil exploitation	function of fraction LLF in total Oil demand
EPIP		Expected Profits from Investments in Production	

r=region, t=time

Resource base.

A very important assumption in the fuel supply models is about the available resource base. In literature, a wide range of estimates of world ultimately recoverable oil resources can be found, both for ‘conventional’ and unconventional supplies. For conventional oil, most estimates for the remaining resources in the mid 1990s are between 13.000 and 18.000 EJ [56] (see for instance, Masters, 1994, Lako, 1999, IEA, 1998b). Low range estimates are in the range of 7.000-10.000 EJ (Laherrère, 1998; Lako, 1999). Such differences are quite normal in view of different definitions, inclusion of gas liquids etc. (Laherrère, 1999). For the present model implementation, we have used estimates of the size of regional conventional and unconventional oil resources based on Rogner (1997), shown in *Figure 6.2* and *Table 6.5*.

[56] Some uncertainty already exists regarding estimates on identifed reserves. Estimates range between 5500 and 7300 EJ, in particularly related to possible overestimation of oil reserves in OPEC countries (see Laherrère, 1998). The mid-estimate (6400 EJ) would allow production for 44 years at present (1995) extraction rates.

Rogner's estimate of world ultimately recoverable conventional oil resources is about 18.000 EJ, which is at the higher end of the range mentioned above. Rogner's estimate of unconventional oil occurrences is an astounding 92.000 EJ.

The question is which oil resources can be mobilised depending on the extraction costs. *Figure 6.3* shows some of different supply cost curves for conventional and unconventional oil found in literature. These curves can be interpreted as the rate at which oil production costs may be expected to increase in a world without fuel trade barriers.

Table 6.5: Global oil resources, 1994 according to Rogner (1997)

Type of oil	*Occurrence*	EJ
Conventional Oil	Cum. Prod (1971-1995)	3057
	Proved reserves	6289
	Estimated Additional	2542
	Add. Special	3534
	Enhanced recovery	5774
Shale, Bitumen and Heavy Oils	Reserves	1893
	Resources	14052
	Add. Occurences I	24582
	Add. Occurences II	51768

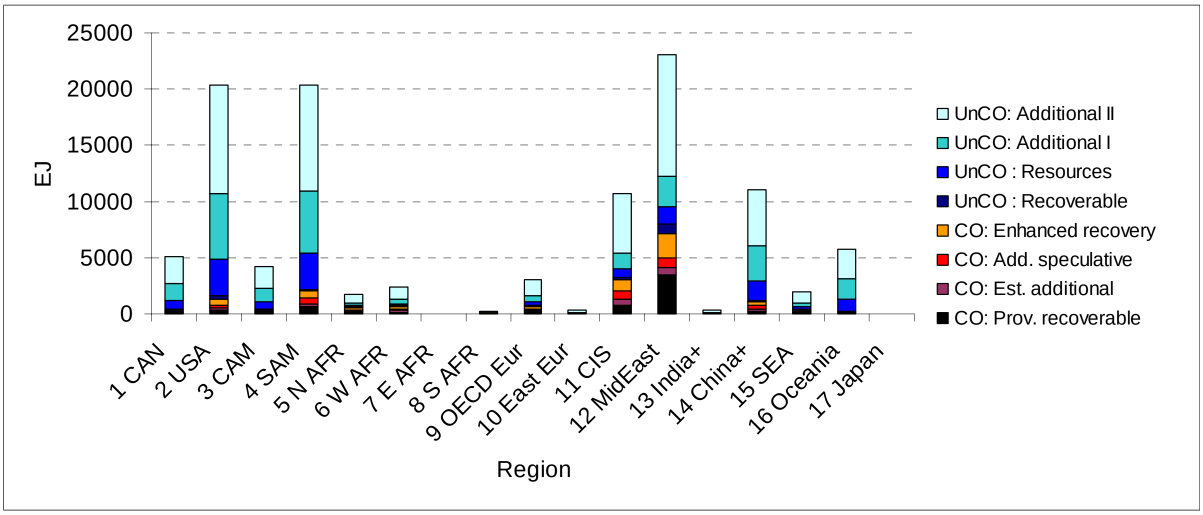


Figure 6.2: Regional crude oil resources according to Rogner, 1997

It should be noted that the different supply curves have been constructed using different assumptions with regard to technology development and available resources and it is often hard to trace back their consequences. The two curves shown for Rogner, for instance, are based on different assumptions with regard to the ultimately extractable resource base (30000 vs. 110000 EJ); both include the assumption that technology will reduce future extraction costs at a rate of about 1 %/yr. The curve by (Vries, 2000) has been constructed using detailed regional data, again mostly based on Rogner's dataset but this time free of technological development. Interestingly, the different studies are in fair agreement on the trajectory for the first 30000 EJ. The most significant differences, in fact, seem to be caused by a different assumption on current extraction costs.

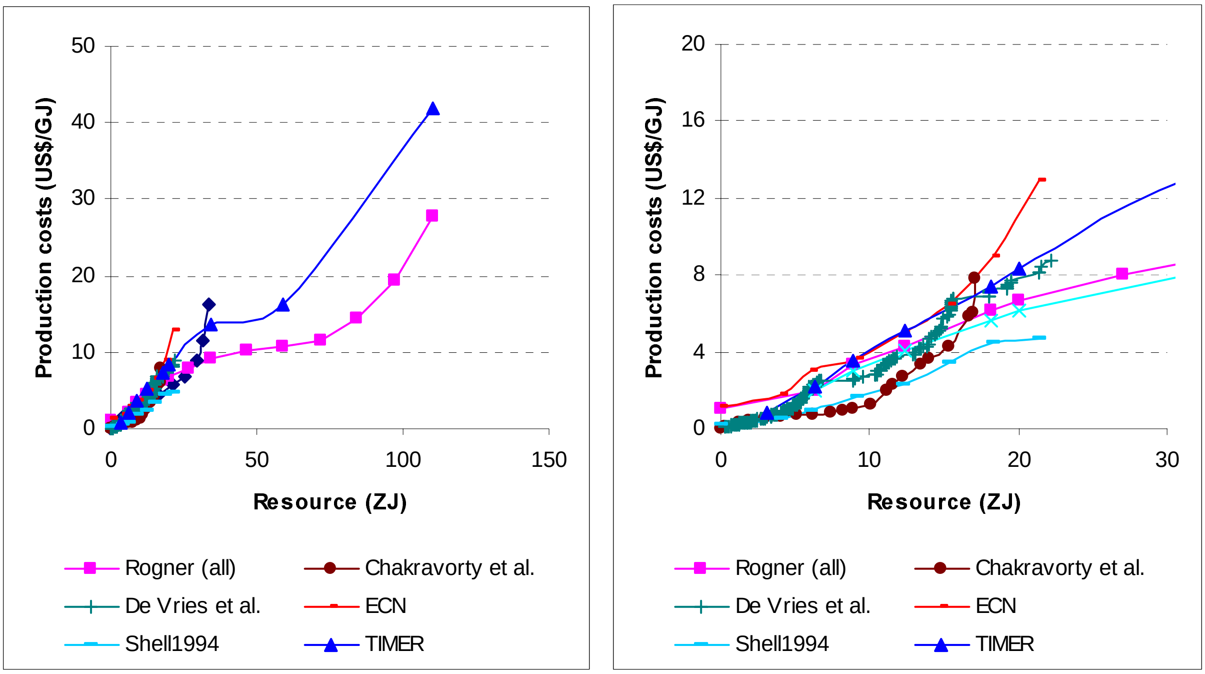


Figure 6.3: The long-run global supply cost curves for crude oil in 1995 US$/GJ. The curves are based on the resource size and classifications of Rogner, 1997.

Note:

Legend	*Source*	*Assumptions*
Rogner (all):	Rogner, 1997	Including technological progress; resource base 110,000 EJ
Charkravorty	Chakravorty, 1997	
ECN	ECN, 1995	
Shell, 1994	Kassler, 1994	
De Vries *et al.*	Vries, 2000	Based on Rogner, 1997, no technological progress;
TIMER	This report	Based on Rogner, 1997,regionalised curves, no technological progress

On the basis of personal communication and some additional assumptions, we have converted Rogner's size and cost estimates into regional supply cost curves. We had to convert the original cost estimates as costs reductions as a result of technological progress are explicitly modelled in the TIMER model. The different values for oil production costs – based on current technology – in different regions and for different types of oil resources have been based on various sources. Historic data on production costs of different regions is rather scarce (or at least open data sources are). Nevertheless several publication give indications of production costs that we could use to estimate the production costs of the IMAGE regions, in particular (Baddour, 1997b; Ismail, 1994; Adelman, 1993a; Stevens, 1997b; Adelman, 1997; IEA, 1995). Some of these sources give time-trends and cross-country comparisons. Others do divide the production costs in various production factors (in addition, see also IPAA, 2000). These literature sources indicate important differences between our regions. For the USA signs of the impact of depletion on oil production costs have been reported (AGOC-reports, 1998). For the OPEC countries, an important question is how possible cartelisation gains are accounted for (Berg, 1997). In addition to information on conventional oil, we also need to have some indication of the production costs of non-conventional oil sources. Besides the numbers given by (Rogner, 1997), other publications indicate the huge progress that has been made in bringing down the production costs of these type of resources (Gurney, 2000; IEA, 1998b). We have used these data to construct our long-term supply curves.

A crucial aspect in calibrating the oil model are the resulting trade flows among the regions (for which good data are available). Calibration of the oil model is therefore done fully integrated with the oil trade model discussed in *Chapter 7*.

The final global supply cost curves for crude oil is shown in *Figure 6.3 (TIMER2).* The underlying regional curves are shown in *Figure 6.4*. Of course, the derived cost curves are highly speculative beyond the presently identified reserves. It should be noted that the simulated oil production costs will be less than the costs indicated in *Figure 6.4* because we assume a decline in the capital-output ratio due to technical innovations[57]. Also, production costs are not equal to prices: market barriers, royalties and oligopolistic price formation all influence the actual market prices.

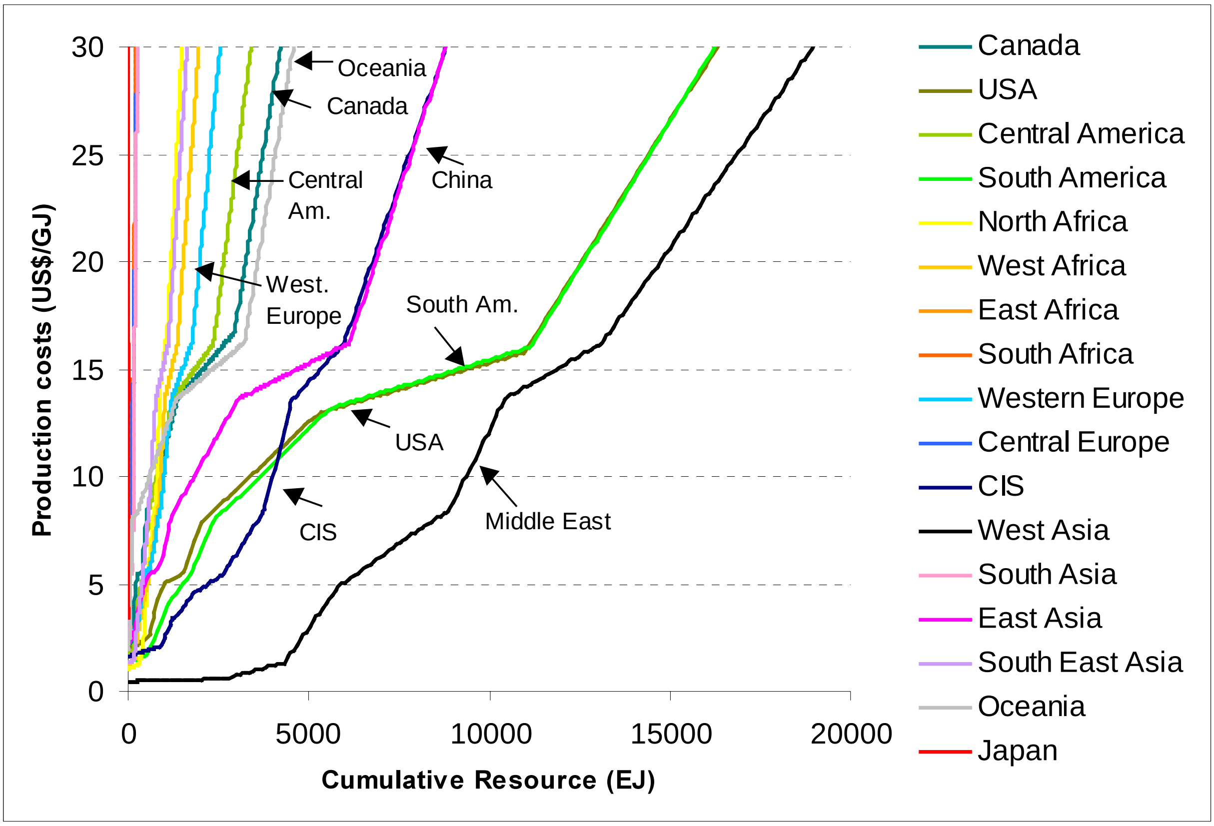


Figure 6.4: The long-run regional supply cost curves for crude oil in 1995 US$/GJ as used in TIMER. The curves are based on the estimates in Figure 6.3.

Oil production.

For the crude oil supply, we use parameter estimates from several previous analyses. Some parameters are constant and the same for all regions. These are:

- the desired Gross Margin (20%),
- the discount/interest rate (10%),
- the technical LifeTime of capital stocks (15 years),
- the economic LifeTime of capital stocks (5 years),
- the desired Reserve Production rate (15 years), technically maximum rate at which reserves can be exploited (15%),
- the fixed price ratio between LLF and HLF (2).

[57] The importance of such innovations can be judged from recent estimates of the costs of off-shore oil production.

Table 6.6: Parameter values for oil production simulation

	Initial Oil production costs	Total resource base	Transformation losses (τ)	Learning rate (π)	Initial Capital output ratio refining
	$/GJ	EJ	-	-	$/GJ
	1971	1971	1995	1990	1971
1 CAN	2.0	5500	0.06	0.9	3.8
2 USA	1.9	20457	0.07	0.8	3.6
3 CAM	1.6	4295	0.13	0.9	4
4 SAM	1.3	20559	0.10	0.75	4
5 N AFR	1.1	2387	0.10	0.92	4
6 W AFR	1.3	2478	0.12	0.9	4
7 E AFR	3.4	3	0.06	0.9	4
8 S AFR	2.5	274	0.11	0.86	4
9 OECD Eur	2.3	3212	0.06	0.88	4
10 East Eur	2.4	316	0.13	0.9	4
11 CIS	1.6	11243	0.10	0.88	4
12 MidEast	0.5	23508	0.06	0.88	4
13 India+	2.5	321	0.09	0.92	4
14 China+	2.2	11099	0.07	0.91	4
15 SEA	1.4	2079	0.11	0.95	4
16 Oceania	1.9	5729	0.03	0.9	4
17 Japan	3.4	29	0.05	0.9	4

BLF supply.

The BLF-formulation is still very simple. Some variables are taken constant and the same for all regions. Among these are:

- the Desired Gross Margin in BLF production (8%),
- the Technical LifeTime of BLF capital (15 year),
- the economic LifeTime of BLF capital (5 years),
- the average transformation losses in BLF (5%),
- the substitution elasticity between BLF and oil-derived LLF (4),
- the delay in penetration of BLF (5 years),
- the initial capital-output-ratio for biomass production (14.5 US$/GJ),
- the initial capital-output-ratio for conversion into fuels (87 US$/GJ).

The learning coefficients for BLF have also been set equal for all regions: i.e. 0.95 for biomass production and 0.88 for the conversion into final fuels. For the land price we use estimates based on IMAGE-TES and population and economic data, resulting in values ranging from 400 to 2500 $/ha. Comparison with existing land price data (FAO, 1997) indicates that these prices are underestimated (for Western Europe, available land use data suggests a price between 3000-5000 US$) but during the calibration process this is probably compensated by higher assumptions for capital inputs.

Table 6.7: Parameter values for biomass-derived liquid fuels

	Land price (US$/ha)	Initial yield (GJ/ha)	Resource (EJ/yr)	Demo fraction (1995)
1 CAN	1000	200	19.4	0.000
2 USA	1390	225	46.5	0.002
3 CAM	786	230	11.4	0.001
4 SAM	735	230	114.2	0.042
5 N AFR	754	230	0.0	0.000
6 W AFR	482	230	57.1	0.000
7 E AFR	472	230	0.8	0.000
8 S AFR	551	230	47.4	0.000
9 OECD Eur	1802	230	22.0	0.000
10 East Eur	1175	230	6.4	0.000
11 CIS	624	230	95.2	0.000
12 MidEast	776	200	0.2	0.000
13 India+	1044	230	45.6	0.000
14 China+	800	230	44.3	0.000
15 SEA	853	230	21.8	0.000
16 Oceania	781	230	16.1	0.000
17 Japan	2330	230	1.5	0.000

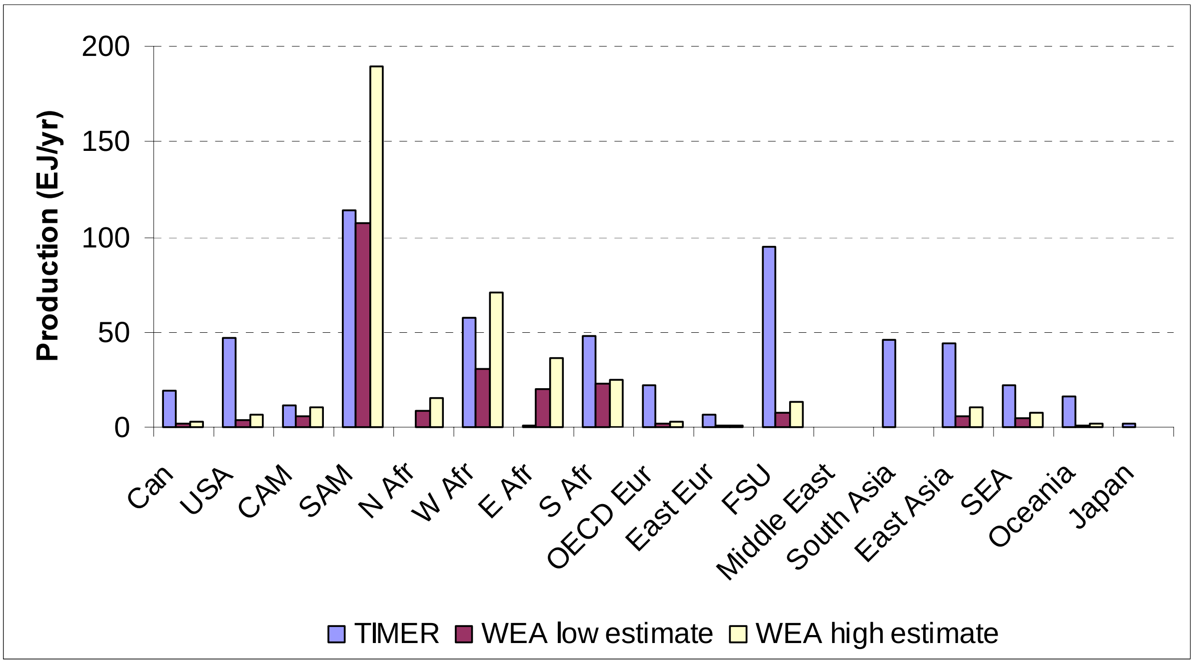


Figure 6.5 The estimates of the technical BioFuel production potential. Source: Regional curves from IMAGE-TES; global curves described in Hoogwijk, 2000 and the World Energy Assessment WEA, 2000

Dynamically, an important parameter is the biofuel depletion multiplier, that is, the factor by which the yield is divided on approaching the technical potential. *Figure 6.*5 shows our estimates of the biofuel (BLF and BGF) potential which are based on calculations using the IMAGE-TES model. The global curves derived in a similar way have been described in Hoogwijk, 2000. *Figure 6.5* also shows a comparison with the figures mentioned in the World Energy Assessment (WEA). For many regions, the TIMER assumptions are slightly higher than the figures mentioned in WEA For South America, however, the TIMER figures are lower.

Figure 6.6 shows the assumed decrease in land yield upon approaching this limit – it represents counteracting forces in the market penetration of BLF/BGF due to entry into less productive lands and competition with food production. The initial cost of BLF is determined by the initial assumptions for capital-output-ratios and land use prices, and is, in combination with the learning coefficient and the cumulated production in the year in which learning is supposed to start, determining the cost development of BLF.

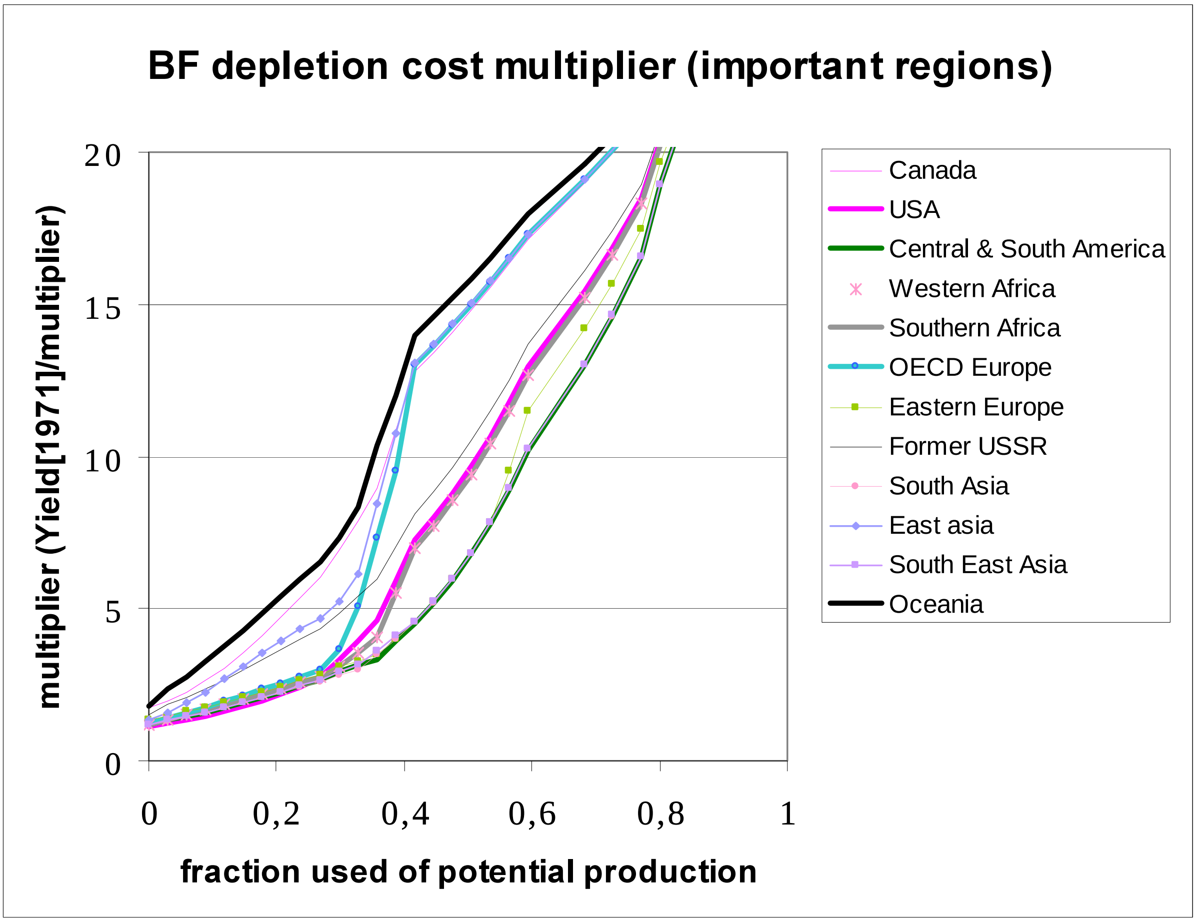


Figure 6.6 The depletion multiplier used for biofuels, indicating with which factor the capital-output ratio is multiplied. Source: Regional curves from IMAGE-TES; global curves described in Hoogwijk, 2000.

6.4 The Gaseous Fuel (GF) model

Basically, the GF-model has the same set-up as the LF-model. The only difference is that the capital investments for transport and upgrading are different and that no distinction is made between various grades (like HLF and LLF for liquid fuels). As in the LF-model, there are exploration and exploitation processes, a capacity-related price mechanism and an alternative, biomass-based fuel referred to as BGF. Because of these similarities, the model is not discussed in any further detail here.

In the implementation, some differences between oil and gas showed up. First, the natural gas exploration and exploitation cycle started later in all regions; hence, the depletion and learning behaviour is different. Secondly, quite a few parts of the natural gas system are intricately related to the oil system. For instance, much gas is produced as associated gas. A third difference is that gas transport is much more expensive than oil (product) transport which has to be reflected in the over-all Capital-Output Ratio. The combination of these factors cause, amongst others, that flaring of natural gas still accounts for an estimated 10% of world production although it has declined significantly in the last 4-5 decades. One reason for this is that the need for capital-intensive transport systems – sometimes in politically risky regions - is an obstacle to opening up markets.

Resource base.
As for crude oil, we have used estimates of the size of regional conventional and unconventional gas resources based on Rogner, 1997 (*Table 6.8*).

Table 6.8: Natural Gas resources according to Rogner, 1997

		Resource size (EJ)
Conventional gas resources	A Proved recoverable	5393
	B Estimated Additional	4685
	C Add. Speculative	6431
	D Enhanced Recovery	2324
Coalbed methane, tight	E Recoverable Reserves	5652
formation gas, clathrates etc.	F Resources	10802
	G Add. Occurrences I	16162
	H Add .Occurrences II	785439

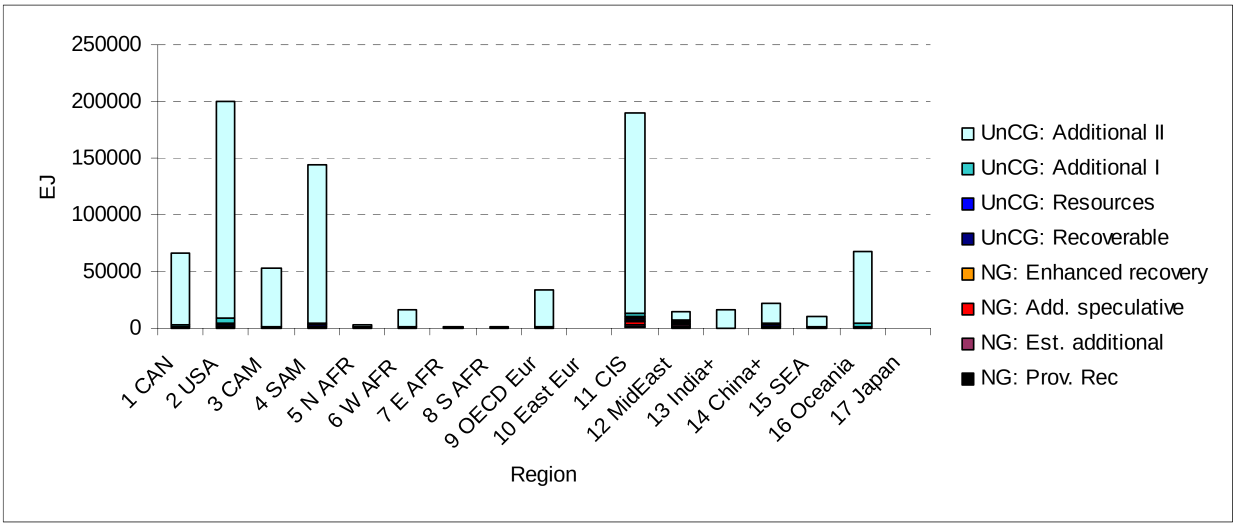
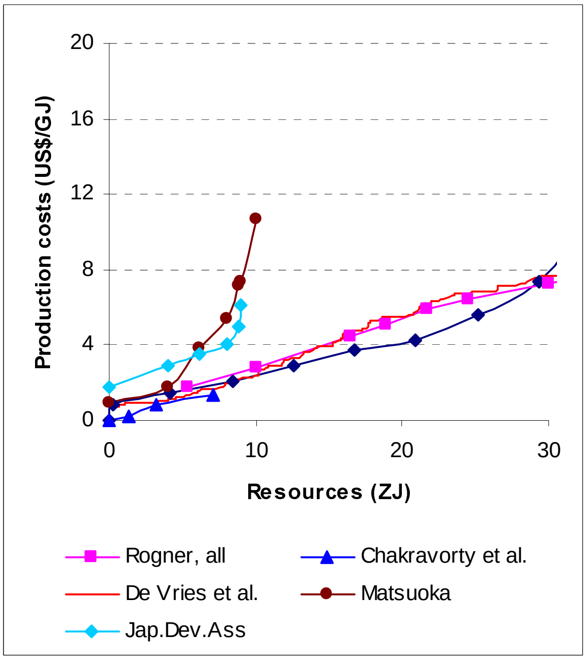


Figure 6.7: Regional natural gas resources as assumed in TIMER based on Rogner, 1997

As for oil, the recourses have been desaggregated to the regional level of the TIMER model. Both *Table 6.8* and *Figure 6.7* show the dominance of non-conventional gas resources in the total. The question of these resources can and will ever be exploited is, however, still open. Conventional natural gas resources are much smaller in size – and in fact, slightly smaller than the available conventional oil resources.

For use in the TIMER model, the resources need again to be converted in long-term supply cost curves (without taking into account technology progress). On the basis of some additional assumptions, we have converted Rogner's size and cost estimates into regional supply cost curves expressed in the functional GasDeplM. Additional information on (current) regional production costs have been taken from various sources, among which (Quast, 1997b; IEA, 1998b; Carson, 1997; IEA, 1999). The regional curves are shown in *Figure 6.9*.

From these one can derive the world supply cost curves for natural gas, shown in *Figure 6.8*. The actual global aggregated curve in TIMER is more-or-less comparable to the curve of (Vries, 2000). The curve is determining the rate at which gas production costs may be expected to increase in a world without fuel trade barriers. The explanation is the same as with oil. Here, too, it should be noted that the simulated gas production costs may differ because we assume a decline in the capital-output ratio due to technical innovations and non-zero interregional transport costs[58]. Also, production costs are not equal to prices: market barriers, royalties and oligopolistic price formation all influence the actual market prices.



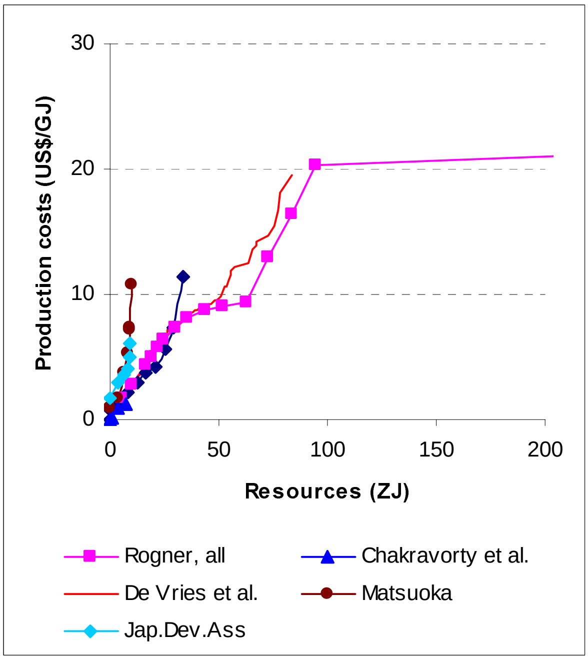


Figure 6.8: Cost-supply curves for natural gas, according to (Rogner, 1997; Chakravorty, 1997; Vries, 2000; Matsuoka, 1994)

[58] The importance of such innovations can be judged from recent estimates of the costs of off-shore oil production: an annual cost reduction of 7%/yr in the Mexican Gulf.

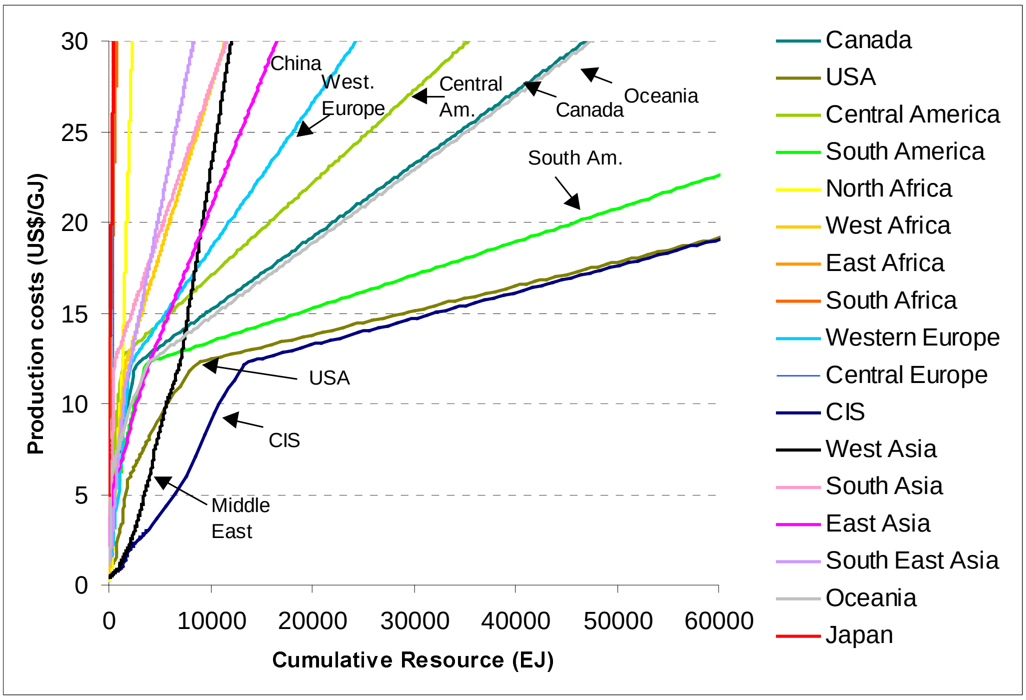


Figure 6.9 Assumed regional gas supply cost curve, expressed as the factor with which the Capital_Output Ratio is multiplied on depletion.

Gas production.
Similar to oil, we use for the natural gas supply parameter estimates from several previous analyses. Some parameters are constant and the same for all regions:

- the Desired Gross Margin (20%),
- the discount/interest rate (10%),
- the technical life time of capital stocks (15 years),
- the economic life time of capital stocks (5 years),
- the technically maximum rate at which reserves can be exploited (15%),
- the Desired Reserve Production rate (30 years).

Other parameters are region-specific as indicated in *Table 6.9*.

BGF supply.
The BGF-formulation is similar to the one for BLF, with a number of parameters constant and equal for all regions. BLF and BGF are each having their own cost determinants, such as learning behaviour. However, the depletion curves are for BLF and BGF together, that is, we use the sum of BLF and BGF production to estimate the yield decrease which is then applied to both. All parameters have been set equal to those of BLF, with two main exceptions:

- the Capital-Output-Ratio for upgrading biomass into bio-gaseous fuels is slightly lower (65 US$/GJ);
- there have been introduced no historically forced market shares / demonstration projects as for BLF.

Table 6.9: Parameter values for natural gas production model.

	Initial Oil production costs	Total resource base	Transformation losses τ	Learning rate (π)	Initial Capital output ratio refining
	$/GJ	EJ	-	-	$/GJ
	1971	1971	1995	1990	1971
1 CAN	0.86	66653	0.162	0.86	5.6
2 USA	0.94	200177	0.115	0.92	5.6
3 CAM	1.41	53058	0.229	0.92	6.2
4 SAM	1.84	143428	0.386	0.91	6.2
5 N AFR	0.27	2545	0.390	0.88	6.4
6 W AFR	0.60	15839	0.879	0.90	6.4
7 E AFR	5.00	1080	0.200	0.90	6.4
8 S AFR	3.00	1080	0.010	0.90	6.4
9 OECD Eur	1.22	34215	0.065	0.95	6.2
10 East Eur	2.29	473	0.083	0.90	6.2
11 CIS	0.46	189553	0.070	0.93	6.2
12 MidEast	0.40	14279	0.349	0.93	6.4
13 South Asia	1.90	16504	0.093	0.90	6.2
14 East Asia	2.14	22095	0.345	0.87	6.2
15 SEA	1.34	9678	0.697	0.88	6.2
16 Oceania	1.11	66995	0.172	0.90	6.2
17 Japan	5.00	679	0.009	0.90	5.5

6.5 Calibration results LF and GF model 1971-1995

We will discuss the results of the calibration first for crude oil, next for natural gas and finally for bioliquid and biogaseous fuels.

Crude oil production

The model settings as discussed in the previous section results in the regional crude oil production costs for the year 1971, 1980 and 1995 as indicated in *Figure 6.10*. The figure shows the large differences between the regions – with some regions producing oil at very low costs (Middle East, around 0.6 US$/GJ; followed by Northern Africa, Western Africa and South America), other regions at medium costs (e.g. Canada and USA) and some regions at very high costs. The trends in production costs between the regions also differ: in some of them, technology development clearly brings down costs such as in Western Europe; in others, depletion seems to be a stronger factor, such as in the regions with very small reserves (Central Europe, Japan, Eastern Africa) but also already in the USA.

On top of the production costs, a supply-demand factor determines the price of crude oil. The calculated regional oil prices are the main input into the trade model (*Chapter 7*) and determine, in combination with transport costs and exogenous trade barriers, the oil production per region. *Figure 6.11* shows that the final model results reproduce the historical trends very well. The main difference is that the modelled trends are slightly smoother than the historical data. As with *Figure 6.10*, this only indicates that a well-chosen combination of model parameters allows for a good reproduction of statistical data. Sometimes this is rather trivial, for instance, the exogenously introduced (oil) trade barriers for some regions make good calibration results a straightforward consequence, not an achievement. In other cases, this is not so: for instance, the combination of (oil) resource depletion multiplier, initial capital-output ratio, learning rate and price elasticities on internal and external markets are all determinants of (oil) costs and production flows. The parameter settings should be based on the best available empirical data – yet, more than one combination is possible, which in turn affects simulated future trends.

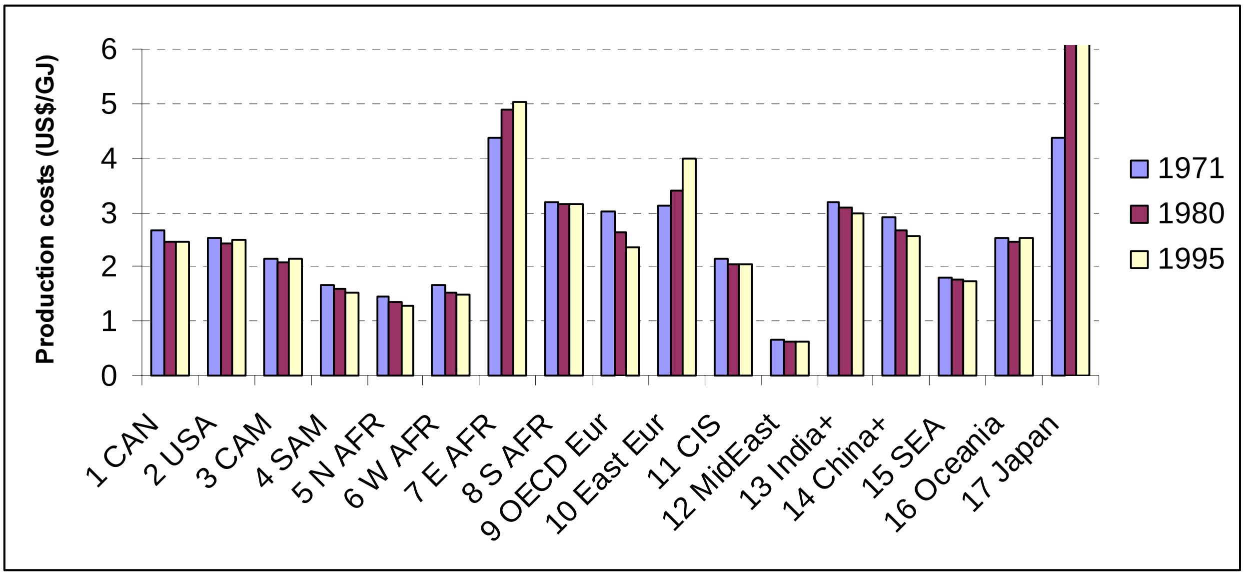


Figure 6.10: Production costs in different regions

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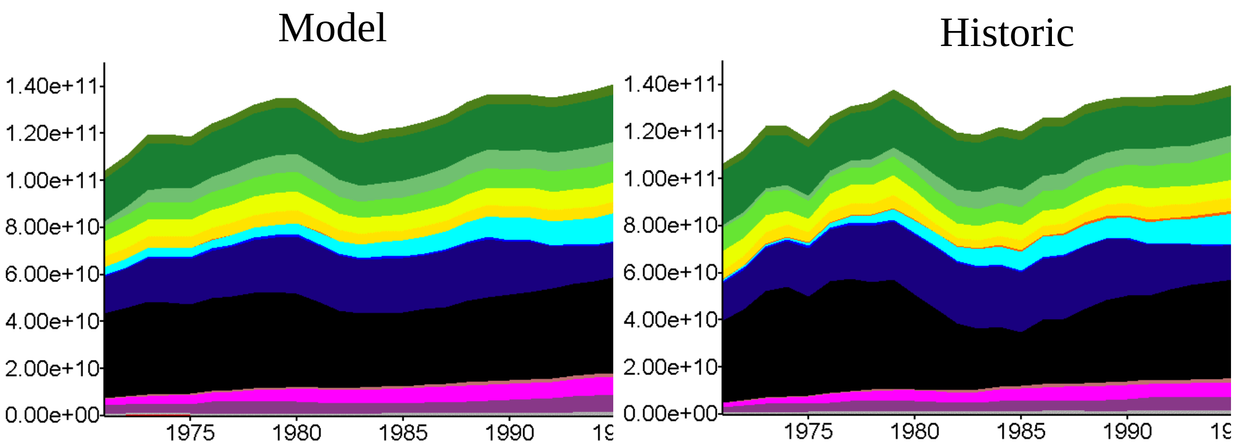

Figure 6.11: Oil production 1971-1995, model result and historical data.

Figure 6.12 compares the differences in more detail for 1995. Again, the figure shows that after calibration the deviations between historical data and the model results are rather small. By far the largest oil producing region is the Middle East, followed by the USA and OECD Europe. Several regions have hardly any oil production.

In the first simulation rounds, oil demand was overestimated. As the oil price hikes of the 1970s and 1980s and the recent ones in 2000 itself are not modelled explicitly, we have introduced them exogenously. Obviously, this is no a matter of principle: the inclusion of regional supply-demand multipliers and the simulation of oligopolist mechanisms on world (oil) markets are able to reproduce the kind of shocks seen in the past. However, such a calibration yields parameter values which easily lead to instabilities – which can be considered one expression of the sheer complexity of the underlying phenomena, as is evident from the variety of models found in the literature.

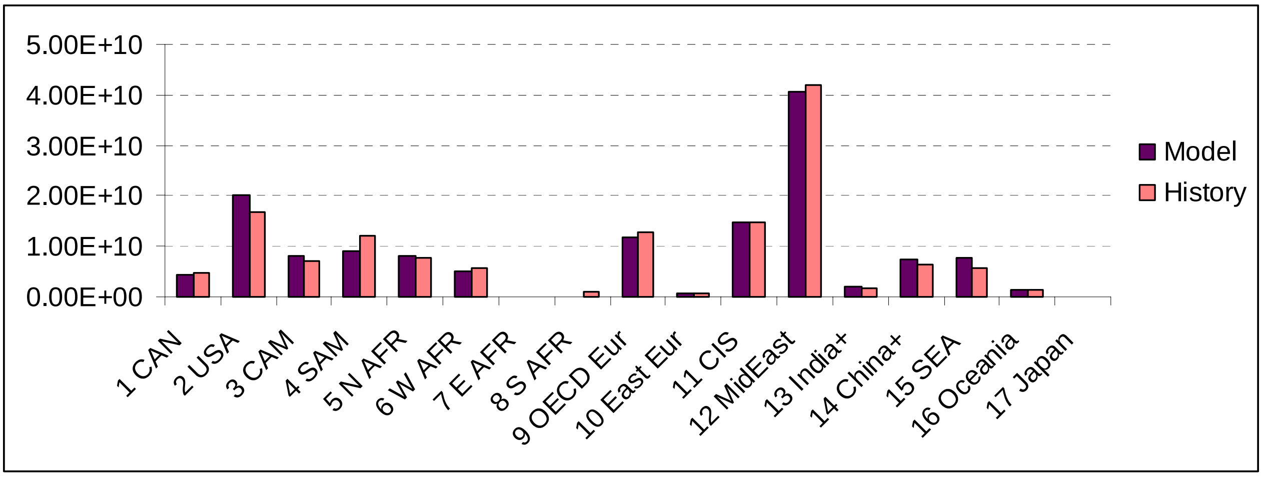

Figure 6.12: Comparison for oil production in 1995, simulated versus historical data.

After trade, the oil prices per region are much smaller than the differences in production costs. *Figure 6.13* shows the global trend in oil price – which is followed in most of the regions – for both historical data and according to the TIMER model. For the latter, we show the model results with and without the exogenously introduced oil crises (added to production costs). One can see that the global oil price level of the model does seem to be similar to the historical data.

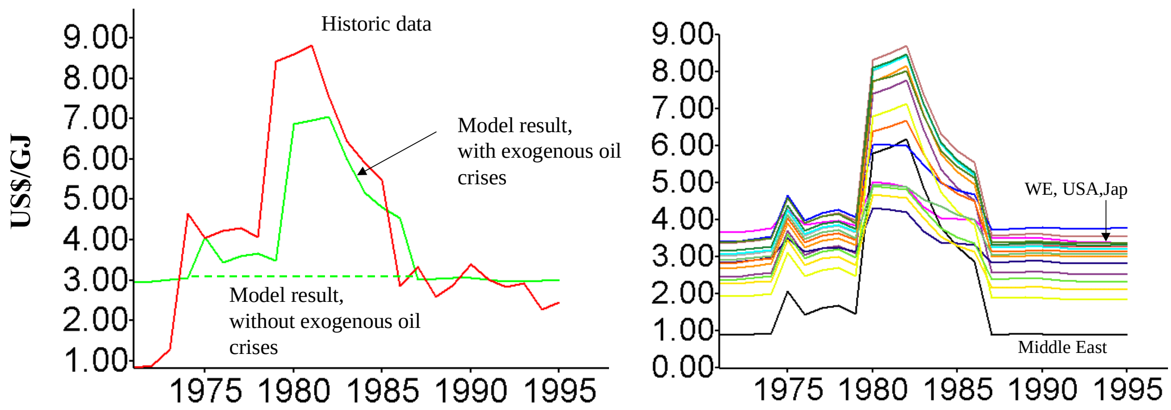

Figure 6.13: World oil price, historical data versus model results – before and after introduction of exogenous oil price data (left) and model results for regional oil prices (right).

The result of introducing the oil price shocks on the regional oil market prices was a significant demand reduction, partly through energy efficiency investments and partly through substitution to other fuels. However, in our simulation it has not affected the relative competitiveness of producers on the world oil market, at least not directly. A closer look into the Middle East region shows this (*Figure 6.14*). The model reproduces the much higher oil production than consumption in this region: the Middle East is a large exporter. Again, the model results are smoother than the historical data – in particular during the fall in production between 1980 and 1985. However, the simulated fall in oil output in the Middle East region is less rapid and deep than occurred in reality, which can be explained because the model did not capture the market share loss of the Middle East – and other OPEC countries – through a variety of mechanisms.

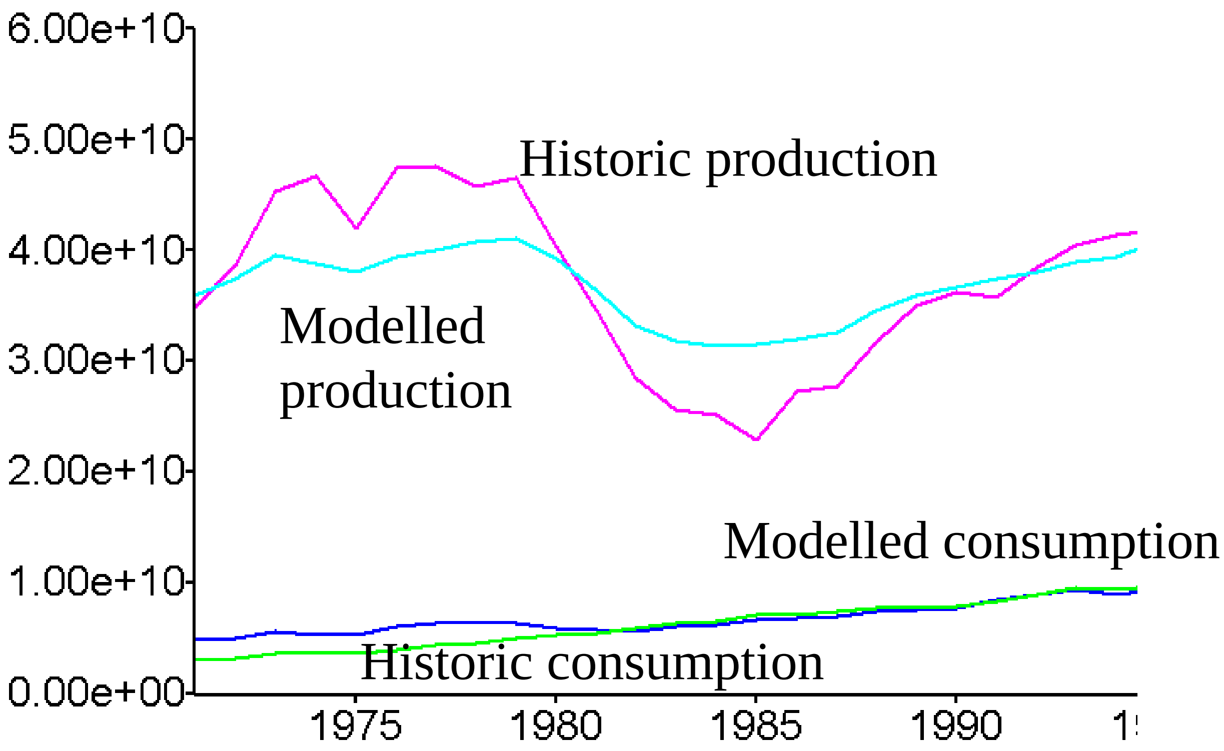

Figure 6.14: Oil consumption and production trends in the Middle East; simulated versus historical data

Natural gas production
The assumptions described in 6.4, finally result in regional natural gas production costs as indicated in *Figure 6.15*. As for crude oil, we can see large differences in production costs of natural gas. Very low production costs are found for most 'oil-producing' regions such as Northern Africa and Middle East. Also Western Africa and the Former Soviet Union have relatively low costs. In most regions, the current settings for technology development offset the assumptions made for depletion. This is, however, not in all regions. In two large oil consuming and producing regions, the USA and Western Europe, in fact the model results in increasing natural gas production costs. In Japan, natural gas production costs are extremely high.

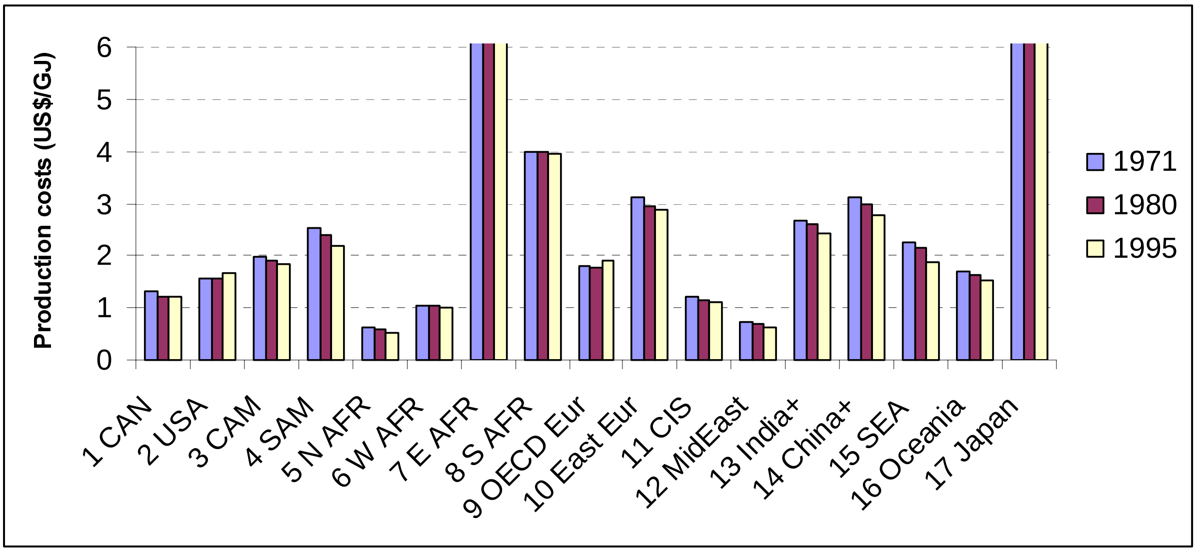

Figure 6.15: Natural gas production costs

Figure 6.16 shows the model results for world-wide consumption and production of natural gas (after calibrating also the natural gas trade model). The figure shows that currently, trade in natural gas among the TIMER regions is still relatively small (in most cases, production almost equals consumption). An important exception is Japan, which imports large amounts of (liquefied) natural gas from South-East Asia and the Middle East. Also Western Europe and the USA import natural gas, from respectively Northern Africa/FSU and Canada.

For the largest producing regions, *Figure 6.17* compares the model results with the historical data and indicates that the model is very well able to reproduce the historical trends. Finally, *Figure 6.18* shows the model results for natural gas prices per region, after trade. In comparison with oil, we see a much larger divergence in regional prices. The main reason is that there is much less interregional trade largely due to the much higher transport costs.

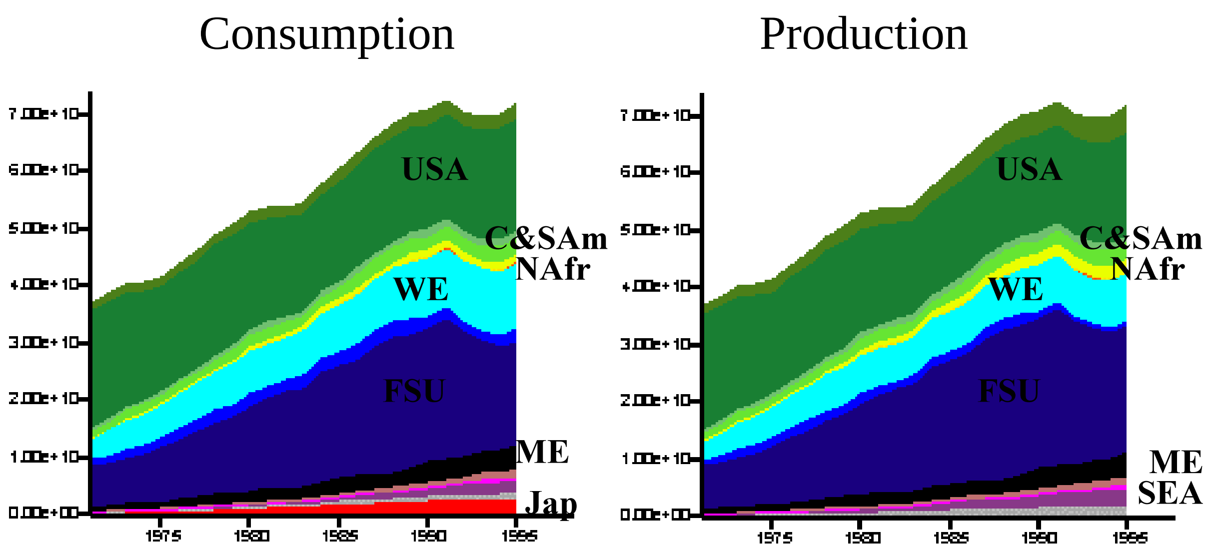

Figure 6.16: Consumption and production of natural gas, model results

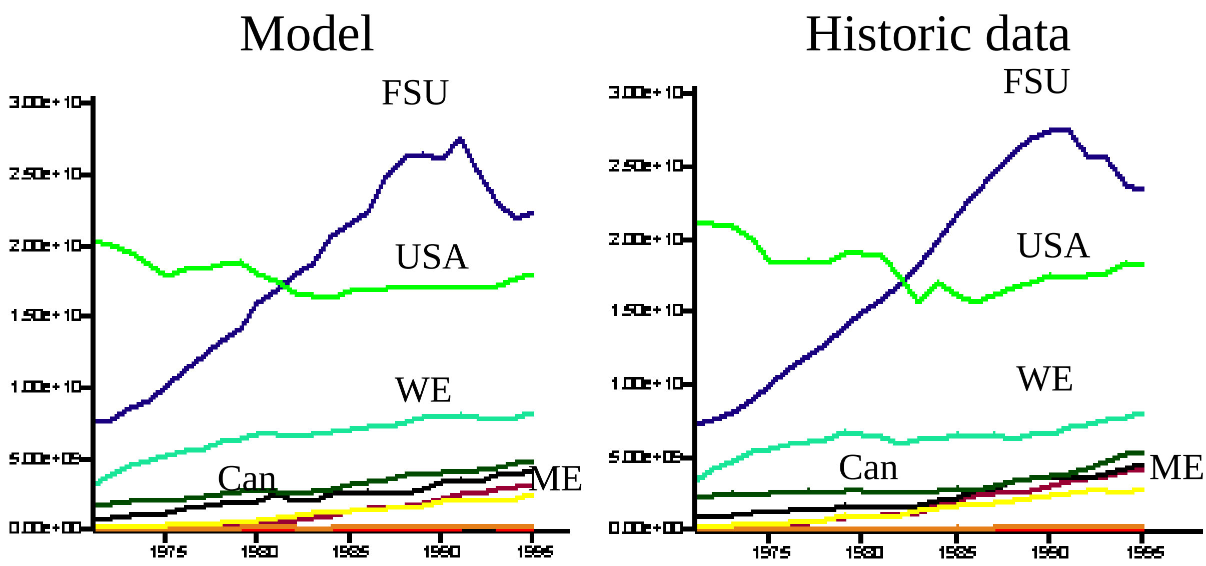

Figure 6.17: Natural gas production, model results versus historical data

Production of bioliquid fuels (BLF) and biogaseous fuels (BGF)

As with non-fossil electricity generation options, the use of commercial biofuels is an incipient technology with quite limited experience. In the TIMER model formulation, the production costs of bioliquid fuels and biogaseous fuels in TIMER are subject to technology development on the one hand and depletion of suitable land for biomass production on the other. In the calibration period, the last process is irrelevant in most regions – except for regions that already have limited means for food production. In these regions, we already see production costs to increase (Middle East, Northern Africa) or to remain high (other African regions) based on the assumption for land-availability as derived from the IMAGE Terrestrial Environment System (TES (*Figure 6.19*). In all other regions, we can see a strong decline of production costs driven by learning-by-doing, in particular in regions with relatively high production levels such as Southern America and the USA. The final production costs are still higher than fossil-based alternatives but in line with current estimates of biofuel production costs.

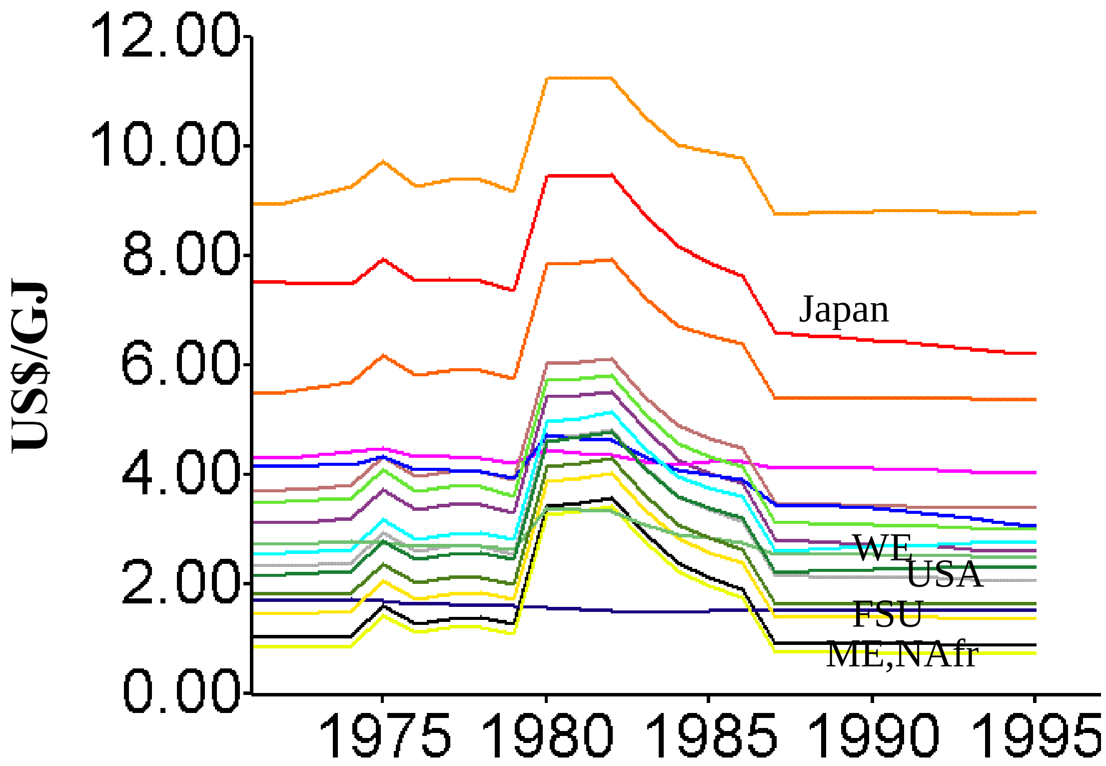

Figure 6.18: Simulated prices of natural gas per region

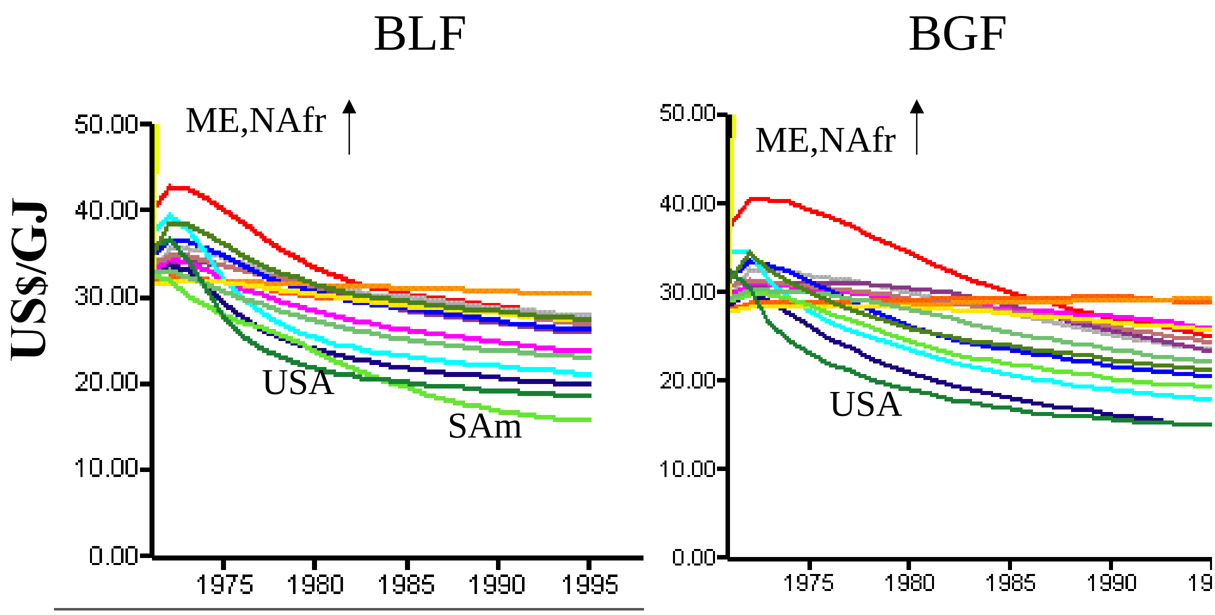

Figure 6.19: Simulated production costs of bioliquid and biogaseous fuels

Based on production costs and scenario driven 'demonstration projects' biofuels compete with their fossil fuel alternatives. *Figure 6.19* shows the production of bioliquid fuels, according to the model and according to historical data. It should be first of all noted that the production and consumption levels are relatively low compared to those for fossil fuels (compare for instance with *figure 6.11* and *6.16*). In South America the penetration of bioliquid fuels is largest – but still constrained to a few percent of total liquid fuel consumption. In *Figure 6.20* we can see that the model slightly overestimates production of biofuels – as in many regions the competition described by the multinomial logit equation results in a very small, but non-zero production level. For the largest bioliquid fuel producing regions, the South America and the USA the resulting production levels are comparable to the historical data.

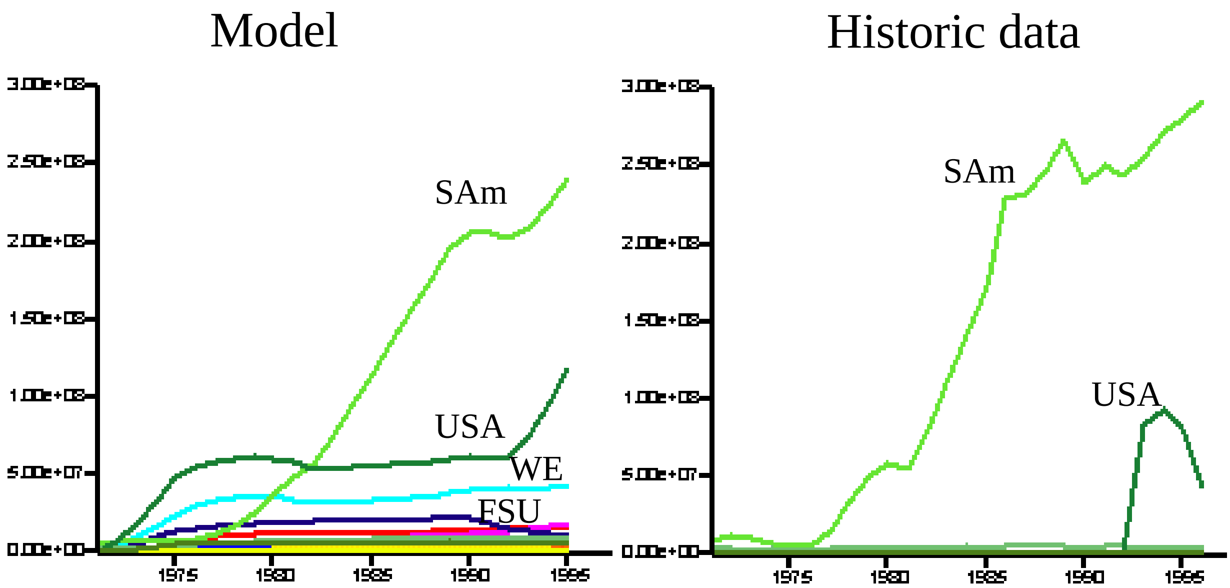

Figure 6.20: Production of bioliquid fuels, model results versus historical data

Figure 6.21 shows the model results for biogaseous fuels. Compared to bioliquid fuels, the production levels here are again a factor five lower. It is difficult to estimate the historic trends from the IEA data as this data source does not distinguish between waste and biofuels in electricity production nor between biogaseous and bioliquid fuels.

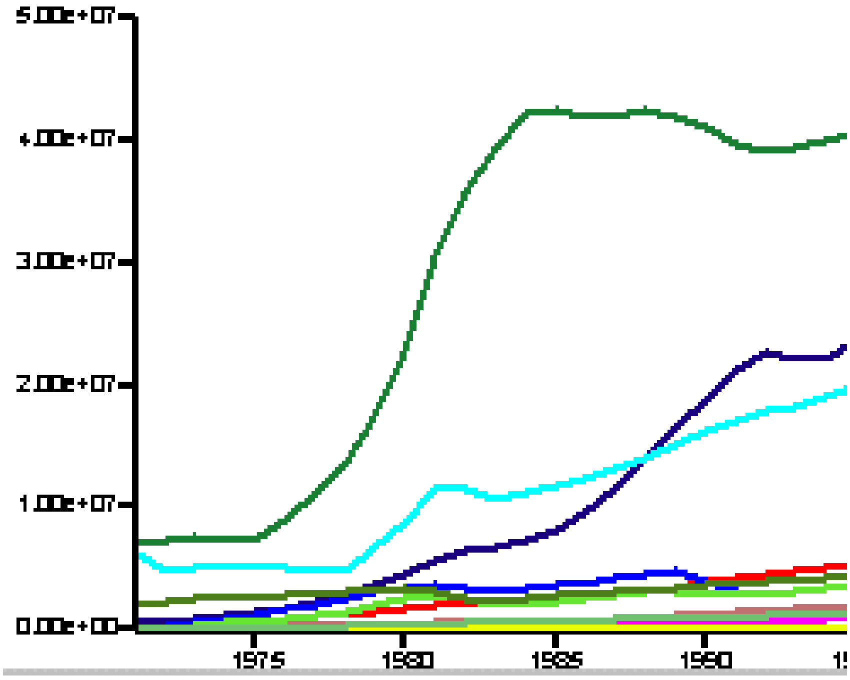

Figure 6.21: Production of biogaseous fuels, model results

6.6 Directions for future research

- At present, the add-on costs within a region to represent market prices is crudely modelled with help of aggregate multiplication factors. A more detailed, regional analysis can provide better insight into the role of oil/gas quality and associated upgrading (refining/conversion) and transport costs.
- As with coal, crude oil and gas can also be used to produce synfuels or other alternatives. For instance, it can be desirable to construct a long-term supply cost curve on more parameters than estimated production costs only: distance to user or trade centres, special products or techniques as with tar sands, oil shales or LPG.
- The modelling of traditional biofuels – and in particular the substitution with commercial biofuels – can be improved. Obviously, this is driven as much by the local resource situation – simulated to some extent in the IMAGE Terrestrial Environment System (TES) model – as by rational-choice market dynamics. The processes of urbanisation, of opening up of higher-income strata for commercial fuels such as kerosene and the informal exchange processes among the low-income segments in low-consumption regions should be better understood.
- Biofuels will be modelled in more detail, using the information available in the Terrestrial Environment System (TES) of the IMAGE 2.2 model. Biomass production functions will be improved. A separate description of biomass upgrading and conversion routes will be incorporated.

7. Regional Interactions: fuel trade and technology transfer

7.1 Introduction

An essential new dimension of this version of the energy model compared with previous IMAGE versions is the explicit treatment of reasoned interactions between regions. In the process of globalisation, markets for fuels and technologies are becoming increasingly global in scale and dynamics. Regional (energy) developments and policies have to deal increasingly with regional interactions and world-wide changes in prices and technologies. In this Chapter we describe the fuel trade model which has been applied in TIMER-17, and a mechanism for technology transfers between regions.

Aim of the fuel trade modules is to simulate the import and export flows for crude oil, coal, natural gas, bioliquid and biogaseous fuels (BLF, BGF). They are all part of the supply modules described in Chapter 5 and 6. First per region the demand for each fuel type is determined, and the associated production costs if this demand would be fulfilled by domestic production. Next, this demand can, in principle, be supplied by all regions based on their different production and transport costs (thus 17 different markets with in each market 17 different suppliers). These markets can be constrained by import and export barriers. The finally resulting import and export flows are added to the desired domestic fuel demand to result in desired production. In this way we are able to explore the long-term relevance of fuel trade on the energy efficiency trends and penetration dynamics of non-fossil options.

Trade liberalisation and the downward trend in transport costs make that the world's exploitation of fossil fuels occurs increasingly according to the hypothesis that the cheapest resource deposits are exploited first. In the past, this has not been the case at the world level, an obvious violation being the discovery of the giant low-cost oil fields in the Middle East (Yergin, 1991). However, since the 1950s there is effectively one world market for oil and for coal a world market is rapidly developing (Ellerman, 1995). For natural gas, this is not yet the case due to high transportation costs; this too may change in the next decades (Wit, 2000).

In our model formulation, we have attempted to represent the constrained market dynamics in a simple and transparent way. However, world fuel trade is a very complex phenomenon, as the large amounts of analysts and wrong predictions testify. The complexity of world fuel trade is reflected in the history of the oil market. *Figure 7.1* gives the oil price for different parts of the world. The figure clearly indicates the large ups and downs in the oil price over the last 28 years – but also the correlation between the oil prices for oil produced in different part of the world, which indicates the existence of a large global market. A detailed description of different events that have influenced the oil price can be found at the website of the EIA (EIA, 1999; http://www.wtrg.com). From World War II to 1973, oil production growth in new low-cost areas greatly outstripped growth in old high-cost areas. With the oil crises of 1973 and 1979, the lowest-cost producers, the members of the Organisation of Petroleum Exporting Countries (OPEC), exerted their market power and world market prices went up. This has induced waves of energy efficiency improvement and investments in fuel production elsewhere, with a subsequent decline in prices in the late 1980s. Another development is that oil-exporting countries increasingly use natural gas – instead of flaring it – in an attempt to free up oil for additional exports, because gas is more difficult to export in view of its high transport costs (Radetski, 1994). Non-OPEC-producers started seizing a larger share of the global market, a trend which has reverted with the oil price decline of the mid 1980s (*Figure 7.2*). The OPEC-members have cut back output and investment and produce only as much as they can sell, at current prices, while Non-OPEC producers sell all they can produce.

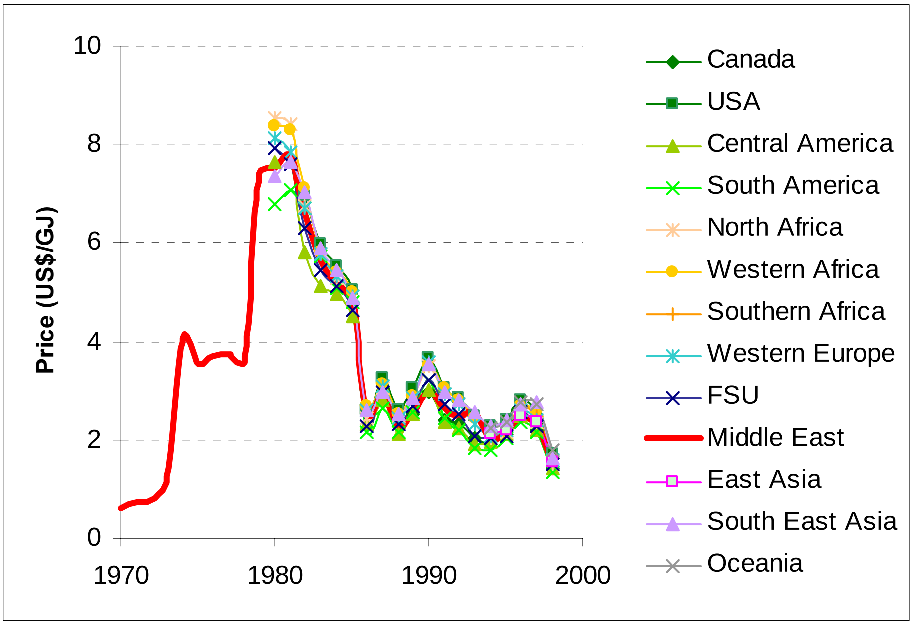

Figure 7.1 Nominal price of oil produced in different parts of the world, 1970-1998. Source: IEA, 1999 (thick line for Middle East is the price of Arabian light)

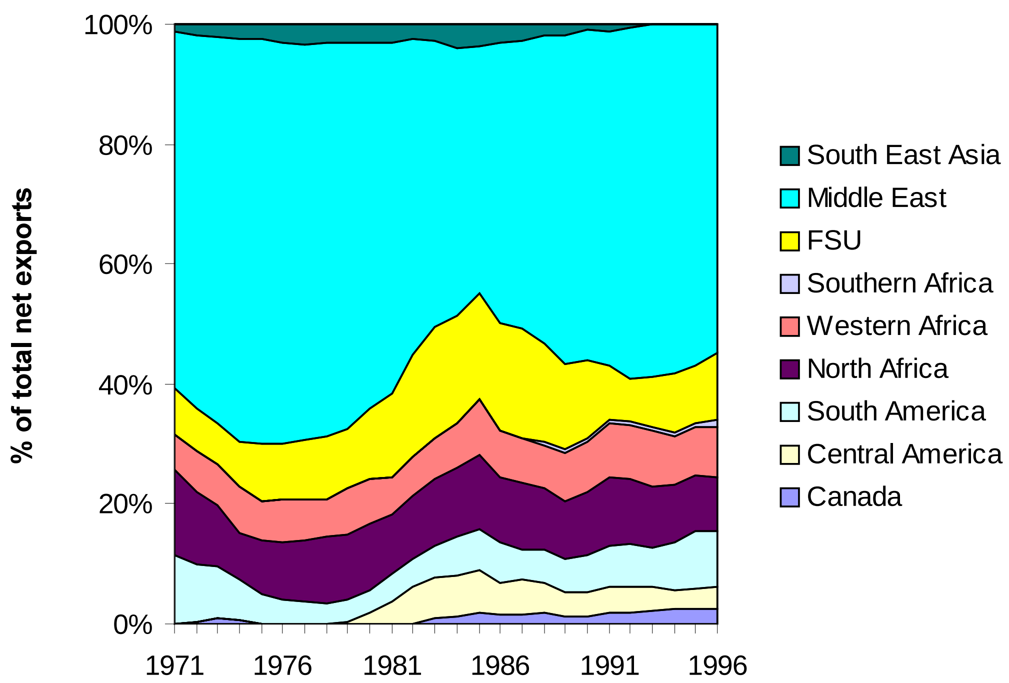

Figure 7.2. Regional shares of oil suppliers on the global market

According to Adelman (1994) the increasing oil prices in the 1970s and 1980s can not be explained by higher demand, deficient supply, changes in discounting, or political objectives.

Adelman argues that the explanation is the success of the sellers to achieve some degree of market control, i.e. oligopoly. When the oligopoly falters, the price declines. Because of expansion in higher-cost producing areas, the lower-cost producing areas lost their market control and hence market share. Attempts to regain their oligopolistic power have been only partially successful: the oil price in 1990 is in nominal terms about 4 times higher than in 1970, instead of 14 times higher as was the case in 1980. By the end of the 1990s the dropped back to a level twice the 1970 level. More recent attempts to reach agreements on producer quota among OPEC-producers appear to be more successful. The extent of an oligopoly in the world oil market can be judged from *Figure 7.3*, which shows the major trade movements and reflects the dominant role of the Middle-East in a different way. Several other interesting analyses of the recent history of the world fuel and especially oil market have been published, all of them emphasising the structural change in the form of transitions from a regime dominated by the multinational firms to one with producer and later consumer dominance (Baddour, 1997a; Stevens, 1996). Also other analyses of the role of OPEC on oil prices in more recent periods can be found (Reynolds, 1999; Berg, 1997). In the formulation of the TIMER-model, the objective is to be able to simulate directly or indirectly with proximate variables these complex events in such a way that they support scenario storylines (cf. Vries, 2000). First we briefly discuss fuel transport costs.

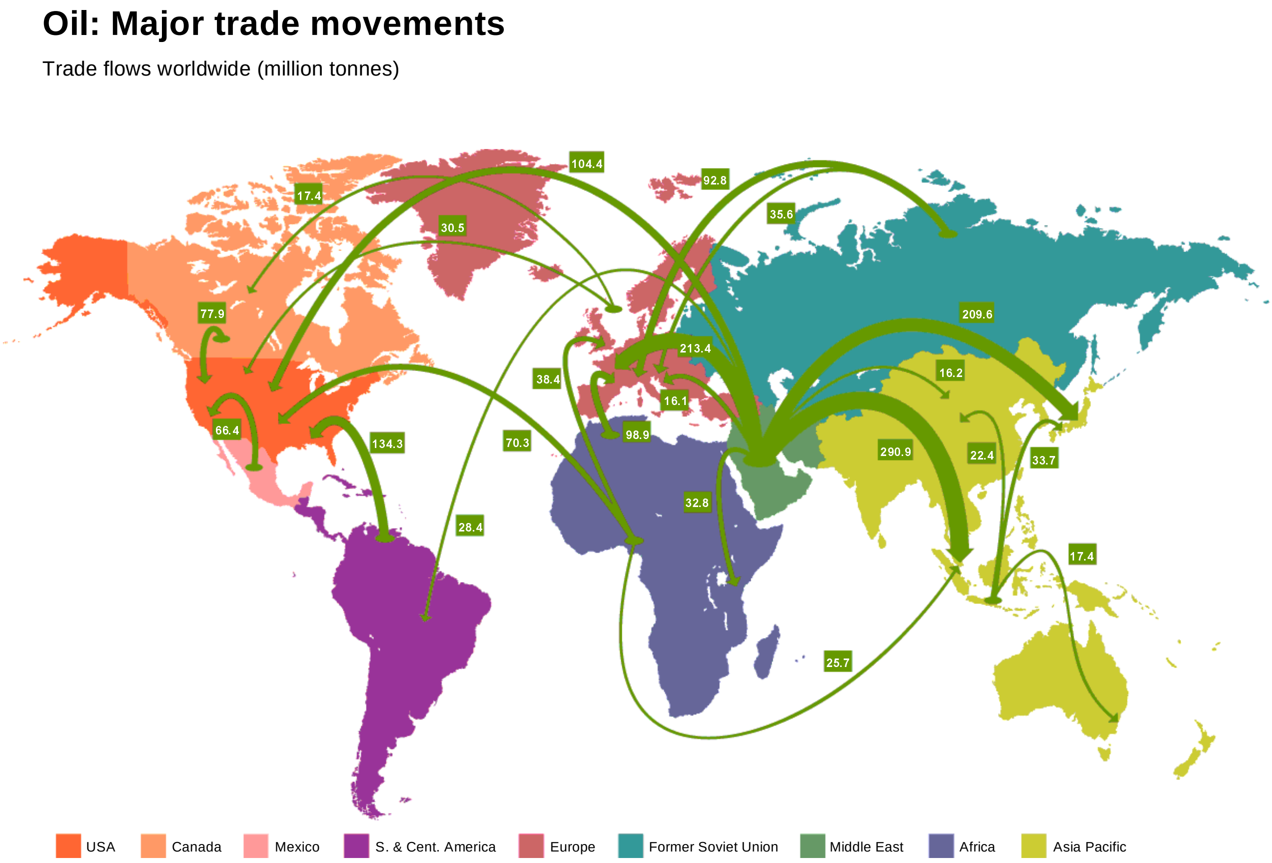

Figure 7.3. Major oil trade movements in 1999 (Source:BP, 1999, http://www.bpamoco.com/)

7.2 The trade models in TIMER 1.0

The trade module as developed for TIMER differs from most models as we do not apply the traditional equilibrium approach. In global trade models - for energy or other goods - the starting point is usually an optimisation routine in which the prices of the goods change in such a way that an equilibrium between supply and demand holds (e.g. Edmonds, 1985; CPB, 1995). The trade module of TIMER is a rule-based model where the market-shares are basically dependent by seller prices (which almost equal production costs – see *Chapter 5 and 6*, instead for the 'cartel' regions discussed in the previous paragraph). In a rule-based approach such as ours, relatively simple behavioural rules are incorporated in the model as a representation of 'real-world' agent behaviour. Of course, in reality the behaviour of the agents is far more complex. The reality of modelling is that intelligent and strategic behaviour can not be simulated adequately in a world energy model. Besides, the decisions of the agents depend also on other issues than energy policy alone. However, by extracting what we think is the kernel of their strategies we are able to simulate some essential aspects of fuel trade. In a way, we try to take up the point made by Adelman (1993b) that "*Modelling a supply system must include world wide development in investment/operation costs, but also the unbound unstable cartel, and the underachieving non-cartelists. Models which disregard these problems, and instead address 'geological assessments', have no tie to reality, and will give us no insights, let alone numbers*".

The trade models for all different fuels (oil, coal, natural gas, bioliquid fuels and biogaseous fuels) consist in principle of the following steps:

1. Determination of those regions that have much lower production costs than the main consuming regions – which could lead to cartelisation (only actively used for oil);
2. Determination of the market shares of all regions in all 17 markets based on selling prices (which might be increased with a cartel bonus) and transport costs;
3. Redistribution of market shares of regions that participate in a producers cartel (only used for oil);
4. Blocking imports to regions that have (assumed) active import barriers;
5. Blocking exports from regions that (assumedly) decide not to export to the world market (or limit their exports and producing capacity);

These different steps are discussed below.

7.2.1 Identifying those regions that might benefit from cartelisation

One of the important aspects of the international fuel markets is the existence of oligopoly power. Some regions with low-cost fields may exact high royalty payments if demand on the world market is high enough to support such oligopolistic rents. The interplay between producer countries, consumer countries and multinational fuel firms is an intricate one with complex and changing rules (see e.g. Abdalla, 1995; Austvik, 1992; Gochenour, 1992; Greene, 1998; Stevens, 1997a). We have designed a simplified scheme to simulate this part of the energy system.

We identify those regions that might consider supplying their resources at higher prices than their producer costs. From the production submodels, we know the average prices for energy carriers for the different regions. From this information, we can calculate the average world oil price without trade (a demand-weighted average):

$$WMPriceWT = \sum_R demand_R * price_R / \sum_R demand_R \qquad \$/GJ \qquad (7.1)$$

Regions that have much lower prices (determined by a threshold fraction β) than WMPriceWT can be identified as potential exporter regions. If these regions are able to make some form of mutual agreement to limit price competition, they can supply their resource at prices based on what consumers are willing to pay instead of their own production costs. For oil, we assume that such cartel is active. This limits their market share but increases their profits per unit of resource sold. The trade price at which the exporter group offers fuel on the world market, ExpTradePrice, is calculated as the marginal cost at which this group produces plus a part of the difference between this marginal cost and the WMPriceWT. In formula:

$$ExpTradePrice = \beta * WMPriceWT \qquad \$/GJ \qquad (7.2)$$

for those regions for which $DomPrice_i < \beta$ WMPriceWT. In this way the low-cost producers capture part of the rent in the form of additional producer revenues.

It should be noted that under the assumption of globalising markets, the production costs in the different regions have the tendency to converge. Low costs regions will have larger market shares, and thus the depletion formulation will have a larger impact. This means that in time, less regions will qualify for the condition to have significantly lower production costs than the average consumer price.

7.2.2 Determining market shares

In the next step is our assumption that the price of a fuel of region i on the market of region j is equal to the fuel supply costs in region i plus the transport costs from region i to j. We call this price the trade price of the fuel, TradePrice. Within the region, there are also transport costs. There may also be taxes and subsidies within the region; for instance, some regions may reduce the prices for reasons of employment as is the case in the German coal industry. These are added exogenously to the domestic fuel supply costs as non-zero premium factors reflecting subsidies, royalties or (windfall) profit margins.

The price at which a region i offers fuel on the world market, TradePrice, is in first instance set equal to the domestic price in the other region j plus transport costs from region j to I (TC_{ij}). We will discuss these transport costs in more detail further in this Chapter Hence:

$$TradePrice_{ij,t} = DomPrice_{j,t-1} + TC_{ij,k,t} \qquad \text{for } DomPrice_i > \beta \text{ WMPriceWT}$$

$$TradePrice_{ij,t} = ExpTradePrice_{j,t-1} + TC_{ij,k,t} \qquad \text{for } DomPrice_i < \beta \text{ WMPriceWT}$$

$$\$/GJ \qquad (7.3)$$

In the region itself (i=j), the TradePrice is set equal to the domestic producer price DomPrice plus added cost for inland transport to markets and ports.

We introduce an additional threshold in the decision to export fuels: only when the domestic price is not much higher than the world market price without trade, the region is willing and able to supply. If it is, the boolean variable BoolTHR equals 1, if it is not BoolTHR equals 0. In formula form:

$$BoolTHR_i = 0 \quad \text{if} \quad Dom\Pr ice_{j,t-1} > THR * WM \Pr iceWT \tag{7.4}$$

The next step is to determine the indicated fraction of fuel demand that the region would like to import based on economic consideration, IMSWM. As in similar allocation dynamics in the TIMER-model, the indicated market share is calculated from a multinomial logit formulation with λ the logit parameter:

$$IMS_{ij} = \mathrm{BoolTHR} * \frac{Trade\Pr ice_{ij}^{-\lambda}}{\sum_i Trade\Pr ice_{ij}^{-\lambda}} \quad - \tag{7.5}$$

The logit parameter determines the sensitivity of the market shares for price differences, a near-zero value indicating a low response to price differences.

At this point, we have introduced another distortion into the multinomial logit mechanism: if a region produces at costs above the world market price without trade, its export attractiveness is decreased through a multiplier. This multiplier increases like shown in *Figure 7.4*. For instance, if a region can trade to another region at twice the prevailing world-market price its effective trade price is doubled, whereas its effective trade price is 20% less if it can trade at half the world market price. The application of this multiplier is used to decrease or annihilate in the simulation trade across large distances to regions with (very) low prices, which would naturally occur in a multinomial logit formalism[59].

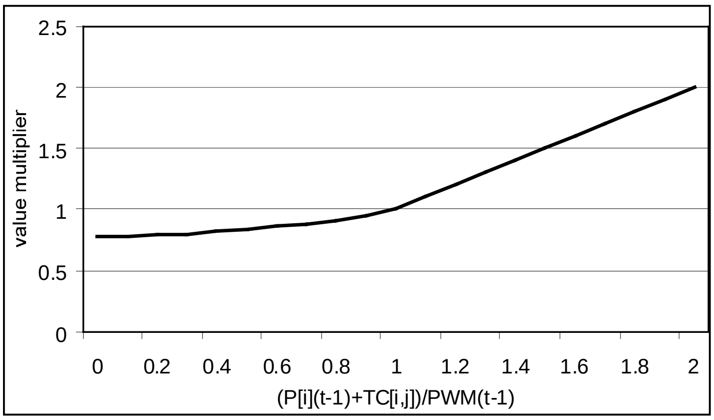

Figure 7.4 Multiplier on trade price (P[i] price of crude energy carrier in region i ($/GJ), TC transport cost ($/GJ), P_{WM} price of crude energy carrier on world market ($/GJ))

[59] The multinomial logit equation tends to give low but non-zero market shares to regions with high production costs. Both this multiplier and the BoolTHR are used to give cap these exports.

7.2.3 Redistributing the shares of the 'exporters group' regions

In equation 7.3 and 7.4, the 'export group' countries have used one common oil price (except for differences in transport costs). Given the equation 7.4, this will mean that they will have comparable market shares. In reality, however, we know that there are important discussion within the cartel group about the individual production levels. In the past, for instance, within OPEC reserves were an important potential factor in determining quota allocations (which gave an incentive for OPEC countries to strongly increase their published reserve estimates). In the TIMER model, we assume that within the export group again production costs determine the quota allocation, giving the largest quota to the producers with the lowest costs. The equation used is almost equal to 7.4, but this time for TradePrice again using DomPrice + TC, instead of the common ExpPrice, and EXP being 1 for 'export group' regions and 0 for other regions.

$$IMS_{ij} = (\sum_i EXP * IMS_{ij}) * \frac{EXP * Trade\Pr ice_{ij}^{-\lambda}}{EXP * \sum_i Trade\Pr ice_{ij}^{-\lambda}} \qquad - \qquad (7.6)$$

7.2.4 Introducing import constraints

Not all regions are open for fuel imports. Historically, for instance several non-market and market economies limit the oil imports to reduce import dependency on OPEC countries or the burden on the balance of trade. Therefore, we introduce a fuel import constraint. If the sum of the indicated market shares over all regions exceeds some historical or prescribed scenario value, IMS is normalised by multiplication with a factor ϕ equal or less than one. If such a constraint operates, it is assumed to affect all desired imports proportionately – which may of course be at fault with real world events.

7.2.5 Introducing export constraints

A final constraint is a limitation on export potential. In the past, some of the regions have not exported oil to the world market based on practical or political considerations. In TIMER, this is implemented by the assumption that some regions cannot export above a exogenously set fraction FracExp of their domestic demand or above the maximum production levels for each region based on existing production capacity in the production model (this latter check is only relevant in case of very fast swings in trade patterns). If the desired exports exceed these constraints, exports are curtailed by changing the calculated market shares IMS. Those regions which would get these exports are then assumed to import from other regions, either proportionately (oil, gas) or if necessary, also by backstop-suppliers (coal: USA and Australia as backstop suppliers). This leads to a new and final set of indicated market shares $IMSWM_{ij}$.

7.2.6 Calculating export flows and other world market parameters

Given the fraction of fuel a region wants to import, the desired imports, ImpDes, are equal to the desired market share times the domestic demand:

$$ImpDes_i = IMSWM_{ij} * DemDom_i \qquad \text{GJ/yr} \qquad (7.7)$$

The desired exports, ExpDes, from i to j are equal to the desired imports from j to i. The calculation allows for exports from i to j and from j to i. As we are basically interested in the net imports and export, we calculate the net imports and exports based on equation 7.6.

$$NetImpDes_i = MAX(0, IMSWM_{ij} * DemDom_i - IMSWM_{ji} * DemDom_j) \qquad \text{GJ/yr} \qquad (7.8)$$

Now, the market price of oil can be calculated.

$$OilPrice_j = \sum_i IMSWM_{ij} * TradePrice_{ij} \qquad \text{US\$/GJ} \qquad (7.9)$$

And the world oil price being equal to the consumption-weighted average.

The total desired imports and exports for any region, ImpDes + ExpDes, is the summation of the desired imports and exports minus the desired production for the own region in any given year (assuming the summation is over all regions). It is referred to as the fuel net trade, FNTrade (cf. Chapter 5 and 6). Hence, the desired production in any region, DesProdn, can be written as:

$$DesProdn_i = DemDom_i + FNTrade \qquad \text{GJ/yr} \qquad (7.10)$$

This information determines, within each of the supply modules (Chapter 5 and 6) the investments into production capacity.

As a final check in the model, the actual export is only equal to the desired export if the production is equal or larger than the demand. If production is less than domestic demand in the own region, export is zero and all production is supposed to be used within the region itself. If the production is less than demand plus desired export but higher than domestic demand, we assume a proportionate reduction: export is reduced by multiplication with the ratio of excess capacity and desired export. The underlying rules: indigenous demand is met first and all exports are cut proportionately, are meant as a crude representation of the real-world rules. Because the changes on the market are assumed to take place quickly, within a year, the simulation results may show discontinuities.

7.2.7 Transport costs

A crucial aspect of energy trade is the transport cost between the importing and the exporting region. By considering 17 regions without spatial detail, we are forced to highly simplify the actual situation on distances, transport routes and costs. The location and geographical situation of both suppliers and demanders largely determine the cost of transport between and within regions. We will discuss briefly some empirical information, and will thereafter discuss how we implement the transport cost into TIMER.

Interregional transport costs are the cost of large-distance transport by ship or pipeline. From the port of entry there are then similar distribution costs as for indigenously produced fuels. The size of transport cost depends among others on the type of fuel and on the kind of region. For example, the onshore location close to deep water, the size of the fields and their geology, largely explain the extremely low production costs of oil in the Gulf (Adelman, 1989). Coal and oil trade is mostly by ship although oil pipelines get an increasing share. Distance, scale and mode are the most important determinants of coal transport cost; capital and fuel costs are the major cost components (IEA/OECD, 1983; IEA/OECD, 1985).

For natural gas, large infrastructure investments are required to develop gas markets. The high initial cost of building the infrastructure of long-distance pipelines and regional distribution networks is a barrier to the use and trade of natural gas. Long-distance transport of gas, either by pipeline or in liquefied form as LNG by ship, is also expensive as compared to oil or coal. Transporting gas in an onshore pipeline might cost 7 times as much as oil; to move gas 5000 miles in a tanker may cost nearly 20 times as much (Jensen, 1994). Investments in pipelines and compressors may greatly exceed the investments in production (see e.g. Groenendaal, 1998). This explains why natural gas is still flared or used in large industrial and petrochemical complexes near the producing sites. In the future, however, extending pipeline infrastructure and large costs reductions in LNG transport can make interregional gas transport much more attractive (Wit, 2000).

In IEA (1994) and Hamilton (1998) (slightly different) relations are given between distance and transportation costs for various oil and gas transport modes (*Figure 7.5*). These relations show that for some transport modes rises rise rapidly with distance (e.g. natural gas pipelines), while for others initial costs are more important (e.g. for LNG). In addition to distance, also time plays an important for transport costs as result of dynamics of scale and innovation. Inland coal transport cost tend to decline linearly in a log-log representation but differently for different modes (IEA/OECD, 1985). Larger tankers, bigger pipelines and the associated innovations with regard to logistics, engine and compressor efficiency etc. all have tended to reduce the unit transport cost. Another factor is the capital-intensive nature of parts of the infrastructure such as ports and pipelines. Given the high initial cost, such infrastructure will be used at its maximum once it is available. This can be done by long-term contracts and can lead to lock-in effects. Once two regions have decided to trade gas or oil via pipelines, such a trade-connection will be more long lasting than using the more flexible tankers.

In the TIMER-model we use a simple approximation of the interregional transport costs. First of all, a distance matrix is used to indicate the distances between the 17 world regions. These distances are multiplied with a factor indicating transport costs per km; for most fuels this is a linear equations – except for natural gas, where the choice for pipelines and LNG depends on their respective costs (and thus on distance). In addition, to account for all other costs a weighing factor WFTC is applied for each possible route. This factor equals 1 unless there are reasons to assume specific transport costs over and above the prevailing long-distance ocean shipping costs. Examples of such 'barriers' are if regions can only be connected over land – in which case more expensive pipeline transport will be used – or political considerations. Such barriers are then represented by a WFTC > 1, that is, it is as if they are separated by a larger distance.

Given some average distance between each pair of regions i and j, D_{ij}, and some unit fuel-dependent cost per GJ, TCsp, the transport cost TC on route ij for fuel k are given by:

$$TC_{ij,} = \alpha + TCsp * D_{ij,} * WFTC_{ij,} \qquad \text{\$/GJ} \qquad (7.11)$$

The distance matrix and the combustion enthalpy are estimated from literature; α has been set to zero for pipelines and shipping, but is non-zero for LNG transport. The weighing factor matrix is filled with estimates based on literature and calibration.

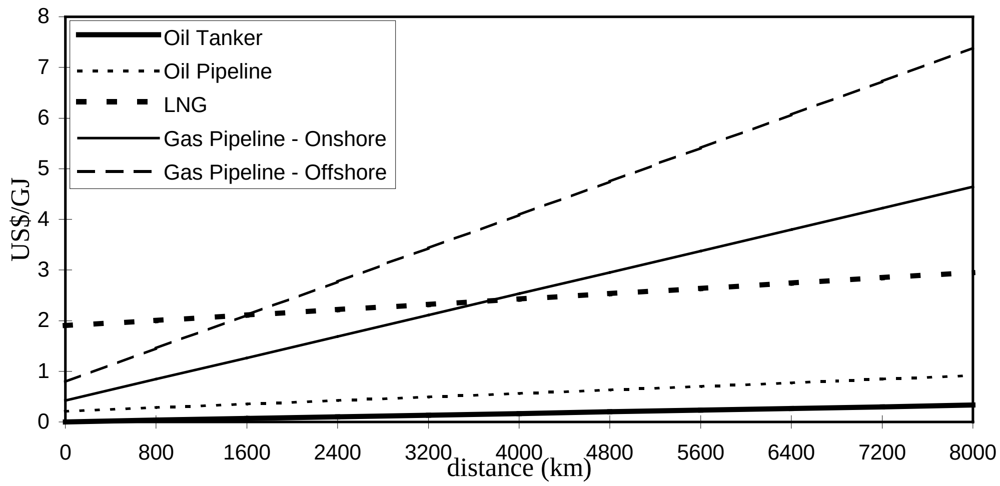

Figure 7.5: Relation between distance and transportation costs (Source: Jensen Associates Inc. as referred in IEA (1994))

Fuel trade issues may lead to interesting situations with large implications for the future world energy system. An example is the Russian natural gas policy in relation to the European gas markets (Quast, 1997a). Due to a larger reduction of domestic consumption, mainly industrial consumption and power generation, a Russian gas supply surplus is being created. The Russian gas-supplier has long term contracts with Western European countries. The dilemma of the Russian export strategy is how to place as much gas as possible in the growing Western European gas market, without destroying gas prices (Nakicenovic, 1998). Similarly, the political aspects of natural gas supply from Uzbekistan to the rapidly growing markets in northern India defy the rules of optimally efficient markets: investors weigh the political risk high enough to make only slow or no progress with these projects in a politically unstable world (Shukla, personal communication).

7.3 Fuel trade model implementation

Implementation of the trade parts in the supply modules is done for coal, crude oil and natural gas. The procedure has been to introduce first historical trade flows and check the simulated prices. After necessary parameter adjustments, the multinomial logit dynamics is switched on and a renewed calibration round is performed. This is a rather tedious procedure because an incorrect simulation of trade flows results in incorrect prices which in turn affect fuel demand and substitution dynamics.

Table 7.1 gives an estimate of coal transport costs for the major routes as of (IEA/OECD, 1983, IEA/OECD, 1985). The numbers indicate the large cost increase for transport and handling between the mine-mouth and the export harbour, which may also include forms of upgrading. Long-distance ocean transport adds less costs due to the large economies of scale. *Table 7.2* indicates crude oil transport costs per ton-km between 1952 and 1984: costs per ton-km have tended to decline as a result of economies of scale, innovations and improved logistics. *Table 7.3* shows the assumed transport costs in TIMER based on (IEA/OECD, 1994, Hamilton, 1998) and the information given in table 7.1 and table 7.2.

The transport distances for interregional transport are given in *Table 7.4*. Calibration is done by varying the values of WFTC, FracImp and FracExp in such a way that the supply and demand of the regions mimic historical records, given the simulated regional fuel prices. At the same time, we also calibrate the fuel trade model by adjusting parameters which determine the regional fuel supply costs within the production models such initial production costs and innovation rate. For some regions we introduced explicit subsidies for domestic production. The resulting calibrated model does not follow all shocks in trade of fossil fuels, but reproduces the general picture of export and import regions.

Table 7.1: Coal transport costs for major routes in the 1980s

Producing region	*Cost at mine*	*Cost at export harbour*	*Ocean transport cost*	
			To Japan	*To WE*
	$/GJ	$/GJ	$/GJ	$/GJ
AUS surface Q'l	0.43	1.25	0.25	0.45
AUS surface NSW	0.97	1.65	0.30	0.45
AUS underground NSW	0.76	1.57	0.30	0.45
US surface Appal	0.97-1.11	1.31-1.51	0.44	0.29
US underground Appal	0.71	1.49	0.48	0.22
US surface Wyoming	0.31	1.43		0.45
US underground Utah	0.82	1.73	0.30	
Canada surface West	0.75	1.52	0.30	0.42
South Africa surface	0.35	0.86	0.36	0.32
Colombia surface	0.87	1.76		0.23

Source: IEA/OECD, 1983, IEA/OECD, 1985

Table 7.2: The cost of crude oil transport (Stevens, 1997a).

	Crude price fob $/barrel	*Freight cost Gulf-US East Coast $/barrel*	*Freight cost as % of cif price*
1952	1.44	1.73	54.6
1972	2.47	0.92	27.2
1984	29.00	1.11	3.7

Table 7.3: Assumed transport costs in TIMER

	Coal	Oil	NG	LNG	
			Pipeline	fixed costs	variable costs
	US$/PJ/km	US$/PJ/km	US$/PJ/km	US$/PJ	US$/PJ/km
1971	60	34	683	2.5	171
1975	55	34	651	2.4	163
1980	50	34	620	2.3	155
1985	45	34	590	2.2	148
1990	45	34	579	2.1	145
1995	45	34	551	2.0	138

(see also Figure 7.5)

Table 7.4: Distance matrix used in TIMER-17 in '000 km

	1CAN	2USA	3CAm	4SAm	5 NAf	6 WAf	7 EAf	8 SAf	9 WE	10 CE	11 FSU	12 ME	13 SA	14 EA	15 SEa	16 OC	17 Jap
1 CAN	0.0	2.4	5.7	9.6	11.5	10.1	15.6	13.9	7.8	8.6	10.1	18.6	14.8	13.0	15.7	14.1	10.9
2 USA	2.4	0.0	2.7	8.4	10.5	7.4	15.5	12.6	5.9	9.8	11.1	18.8	15.9	13.4	15.7	13.4	11.3
3 CAM	5.7	2.7	0.0	7.3	12.1	11.0	17.1	14.2	10.5	11.8	13.2	19.1	18.8	17.0	21.6	16.2	15.0
4 SAM	9.6	8.4	7.3	0.0	10.8	6.6	12.5	7.0	9.9	12.2	12.6	22.7	15.8	19.5	17.2	15.8	17.7
5 NAf	11.5	10.5	12.1	10.8	0.0	8.7	6.0	12.3	3.3	1.4	1.8	9.0	8.0	16.5	10.8	19.8	16.3
6 WAf	10.1	7.4	11.0	6.6	8.7	0.0	9.8	4.3	8.1	9.6	10.1	14.2	12.7	19.0	15.1	19.1	20.5
7 EAf	15.6	15.5	17.1	12.5	6.0	9.8	0.0	5.4	9.0	6.2	6.6	4.4	4.2	12.1	6.7	12.5	12.1
8 SAf	13.9	12.6	14.2	7.0	12.3	4.3	5.4	0.0	11.4	11.4	11.7	9.9	8.4	14.7	10.8	24.0	16.2
9 WE	7.8	5.9	10.5	9.9	3.3	8.1	9.0	11.4	0.0	1.7	2.7	12.0	10.9	19.4	13.7	22.7	19.2
10 CE	8.6	9.8	11.8	12.2	1.4	9.6	6.2	11.4	1.7	0.0	0.5	9.2	8.2	16.6	11.0	19.9	16.5
11 FSU	10.1	11.1	13.2	12.6	1.8	10.1	6.6	11.7	2.7	0.5	0.0	9.7	8.4	1.8	5.7	9.7	1.2
12 ME	18.6	18.8	19.1	22.7	9.0	14.2	4.4	9.9	12.0	9.2	9.7	0.0	4.7	11.0	7.3	13.0	12.7
13 SA	14.8	15.9	18.8	15.8	8.0	12.7	4.2	8.4	10.9	8.2	8.4	4.7	0.0	6.6	2.9	10.5	8.2
14 EA	13.0	13.4	17.0	19.5	16.5	19.0	12.1	14.7	19.4	16.6	1.8	11.0	6.6	0.0	3.9	8.5	2.1
15 SEa	15.7	15.7	21.6	17.2	10.8	15.1	6.7	10.8	13.7	11.0	5.7	7.3	2.9	3.9	0.0	7.8	5.6
16 OC	14.1	13.4	16.2	15.8	19.8	19.1	12.5	24.0	22.7	19.9	9.7	13.0	10.5	8.5	7.8	0.0	8.3
17 Jap	10.9	11.3	15.0	17.7	16.3	20.5	12.1	16.2	19.2	16.5	1.2	12.7	8.2	2.1	5.6	8.3	0.0

Table 7.5 indicates that the import constraints for oil and natural gas are only active (values lower than 1.0) in a limited number of regions, for which it is known that they have been closed of the global market in specific time periods. For coal, more import constraints have been introduced.

Table 7.5: The values of FracImp for the period 1971-1995.

		1CAN	2USA	3CAm	4SAm	5 NAf	6 WAf	7 EAf	8 SAf	9 WE	10 CE	11 FSU	12 ME	13 SA	14 EA	15 SEa	16 OC	17 Jap
Coal	1971	0.4	0.0	0.3	0.3	1.0	0.5	1.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7
	1995	0.0	0.0	0.2	0.1	1.0	1.0	1.0	0.0	0.8	0.0	0.0	0.5	0.1	0.2	0.1	0.0	1.0
Oil	1971	0.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.8	0.0	1.0	0.7	0.3	1.0	1.0	1.0
	1995	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.8	0.0	1.0	0.7	0.8	1.0	1.0	1.0
NG	1971	1.0	1.0	1.0	1.0	1.0	1.0	0.0	0.0	1.0	0.1	0.0	1.0	0.0	0.0	1.0	1.0	1.0
	1995	1.0	1.0	1.0	1.0	1.0	1.0	0.0	0.0	1.0	0.8	0.0	1.0	0.5	0.5	1.0	1.0	1.0

7.4 Results of the calibration of the fuel trade models

Figure 7.6 shows the final indicated market shares at the Western European oil market as calculated by the model. It shows a continues trend with slightly declining Middle East market share and increasing market shares of domestically produced oil. This trend is in TIMER mainly driven by the assumed reduction in production costs in Western Europe. The trend does resemble historic trends in imports reasonably well. To give an indication of the overall performance of the trade model for oil, gas and coal – *figures 7.7, 7.8 and 7.9* compare model results for the average net imports of oil, gas and coal in the 1970-1985 and 1986-1995 with the historic data for the same period. The figures show all trade models to reproduce the historic trends and the main importing and exporting regions very well.

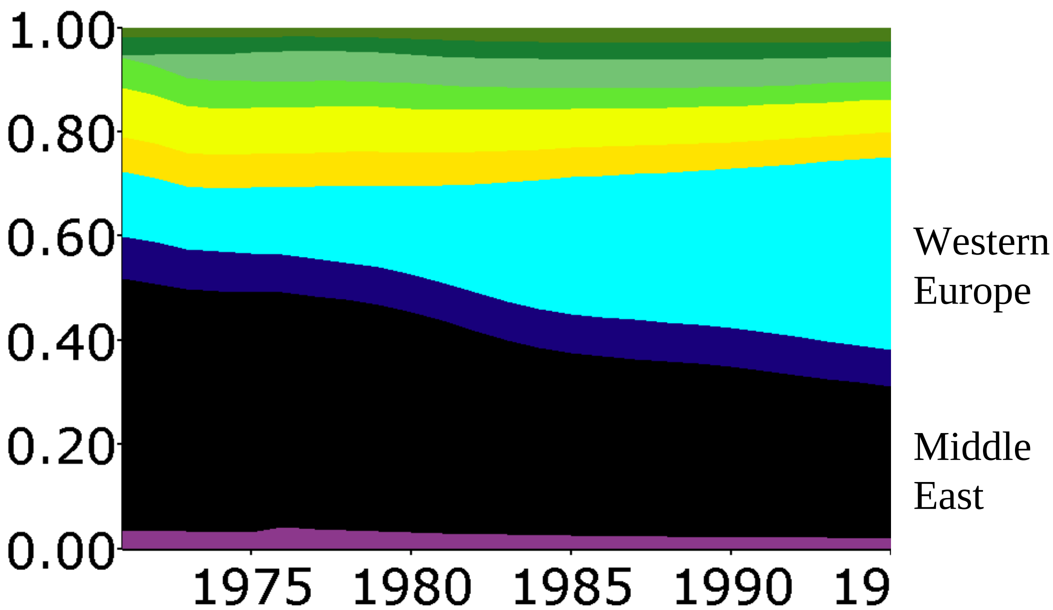

Figure 7.6: Market shares at the Western European oil market (model result)

For oil, both model and historic data indicate USA, Western Europe and Japan to be the main importing regions – and Middle East to be the main exporting region. In time, exports of Middle East have slowly declined (although they show a clear upward trend in the 1990s).

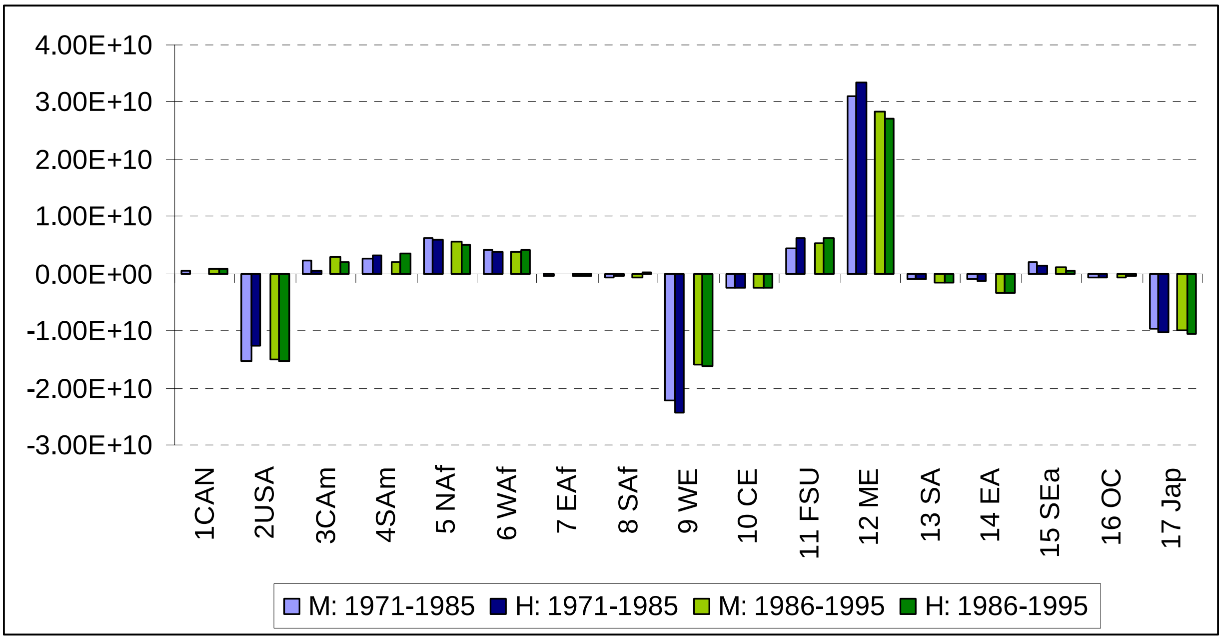

Figure 7.7: Results of the calibration of the oil trade model

For natural gas, the main importing regions are again Western Europe, USA, Japan and now also including Central Europe. The main exporting regions are Canada, FSU and South East Asia.

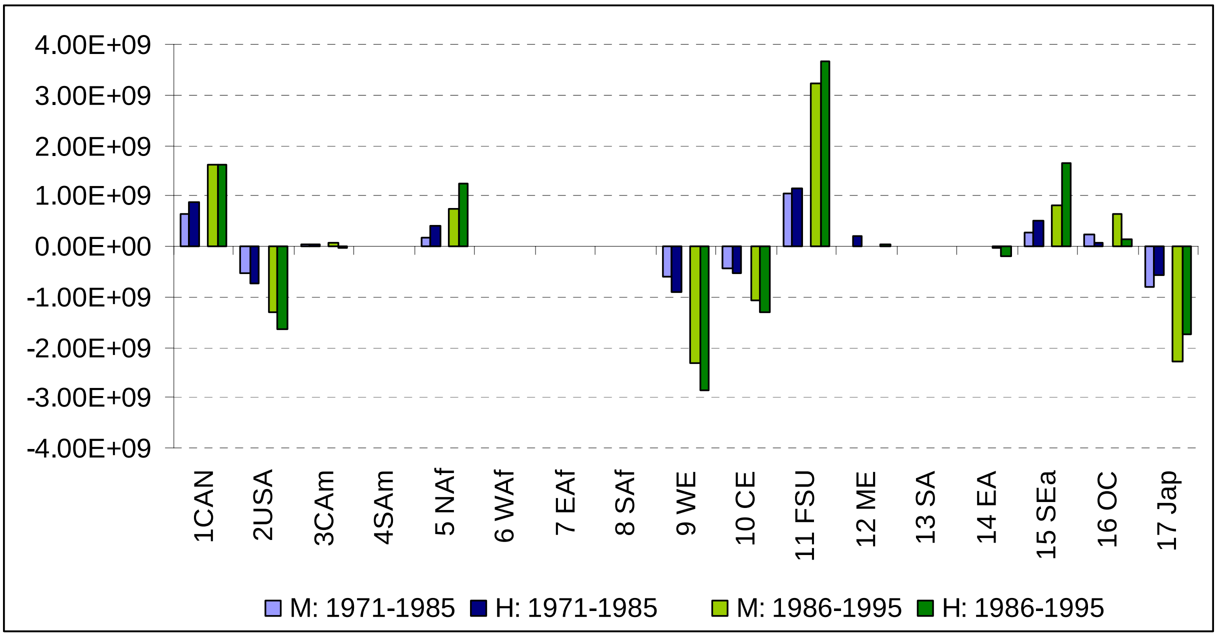

Figure 7.8: Results of the calibration of the natural gas trade model

For coal, the main importing regions are Western Europe and Japan – with imports rising in time. The most important exporting regions are USA, Oceania and Southern Africa.

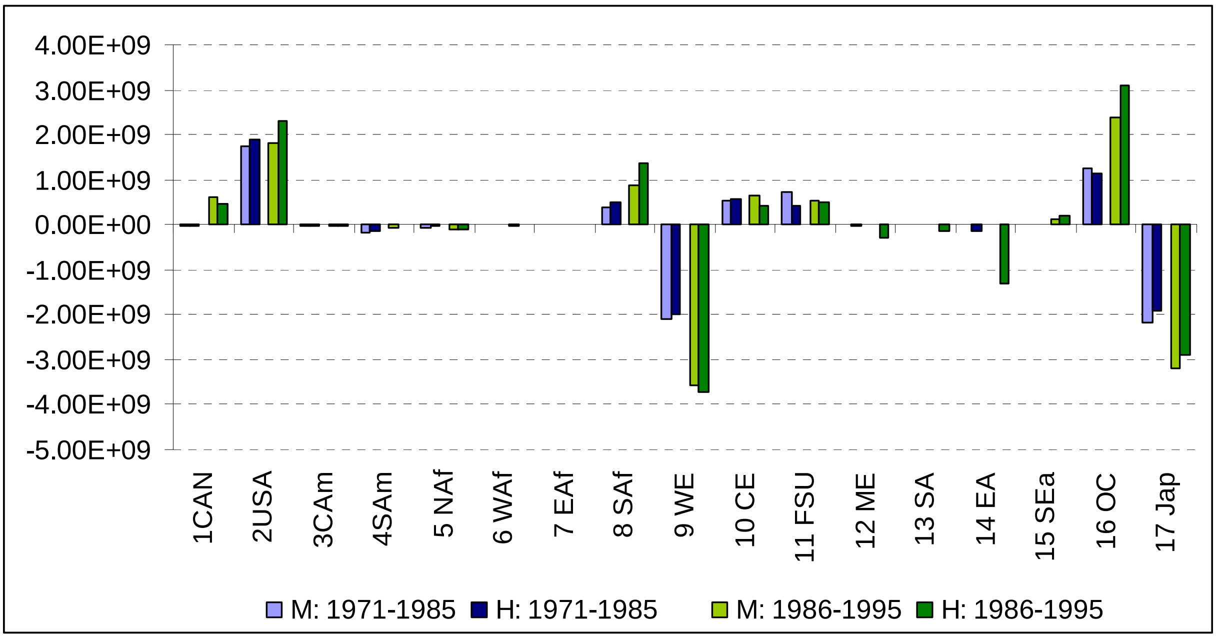

Figure 7.9: Results of the calibration of the coal trade model

7.5 Technology Transfers

7.5.1 Introduction

In explaining regional differences of economic growth, differences in technological development are a crucial factor. In relation to the energy model, the differences in technological development determines the differences in economic efficient reduction levels.

For policy analysis, it is interesting how to speed up technological development in order to meet climate change targets at the lowest possible cost.

Although neo-classical theory argues that technology is assumed to spread immediately there is a substantial amount of literature on technology transfers between national economics, which are often related to traded good as carriers of spillover (eg. Griliches, 1979, Silverberg, 1994). On the other hand knowledge can be transmitted by channels such as conferences, scientific literature, labour mobility, patent information, or pure imitation.

We follow the notion that technology diffusion is related to activities and abilities of the agents. Abromovitz (Abramovitz, 1986) argues that the catching-up process is conditional upon some specific factors, referred to a social capability and technological congruence. Social capability refers to all factors that facilitate the imitation of a technology, or the implementation of technology spillovers. This related to factors like education, financial conditions and labour market relations. Technological congruence concerns the extent to which the country is technologically near to the leader country, i.e. to which extent it is able to apply the technical features from the new knowledge.

In many places of TIMER, we use the 'learning-by-doing' concept to describe technology development. As the learning curve formulation is implemented at the regional level, this original formulation does not allow for technology to transferred among regions. Obviously, we know that in reality technology developed in one region will often become available in other regions as well – although the knowledge how to use and operate these technologies might be lacking for some time. Aim of this section is to describe how we have introduced in TIMER a simple formulation of the complex dynamics of technology diffusion in order to be of use in the energy policy model TIMER.

7.5.2 Description

We implement the catching-up process in line with the Worldscan model (CPB, 1999a), such that we can compare and use scenarios of Worldscan more easily. However, we also want to have the flexibility of a standalone model, and want to apply scenarios in order to assess the impact of increasing knowledge transfers on the energy supply and demand technology.

Define the technological front (TF) as the minimum of the technology level parameter (TL) over all the regions (that is if a decrease of the parameter reflex an improvement of technology, otherwise take the maximum):

$$TF(t) = (1-\tau)*MIN(TL[r](t-1)) \tag{7.12}$$

where τ is the mark-up of the notional technological frontier (in all cases chosen to be 0).

It is unclear which determinants determine catching up. CPB (CPB, 1999a) includes, among other determinants, capital-labour ratio and price competitiveness. However, the conditional factors as described in Abromovitz (Abramovitz, 1986) are not included adequately in both Worldscan and TIMER. We therefore want to have the freedom to define scenarios, which represent the complex qualitative developments in social capability and technological congruence. For example we may assume that political changes may lead to increasing social capability and technological congruence, and therefore are able to catch-up the technological development. Compare, for example, the developments in China, where a change in political conditions (allowance of capitalism in a communistic country) led to a drastic economic and technological catching-up.

So, by assuming scenario for, $\gamma[r]$, transformation factor we are able to mimic such developments. If γ is equal to 0 then there is no catching up to the technological frontier. In case of high values, the region will rapidly catch-up its technology to the level of the technological frontier.

We will assume $\gamma[r]$ to be a scenario variable representing the ability to catching up knowledge, but we can also relate γ to scenarios of the WorldScan model (CPB, 1999a) in which the transformation factor is estimated for different sectors. However, we are interested in more detailed analyses of the energy sector which makes the scenarios of Worldscan not a perfect fit for our goals.

Now, the catching-up is formulated as

$$\mathrm{LC_r(t)} = \frac{\mathrm{LOG}(\{\mathrm{TL_r(t-1)/TF(t)}\}^{\gamma}}{p * Q_r} \tag{7.13}$$

With p being the learning exponent (equal to –log(π)/log(2)) and Q the cumulative production in region r. The experience level after technology transfer is given by:

$$ExpLevel_r = Q_r + LC_r \tag{7.14}$$

Note that the regions itself learn due to the production of fuels, and can stimulate the learning (of alternative fuels) by R&D programs. The technology transfers (depending on the value of γ), however, will cause the fact that other regions may benefit from the early investments of the pioneer region. In the next Chapter some dynamic characteristics of the technology transfer module are discussed.

7.5.3 Calibration

In the calibration of the TIMER model, we have assumed technology transfer to be zero. Implicitly, technology transfer might have been taken into account by the different progress ratios used for different regions. In most of our scenarios, technology transfer is set at small, but non-zero levels.

8. TIMER Emission Model (TEM)

8.1 Introduction

This Chapter describes the TIMER Emission model (TEM). The objective of the TEM model is to calculate the regional energy-and industrial related emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), nitrogen oxides (NO_x), carbon monoxide (CO), non-methane volatile organic compounds (NMVOC), and sulphur dioxide (SO_2). In addition the model simulates also the emissions of the halocarbons, i.e. CFCs, HCFCs, HFCs etc. The model consists of two submodules: the energy-emission- and the industry-emission module, which calculate the energy- and the industrial related emissions of the greenhouse gases and other compounds. The TEM model replaces the original energy-industry emission model of the EIS model of IMAGE 2.1 (Vries *et al.*, 1994; Alcamo *et al.*, 1998). The methodology used is similar as in the original version, and recently updated with the following elements:

(i) emission factors for the different energy sectors and energy carriers for the period 1970-1995 are based on aggregated data from EDGAR 2.0 (Olivier *et al.*, 1999);
(ii) accounting for the time pathway of surface and deep coal mining, associated with coal mining emissions of CH_4;
(iii) The distinction of liquid fuel into HLF and LLF;
(iv) the explicit inclusion of the following new energy sectors (compared to the IMAGE 2.1 version): marine bunkers (notably for CO_2 and SO_2), gas flaring associated with oil production (CO_2) and feedstock use (CO_2) , and the distinction between surface and underground coal production (CH_4);
(v) the spatial scale is now extended to the 17 regions;
(vi) an update of the base year to 1995;
(vii) the inclusion of the three groups of greenhouse gases, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF_6);
(viii) the inclusion of the 1995-2100 trends of the inclusion of the technological improvements and mitigation/abatement strategies of the emission factors as used for the development of the latest IPCC SRES scenarios, in line with the narratives.
(ix) an updated methodology for the calculation of the energy SO_2 emissions by combining regional fuel consumption figures with data on fuel properties, in particular the sulphur content of coal and oil, ash retention characteristics of each fuel and combustion process, and the level of emissions controls in each sector.

The TEM model consists of two submodels: energy-emissions submodel and the industry-emissions submodel.

8.2 Energy Emissions submodel

The Energy Emissions submodel calculates the regional energy-related emissions of the three major greenhouse gases: CO_2, CH_4 and N_2O, and the acidifying compounds: NO_x and SO_2, as well as the ozone precursors: CO and NMVOC. The main input forms the energy end-use consumption, energy consumption by electric generation and the total energy production as simulated by the TIMER energy demand and supply submodel, as described in the previous Chapters. The module itself applies emission factors to the regional energy consumed and produced per energy carrier in each energy sector to compute the energy-related greenhouse gas emissions.

The following nine energy sectors are considered:
(i)–(v) five energy end-use sectors, i.e. industry, transport, residential (households), services (commercial and public) and others (agriculture and others);
(vi) energy consumption by electric power generation;
(x) other energy transformation;
(xi) fossil fuel production (coal production, flaring of gas associated with oil production, gas transmission, etc.); (ix) marine bunkers (international shipping).
The five energy carriers distinguished are the four types of fossil fuels, i.e.
(i)-(iv) solid (coal and coal products), Heavy Liquid Fuel (HLF) (diesel, residual fuel oil and crude oil), Light Liquid Fuels (LLF) (LPG and gasoline), gas (natural gas and gasworks gas); and
(v) modern biofuels (such as ethanol).
Emissions from burning of traditional biofuels (fuelwood etc.) are calculated in the Land use emissions model. Any 'net' CO_2 emissions from production and use of modern biofuels are also calculated in the Land use emissions model.

Overview reduction measures & costs

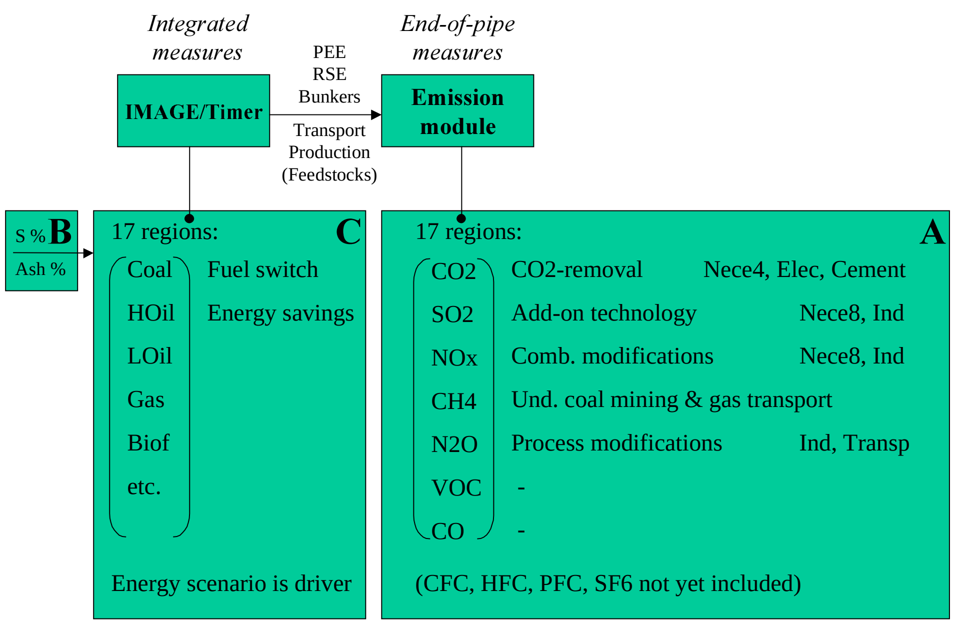

Figure 8.1: Overview of reduction measures and costs

The distinction of liquid fuel into HLF and LLF, and the explicit inclusion of the following energy sectors are new elements of the present model compared its IMAGE 2.1 version: marine bunkers (notably for CO_2 and SO_2), CO_2 from gas flaring associated with oil production and feedstock use of energy carriers. We also distinguish between surface and underground coal mining (related to the CH_4-emissions). Because of its non-energy character, the use of energy carriers as chemical feedstock is treated as a non-fuel source of CO_2 in the Industrial Emissions module.

General approach. The general methodology to estimate the combustion emissions for compound *C* (*EM*) is by applying emission factor (*EF*) to the regional activity levels (energy consumption and production) (*EN*) for region *r*, energy sector *s* and energy carrier *f* at time *t*:

$$EM_C\,[r,s,f]\,(t) = EN[r,s,f]\,(t) \times EF_C\,[r,s,f]\,(t) \times abt_C\,[r,s,f]\,(t) \qquad (8.1)$$

with abatement factor *abt* for mitigation and abatement technologies (see next paragraph). The Input of the model forms the energy end-use consumption, energy consumption by electric generation and the energy production (TIMER energy demand and supply submodel). For primary coal, oil and gas production, where emissions are partly due to non-combustion processes such as venting and gas leakages, the model uses the same approach as described above.

Table 8.1: Energy consumption and production activity matrix for the various regions, energy sectors and energy carrier types. Emissions of traditional biofuels are calculated in IMAGE-TES

17 IMAGE 2.2 regions (*r*)	9 energy sectors (*s*)	5 energy carriers (*f*)
Canada USA	Energy end-use: Industry	Solid
Central America Latin America	Energy end-use: Transport	Heavy Liquid fuels (HLF)
North Africa East Africa	Energy end-use: Residences	Low Liquid fuels (HLF)
South Africa OECD-Europe	Energy end-use: Services	Gas (natural gas)
Eastern Europe *CIS*	Energy end-use: Other	Modern biofuels*
Middle East India	*Transformation*	
China & CPA West Asia	*Power generation*	
Oceania Japan	*Energy production (Losses/venting)* *Bunkers*	

*Emissions reduction options***.** In the overall TIMER model (including the TIMER energy demand and supply submodel and the TIMER emissions submodel), roughly two types of emission reduction options can be distinguished: add-on technologies and integrated (energy) technologies. Add-on technology concerns end-of-pipe technologies, which do not directly interfere with the energy system. Therefore, these emission reductions are calculated separately in the Energy-Industry Emission model. Add-on technologies, potentials are particularly relevant for the assessment of mitigation strategies for regional air pollution. Examples of add-on or end-of-pipe technologies are given in *Table 8.2*. Integrated reduction options, such as efficiency improvements, energy conservation and fuel switch (particularly relevant for climate change mitigation), take place in the heart of the energy system and thus the TIMER energy demand and supply submodel.

Emissions factors

Since we use highly aggregated sectors and energy functions (heat and electricity demand) in the TIMER model, we must also use specific aggregated emissions factors for the different energy sectors and energy carriers. For the IMAGE 2.2 version the values of the emissions factors for each energy carrier type, energy sector, substance and the 17 IMAGE regions are all adapted. The factors are now based on aggregated data from EDGAR 2.0 (Olivier *et al.*, 1996;

1999)[60], except for SO_2 in industrialised regions where emission factors have been calibrated against other published emission estimates. The EDGAR 2.0 emission factors are in line with the values for CO_2 used by Marland *et al.* (1994) and for other compounds with defaults emission factors recommended by the IPCC (IPCC, 1996). In fact the latter are to a large extent global aggregates of regionally aggregated emission factors from EDGAR 2.0.

Table 8.2: End-of-pipe SO_2 emissions control techniques for the different energy sectors.

Energy carriers	End-use	Electric power generation	Fuel supply sectors
Solid (hard coal, brown coal, coke)	Clean coal technologies, mainly in industry	FGD, integrated gasifiers a.o. in power plants	Coal cleaning (indigenous and import)
Liquid (crude oil based LLF and HLF [a])	Fuel specification standards and abatement techniques for LLF in transport, residential and services and HLF in industry and other.	FGD, integrated gasifiers a.o. in power plants; Fuel specification standards. CHP, small gasturbine, fuel cells	Oil refineries (Claus plants), bunkers
Gaseous (natural gas)	As with Liquid	CHP, small gasturbine, fuel cells	
Hydropower, nuclear power a.o.			
Other renewables (solar, wind, biomass-derived)	Fuel specification standards and abatement techniques for (commercial) biofuels; passive solar, small-scale wind.	Fuel specification standards and abatement techniques for (commercial) biofuels; solar PV and wind.	

a) Light Liquid Fuels LLF, Heavy Liquid Fuels HLF

The emission factors of CO_2 of the end-use combustion sources and the electric power generation were all set equal to the fixed global value for each of the five energy carriers considered [61], as in EDGAR 2.0. These factors are based on IPCC (1994) and Marland and Pippin (1990) and are very similar to those of CDIAC (for a comparison see Marland *et al.*, 1999). Also for marine bunkers the emission factor was set on a fixed global value, based on EDGAR aggregates of IPCC recommended factors (IPCC, 1996). For the oil production sector, the emission factors of CO_2 from gas flaring are based on regional factors from EDGAR 3.0, which are based on CDIAC data (Marland *et al.*, 1994).

For CH_4 the emission factors per sector and energy carrier were set equal for all regions and kept constant over time, except for the transport sector where emission factors are region dependent. In addition, the model takes into account emissions of CH_4 that are related to fuel production and transportation/distribution (surface and underground coal mining, oil and gas production, gas supply) such as CH_4 leakage from natural gas pipelines. The emission factors of CH_4 for these sources have been taken from EDGAR.

[60] The EDGAR database is a joint project of RIVM and TNO and stores global inventories of direct and indirect greenhouse gas emissions including halocarbons both on a per country basis as well as on 1o x 1o grid. The database has been developed with financial support from the Dutch Ministry of the Environment (VROM) and the Dutch National Research Programme on Global Air Pollution and Climate Change (NRP), in close cooperation with the Global Emissions Inventory Activity (GEIA), a component of the International Atmospheric Chemistry Programme (IGAC) of the International Geosphere-Biosphere Program (IGBP).

[61] In IMAGE 2.1 model a correction was made for the coal products used in Eastern Europe, since for this region there is a relative high share of brown coal in total solid fuel consumption.

For N_2O from stationary sources, emission factors were set equal for all regions and kept constant over time, except for the emission factors for national transport sources (energy carrier: LLF, i.e. gasoline). For non-OECD regions the same value was used for the period 1970-1995, except for the regions Canada, USA and Japan, which were assigned to a higher factor over the period 1970-1995 because of the increasing fraction of catalyst-equipped cars in the vehicle fleet, and Oceania and OECD Europe having introduced catalytic converters in the late 80's. Emission factor values are calibrated to the shares of catalyst equipped gasoline cars in these regions in 1990 as determined for EDGAR 2.0 (Table 1 in Olivier *et al.,* 1999). In IMAGE 2.1 these region- and year-specific emission factors for (road) transport were only included for the Canada and USA.

For CO, NO_x and NMVOC, the region-, energy carrier- and sector-specific emission factors for 1990 were based on the aggregated factors from EDGAR 2.0. Subsequently, it was assumed that emission factors which are in 1990 lower than the 1990 global average factor for that sector and fuel type, were higher in the past due to active or gradual improvements in technology or increased application of control technology. Thus, in these cases the emission factors for 1970 were put at the average value of 1990 with interpolated values in between. For emission factors in 1990 that were higher than the global average the values are assumed to be constant in the period 1970-1990. The transportation sector is the dominant sector for the CO and NMVOC emissions from fossil fuel use and is also a major contributor to NO_x emissions.

SO_2 emissions which are the largest source of sulphate aerosols and, thus important in assessing climate change, are primarily caused by the energy-related sulphur emissions. Sector- and region-specific emission factors for 1990 were taken from EDGAR 2.0 (Olivier *et al.*, 1996; 1999), for fuel combustion provided by Berdowski (pers. comm., 1995), Kato and Akimoto (1992).

For the calculation of the energy SO_2 emissions an updated methodology is used by combining regional fuel consumption figures with data on fuel properties, in particular the sulphur content of coal and oil (*SuC*), ash retention characteristics of each fuel and combustion process, and the level of emissions controls in each sector. For each region the following equation is summed over fuel types and consumption:

$$EM_{SO2}[r,s=7,f](t) = EN[r,s=7,f](t) \times SuC[r,f](t) \times (1 - f_{ash}[r]) \times (1 - f_{control}[r,s=7,f](t)) \quad \text{[TgS/yr]} \qquad (8.2)$$

where f_{ash} is the fraction of the sulphur retained in ash and $f_{control}$ is the fraction that is removed by emissions controls, which could be several end-of-pipe desulphurization techniques, such as Flue Gas Desulphurization (FGD) in the electricity sector. Examples of reduction techniques are described in *Table 8.4*. The sulphur content for the different fossil fuel types, i.e. coal and oil is calculated by the TIMER model, and depends on the various fossil trade flows between regions, and the actual sulphur content of the available coal and oil in a region.

Table 8.3: Model variables for calibration construction of the emissions model.

Variable	Subscript	Description	Unit/domain
$EF_{CO2}[r,s,f](t)$	$r,s=9,f=1..3, t$	Emissions factors of CO_2-emissions related to the bunker emissions	GtC/GJ
$EF_{SO2}[r,s,f](t)$	$r,s=1..5,f, t$	Emissions factors of SO_2-emissions that are related to the five energy end-use sectors	TgS/GJ
$EF_{SO2}[r,s,f](t)$	$r,s=9,f=1..3, t$	Emissions factors of SO_2-emissions related to the bunker emissions	TgS/GJ
$f_{ash}[r]$	r	the fraction of the sulphur retained in ash related to the SO_2-emissions	0-1
PPPmult(t)	t	PPP-income multiplier for SO_2-emissions controls	0-1
ENV(t)	t	environmental multiplier for SO_2-emissions controls	0-4
WTP[r] (t), or $f_{control}[r,s=7,f](t)$	t	willingness to pay multiplier, or fraction that is removed by emissions controls in the power energy sector	0-4, or 0-1
$f_{control}[r,s,f]$(t)	$r,s=1..6,f, t$	fraction that is removed by SO_2-emissions controls for the various energy end-use sectors	0-1
$f_{control,\ ind}[r]$(t)	r, t	fraction that is removed by the overall SO_2-emissions controls within the industry sector	0-1

Table 8.4: Model variables for scenario construction of the emissions model

Variable	Subscript	Description	Unit/domain
$EF_{CH4}[r,s,f](t)$	$r, s=8,f, t$[a]	Emissions factors of emissions of CH_4 that are related to fuel production and transportation/ distribution losses (surface and underground coal mining, oil and gas production/ supply)	TgCH4/GJ
CSS[r](t)	r, t	Fraction of the total coal production from surface mining related to the CH_4–emissions (calculated by the TIMER model)	-
$EF_{N2O}[r,s,f](t)$	$r,s=2,f=3\ t$	Emissions factors of emissions of N_2O that are related to energy-end use in the transport sector from fuel type LLF	TgN/GJ
$EF_{CO}[r,s,f](t)$	$r,s=2, f, t$	Emissions factors of emissions of CO that are related to energy-end use in the transport sector from fuel type LLF and HLF	TgCO/GJ
$EF_{NOx}[r,s,f](t)$	$r,s=2, f, t$	Emissions factors of emissions of NO_x that are related to energy-end use in the transport sector from fuel type LLF and HLF	Tg NO_x/GJ
$EF_{NOx}[r,s,f](t)$	$r,s=7, f, t$	Emissions factors of emissions of CO that are related to electric power sector	Tg NO_x/GJ
$EF_{VOC}[r,s,f](t)$	$r,s=2, f, t$	Emissions factors of emissions of NMVOC that are related to energy-end use in the transport sector from fuel type LLF and HLF	TgVOC/GJ
SuC[r,f](t)	$r,s=7, f, t$	sulphur content for the different fossil fuel types, i.e. coal and oil (calculated by the TIMER model)	TgS/GJ
$f_{control}[r,s,f]$(t)	$r,s=1..6,f, t$	fraction that is removed by SO_2-emissions controls for the various energy end-use sectors	0-1
$abt_C[r,s,f](t)$	$r,s=1..6,f, t$	Abatement factor for the emissions control (various technologies) for the emissions	
$f_{control,\ ind}[r]$(t)	r, t	fraction that is removed by the overall SO_2-emissions controls within the industry sector	0-1
WTP(t)	t	willingness to pay multiplier	0-4

a) Starting from 1990

The fraction that is removed by emissions controls ($f_{control}$) is calculated as the willingness to pay multiplier (*WTP*), representing the environmental awareness in line with the narrative of the scenario, times an PPP-income and environmental impact multiplier. The environmental impact depends on the actual emissions, the deposition area, and the area-specific impact sensitivity to sulphur deposition. In formula:

$$f_{control}[r,s=7,f](t)=WTP(t)\times PPPmult(t)\ (PPP[r](t))\times ENV(t)\ (EM_{SO2}[r](t),Sens_{SO2}[r]) \quad (8.3)$$

with *PPP* the Purchase Power Parity (PPP) an alternative indicator for GDP/capita, based on relative purchase power of individuals in various regions, that is the value of a dollar in any country, i.e. the amount of dollars needed to buy a set of goods, compared to the amount needed to buy the same set of goods in the United States. The PPP-income multiplier (see *Figure 8.2a*) increases with an increasing PPP-income, reflecting the dynamics of more emphasis on environmental pollution measures when the income rises within a region. The environmental multiplier (*ENV*) (see *Figure 8.2b*) increasing when serious acidification impacts manifest in a region, which is modelled as an acidification impact index. This index is calculated on the basis of the total regional SO_2 emissions divided by the size of the affected area (within that region), and the sensitivity of that area towards acidification impacts. The overall environmental multiplier is indexed based on the calculated acidification impact index of Western Europe for the 1980s, when the acidification policy started.

The calculated energy-related SO_2 emissions for Canada, USA, OECD Europe, Eastern Europe and CIS (partly) were checked against figures reported to UN-ECE (1994) and in case of substantial differences modified accordingly (notably emission factors for coal combustion in industry and power generation). For Japan the emissions were calibrated the 1990 level used by Foell *et al.* (1995) for RAINS-ASIA, which was based on a follow-up analysis of Kato and Akimoto (1992). For the OECD regions Canada, USA, OECD Europe and Japan, historical emission factors for combustion for 1970 and 1980 were based on emission trends specified in OECD (1991), whereas for Eastern Europe and CIS historic figures reported to UN-ECE (1994) were used to derive the historical factors. For other regions emission factors were assumed to have stayed constant in time.

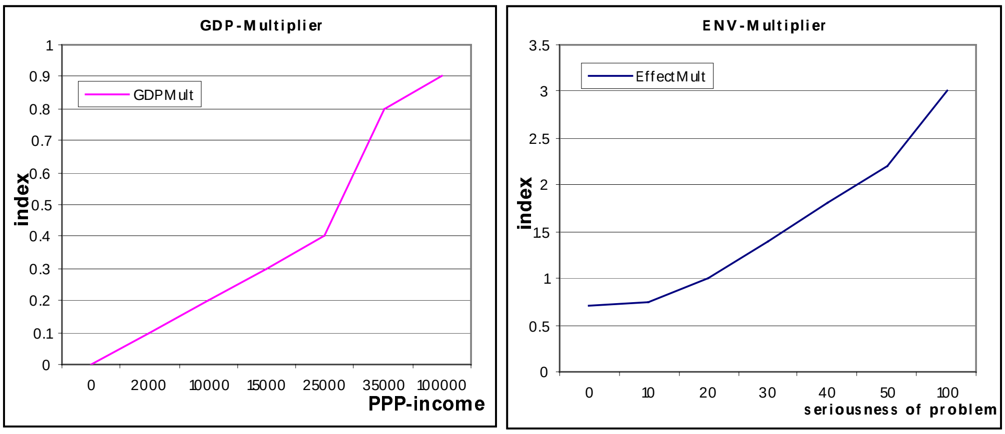

Figure 8.2a-b: The PPP-income multiplier (left) and environmental multiplier (right) for the calculation of the SO_2 emissions controls

8.3 Industrial Production and Industrial Emissions submodel

The Industrial Production and Emissions module are used to compute emissions of greenhouse gases or their precursors that are not directly associated with energy use (Emissions coming from the combustion of fuel by industry are taken into account in the “Industry" sector of the Energy Emissions model described above).

The categories of industrial production that are taken into account are: cement production (CO_2, NO_x), feedstock use of energy carriers (CO_2), chemical manufacturing (NMVOC), adipic acid production (N_2O)[62], nitric acid production (N_2O, NO_x), ammonia production (NO_x), solvent use (NMVOC), steel and iron industry (CO, NMVOC), sulphuric acid production (SO_2), copper melting (SO_2), and miscellaneous (NMVOC, SO_2). These categories are roughly the same as in IMAGE 2.1, except that now the CO_2-emissions related to non-energy use of energy carriers, as chemical feedstocks are included. The emission factors for CO_2 from chemical feedstocks are aggregated factors from EDGAR 3.0, based on IPCC recommended default factors and default fractions of carbon stored (IPCC, 1996). Other minor changes are the exclusion of negligible industrial emissions sources of CH_4, adaptations of some of the emissions factors within their possible ranges until good agreement was obtained between the simulated emissions and the data for global and regional emissions in 1990, and the aggregation towards the IMAGE 2.2 regions.

The model uses the IMAGE 2.1 methodology for the calculation of the industrial emissions, namely: based on the industrial production and specific emissions coefficients. The cement production is indexed to the population growth, and the level of other industrial activities are indexed to the energy end-use consumption in the industry sector as simulated by the TIMER model. The historical (1970-1995) level of these industrial processes are based on historical figures from the literature, as described in Vries *et al.* (1994).

The emissions of the halocarbons are set exogenously, based on the IPCC SRES emissions scenarios developed by Fenhann (1999). The emissions of the halocarbons regulated in the Montreal Protocol, i.e. the CFCs, HCFCs, halons, carbon tetra chloride and methyl chloroform follow, similar as in the IPCC SRES emissions scenarios, the Montreal protocol scenario (A3) of WMO (1999). The emissions of the three groups of greenhouse gases, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF_6) (all new gases compared to the IMAGE 2.1 model), which in the Kyoto Protocol were added to the gases CO_2, CH_4 and N_2O in the UNFCCC, are also based on Fenhann (1999).

8.4 Model calibration 1971-1995

The global energy- and industry related emissions of CO_2, CH_4, N_2O, NO_x SO_2, CO and NMVOC for the 9 energy-sectors and the overall industry sector for the period 1970-1995 using the TIMER simulated energy consumption and production are depicted in *Figure 8.3.* The 1990 and 1995 values are in good agreement with IPCC estimates, whereas the regional estimates differ up to 10-20% with the regional estimates of EDGAR (not shown here). Since we use aggregated emissions factors of EDGAR the differences are mainly caused by differences in the simulated energy consumption and production data of TIMER and EDGAR (IEA).

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[62] The emissions of N_2O from the production of adipic acid are set exogenously following the IPCC SRES emissions scenario developed by Fenhann (1999).

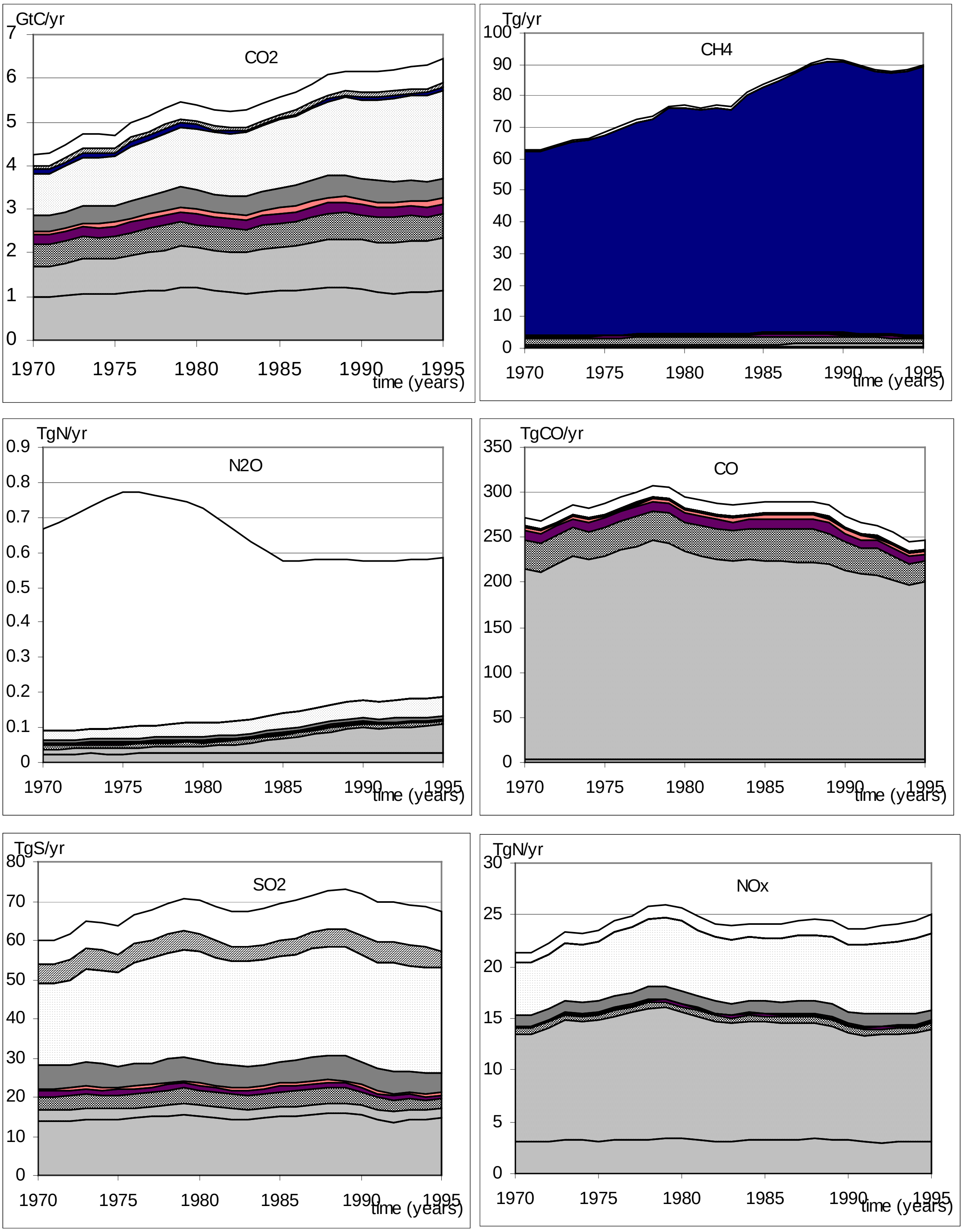

Figure 8.3 (see next page)

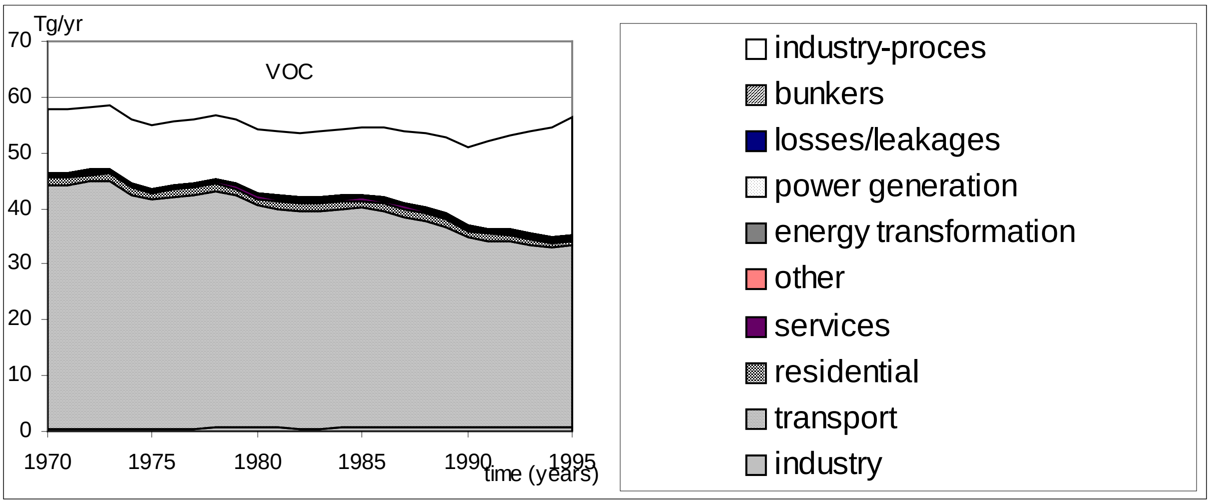

Figure 8.3: The global energy- and industry related emissions of CO_2, CH_4, N_2O, NO_x SO_2, CO and NMVOC for the 9 energy-sectors and the overall industry sector for the period 1970-1995 using the simulated energy consumption and production of TIMER.

In more detail, we analyse the emissions of CO_2 and SO_2, and compare our estimates from literature. For the other energy- and industry-related emissions of other greenhouse gases and compounds there is no regional historical data available, except for the 1990 emissions estimate.

We consider two cases for the simulated values of the TEM-model: energy-production and consumption data of the (ii) IEA-statistics for the period 1970/1971-1995 (IEA, 1999) and (iii) TIMER-model. This has been done to differentiate between the differences with literature data caused by the differences in historical energy production and consumption data by the IEA database and TIMER model, and caused by the differences in historical emissions factors by the literature and the TEM-model.

CO_2: The simulated regional energy-industry related emissions of CO_2 (excluding the feedstock and bunker emissions) for both cases are compared with the regional CO_2 emissions database of the Oak Ridge National Laboratory (ORNL) (see *Figure 8.4*). This database is also referred to as ORNL-CDIAC (CO_2 Data and Information Assessment Centre) (Marland and Rotty, 1984; Marland *et al.*, 1999a; Andres *et al.*, 1999). The ORNL-CDIAC database has a long tradition of compiling CO_2 emissions from fossil fuel combustion (and cement production) based on the annually updated UN energy statistics on total domestic fuel consumption per country for coal, oil, and gas. The data set does not contain CO_2 emission estimates for land use. More information on the ORNL-CDIAC data set can be found on the CDIAC website (http://cdiac.esd.ornl.gov, and in Marland *et al.* (1984, 1994).

The differences between the regional TEM and CDIAC data are marginal, except for the former Soviet Union are less than 5 %. This implies that also the sum of all regional energy-industry related emissions of CO_2 of the CDIAC and TEM are comparable (differences less than 5%). However, at the global level, the energy-industry related emissions of CO_2 now also include the feedstock and bunker emissions (*Figure 8.5*), and now the TEM-model data are somewhat higher than the CDIAC data. The differences are mainly caused by the differences in the historical feedstock CO_2-emissions factors between EDGAR (used in TEM) and CDIAC.

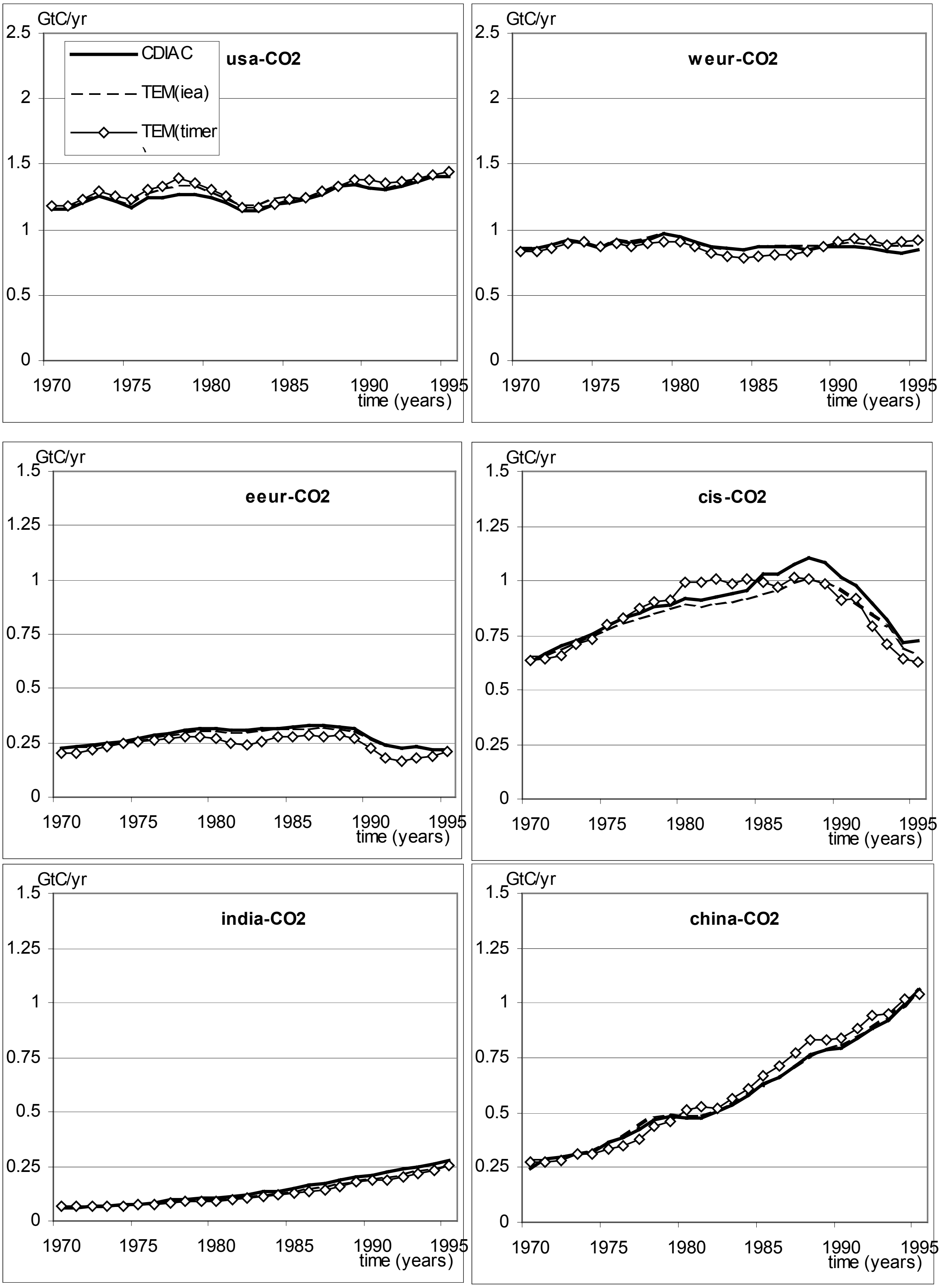

Figure 8.4: The regional energy- and industry related emissions of CO_2, for the period 1970-1995 for the (i) CDIAC data; and the TEM-simulated data using the energy-production and consumption data of the (ii) IEA-statistics and (iii) TIMER-model.

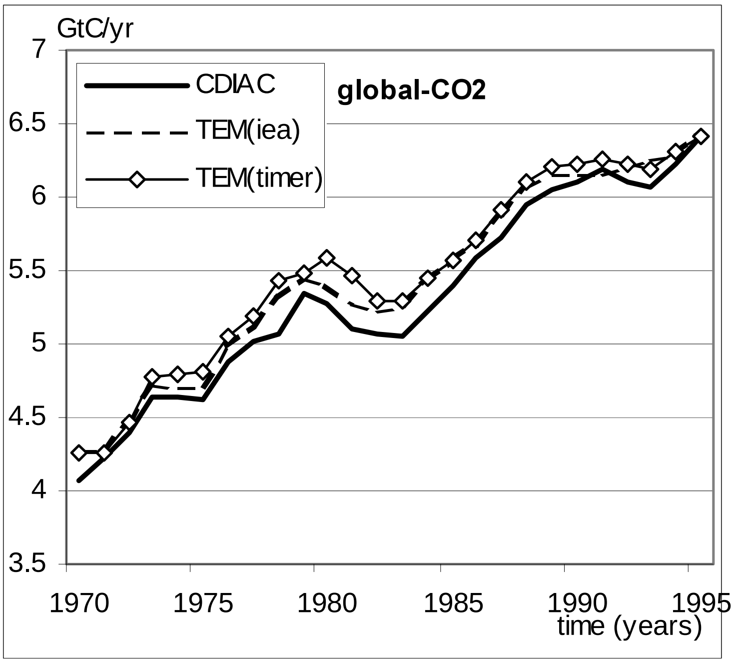

Figure 8.5: The global energy- and industry related emissions of CO_2, (including bunker and feedstock emissions) for the period 1970-1995 for the (i) CDIAC data; and the TEM-simulated data using the energy-production and consumption data of the (ii) IEA-statistics and (iii) TIMER-model.

Box 8.1 Uncertainties in the historical fossil-fuel CO_2 emissions

The uncertainties in CO_2 emissions from fossil fuel combustion arise from:

- *Activity data:* There is an inherent uncertainty in the determination of historical activity data per country due to the lack of reliable statistics or complete absence of activity data. Comparison between data sources for energy is possible for the period after 1960/1970 (e.g. between UN and IEA data) but for older data - such as the new ORNL-CDIAC data set (Andres *et al.*, 1999) - this is much more difficult.
- *Emission factors:* It can be assumed that the quality of fossil fuels produced - and thus also the carbon content - has changed in the course of time. Even for the present, the energy content per unit of mass, for example for coal, is not accurately determined for all countries. Marland *et al.* (1999) show differences of up to 78 Mton or 8% for the former Soviet Union and up to 28 Mton or 50% for North Korea when comparing estimates based on UN and on IEA data. Since we may assume that the energy content of fossil fuels will have changed in time, but to an unknown degree, this will be an additional factor contributing to the uncertainty of CO_2 emissions prior to 1950.
- *Definition of bunker fuels:* Because emissions in the Kyoto Protocol related to international air traffic and international shipping are excluded from the national emission totals, special consideration is necessary for the exclusion of bunker fuel emissions from the historical data sets of national emissions. In this regard the ORNL-CDIAC and EDGAR-HYDE data sets (Olivier *et al.*, 1996, 1999; Klein Goldewijk and Battjes, 1997) report separately on international bunkers for international transportation on the basis of figures recorded in the energy statistics. However, it is well known that the uncertainty in these figures is fairly large. This pertains in particular to international aviation bunkers for which countries use different definitions or do not provide any separate figures (IEA, 1998), thus introducing additional uncertainty in estimating national total emissions as defined under the Kyoto Protocol.

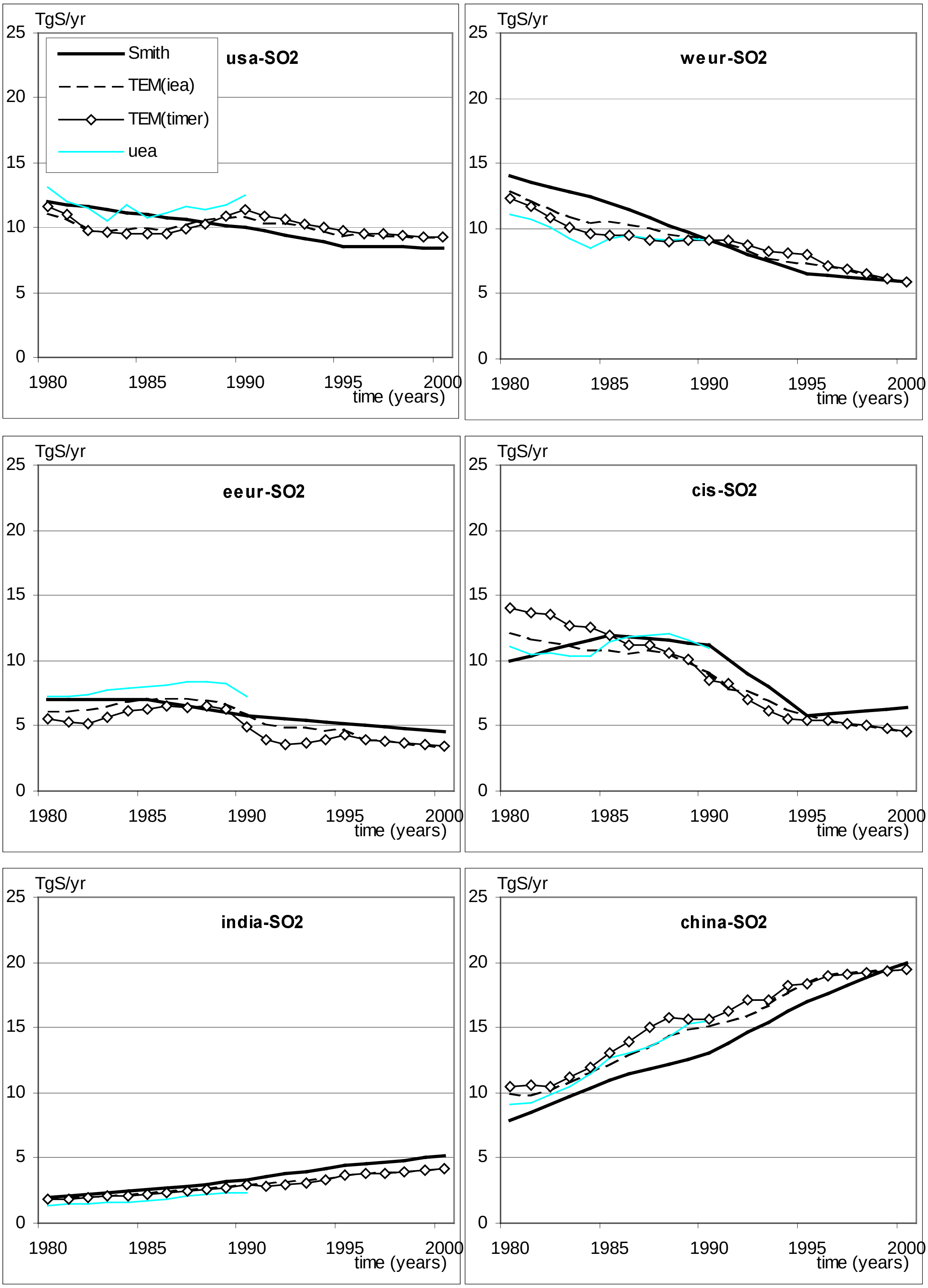

Figure 8.6: The regional energy- and industry related emissions of SO_2, (including bunker emissions) for the period 1980-2000 for the (i) Smith et al. (2000) data; and the TEM-simulated data using the energy-production and consumption data of the (ii) IEA-statistics and (iii) TIMER-model.

SO_2: Now, the simulated regional and global energy-industry related emissions of SO_2 (including the bunker emissions) were compared with the regional SO_2 emissions databases of Smith *et al.* (2000) and Lefohn *et al.* (1999) (see *Figures 8.6* and *8.7*). The simulated global energy-and industry related SO_2 emissions for the period 1980 to 2000 differ from the global estimate of Smith *et al.* (2000) with only about $\pm$2-3% for the time period 1990-2000 and up to $\pm$5% in earlier years. However, at a regional level the differences between emissions estimates between the TEM-model and the Smith *et al.* -database increase, to 10-20% for some regions for the time period 1990-2000. Smith *et al.* already explain for some regions the differences between their estimates and those of EDGAR (the underlying source for the emissions factors for our model).

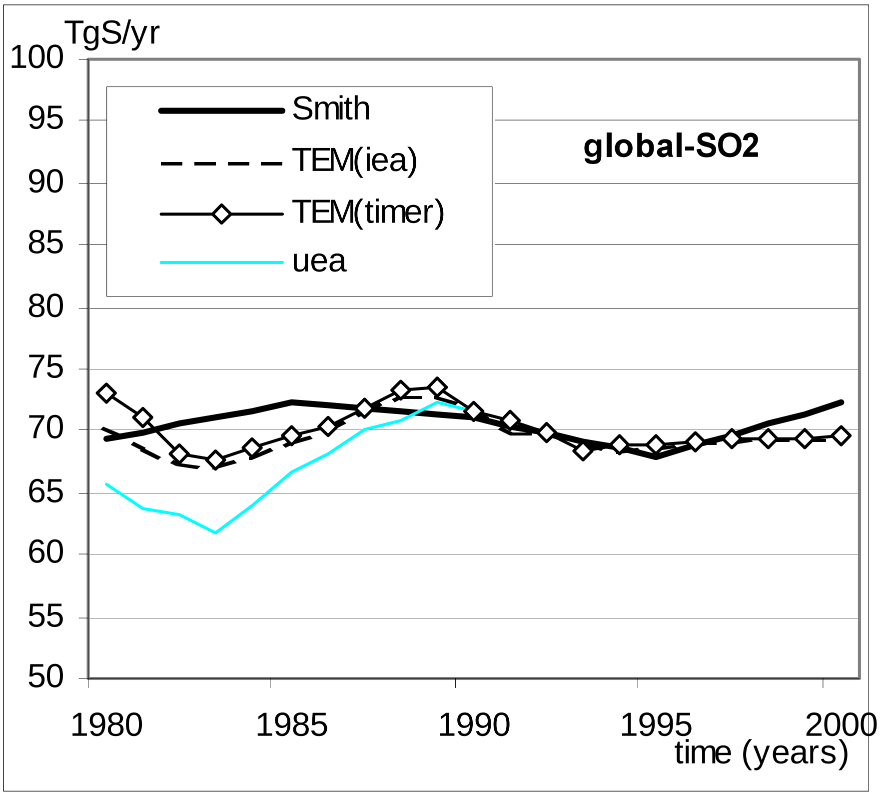

Figure 8.7: The global energy- and industry related emissions of SO_2, (including bunker emissions) for the period 1980-2000 for the (i) Smith et al. (2000) data; and the TEM-simulated data using the energy-production and consumption data of the (ii) IEA-statistics and (iii) TIMER-model and the UEA data (University of East Anglia).

8.5 Linkages of the Energy/Industry System (EIS) with rest of IMAGE 2

In the Atmospheric chemistry Model and the Carbon cycle model of IMAGE 2.2, emissions from the Energy-Industry model are added to land-use related emissions of CO_2 and other greenhouse gases coming from the Land Emissions model (including all emissions from traditional biofuels and any CO_2 related to production and use of modern biofuels); the model then computes the resulting atmospheric concentrations.

8.6 Directions for future Research

In co-operation with the TNO-MEP, the TEM model will be extended with more specific methodologies for emission reduction costs and potentials for emissions of the substances NO_x and SO_2 and greenhouse gases. In first instance, the focus will be on end-of-pipe emission reduction technologies and the associated costs curves, especially to mitigate the emissions of NO_x and SO_2. These options will be important to identify joint strategies to control regional air pollution and climate change. Also more generic measures such as speed limits for high way traffic and building codes (volume and intensity developments), as well as present policies and autonomous developments will be included in the model to improve the different scenarios. This will lead to developments of emission factor values over time as a result of the emission reduction options. Next also and-of-pipe mitigation options as well as its costs curves for controlling the emissions of the major greenhouse gases will be included.

9. Analysis of generic model parts in TIMER

9.1 Introduction

The model behaviour of TIMER can be difficult to understand directly because of the complex dynamics with feedbacks and delays. However, most dynamics of the TIMER model are the result of a small number of general building blocks. For example, learning by doing is formulated in the same way across sectors and regions and energy efficiency and supply technologies. The same holds for aspects of energy demand, fuel substitution, resource depletion, target-based policies, technological catching up and trade. For each general building block we describe in this chapter the basic dynamics and analyse the sensitivity for the main parameters. Understanding these general dynamics will improve the understanding of the overall model behaviour of TIMER in the scenarios as described in the chapters hereafter.

9.2 Energy Demand

The useful energy demand calculation of a sector in a certain region, UED, can be summarised by the following formula (cf. eqn. 3.1):

$$UED_{trsj} = A_{trs} * POP_{tr} * UEI_{trs} * AEEI_{trs} * PIEEI_{trs} \qquad \text{GJ} \qquad (9.1)$$

UED equals the product of the per caput activity level A, the population POP, the useful energy intensity UEI, the autonomous energy efficiency factor AEEI and the price-induced energy efficiency improvement factor PIEEI. The components UEI, AEEI and PIEEI will be analysed in more detail below.

Useful Energy Intensity (cf. Paragraph 3.2)

Useful energy intensity, measured as energy per monetary unit of economic activity, changes due to structural changes in the economic system. We assume a bell-shape curve of energy inputs per economic activity which reflects a shift within each sector that first increases energy-intensity (e.g. growth of heavy industry) and later on a decline in energy-intensity (e.g. industrial value added at low additional energy use or saturation tendencies). The maximum intensity occurs at an activity level A_{max}. The resulting equation is in simplified form (cf. eqn. 3.4):

$$UEI = I\lim \Big/ \left(A + c_1 * A^{c_2}\right) \qquad \text{GJ/\$} \qquad (9.2)$$

$$c_1 = -(A_{\max} / c_2)^{1-c_2} \qquad (9.3)$$

where Ilim is the useful energy intensity in the long run. c_1 and c_2 are parameters of the bell-shaped function and correspond with $c_1 = \gamma_{r,s,i}$, $c_2 = \delta$, $\alpha_{r,s,i} = 0$ and $\beta_{r,s,i} = 1$ in eqn. 3.4.

Let us redefine the parameters c_i in such a way that Ilim=1 and let A increase in time, we then can calculate UEI for different value of A_{max} and c_1 (*Figure 9.1*). The lower the value of c_2 the higher the useful energy intensity in the maximum. A lower value of A_{max} leads also to a higher value of UEI in the maximum. The curve can describe both the assumed bell-shape with a maximum at some activity level and saturation phenomena with smoothly declining energy-intensity.

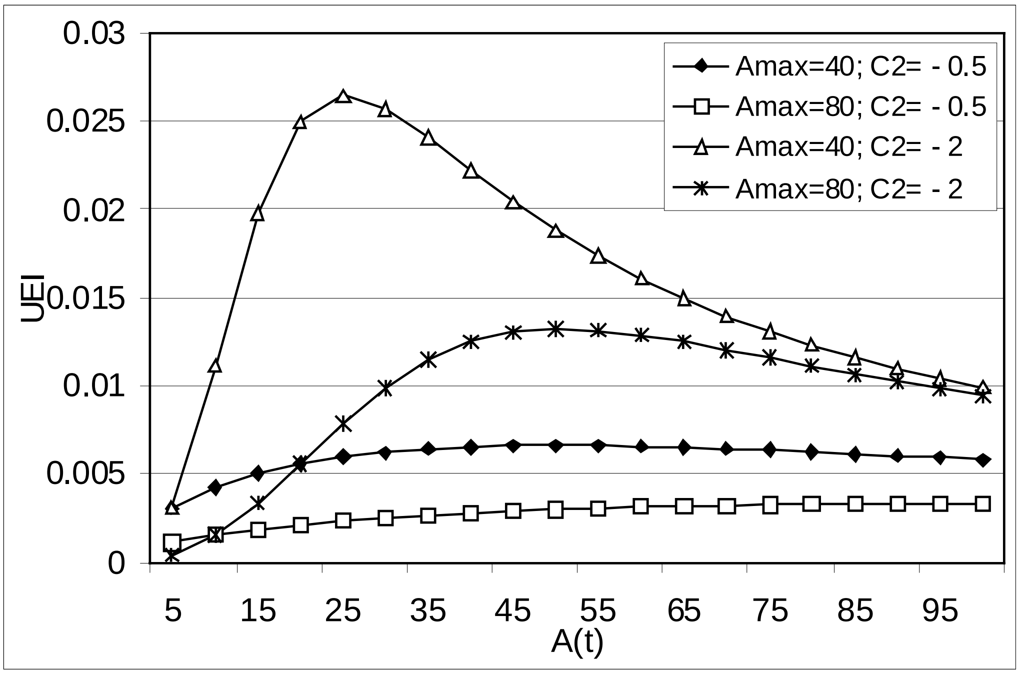

Figure 9.1: Useful energy intensity for different values of A_{max} and c_2

Suppose Ilim=1 and A=A_{max}, we can derive the relation as depicted in *Figure 9.2*. The lower the value of c_2 and A_{max}, the higher the value of UEI. Thus the energy intensity is low when the intensity reaches the maximum for a high activity level, and a high value of c_2. The influence of A_{max} on the shape of the structural change curve is relevant in view of the hypothesis that, through technology transfer and other phenomena, presently less developed regions may reach their maximum energy intensity at lower values of A_{max}.

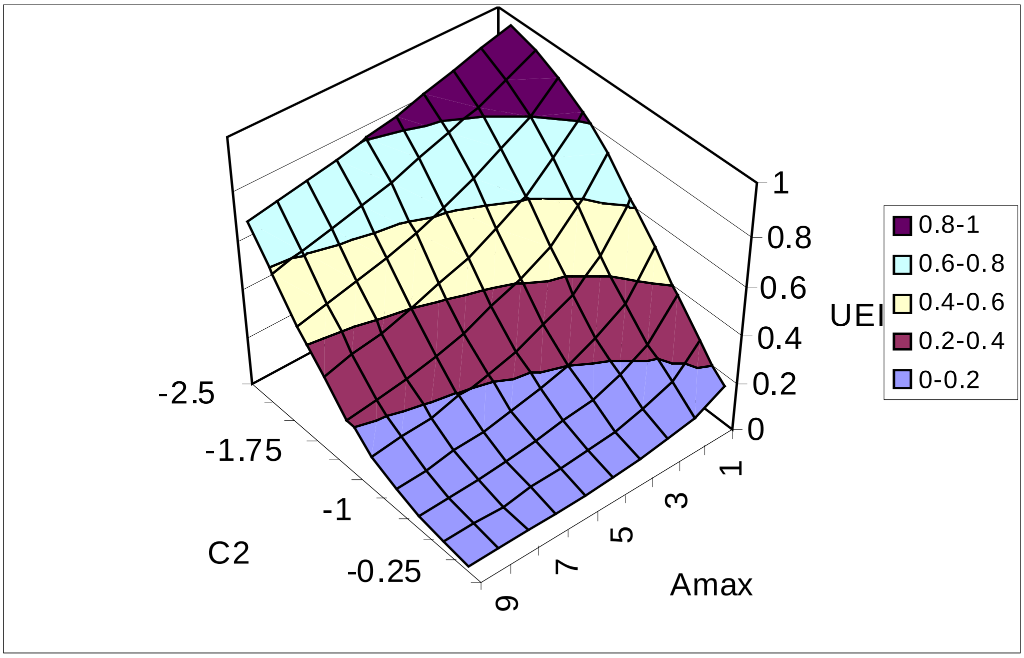

Figure 9.2: Relation between SC, C2 and A_{opt}, when Ilim=1 and A=A_{opt}

Autonomous Energy Efficiency Improvements (cf. Paragraph 3.3)

The autonomous energy efficiency improvement factor AEEI decreases due to a decrease of the average energy intensity of old and new capital, AvInt (cf. eqn. 3.7):

$$AEEI_{t,rsi} = AEEI_{t-1,rsi} * \left\lfloor AvInt_{t,rsi} / AvInt_{t-1,rsi} \right\rfloor \quad (9.4)$$

Assume that there is no increase in activity levels, and that the share of new capital is constant overtime denoted by β. Furthermore, assume that the function f(t)=-αt/100. Then we can write IA=β exp(-αt/100)+(1-β)*IA(t-1). For a range of values for α and β the AEEI in t=100 is calculated (*Figure 9.3*). The higher α (decrease intensity new capital) and β (replacement fraction capital), the more autonomous energy efficiency improvements will occur. The yearly percentage improvement of the autonomous energy efficiency improvement can be recalculated as (1-AEEI(t=100)^0.01)*100%, leading to 1%/yr improvement for α=1 and β=0.1.

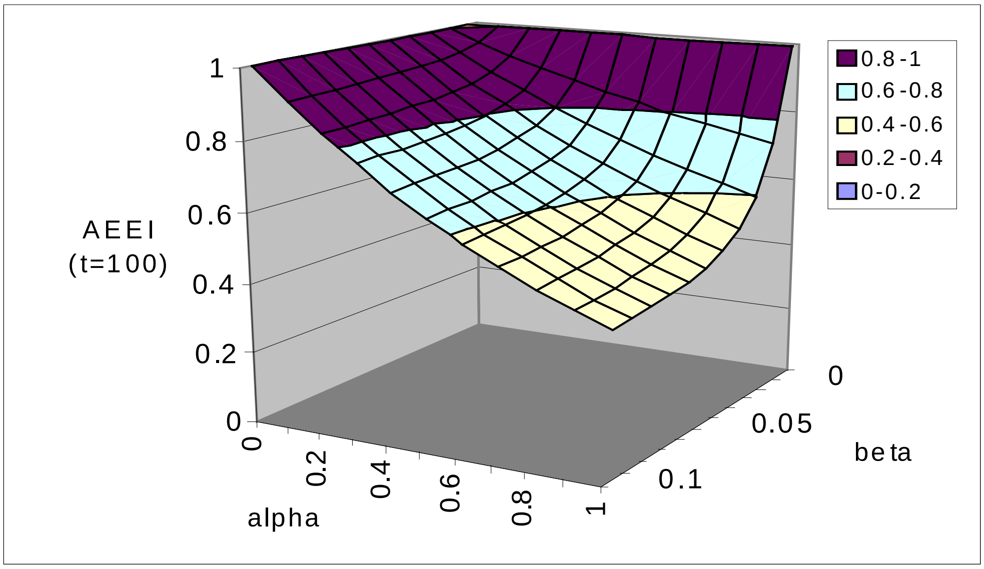

Figure 9.3: Relation between AEEI after 100 years and parameters α and β.

Price Induced Energy Efficiency Improvements (cf. Paragraph 3.3)

Price Induced Energy Efficiency Improvement (PIEEI) is the user response to rising costs of Useful Energy, that is, of the product of secondary fuels / electricity and their respective prices divided by the product of secondary fuel / electricity use and conversion efficiency. A simplified description is the following (cf. Eqn. 3.9), with the PIEEI multiplier is defined as 1 – EEopt:

$$EEopt_{rsi} = CC\max_{rsi} - 1/[\sqrt{CC\max_{rsi}^{-2} + CostUE_{rsi} * PBT_{rsi} / (CCS_{rsi} * CCI_{rsi})} \quad (9.5)$$

with CCM the maximum feasible reduction, CostUE the fuel costs, PBT the desired payback time, CCS the steepness of the cost curve and CCI the cost curve improvement given by

$$CCI(t) = CCI(t-1) * (1 - CCIrate(t)) \quad (9.6)$$

with CCIrate the annual rate of the cost curve decline. Note that the PIEEI-multiplier, i.e. the price-induced reduction in the energy-intensity as of 1971, equals 1 for zero energy cost (no price-induced efficiency improvement) and approaches 1-CC for infinite energy cost (maximum possible price-induced efficiency improvement).

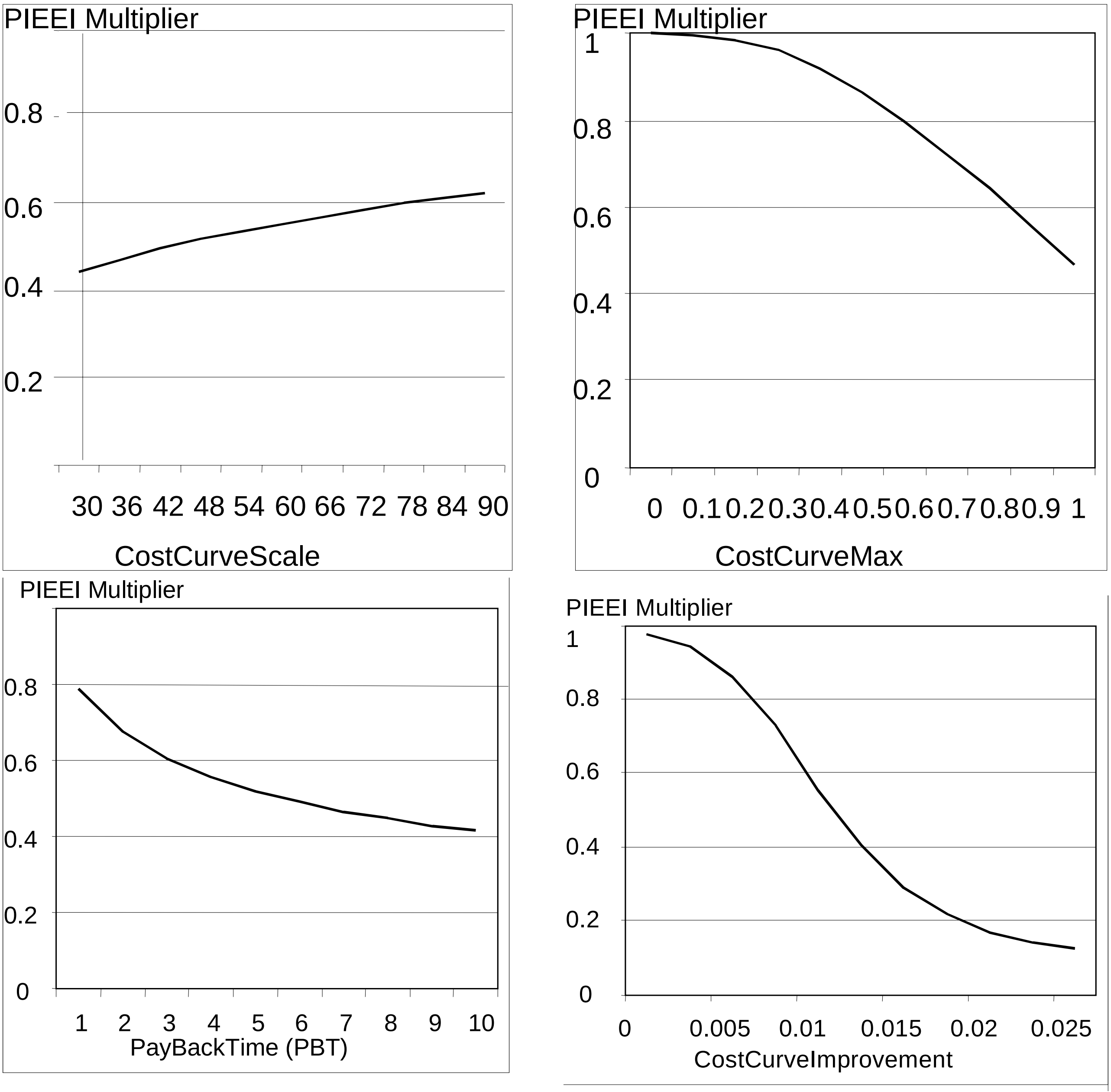

Figure 9.4: Relations between PIEEI and CCS, CCM, PBT, CCIrate, when CostFuel =1. Each figure represents a separate experiment (no simultaneous variations)

Let us explore the behaviour of 1-PIEEI, representing the intensity of price-induced efficiency improvements, in more detail for a default set of parameter choices. It is negatively related to the CCS-value, i.e. to the steepness of the conservation cost curve. The reason is obvious: energy efficiency investments per unit of energy saved are more costly for higher CCS given a choice of payback time and fuel / electricity prices. A doubling of CCS from 30 to 60, implying a lower energy demand price elasticity in economic terms, decreases the price-induced efficiency improvement from 55% to less than 45% (*Figure 9.4*, left upper). Obviously, if the maximum possible CCmax goes up, the degree of efficiency improvement increases (*Figure 9.4*, right upper). In first instance, all regions are assumed to face the same conservation cost curve but their starting-point is different due to different desired payback times and fuel / electricity prices.

The higher the cost curve improvement CCIrate, the lower the cost of conservation and thus the higher the price induced energy efficiency improvement (*Figure 9.4*, right below). In this way technical innovations and mass scale production in energy efficiency equipment is taken into account. A higher pay back time PBT reduces the discount rate of investments, leading to higher investments for energy efficiency improvements. An increase of the pay back time decrease therefore the PIEEI multiplier on a decreasing rate (*Figure 9.4*, left below). This parameter can be used to reflect changes in consumer perceptions and as a proxy for government subsidies for energy efficiency measures.

9.3 Learning by doing

It is well known that the costs and performance characteristics of a given technology change over time due to various dynamical factors. One of them is the ability of people to learn by doing. This phenomenon, variously called the learning curve, learning-by-doing, organisational learning a/o., has been investigated in detail and for a variety of products and processes. Hirchmann (1964) gives it the status of a natural law. Its formulation is that a cost measure y tends to decline as a power function of an accumulated learning measure x:

$$y = q(tL) * x^{-\pi} \tag{9.7}$$

(or log y = log q(tL) - π log x) with tL the time at which learning is support to start and q(tL) a conversion factor equal to $x^{-\pi}$ for t<tL. Examples of a cost measure y are specific investment costs and of a learning measure x the cumulated investment or output. Often, the learning rate π is expressed by the progress ratio ρ which indicates the factor with which the costs measure y decreases on a doubling of experience x. It is easily seen that $\rho=2^{-\pi}$. Many illustrations of this law have been found and published as *Table 9.1* shows. *Figure 9.5* shows the value of y for various values of π.

For model implementation, one has to gauge the learning behaviour to some reference situation in year tL:

$$y / y_{tL} = x^{-\pi} \big/ x_{tL}^{\ -\pi} \tag{9.8}$$

Hence, one has not only to choose the value of π but also of x_{tL} . The less accumulated experience one assumes for the start year tL, the steeper the cost measure y will fall.

Most data are for the United States and it has been found that the progress ratio in almost all cases investigated is between 0.65 and 0.95 with a median value of 0.82 (Argote and Epple, 1990) (see *Figure 9.5*). There are several reasons why it varies. Hirchmann (1964) suggests that because it are humans that are capable of learning, the progress ratio is higher for activities with a high labour content. He also notices the relationship between learning rate on the one hand and targets and expectations on the other hand. Knowledge from learning may also depreciate, in which case more weights should be given to recent production rates.

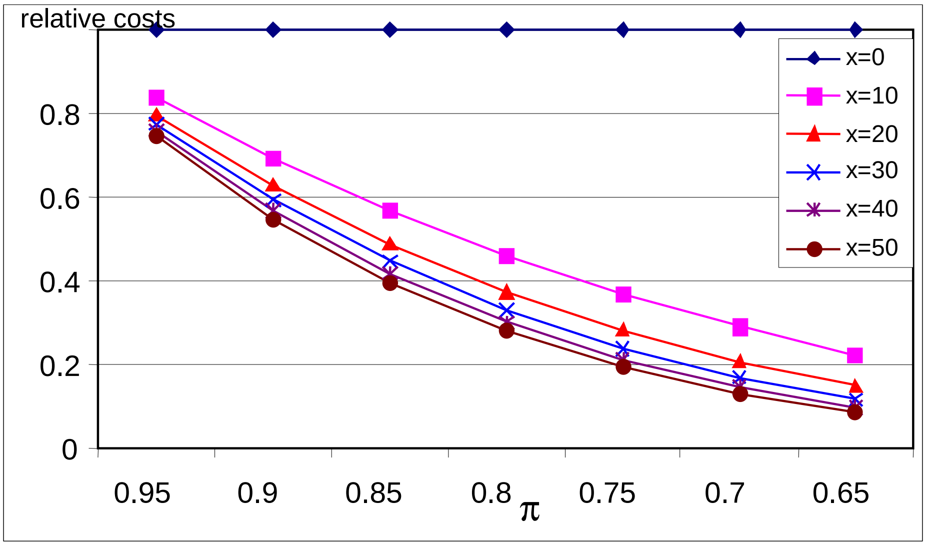

Figure 9.5: The relative costs (y of equation 9.7), as function of x (cumulative investments) and ρ, the progress ratio.

Table 9.1: Representative learning variables

Product/process	*y*	*x*
Aircraft manufacturing	Direct man-hours per lb	Cumulative amount of planes
Petroleum refining	Days per 1000 bbl processed	Cumulative amount of bbls processed
	Direct manhours per bbl refined	Cumulative bbls refined
Catalytic Cracking	Cost per bbl of capacity	Total capacity
Power plant manufacturing	Cost per kWe capacity	Total Capacity Installed
Power plant maintenance	Average time per replacement	Cumulative number of replacements
Nuclear power	Unplanned loss factor	Years of operation
Basic steel production	Manhours per unit produced	Cumulative units produced
Solar photovoltaics cells	Investment cost per kWe	Cumulative kWe produced

In the TIMER-model, the learning factor is influencing the costs of oil and gas production. In this case *x* is given by the cumulative oil or gas production, while *y* represents the capital output ratio for oil or gas production. Learning also plays a role in the decline of the energy conservation cost curves, in the costs of non-thermal electricity (solar, wind, nuclear) generation options, in the costs development of biofuels and in surface coal mining. The value of the learning rate p varies from a high 0.7 to a low 0.95.

9.4 Depletion Dynamics

Costs of supplying fuels from a limited resource (fossil fuels, land for biomass) will increase in the longer term due to depletion of an exhaustible resource. In other words, costs increase with cumulative production. To simulate the cost trajectory of a fuel, the TIMER-model combines this depletion and the counteracting force of learning-by-doing described in the previous paragraph.

In the TIMER model the depletion cost curve is a simple relation between an important cost determinant, usually the Capital-Output Ratio (COR), and the ratio between cumulated production and initial resource base. In this way, one needs ever more capital to produce a single unit of output as the resource gets depleted. The difficulty is the uncertainty of the curve.

It is not known what the ultimate resource base is nor what the costs are at which – often as yet undiscovered – resources can be exploited at present technology. Hence, an important part of the long-term supply cost curve is inherently uncertain and speculative. These uncertainties can have important consequences for the supply/demand of the resource and the resource trade flows and greenhouse gas emissions.

In *Figure 9.6* three examples are given of an exogenously curve supply cost as it could be constructed from expert estimates in the literature. Line *a* denotes a cost curve of a scarce resource, leading to fast increasing prices, while line *c* denotes a resource which will be depleted at lower costs. Because at lower costs demand may be larger, the actual cost profile over time for the situations a and c may be the same.

An interesting question is how the combination of learning-by-doing and depletion works out. Both are dynamic processes related to the cumulated output but working in opposite directions. In principle, three 'stylised curves' are possible. If learning-by-doing dominates depletion, costs will go down. If depletion dominates learning-by-doing, costs will go up. Different rates of both processes may give rise to cost curves with either a minimum or a maximum over time.

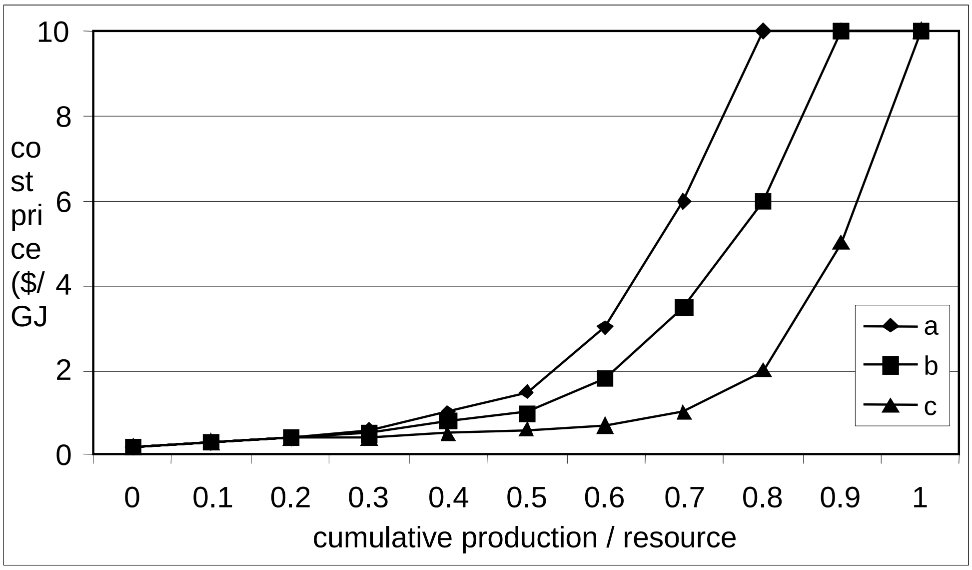

Figure 9.6: Increasing cost, due to relative depletion of the ultimate resource.

9.5 Multinomial Logit Model

In several submodels, there is the question of allocation. For instance, what determines the relative use of coal, oil [products] or gas as a fuel to provide heat or to generate electricity? Or which part of the available investments for coal supply goes into surface mining? Such allocation mechanisms are described by the multinomial logit model and is based on the formula:

$$IMS_i = \frac{e^{-\lambda c_i}}{\sum_j e^{-\lambda c_j}} \tag{9.9}$$

with IMS_i the indicated market share of product/process i, λ the logit parameter and c_i the cost c.q. the price of the products/processes i. This formula can be rewritten and approximated by dividing upper and lower part by exp($-\lambda$*c_i) and expanding each exponent into its first terms:

$$IMS_i = \frac{1}{\left[1 + \sum_{j<>i} (1 - \lambda(c_j - c_i) + \lambda^2 (c_j - c_i)^2 / 2)\right]} \tag{9.10}$$

This form shows that for equal cost c.q. price all market shares become 1/n in case of n products/processes. For small λ-values, indicated market shares ten to become inelastic i.e. independent of relative cost c.q. prices. The higher the logit parameter, the faster a change in relative cost can change the composition of fuel inputs. Therefore, the logit parameter is a measure of the substitution elasticity between competing options.

An alternative formulation of eqn. 9.10 is based on the cost ratio $\gamma_{i1} = c_i / c_1$:

$$IMS_i = c_i^{-\lambda} / \sum_i c_j^{-\lambda} = \frac{1}{\left[1 + \sum_{i>1} \gamma_{i1}^{-\lambda}\right]} \tag{9.11}$$

In this case, the parameter λ equals the cross-price elasticity. This formulation is used in the TIMER-model.

In most applications in the TIMER-model, it is assumed that the actual market share MS_i is lagging behind the value which is indicated by the cost c.q. price differences or ratio's. This delayed response is described by the equation:

$$dMS_i / dt = (IMS_i - MS_i) / ADJT \tag{9.12}$$

with ADJT the adjustment time representing the system's resistance to rapid changes. It has been shown that he multinomial logit model is consistent with the existence of a large group of consumers/producers which aspire minimum costs as given with a translog production function (Edmonds and Reilly, 1986). If the model is used to simulate the introduction of completely new and different technologies, the indicated market share most adequately refers to the new capacity c.q. investment. This ensures a slow penetration of the new product/process.

As an illustration of the multinomial logit model, *Figure 9.7* shows the market shares of product 1 at t=100 when the relative cost c.q. price of product 1 is increased up to six times the present level of the cost c.q. price of product 2. The higher the cross-price elasticity, the steeper the curve, i.e. the more responsive the market substitution process is to price differences/ratio.

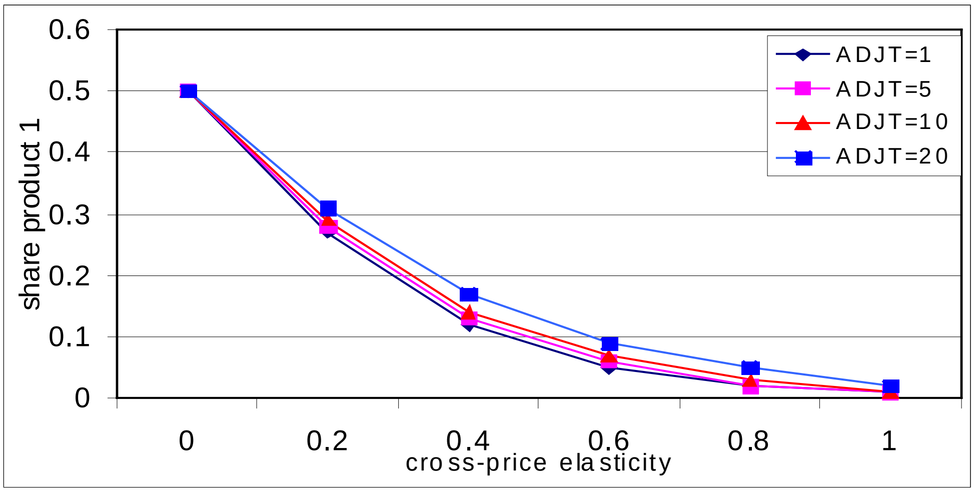

Figure 9.7: The market share of product 1 as function of λ, the cross-price elasticity, and ADJT, the adjustment time.

The conceptual background of the multinomial logit allocation is in economic production theory. Let us assume that an actor can chose for his energy supply from a set of two fuels, 1 and 2. Alternatively, one can think of a large group of actors with such a choice. It can also relate to other choices, for instance the fraction of available or required investments going into options 1 and 2. Suppose that the energy part of the actor's production function is given by:

$$Y = \left[a(F_1 - F_{10})^{-\beta} + b(F_2 - F_{20})^{-\beta}\right]^{-1/\beta} \qquad (9.13)$$

with Y the output and F_I the respective fuels. This is the well-known Constant Elasticity of Substitution (CES) production function (see e.g. Jones, 1976). However, we have included the lower bounds F_{i0} to take into account that for every fuel c.q. option a certain amount cannot be substituted because it is tied to specific applications (Vries *et al.* 1981). Examples coking coal use in the iron and steel industry or gasoline in transport. The total energy costs for the actor are now:

$$E = p_1 F_1 + p_2 F_2 \qquad \text{\$/yr} \qquad (9.14)$$

with p_i the respective fuel prices. Minimisation of the energy costs E under the boundary condition of eqn. 9.9 is satisfied, using LaGrange multipliers, if:

$$\frac{p_1}{p_2} = \frac{\partial Y / \partial F_1}{\partial Y / \partial F_2} = \frac{a}{b}\left(\frac{F_2 - F_{20}}{F_1 - F_{10}}\right)^{1+\beta} \qquad (9.15)$$

Substituting for the indicated market share IMS_2, defined as $F_2/(F_1 + F_2)$, and rewriting eqn. 9.11 gives for the condition of minimum energy costs:

$$\left(\frac{bp_1}{ap_2}\right)^{1/(1+\beta)} = \left(\frac{\left(\frac{IMS_2}{1 - IMS_2}\right)F_1 - F_{20}}{F_1 - F_{10}}\right) \qquad (9.16)$$

It is easily seen that for $\lambda = 1/(1+\beta)$, a=b and $F_{i0}=0$ for i=1,2, eqn. 9.15 changes into eqn. 9.11, the basic equation for the multinomial logit equation ($\gamma_{21} = p_1 / p_2$). The two approaches are equivalent and the multinomial logit parameter λ is directly related to the substitution elasticity β of the underlying production function.

The condition that a=b implies that at equal prices each fuel takes half of the market. Alternatively, one can view the prices bp_1 and ap_2 as shadow (or perceived) prices. If we redefine $\gamma = (bp_1/ ap_2)$ and introduce $\phi=(\gamma^{\lambda}F_{10}-F_{20})$, it can also be derived that:

$$IMS_2 = \frac{\gamma^{\lambda} F_1 - \phi}{(1+\gamma^{\lambda})F_1 - \phi} \tag{9.17}$$

which shows again the equivalence with eqn. 9.11 but also that the calculation of the IMS-values is recursive unless $\phi=0$ i.e. for $F_{i0}=0$ for i=1,2. If only $F_{20}=0$ and we introduce $\alpha= F_{10}/(F_1 + F_2)$ as the fraction of fuel c.q. option 1 which cannot be substituted away, then eqn. 9.13 can be rewritten as:

$$IMS_2 = \frac{IMS_1 - \alpha}{(\frac{1+\gamma^{\lambda}}{\gamma^{\lambda}})IMS_1 - \alpha} \tag{9.18}$$

This has been used to account for parts of the market of fuel c.q. option 1 inaccessible for substitution by fuel c.q. option 2.

9.6 Catching Up

In explaining regional differences of economic growth, differences in technological development are a crucial factor. In the energy model, differences in the state of (energy) technology are reflected in different energy conservation and supply cost curves among regions. For policy analysis, it is interesting question how to speed up technological development in order to meet climate change targets at the lowest possible cost.

Although in neo-classical theory technology is assumed to spread immediately, there is a substantial amount of more thoughtful analyses on technology transfers between economies. Some emphasise traded good as carriers of spillover (eg. Giliches, 1979; Silverberg and Soete, 1994; CPB, 1995); others point out that knowledge can be transmitted by channels such as conferences, scientific literature, labour mobility, patent information, or pure imitation. We follow the notion that technology diffusion is related to activities and abilities of the agents. Abromovitz (1986) argues that the catching-up process is conditional upon some specific factors, referred to as social capability and technological congruence. Social capability refers to all factors that facilitate the imitation of a technology, or the implementation of technology spillovers. This relates to factors like education, financial conditions and labour market relations. Technological congruence concerns the extent to which the country is technologically near to the leader country, i.e. to which extent it is able to apply the technical features near or at the production frontier.

In this section we describe a simple, transparent formulation of the complex dynamics of technology diffusion in order to be of use in the energy policy model TIMER. The focus is on the AEEI and PIEEI multipliers and the learning curves for fossil fuels and non-fossil alternatives.

Description

We implement the catching-up process in line with the Worldscan model (CPB, 1995), such that we can compare and use scenarios of Worldscan more easily. However, we also want to have the flexibility of a stand-alone model and to apply scenarios in order to assess the impact of increasing knowledge transfers on the energy supply and demand technology.

Define the technological front (TF) as the minimum of the technology level parameter (TL) over all the regions (that is, if a decrease of the parameter reflex an improvement of technology, otherwise take the maximum):

$$TF_t (1-\tau) * MIN(TL_{t-1,r} \tag{9.19}$$

where τ is the mark-up of the notional technological frontier.

It is unclear which determinants determine catching up. CPB (1995) includes, among other determinants, the capital-labour ratio and price competitiveness. However, the conditional factors as described in Abromovitz (1986) are not included adequately in both Worldscan and TIMER. We therefore want to have the freedom to define scenarios, which represent the complex qualitative developments in social capability and technological congruence. For example we may assume that political changes may lead to increasing social capability and technological congruence and are therefore stimulating catching-up. An example are the political changes in China, the former Soviet-Union and India, which have caused various kinds of economic and technological catching-up.

So, by assuming a time-path for a variable we call transformation elasticity, γ[r], it is possible to mimic such developments. If it is low (γ=0) there is no catching-up to the technological frontier; at the other extreme is the situation that a region experiences an immediate technology transfer to the level of the frontier region (γ[r]=1). Hence, γ[r] is a scenario variable representing the catch up which in principle can be related to scenarios of the WorldScan model (CPB, 1995) in which the transformation elasticity is estimated for different sectors.

In the simulation the catching-up dynamics is formulated as:

$$TL_{t-1,r} / TL_{t,r} = \left[TL_{t-1,r} / TF_t\right]^{\gamma_r} \tag{9.20}$$

such that

$$TL_{t,r} = TL_{t-1,r} / \left[TL_{t-1,r} / TF_t\right]^{\gamma_r} \tag{9.21}$$

All regions will experience learning-by-doing through cumulated production and RD&D programs, as has been set forth in the previous paragraphs. However, inclusion of the technology transfer mechanism speeds up the learning in less advanced regions as a result of experience and efforts in the more advanced regions. In case of a learning by doing multiplier, the catching-up (CU) can be derived by assuming that the catching-up elasticity p(t) may increase in time due to technology transfers.

$$\left[\left(CUMPR_{t,r} + CU_{t,r}\right)/ CUMPR_{tL,r}\right]^{-p_t} = TL_{t-1,r} / \left[TL_{t-1,r} / TF_t\right]^{\gamma_r} \tag{9.22}$$

where tL is the year in which the region starts learning and CUMPR is the cumulative production, such that:

$$CU_t = MAX\left[0, CUMPR_{tL,r} * (TL_{t-1,r} / \left[TL_{t-1,r} / TF_t\right]^{\gamma_r})^{-1/p_t} - CUMPR_{t,r}\right] \tag{9.23}$$

and

$$TL_{t,r} = \left[(CUMPR_{t,r} + CU_{t,r}) / CUMPR_{tL,r}\right]^{-p_t} \tag{9.24}$$

In Figure 9.8 a possible trajectory for catching up between an advanced frontier region with constant technology (set at 0.5) and a less advanced region (set at 1) is shown. Cumulative production is taken to increase from 1 to 4 in 30 time steps. Using γ=0.15 and p=0.5, this leads to a parabolic curve of catching up as a result of which the lagging region reaches at timestep 30 the level of the frontier region.

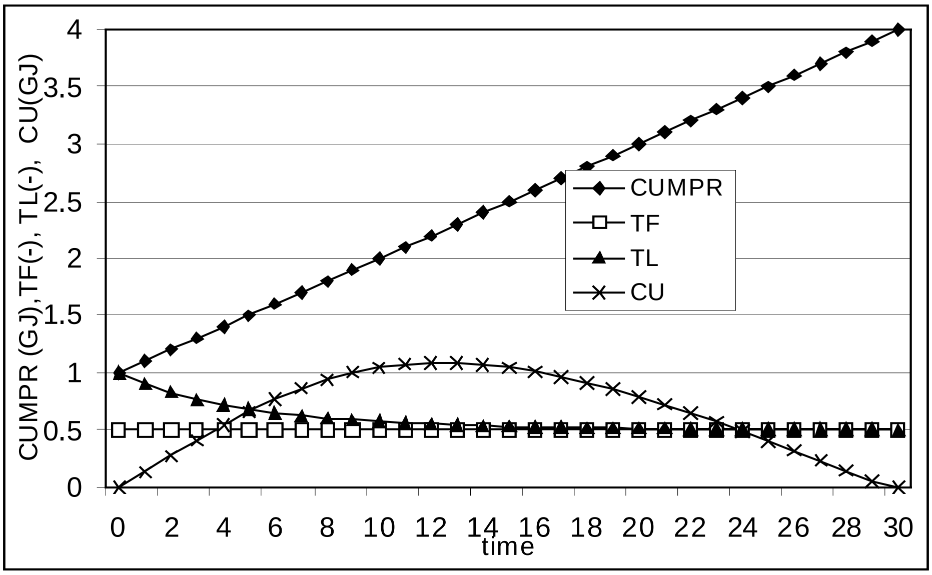

Figure 9.8: Example of catching up module.

By way of sensitivity analysis, Figure 9.9 shows the normalised production costs of a resource at some technology level for a variety of values of the mark-up of the notional technological frontier, τ, and the transformation elasticity, γ. Expectedly, the lowest costs – and highest state of technology – are for high mark-up rates and transformation elasticities.

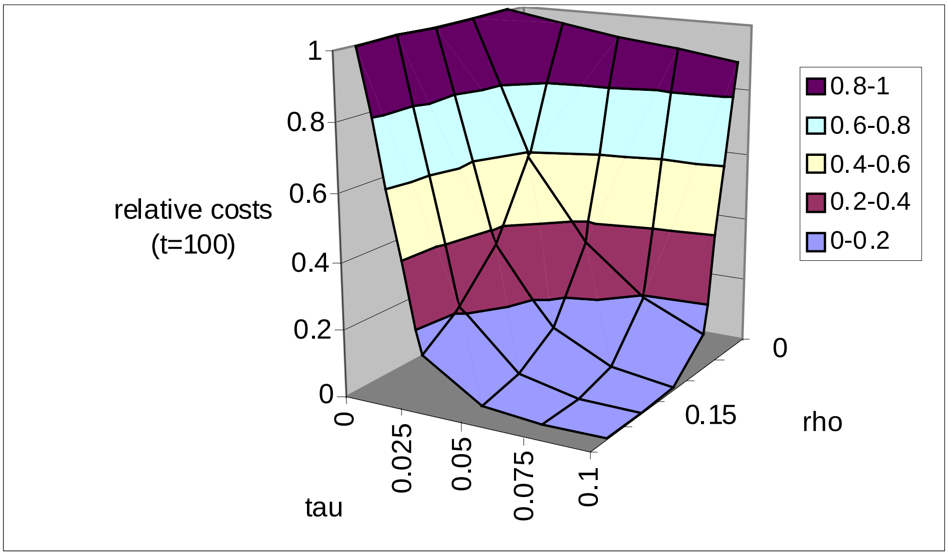

Figure 9.9: Relative costs as a function of τ, mark-up rate and γ, transformation elasticity

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Appendix A: Data-sources

In TIMER a large amount of data is used from various sources. An overview is given in Table A.1. All datafiles are part of the RIVM – international database and assumptions have been described in detail. This appendix only discusses the energy data in some more detail.

	Contents	Time period	Source
Economy	Gross Domestic Product (1995$)	1970 – 1995	WB-WDI
	Value added services (%)	1970 – 1995	WB-WDI
	Value added industry (%)	1970 - 1995	WB-WDI
	Value added agriculture (%)	1970 - 1995	WB-WDI
	Private consumption (1995$)	1970 - 1995	WB-WDI
	Purchasing power parity (1995$)	1970 – 1995	WB-WDI
Energy	Final energy consumption (PJ)	1971 - 1995	IEA-2020
	Primary energy consumption (PJ)	1971-1995	IEA-2020
	Energy production (PJ)	1971-1995	IEA-2020
	Energy use in electricity production (PJ)	1971-1995	IEA-2020
	Energy imports and exports (PJ)	1971-1995	IEA-2020
	Non-energy use (PJ)	1971-1995	IEA-2020
	Overhead factors energy production (%)	1971-1995	IEA-2020
	Fraction LLF-HLF (%)	1971-1995	EDGAR
	Fraction underground coal production (%)	1971-1995	EDGAR
	Energy prices (1995$/MJ)	1971-1995	IEA
Population	Total population (-)	1970 – 1995	UN
	Rural population (%)	1970- 1995	UN
Distances	Distances (km)	1970-1995	-

For EDGAR see Olivier *et al.*, 1999.

Energy

Almost all energy consumption and production data have been extracted from the IEA database (Beyond 20/20 1998). In some cases, information from the EDGAR database and other sources have been used to provide additional data where necessary. The country data have been aggregated into IMAGE regions. The IEA database contains three (relatively small) grouping for ‘other Asia’, ‘other Africa’ and ‘other Latin America’. These groupings have been attributed to IMAGE regions on the basis of UN data for consumptions and on the basis of the shares of relevant IMAGE groupings for production data.

We know that the IEA data are certainly not perfect. Therefore, the data have been subjected to close scruteny. Clear errors or unspecificied energy consumption have been removed – as described in the data files.

Appendix B: TIMER indicators on IMAGE 2.2 cd-rom

Views

- Secondary energy
- Primary energy
- Electricity generation
- Trend (KAYA)

The above indicators visualize a distinction between primary and secondary (final) energy use. In addition, information is given on electricity generation and a set of trend ('Kaya factors') indicators.

- Secondary energy use is defined as the amount of energy consumed by the end-user and does not include the energy lost in the production and delivery of energy products. Neither does it include the use of feedstocks and non-energy use. Our definition of secondary energy use is almost equal to 'Total Final Consumption' as defined by the International Energy Agency, except for the fact that the latter term does include feedstocks and non-energy use.
- Primary energy use, in contrast, is the sum of all energy consumed, including losses at various stages of energy upgrading and processing. Primary energy here includes non-energy use and feedstocks. The terms 'use', 'demand', 'consumption' and 'supply' are often used for the same energy flow in energy statistics and modelling, as it is assumed that demand is fully met. This is also the case in the TIMER model scenarios. Our definition of primary energy use is equal to the term 'Total Primary Energy Supply' as defined by the International Energy Agency.

The indicators included in "secondary energy" follow the break-up in energy carriers used within the demand submodel of TIMER: solid fuels (i.e. coal), heavy liquid fuels (only those based on fossil fuels) (HLF), light liquid fuels (only those based on fossil fuels) (LLF), gaseous fuels (only those based on fossil fuels), modern biofuels, traditional fuels (wood, straw, dung, charcoal etc.), electricity and secondary heat. The definition of these energy carriers corresponds to those used by the International Energy Agency (IEA). Solid fuel consists of all types of coal (steam, coking) excluding feedstocks. Liquid fuels are divided into two categories: light liquid fuels (LLF) include all fuels that have an energy content higher than gas/diesel oil (i.e. 1.035 ton oil equivalent per ton) and heavy liquid fuels (HLF) are those that have an energy content equal to/or lower than gas/diesel oil (i.e. 1.035 ton oil equivalent per ton). The category modern biomass includes both modern biomass used as liquid and gaseous fuels. Feedstocks are excluded.

Secondary energy use

unit: PJ/yr (Petajoule per year)
dimension: region, secondary energy carrier

Secondary energy use shows the total demand for secondary energy in each region. Secondary energy use is equal to the amount of energy consumed by the end-user and does not include the energy lost in the production, processing and delivery of energy carriers. Neither does it include the use of feedstocks and non-energy use.

In the TIMER model the demand for secondary energy is derived from the demand for energy services multiplied by time-dependent conversion efficiencies. Unless potential investments are constrained or there are delays in actual investments, the demand for final energy is fully satisfied and thus equals its use. A description of the energy cariers is given under the information for the total box of secondary energy indicators.

Sectoral secondary energy use

unit: PJ/yr (Petajoule per year)
dimension: region, secondary energy carrier, sector

Sectoral secondary energy use or final energy use presents the use of secondary energy carriers for each region (i.e., for all five sectors industry, transport, residential, commercial and other). Secondary energy use is equal to the amount of energy consumed by the end-user and does not include the energy lost in the production, processing and delivery of energy carriers. Neither does it include the use of feedstocks and non-energy use.

In the TIMER model, the demand for secondary energy is derived from the demand for energy services multiplied by time-dependent conversion efficiencies. Unless potential investments are constrained or there are delays in actual investments, the demand for final energy is fully satisfied and thus equals its use. A description of the energy cariers is given under the information for the total box of secondary energy indicator.

Sectoral secondary energy use per capita

unit: GJ/yr (Gigajoule per year)
dimension: region, sector

Sectoral secondary energy use divided by population (see further the main description of secondary energy indicators.

Secondary energy use per capita

unit: GJ/yr (Gigajoule per year)
dimension: region

Total secondary energy use divided by population (see further the main description of secondary energy indicators).

Market share of secondary energy carriers

unit: none (fraction, no dimension)
dimension: region, secondary energy carrier, sector

The market share of secondary energy carriers shows the fraction of each energy carrier in the total secondary energy use for each region and each sector. This fraction, or market share, is calculated on the basis of relative prices and certain premium factors. These premium factors are used to incorporate factors other than market prices (e.g., consumer preferences and government policies) that also determine market shares. In some cases (mainly historically) markets have been shielded for full competion of the different cariers. In the energy mode, the fuel-substitution dynamics is described by a multinomial logit formulation, according to which the market share of a fuel increases as its relative price falls. If two fuels have the same price, each has a market share of 0.5.

Price of secondary energy carriers

unit: US$(1995)/GJ (1995-US dollars per Gigajoule)
dimension: region, secondary energy carrier

Price of secondary energy carriers shows the secondary fuel and electricity prices in each region. These are the prices paid by the end-use energy users for the secondary energy carriers, including taxes. The "fuel supply" and "electric power generation" submodels calculate for each year for each region the costs to produce fossil fuels (coal, oil, natural gas), biomass-derived fuels (bio-liquid fuels and bio-gaseous fuels) and electricity. These costs are based on production costs in the region and the import-export flows between regions. The latter makes regional energy supply costs a function of the supply-demand dynamics in the world market. In the "energy demand" submodel the regional energy supply costs are converted into end-use prices for solid, liquid and gaseous fuels and electricity. In this conversion, costs of transport and distribution within the region and fuel taxes are included.

Total primary energy use

unit: PJ/yr (Gigajoule per year)
dimension:

Total primary energy use shows the use of all primary energy carriers for each region. Primary energy use is defined as the sum of all energy consumed, including losses at various stages of energy upgrading and processing. It also includes non-energy use and feedstocks.
The definition of the eight primary energy carriers corresponds to those used by the International Energy Agency (IEA). The distinction between the two categories of liquid fuels (heavy and light) is not made for primary energy use - and all crude oil use has been indicated as 'heavy oil' (the distinction is only relevant for secondary fuels). The categories bio-liquid fuels and bio-gaseous fuels are aggregated into the category modern biofuels
.
In TIMER, use of primary energy carriers is calculated from the secondary energy use and includes the energy losses in the system in the chain from primary fuel production to secondary fuel use. The most important losses are associated with the generation of electricity and are calculated in the electric power generation submodel. The conversion efficiency from fuel-based thermal power plants is based on exogenous time, region and fuel dependent data and assumptions. The conversion efficiencies for other electricity generation options (hydropower, nuclear, wind, solar, etc.) are set at unity. For fossil fuel production the conversion losses are among other due to refining, transformation and interregional transport.

Total primary energy production

unit: PJ/yr (Gigajoule per year)
dimension: region, primary energy carrier

Total primary energy production shows the production of primary energy carriers for each region. On a global scale, total primary energy production equals total primary energy use. Regional differences between primary energy use and primary energy production are a result of fuel trade. The definition of the eight primary energy carriers corresponds to those used by the International Energy Agency (IEA).

Export (+) and Import (-) of Fuel

unit: PJ/yr (Gigajoule per year)
dimension: region, primary energy carrier

Net fuel trade shows the fuel exports minus fuel imports of fossil and biomass-derived fuels in a region. Fuel trade is based on the assumption that each region desires to import fuel from another region depening on the ratio between the production costs in that other region plus transport costs, and the production costs in the importing region. Transport costs are the product of the representative interregional distances and time and fuel dependent estimates of the costs per GJ per km. To reflect geographical, political and other constraints in the interregional fuel trade, some additional parameters are used to simulate the existence of trade barriers between regions.

As TIMER is a long-term energy model, it is more important to focus on long-term trends than on short-term fluctuations in energy trade. Some of these are caused by sudden increases in production costs in specific regions - after which the model needs to find a new balance in trade flows.

Energy costs as share of GDP

unit: none (fraction)
dimension: region

Total energy costs are defined as the product of the secondary energy carriers and the corresponding prices for end-use consumers, plus the annual investments made by end-users in energy efficiency. These energy costs divided by GDP are a measure of the economic importance of the energy system. In general, this ratio tends to decline as result of a slower growth of energy consumption than GDP. In early stages of economic development, however, the ratio between energy costs and GDP might increase along with a growing share of the industry sector. For regions with a large share of heavy industry the ratio is clearly higher than in other regions. Regions with limited energy supply (i.e. Eastern Africa, India) might in low-trade scenarios suffer from high fuel prices and thus from high energy costs compared to GDP.

Energy investments

unit: 1,000,000,000 US$(1995)/yr (billion 1995-US Dollars per year)
dimension: region, investment type

Energy investments show the 5 year running-average investment flows in each region associated with:

- the production of fossil fuels;
- the production of modern biofuels;
- electricity generation and distribution; and
- end-user investments in energy efficiency.

Energy investments are based on estimates of the required capital stock, given a forward estimate of demand and capital-output ratios. They include expansion as well as replacement investments. Energy system investments are an indicator of the economic inputs required to satisfy energy demand or use it more efficiently. Unless otherwise stated, it is assumed that the required investments are always available in time so that energy carrier demand is fully satisfied and thus equals the energy carrier use. Investments have fluctuated strongly in the past; in some of our scenarios they do as well in response to regional depletion and trade patterns.

Electricity generation mix

unit: none (fraction)
dimension: region, energy carrier

The indicator shows the share of electricity generated by the various types of inputs. In the TIMER energy model, several options exists to generate electricity. Electricity can be generated in thermal power plants using solid, liquid or gaseous fuels, in hydropower plants and in non-thermal power plants referring here to power plants based on nuclear fuels, geothermal heat and/or renewable sources such as wind and solar. Within the categories of solid, liquid and gaseous fuels, a distinction is made between fossil-fuel based coal, heavy and light oil (products) and natural gas, and traditional and commercial biomass-derived fuels. Each of the fuels and options has its specific conversion efficiency and investment costs. For non-thermal power plants the conversion efficiency is always equated to one.

Installed capacity

unit: 1000 MW (thousand MegaWatt)
dimension: region, energy carrier

Electricity is being generated in four distinct, aggregate capital stocks representing four types of powerplants: thermal, hydropower, non-thermal nuclear and non-thermal wind/solar/other renewable. They operate with different load factors and different time-dependent fuel conversion efficiences and specific investments costs. Thus, the installed capacity determines the electricity that will be or can be produced.

Kaya-indicators

The Kaya indicators consist of the four factors of the so-called Kaya identity (Kaya, 1989). Carbon emissions are formulated in the Kaya identity as the product of population, GDP per capita, energy use per unit of GDP (i.e., energy-intensity) and carbon emission per unit of energy (i.e., carbon factor). In the User Support System, the four factors and the resulting carbon dioxide emissions have been indicated in the same way as indicated in the above formula. The upper set of five graphs shows the factors in absolute numbers. The lower set shows the annual changes in each of them. The latter show the moving average values, which have been determined independently - which means that adding the changes in each of the factors not always gives the exact changes in carbon emissions for each year. Long-term trends are correct, however.

Population

unit: million persons
dimension: region

The population view shows the historical (1971-1995) and projected (1995-2100) human population for each of the 17 regions and for the world. Historical population data are based on the United Nations (see HYDE; Klein Goldewijk, 2001). The scenario projections are based on the Special Report on Emissions Scenarios (SRES) (IPCC, 2000) (see also the population indicators).

Gross domestic product per capita

unit: 1000 US$ (1995)/yr (thousand 1995-US$ per year)
dimension: region

Gross domestic product (GDP) per capita is the ratio of regional gross domestic product (GDP) and population. It is presented for the historical (1971-1995) and projected (1995-2100) periods for each of the 17 regions and for the world. Historical data are based on the World Bank and aggregated interregional data (available at the RIVM site). The scenario projections are based on simulations with the WorldScan-model (CPB, 1999) (see also economic indicators).

Energy intensity

unit: GJ/US$ (1995) (Gigajoule per 1995-US dollars)
dimension: region

Energy intensity is the ratio between primary energy use and gross domestic product (GDP). It is presented for each region and the world. For the industrialized regions it tends to decline for the time period considered. This is the result of, among others, the structural change from industrial to service- and information-oriented activities, efficiency improvements and saturation tendencies. In the less industrialized regions this decline is also expected also on the long-run but possibly only after an initial rise as a result of ongoing industrialization.

Energy intensity should not be confused with energy efficiency. The relationship between monetary economic activities as measured in GDP and physical energy flows is a complex one. If basic industrial processes such as mining, steel and petrochemicals manufacturing and freight transport make up a large part of GDP, energy intensity will be high. If knowledge and information-intensive sectors contribute strongly to GDP, energy intensity is lower - partly because the energy incorporated in the non-energy imports is not accounted for.

Carbon factor

unit: kg C /GJ (kilogram C per Gigajoule)
dimension: region

The carbon factor indicates the amount of carbon released per unit of primary energy consumption (where 1.0 kg Carbon equals 3.7 kg carbon dioxide) for each region and the world. The higher the share of high-carbon content fuels in total energy consumption, the higher the carbon factor. In case of a full transition to renewable energy sources, such as wind and hydropower, the carbon factor will be equal to zero.

The amount of carbon dioxide (CO2) emitted per GJ of energy consumption strongly differs among the various energy carriers. In the TIMER model, the carbon factor is calculated on the basis of information contained in the matrix 'total primary energy supply', using the following carbon-contents:

- coal: 25.5 kg C/GJ
- crude oil: 19.3 kg C/GJ
- natural gas 15.3 kg C/GJ

With regard to biofuels (both traditional and modern) it is assumed that net carbon emissions to the atmosphere are zero.

CO_2 emissions from energy use

unit: Pg C/yr (Petagram C per year)
dimension: region

CO_2 emissions from energy use specify the energy-related CO_2 emissions for each region and the world as a whole. Energy use forms one of the most important sources of CO_2 emissions (see also emission indicators.

Energy determinants

unit: none (1971=0)
dimension: region, sector, energy function, determinants

The energy determinants indicate for each sector and energy function how the demand for secondary energy carriers is built up in a region. The graph has to be read as a sequence of curves, showing how activity leads to useful energy demand, is influenced by sectoral changes, is lowered by conservation and changed by fuel switches. Each of the determinants has been expressed as the power-10 logaritm of the index between its value and its value in 1971.This gives a good indication of the changes of this determinant since 1971. The determinants of secondary energy use are:

- increase of activity levels. Activity levels in the model are measured in monetary units. Several proxies are used to determine changes in activity levels for each sector. For the industrial sector, the activity indicator is industrial value added; for the transport sector it is GDP; for the residential sectors it is private consumption; for the services sector it is services value added; for the other sectors it is GDP; and, finally, for the economy as a whole it is GDP.
- sectoral change (only relevant for the economy as a whole). Sectoral change indicates the impacts of changes in the shares of the five sectors in total energy use for the ’energy intensity’ of the economy as a whole.
- effect from structural change (intersectoral shifts) and life-style changes. Structural change indicates the impact of changes in the mix of products/processes in each sector, such as shifts from light to heavy industry or from road truck to train in freight transport.
- energy conservation (energy efficiency improvement). Energy conservation accounts for investments in energy efficiency improvement and includes price-induced and autonomous trends.
- fuel switch. The changes shown for ’fuel switch’ reflect the different end-use efficiencies of different fuels. For example, most energy services can be provided with less GJ/unit by natural gas than by coal.

The last four factors together determine energy intensity. Sectoral energy demand in the form of secondary fuels and electricity is the product of energy intensity and sectoral activity.

Appendix C: Overview of input variables into the energy submodels

Variable (program code)	Unit	Current value(s) lowest	Highest	Reference	Location	Description	Variable (this report)
Datenerg (general data files)							
GDP[NR17](t)	1995US$/cap	192.00	1.1E+05	Historic data/scenario	"endatreg/scen/global/gdp_pc.scn"	Gross Domestic Product	GDP
IVA[NR17](t)	1995US$/cap	31.00	2.9E+04	Historic data/scenario	"endatreg/scen/global/iva_pc.scn"	Industry Value Added	IVA
PRIVC[NR17](t)	1995US$/cap	147.00	7.8E+04	Historic data/scenario	"endatreg/scen/global/pcons_pc.scn"	Private consumption	Priv.Cons
SVA[NR17](t)	1995US$/cap	63.68	7.8E+04	Historic data/scenario	"endatreg/scen/global/sva_pc.scn"	Services Value Added	SVA
POP[NR17](t)	Mcap	19.32	2.1E+03	Historic data/scenario	"endatreg/scen/global/pop.scn"	Population	Pop
RURPOP[NR17](t)	Fr.	0.11	0.94	Historic data/scenario	"endatreg/scen/global/rurpop.scn"	Fraction rural population	Urban_pop
UnitLabourCostinp[NR17](t)	1995US$/cap	192.00	1.1E+05	Historic data/scenario	"endatreg/scen/global/gdp_pc.scn"	Unit labour cost equated to gdp/cap	
discountrate[NR17](t)	Fr.	0.10	0.10	Historic data/scenario	"endatreg/scen/engen/disc.scn"	Discount rate	r
CatchTransElast[NR17](t)	-	0.00	0.01	Historic data/scenario	"endatreg/scen/engen/ttelas.scn"	Transfer elasticity in catching up of technology	
EnergyConv[NR17,3](t)	PJ	-309.22	713.71		"endatreg/scen/engen/enerconv.scn"	Conversion of fossil energy carriers into other cariers (coal gasification etc.) - External scenario	EC
BioProdMax[NR17]	GJ	1.6E+07	1.1E+11		"endatreg/scen/engen/bioprodp.dat"	Production level at which maximum price for biofuel production is reached (maximum production)	BioPotSup
CO2Target(t)	GtC/yr	2.4E+12	8.1E+12		"endatreg/scen/engen/targtco2.scn"	CO2 target scenario as comparison (e.g. 550 ppmv stabilisation)	
BioDeplMultFac[NR17](bkfbio)		0.00	32.00		"endatreg/data/engen/biodepl.cal"	Multiplier as a result of which yield decreases as a function of BFprodn/BFPotProdn	f_{bio}
LandPrice_i[NR17]	1995US$/ha	472.08	2329.86		"endatreg/data/engen/landpric.ini"	Price of land in 1970	LandPrice
TaxInd[NR17,NEC](t)		0.00	3.06		"endatreg/scen/engen/taxind.scn"	Tax on secondary fuels for industry (1971-1995 hist, thereafter scenario)	TAX
TaxTrp[NR17,NEC](t)		0.00	16.00		"endatreg/scen/engen/taxtrp.scn"	Tax on secondary fuels for transport (1971-1995 hist, thereafter scenario)	TAX
TaxRes[NR17,NEC](t)		0.00	10.00		"endatreg/scen/engen/taxres.scn"	Tax on secondary fuels for residential (1971-1995 hist, thereafter scenario)	TAX
TaxSer[NR17,NEC](t)		0.00	8.00		"endatreg/scen/engen/taxser.scn"	Tax on secondary fuels for services (1971-1995 hist, thereafter scenario)	TAX
TaxOth[NR17,NEC](t)		0.00	10.00		"endatreg/scen/engen/taxoth.scn"	Tax on secondary fuels for other (1971-1995 hist, thereafter scenario)	TAX
DieselGasTaxRatio[NR17](t)		0.50	0.50		"endatreg/scen/endem/gsdiestx.scn"	The ratio between diesel and gasoline taxes	
ImplMultGas[NR17,NS](t)		0.40	1.40		"endatreg/scen/engas/implmult.scn"	Correction on calculated primary fuel prices per region, based on historic data.	
ImplMultOil[NR17,NS](t)		0.40	1.50		"endatreg/scen/enoil/implmult.scn"	Correction on calculated primary fuel prices per region, based on historic data.	
ImplMultCoal[NR17,NS](t)		0.95	3.00		"endatreg/scen/encoal/implmult.scn"	Correction on calculated primary fuel prices per region, based on historic data.	
TPESMARKER[5,9](t)		0.00	8.1E+11		"endatreg/hist/engen/tpesb1.scn"	Comparison scenario	
RSEMARKER[5,9](t)		0.00	6.1E+11		"endatreg/hist/engen/rseb1.scn"	Comparison scenario	
BioSupplyBL[NR17,3](t)		0.00	1.8E+04		"endatreg/scen/baseline/bio_bl.scn"	Comparison scenario	
TPESBL[NR17,8](t)		0.00	5.5E+04		"endatreg/scen/baseline/tpes_bl.scn"	Comparison scenario	

CO2BL[NR17](t)		4.4E+09	1.8E+12		"endatreg/scen/baseline/co2_bl.scn"	Comparison scenario	
UserCostNTBL[NR17](t)		1.4E+09	1.6E+12		"endatreg/scen/baseline/usct_ntbl.scn"	Comparison scenario	UECost
UserCostBL[NR17](t)		1.4E+09	1.6E+12		"endatreg/scen/baseline/usct_bl.scn"	Comparison scenario	UECost
TotInvBL[18,8](t)		-2.1E+08	9.1E+11		"endatreg/scen/baseline/totinv.scn"	Comparison scenario	
EXOCarbonTax[NR17](t)		0.00	0.00		"endatreg/scen/engen/ctax.scn"	Carbon tax value	
EXOCgas[NR17](t)		0.33	1.00		"endatreg/exo/cgas.dat"	Scenario files that can be used instead of calculated values (normally not used)	
EXOCoil[NR17](t)		0.20	1.00		"endatreg/exo/coil.dat"	Scenario files that can be used instead of calculated values (normally not used)	
EXOSFPrice[NR17](t)		0.01	10.85		"endatreg/exo/sfprice.dat"	Scenario files that can be used instead of calculated values (normally not used)	
EXOLFprice[NR17](t)		0.19	24.37		"endatreg/exo/lfprice.dat"	Scenario files that can be used instead of calculated values (normally not used)	
EXOGFprice[NR17](t)		0.14	20.75		"endatreg/exo/gfprice.dat"	Scenario files that can be used instead of calculated values (normally not used)	
EXOELprice[NR17](t)		2.56	71.41		"endatreg/exo/elprice.dat"	Scenario files that can be used instead of calculated values (normally not used)	
EXOLLFprice[NR17](t)		0.57	28.45		"endatreg/exo/llfprice.dat"	Scenario files that can be used instead of calculated values (normally not used)	
EXOHLFprice[NR17](t)		0.19	14.22		"endatreg/exo/hlfprice.dat"	Scenario files that can be used instead of calculated values (normally not used)	
TargetStorage[NR17](t)		0.00	0.00		"endatreg/scen/engen/storage.scn"	Target for carbon removal and storage for power plants	
BioSinks(t)		0.00	0.00		"endatreg/scen/engen/biosinks.scn"	The amount of biosinks (subtracted from carbon dioxide emission target)	
TargetStorageRSE[NR17](t)		0.00	0.00		"endatreg/scen/engen/storrse.scn"	Target for carbon removal and storage for secondary use	
Datdem (for demand submodel)							
ConservInvCum_i[NR17,NS,NEF]	US$1995	8.6E+07	9.6E+10	Calibration	"endatreg/data/endem/consinv.ini"	Initial cumulative investments in energy conservation in the baseyear (US$-1995)	$CumInv_{PIEEI}$
ConservPvalue[NR17,NS,NEF](t)	-	0.81	0.90	Calibration	"endatreg/scen/endem/conspval.dat"	Progress ratio for energy conservation technology	π
ConservRevHtime[NR17,NS,NEF]	Years	1.00	5.00	Exp.judgement	"endatreg/data/endem/ConsHTi.dat"	Halftime of the allowed reversible decrease of energy conservation fraction	
ConservRevMax[NR17,NS,NEF]	Fr.	0.10	0.20	Exp.judgement	"endatreg/data/endem/ConsRMax.dat"	Maximum of the allowed reversible decrease of energy conservation fraction	
ConservCapTechLT[NR17,NS,NEF]	Years	8.00	15.00	Exp.judgement	"endatreg/data/endem/convtelt.dat"	Technical lifetime of end-use conservation capital (year)	TL_conservcap
EndUseCapTechLT[NR17,NS,NEF]	Years	8.00	15.00	Exp.judgement	"endatreg/data/endem/eucptelt.dat"	Technical lifetime of end-use, energy using capital (year)	TL_end use cap
LoadFactor[NR17,NS,NEF]	-	0.20	0.60	Exp.judgement	"endatreg/data/endem/loadfac.dat"	Load factor (-)	LoadFactor
MargIntensStart[NR17,NS,NEF]	Years	15.00	101.00	Calibration	"endatreg/data/endem/meistart.dat"	Regional starting point on the marginal intensity curve (world) in the baseyear (year)	SY_AEEI
OMCost[NR17,NS,NEC]	1995$/GJ	0.00	0.50	Exp.judgement	"endatreg/data/endem/omcost.dat"	Operation and maintenance costs	OMC
SInvCost[NR17,NS,NEC]	1995$	0.00	500.00	Exp.judgement	"endatreg/data/endem/sinvcost.dat"	Specific investment costs	
CostUEInit[NR17,NS,NEF]	1995$/GJ	2.97	70.06	Based on 1971 prices and energy use	"endatreg/data/endem/costue.ini"	Initial price of useful energy - necessary in PIEEI formulation	CostUE

ConservDelayStep[NR17,NS,NEF]	Years	4.00	4.00	Exp.judgement	“endatreg/data/endem/consdel.dat"	Number of years the energy conservation is delayed (year)	ConsDelay
TechFacInp[NR17,NS,NEF+2]	-	0.67	1.00	Calibration	“endatreg/data/endem/techfac.dat"	Ratio between 1975 and 1971 technology in order to make simulation matches historic data in 1995	
IntensRefFile[NR17,NS,NEF+2]	GJ/1995 US$	0.00	0.02	IEA data	“endatreg/data/endem/intref.dat"	Intensity in reference year (1995) in order to result in 100% match between simulation and model in 1995	
IntTotRevFactor(t)	-	1.00	1.00	Choice	“endatreg/data/endem/revers.dat"	Switch that determines whether model shows reversibility in response to declining activity levels	
CalibFactor[NR17,NS,NEF+2]	-	0.84	1.07	Calibration	“endatreg/data/endem/calib.dat"	Factor that can be used to increase/reduce SC formulation to fit history (at expense of missing match in 1995)	
IntUEc0File[NR17,NS,NEF+2]	-	0.00	0.00	Calibration	“endatreg/data/endem/IntUEc0.dat"	Parameters part of the SC formula	c0
IntUEc3File[NR17,NS,NEF+2]	-	-2.81	0.00	Calibration	“endatreg/data/endem/IntUEc3.dat"	Parameters part of the SC formula	c3
IntUEc4File[NR17,NS,NEF+2]	-	1.00	1.00	Calibration	“endatreg/data/endem/IntUEc4.dat"	Parameters part of the SC formula: determines saturation level	c4
IntUEc4Fut[NR17,NS,NEF+2](t)	-	0.80	1.00	Scenario	“endatreg/scen/endem/IntUEc4F.scn"	Multiplyer on historic c4; determines future saturation level	c4
PosMaxFile[NR17,NS,NEF+2]	1995US$	1189.22	1.0E+05	Calibration	“endatreg/data/endem/PosMax.dat"	Position of maximum in energy intensity formulation	Amax
IntensTBFile[NR17,NS,NEF+2]	GJ/1995 US$	0.00	0.00	Calibration	“endatreg/data/endem/IntTB.dat"	A theoretical minimum for intensity	UEIbase
DFRef[NR17,NS,NEF]	1995 US$	443.3	2.7E+04	Historic data	“endatreg/data/endem/DFRef.dat"	Value of activity indicator in 1995	
FracSat[NR17,NS]	Fr.	0.05	0.12	Scenario	“endatreg/data/endem/FracSat.dat"	Relevant to estimate saturation value of energy use in case an alternative driver	
CHINFAC[NR17,NS](t)	-	0.40	3.50	Calibration	“endatreg/data/endem/chinfac.dat"	Calibration factor sometimes used to correct discrepancies between model results and historic data (used with care !!)	
TFMult[NR17]	-	0.04	0.04	Calibration	“endatreg/scen/endem/TFMult.dat"	Determines future income elasticity as function of per capita traditional fuel consumption	
TFelasIncHist[NR17]	-	-3.00	-0.05	Calibration&IEA research	“endatreg/data/endem/TFFac1.dat"	Gives historic income elasticity for traditional fuel consumption	ε1
TFelasUrb[NR17]	-	-0.50	-0.20	Calibration&IEA research	“endatreg/data/endem/TFFac2.dat"	Determines dependency of trad. Fuel use on share urban population	ε2
TFelasAlt[NR17]	-	0.02	0.02	IEA research	“endatreg/data/endem/TFFac3.dat"	Determines dependency of trad. fuel use on price of alternative (oil price)	ε3
TFFacSat[NR17]	GJ/cap	0.00	0.33	Calibration	“endatreg/scen/endem/TFFacSat.dat"	Minimum level of traditional fuel use	TFConsPC_sat
TradFuelInit[NR17]	GJ/cap	1.39	16.41	IEA data	“endatreg/data/endem/TFpc.ini"	Inititial consumption of traditional fuel (based on historic data)	TFConsPC
IndModBioFac[NR17]	Fr.	0.00	0.05		“endatreg/scen/endem/indmdbio.dat"	Share of biomass use in industry that is assumed to be 'modern biofuels	
TradFuelShare[NR17,NS](t)	Fr.	0.00	0.97	IEA data	“endatreg/scen/endem/TFShare.scn"	Share in industry, services, transport and other of traditional biofuels	
MShareExoFile[NR17,NS,(NEC-2)](t)	Fr.	0.00	0.98		“endatreg/scen/endem/msexo.scn"	exogenous marketshare of commercial energy carriers in heat (fraction)	NAMS
RatioLLF[NR17,NS](t)	Fr.	0.06	1.00	IEA data (EDGAR)	“endatreg/scen/endem/LLFFrac.scn"	Ratio of LLF/HLF in end use liquid fuel use	LLF fraction
CostCurveScale[NR17,NS,NEF]	US$1995/GJsaved	17.00	125.00	Calibration	“endatreg/data/endem/CostCurveScale.dat"	Scaling constant for conservation cost curves (US$/GJsaved)	CCS
CostCurveMax[NR17,NS,NEF]	Fr.	0.80	0.80		“endatreg/scen/endem/CostCurveMax.	Maximum intensity-reduction resulting from price changes	CCmax

					dat"		
EffSecFuel[NR17,NS,NEC](t)	Fr.	0.15	1.00		"endatreg/scen/endem/EffSecFuel.scn"	Table of conversion efficiency from secondary energy to useful energy (fraction)	H
LOGMargIntens[NS,NEF](Tmei)	-	-2.8E+05	400.00	Choice	"endatreg/scen/endem/LOGmei.dat"	LOG value of the world curve specifying marginal energy intensity (i.e. intensity	LMI
TTAEEI[NR17](t)	-	1.00	1.40	Scenario	"endatreg/scen/endem/ttaeei.scn"	Effect of technology transfer (policy or autonomous) on AEEI	
MSharePriceElas[NR17,NS]	-	1.50	2.00	Choice	"endatreg/data/endem/priceel.dat"	Price elasticity of the market shares of secondary energy carriers (heat only) (-)	λ
CostCurveImprExo[NR17,NS,NEF](t)	Fr.	0.00	0.01	Literature/scenario	"endatreg/data/endem/piecuexo.scn"	Table of autonomous decrease of conservation cost curves	CCI
PremFacSecFuel[NR17,NS,NEC](t)		0.60	20.00	Calibration	"endatreg/scen/endem/premfac.scn"	Table of premium factor to the price of secondary energy carriers (fraction)	P
HPUERatioFut[NR17,NS](t)	-	0.25	1.00	Scenario	"endatreg/scen/endem/HPRatFut.scn"	Ratio between heat and electricity; scenario parameter (-)	
SecHeatFutMS[NR17,NS](t)	Fr.	0.00	0.53	Scenario	"endatreg/scen/endem/SHFut.scn"	Secondary heat consumption (% of total consumption)	
NonEnInt[NR17](t)	GJ/1995 US$	0.40	5.00	Historic : IEA	"endatreg/scen/endem/NFint.scn"	Energy intensity of non-energy use vis-à-vis IVA	
NonEnEffImpr[NR17](t)	Fr.	0.00	0.01	Calibration	"endatreg/scen/endem/NFEff.scn"	Annual improvement of energy intensity of non-energy use vis-à-vis IVA	
PayBackTimefut[NR17,NS,NEF]	Years	3.00	6.50	Scenario	"endatreg/scen/endem/pbtfut.dat"	Payback time in future	PBT
GasDieselFrac[NR17](t)	Fr.	0.20	0.80	Historic : IEA	"endatreg/scen/endem/gsdiesfr.scn"	Fraction of diesel in total transport fuel demand (only relevant for emissions)	
Datepg (for EPG submodel)							
EPG_FracLLF[NR17](t)		0.00	0.74		"endatreg/scen/enepg/fracllf.scn"	Share of LLF in liquid fuel use for elecitricity production	
NTE_NNProdMax[NR17]		1.2E+10	9.2E+10		"endatreg/scen/enepg/nnprdpot.dat"	Maximum potential for Non Nuclear NTE production (solar/wind)	MAXProd
HydroPotCapacity[NR17]		3.6E+04	9.2E+05		"endatreg/data/enepg/hypotcap.dat"	Potential capacity of hydro power (absolute maximum)	
GrossTransFactor[NR17](t)		0.07	0.30		"endatreg/scen/enepg/transfac.scn"	Gross transformation factor (= net electricity trade, own use, distribution losses and use in other energy transformation sectors)	OULF
EPTDCapPerMWe[NR17](t)		1.1E+05	5.5E+05		"endatreg/scen/enepg/eptdcap.scn"	Capital costs of electricity transmission and distribution	ISP_{TD}
AvailInvestm[NR17](t)		1.0E+15	1.0E+15		"endatreg/scen/enepg/availinv.scn"	Available capital for investments (in case of capital constraint scenario)	
SupprDemandfactor[NR17](t)		1.00	1.00		"endatreg/scen/enepg/supdemfr.scn" !fr.	Factor indicating part of electricity demand that is met by production	
Elecnetimp[NR17](t)		-1.6E+08	1.7E+08		"endatreg/scen/enepg/netimp.scn"	Net electricity imports	NTS
TEEffFuelSpecFile[NR17,FOSSIL](t)		0.22	0.57		"endatreg/scen/enepg/teefffsp.scn"	Fuel specific efficiency in Thermal Electric TE (FOSSIL=coal, oil,gas)	H
TESpInvCost2[NR17,FOSSIL](t)		4.0E+05	1.6E+06		"endatreg/scen/enepg/tespinv2.scn"	Specific investment costs for TE production per fossil fuel type	Isp
FGDRedFactor[NR17](t)		0.00	0.95		"endatreg/scen/enepg/fgdred.scn"	Fraction with which sulfur oxide is removed in Flue Gas Desulf FGD processes	
SSpecEmCoal[NR17]		0.00	0.00		"endatreg/data/encoal/sspecemc.dat"	Sulfur emission from coal burning	
StorageIncrCost		0.30	0.30		"endatreg/scen/enepg/storcost.scn"	Increase in TE production costs due to CO2 removal and storage	
NTEBaseLoadFactorSpec[NR1		0.35	0.75		"endatreg/scen/enepg/nteblf.scn"	Base loadfactor of NTE power plants	BLF

7,2](t)					
NTESpInvCostINIT[NR17,2]	2.8E+06	9.3E+06	“endatreg/data/enepg/ntespinv.dat"	Specific Investment costs for nuclear electricity	I
NTE_NNDeplMultFac[NR17](bkfnn)	0.00	5.00	“endatreg/data/enepg/ntedepl.cal"	Increase in NTE production costs along with production capacity due to depletion	f(Depl)
HydroCapacityHist[NR17](t)	0.00	1.5E+05	“endatreg/hist/enepg/hydrocap.dat"	Historical data for installed capacity of hydro power	
HydroLoadFactor[NR17](t)	0.21	0.79	“endatreg/scen/enepg/hydrolf.scn"	Load factor of hydro power plants	
HydroSpInvCost1990[NR17]	1.5E+06	1.0E+07	“endatreg/data/enepg/hspinv90.dat"	Specific investment costs for hydro production	I
ElecCapacityTrendHor[NR17]	3.00	3.00	“endatreg/data/enepg/elcaphor.cal"	Anticipation of demand planning horizon in electric power planning	
PeakLoadFactorMax[NR17]	0.20	0.30	“endatreg/data/enepg/maxplf.cal"	Maximum allowed peak loadfactor	PLFmax
FracDemBL[NR17]	0.86	0.90	“endatreg/data/enepg/frdembl.cal"	BaseLoad share in electricity demand as fraction of demand asked more than x hr/yr	FracBL
EPEconLT[NR17](t)	12.00	12.00	“endatreg/scen/engen/epeclt.cal"	Economic Lifetime of electricity production	ELT
EPTDTechnLT[NR17]	40.00	40.00	“endatreg/scen/engen/eptelt.cal"	Technical lifetime of transmission/distribution capital	TLT
EPTDEconLT[NR17]	30.00	30.00	“endatreg/scen/engen/eptdeclt.cal"	Economic lifetime of transmission/distribution capital	ELT
TENTEAdjTime[NR17]	4.00	4.00	“endatreg/data/enepg/tenteat.cal"	Adjustment time in TE/NTE substitution process in EPG investments	
TENTELogitPar[NR17](t)	2.50	4.05	“endatreg/data/enepg/tentelog.cal"	Cross-price elasticity in mult log fct determining the shares of TE and NTE in new EPG-investments	λ_TE-NTE
ReserveFactorDes[NR17]	1.10	1.10	“endatreg/data/enepg/desrf.cal"	Desired reserve factor as ratio of desired installed and actual installed capacity	
TEBaseLoadFactor[NR17](t)	0.53	0.89	“endatreg/scen/enepg/teblf.scn"	Base loadfactor of thermal power plants	BLF
TETechnLT[NR17]	25.00	25.00	“endatreg/scen/engen/teteclt.cal"	Technical lifetime of TE production capital	TLT
TEFuelAdjTime[NR17]	7.00	7.00	“endatreg/data/enepg/tefatime.cal"	Adjustment time in fuel substitution process in TE	
TEConstrDel[NR17]	3.00	3.00	“endatreg/data/enepg/tecondel.cal"	Delay for construction of TE production capital	
TELogitPar[NR17]	1.98	2.07	“endatreg/data/enepg/telogpar.cal"	Cross-price elasticity in mult log fct determining the market shares of fossil fuels in TE production	λ_SFLFGF
TEFuelPremium[NR17,FOSSIL](t)	0.45	45.00	“endatreg/scen/enepg/tepremf.scn"	Premium value for different fuel types in TE production as multiplication factor	PT
NTETechnLT[NR17]	25.00	25.00	“endatreg/scen/engen/ntetelt.cal"	Technical lifetime of NTE production capital	TLT
NTETimeStartLearn[NR17]	1960.00	1960.00	“endatreg/data/enepg/ntetsl.cal"	Year in which learning for NTE starts	
NTEConstrTime[NR17]	8.00	8.00	“endatreg/data/enepg/ntecont.cal"	Time required for constructing NTE capital	CT
NTEPvalueSc[NR17,2](t)	0.85	1.04	“endatreg/scen/enepg/ntepval.scn"	Progress ratio for NTE production as fraction decline in spec. inv. costs per doubling of cum.prodn.	π
NTEDemoFrac[NR17](t)	0.00	0.34	“endatreg/scen/enepg/ntedemo.scn"	Fraction desired of Electricity Demand forcefully met by NTE Demo overruling price-market	
NTEMaxFracOfPeak[NR17]	0.90	0.90	“endatreg/data/enepg/ntemaxpk.cal"	Maximum allowed NTE excess production as a fraction of total peak electricity demand	
NNDemoFrac[NR17](t)	0.00	0.50	“endatreg/scen/enepg/nndemo.scn"	Fraction desired of Electricity Demand forcefully met by NN Demo overruling price-market	
HydroDesFracPotCapacity[NR17](t)	0.01	0.99	“endatreg/scen/enepg/hydesfr.scn"	Desired fraction of hydropower potential capacity to be operating	
HydroTechnLT[NR17]	50.00	50.00	“endatreg/scen/engen/hytelt.cal"	Technical lifetime of hydro production capital	TLT
NTECapacityUndConstr_i[NR17]	0.00	2.1E+04	“endatreg/data/enepg/undconst.ini"	NTE capital under construction in start year of simulation	

NTECapacity_i[NR17]		0.00	9548.00		“endatreg/data/enepg/ntecap.ini"	Initial (1971) NTE capital	CAP
NTECumLearn_i[NR17,NTEN]		3.8E+06	4.0E+08		“endatreg/data/enepg/cumlearn.ini"	Cumulative production of NTE prodn before 1970 (denominator in learning equation)	
NTEshareEPInv_i[NR17]		0.00	0.06		“endatreg/data/enepg/shareep.ini"	Initial)1971) share in total investments for NTE	
TECapacity_i[NR17]		254.90	3.6E+05		“endatreg/data/enepg/tecap.ini"	Initial (1971) TE capital	
TEMShare_i[NR17,FOSSIL]		0.00	1.00		“endatreg/data/enepg/temshare.ini"	Initial (1971) market shares of different fuel types	
ReqInv_i[NR17]		1.0E+09	1.0E+09		“endatreg/data/enepg/reqinv.ini"	Initial (1971) required investments in electricity production	
Datcoal (for SF submodel)							
UCReserveIdent_i[NR17]	GJ	3.1E+09	1.5E+13	USGS/BP	“endatreg/data/encoal/iducres.ini"	Initial (1971) identified reserve for Underground Coal (part of resource)	CRI_i
SCReserveIdent_i[NR17]	GJ	1.0E+06	2.7E+12	USGS/BP	“endatreg/data/encoal/idscres.ini"	Initial (1971) identified reserve for Surface Coal (part of resource)	CRI_i
SCFixedCapOutRatio_i[NR17]	$/(GJ/yr)	2.00	150.00		“endatreg/data/encoal/scfxcori.ini"	Initial (1971) capital-output ratio in SC mining	CORSC_I
SCProdCum_i[NR17]	GJ	21.01	3.2E+11		“endatreg/data/encoal/cumscprd.ini"	Cumulated SC (=brown coal) production in base year 1971 (denominator in learning)	
SCLearnCum_i[NR17]	!GJ	500.00	1.0E+10		“endatreg/data/encoal/cumsclrn.ini"	Cumulative SC production in baseyear (should be equal to SCProdCum_i but is not !!!)	CumLearn_I
SCResource_i[NR17]	!	6.3E+05	1.0E+13		“endatreg/data/encoal/scresour.ini"	Initial (1971) resource of SC coal	SC_CRB
UCLabSupply_i[NR17]	personyear	90.00	2.0E+06		“endatreg/data/encoal/uclabsup.ini"	Labour supply for UC mining, baseyear	
UCProdCum_i[NR17]	GJ	5.9E+05	7.2E+11		“endatreg/data/encoal/cumucprd.ini"	Cumulated UC (=other coal) production in base year 1971 (denominator in learning)	
UCResource_i[NR17]	!	6.5E+09	1.1E+14		“endatreg/data/encoal/ucresour.ini"	Initial (1971) resource of UC coal	UC_CRB
AdjRate[NR17]	-	1.00	1.00		“endatreg/data/encoal/clar.cal"	Adjustment rate for health & safety multiplier in UC mining (see Naill, 1977)	
CoalCapacUtilFrac[NR17](cdtcpc)	-	0.00	2.00		“endatreg/data/encoal/clcapfr.cal"	Fraction indicating utilization of coal production capacity as a function of the ratio coal demand/capacity	CUM
CoalLogitPar[NR17]	-	2.50	3.00	Calibration	“endatreg/data/encoal/cllogpar.cal"	Parameter of multinomial logit function for determining share of investments in UC and SC	l
CoalPlannHor[NR17]	year	5.00	5.00		“endatreg/data/encoal/clplanh.cal"	Planning horizon for coal production	UCPH
HAWR[NR17]	!	0.00	0.00		“endatreg/data/encoal/clhawr.cal"	Adjustment rate for hiring UC labourers (see Naill, 1977)	
HiringAdjTime[NR17](puh)	year	0.00	14.00		“endatreg/data/encoal/hiadtime.cal"	Delay time required for hiring new labour (see Naill, 1977)	
PAR[NR17]		0.60	1.00		“endatreg/data/encoal/clpar.cal"		
PriceCapacUtilMult[NR17](cdtcpc)	-	0.00	2.00		“endatreg/data/encoal/prcapmt.cal"	Multiplier to include the effect of capacity utilization on the coal price, as a function of the ratio coal demand/capacity	PCUM
ProdSafetyMult[NR17](ar)	-	0.00	1.40		“endatreg/data/encoal/prmlsf.cal"	Multiplier to include safety measures in UC production (see Naill, 1977)	HSM
RPRDes[NR17]	year	50.00	50.00		“endatreg/data/encoal/desrpr.cal"	Desired reserve production ratio RPR for coal	
SCConstrTime[NR17]	year	3.00	4.00		“endatreg/data/encoal/scconstr.cal"	Construction time for new SC capital	SCCT
SCDiscExo[NR17](t)	GJ	0.00	0.00		“endatreg/scen/encoal/scdiscexo.cal"!	Exogenous discovery rate for surface coal (not used)	SCDR_exo
SCDeplMult[NR17](frcr)	-	0.00	70.00	based on Rogner, 1997	“endatreg/data/encoal/scdepmlt.cal"	Depletion multiplier for SC (costs increase as function of cumulated prodn)	SCDeplM
UCConstrTime[NR17]	year	3.00	3.00		“endatreg/data/encoal/ucconstr.cal"	Construction time for new UC capital	UCCT

UC_ProdCostMult_i[NR17]	GJ	0.45	3.00		“endatreg/data/encoal/uccmult.ini"	Depletion multiplier for UC (costs increase as function of cumulated prodn)	
UCDeplMult[NR17](frcr)	-	0.00	64.00	based on Rogner, 1997	“endatreg/data/encoal/ucdepmlt.cal"	Multiplier to indicate declining productivity of UC mines with increasing depletion of the resource base	UCDeplM
UCDiscExo[NR17](t)	GJ	0.00	0.00		“endatreg/scen/encoal/ucdiscexo.cal"	Exogenous discovery rate for SC (not used)	UCDR_exo
UCTechnLT[NR17](t)	year	15.00	15.00		“endatreg/scen/engen/uctelt.cal"	Technical lifetime for UC capital	UC_TLT
CoalEconLT[NR17](t)	year	8.00	8.00		“endatreg/scen/engen/coaleclt.cal"	Economic lifetime of coal producing capital	
SCTechnLT[NR17](t)	year	15.00	15.00		“endatreg/scen/engen/sctelt.cal"	Technical lfetime of surface coal producing capital	SC_TLT
TradeParCoal[NR17]	-	5.00	5.00		“endatreg/data/encoal/parcoal.inp"	Parameter of multinomial logit function for determining coal trade	
DISTANCE[NR17,NR17]	000 km	0.10	24.45		“endatreg/data/encoal/coaldist.dat"	matrix with distances between major coal trade ports	
CoalPrice_i[NR17]	$/GJ	0.50	50.00		“endatreg/data/encoal/coalpric.ini"	Initial coal price	Price
TradeBiasMultCoal(op)		1.00	10.00		“endatreg/data/engen/trbiamul.dat"		
PremMult(op)		1.00	1.00		“endatreg/data/encoal/premmult.cal"		
CoalMineSFrac[NR17](t)		0.00	0.02		“endatreg/data/encoal/SFrCoal.inp"	Sulphur fraction of coal at minemouth	
SSpecEmCoal[NR17]		0.00	0.00		“endatreg/data/encoal/sspecemc.dat"	Specific sulphur emission coefficient for coal	
CoalDesGrossMargin[NR17]	-	0.20	0.40		“endatreg/scen/encoal/desmarg.scn"	Desired Gross Margin DGM on coal production	DGM
CoalProcOvFac[NR17](t)		0.10	1.20		“endatreg/scen/encoal/procovf.scn"	Coal losses in coal processing factor	CPF
SCPValue[NR17](t)		0.85	0.98		“endatreg/scen/encoal/sclearn.scn"	Progress ratio for learning in SC mining	p
UCRelLabCost[NR17](t)	-	1.00	1.50		“endatreg/scen/encoal/ucrlcost.scn"	Ratio between labour costs in UC mines and UnitLabourCostInp=GDP/cap	UCRelLabCost
CoalTransfFrac[NR17](t)		0.00	0.80		“endatreg/scen/encoal/coaltran.scn"	Coal losses and energy sector consumption fraction	t2
COALFRACDEMCONSTR[NR17](t)	-	0.00	1.00		“endatreg/scen/encoal/mximclfr.scn"	Exogenous constraint on which share of consumption can be met by imports	ImpConstr
COALFRACSUPCONSTR[NR17](t)	-	0.00	1000.00		“endatreg/scen/encoal/mxexclfr.scn"	Exogenous constraint on how many times domestic production can be exported	ExpConstr
CoalFracDemFut[NR17](t)		0.00	1.00		“endatreg/scen/encoal/clfrdmfu.scn"	Scenario value of fraction coal demand imported	
PREMCOALDIS[NR17](t)		0.00	2.50		“endatreg/scen/encoal/premdist.scn"	Added cost for inland transport	
PREMCOALTRD[NR17](t)		0.90	1.00		“endatreg/scen/encoal/premtrad.scn"	multiplier on coal in interregional trade	
TRANSCOST(t)	$/PJ.km	45.00	60.00		“endatreg/scen/encoal/transcos.scn"	Specific overseas transport cost of coal NOT ON LAND?	TC
DIFTRANSPORT[NR17,NR17](t)	-	0.90	5.00		“endatreg/scen/encoal/diftrans.scn"	Artificial trade barrier: Conversion from actual km' in distance matrix to ocean-shipping equivalent km'	TRPDiffFactor
CoalFracSupFut[NR17](t)		0.00	10.00		“endatreg/scen/encoal/clfrsufu.scn"	Scenario value of fraction coal supplied exported;	
Datoil (for LF submodel)							
BLFYieldFact_i[NR17]	GJ/ha	200.00	230.00	TES	“endatreg/data/engen/yieldfac.ini"	Initial yield for biofuel production plantages	$Yield_{bio}$
BLFDesGrossMargin[NR17]	-	0.08	0.08	Expert judgement	“endatreg/data/enoil/blfdesgm.cal"	Minimum desired gross margin of BLF production	
BLFMShareAdjTime[NR17]	year	5.00	5.00	Expert judgement	“endatreg/data/enoil/blfadjt.cal"	Time delay market penetration BLF	
BLFCORInit[NR17]	$/GJ	14.50	14.50	Expert judgement	“endatreg/data/enoil/blfcor.ini"	Capital-output ration for BLF production (crude production)	BLFCOR
BLFConvCOR_i[NR17]	$/GJ	87.50	87.50	Expert judgement	“endatreg/data/enoil/blfcorco.ini"	Capital-output ration for BLF production (conversion technology)	$BLFCOR_{conv}$
BLFLearnCum_i[NR17]		1.1E+07	1.1E+07	Calibration	“endatreg/data/enoil/blfcuml.ini"	Initial cumulated BLF production used for calculating the learning factor	$BLFCumLearn_{tL}$
BLFTechnLT[NR17](t)	-	15.00	15.00	Expert judgement	“endatreg/scen/engen/blftelt.cal"	Technical lifetime of BLF capital stock	TLT

BLFTimeSL[NR17]	year	1970.00	1970.00	Expert judgement	"endatreg/data/enoil/blftimes.cal"	Year at which the learning in BLF production starts	tL
OilBLFLogitPar[NR17]	-	4.00	4.00	Expert judgement	"endatreg/data/enoil/blflogpr.cal"	Determines market based penetration of BLF (price sensitivity)	-λ
OilProdDeplMult[NR17](oo)	-	0.00	92.89	Rogner	"endatreg/data/enoil/oilpdplm.dat"	Production - depletion multiplier for oil production	OilDeplM
OilProdCum_i[NR17]	GJ	1.0E+08	6.1E+11	Estimate	"endatreg/data/enoil/oilprcum.ini"	Initial cumulated oil production used for calculating the learning factor	OilPCum
OilDesGrossMargin[NR17]	-	0.20	0.20	Expert judgement	"endatreg/data/enoil/oildesgm.cal"	Minimum desired gross margin of oil production	DGM
OilResource_i[NR17]	GJ	2.6E+09	2.4E+13	Rogner	"endatreg/data/enoil/resource.ini"	Initial assumed resource base for oil	OilRB
OilCost_i[NR17]	1995$/GJ	0.45	3.40	Historic data	"endatreg/data/enoil/oilcost.ini"	Initial production costs	
OilRPRDes[NR17]	year	15.00	15.00	Calibration	"endatreg/data/enoil/rprdes.cal"	Desired reserve/production ratio	RPR_{des}
DemSupPriceMult(op)	-	0.20	3.50	Calibration	"endatreg/data/enoil/demsuppm.dat"	Multiplier on prices based on market shortages / production on maximum capacity	
EPIPOil[NR17](oa)	-	0.00	2.00	Calibration	"endatreg/data/enoil/epipoil.cal"	Multiplier indicating the Expected Profit from Investments in Production	
PriceRatioLLFHLF[NR17]	-	2.00	2.00	Calibration/data	"endatreg/data/enoil/prratlf.cal"	Determines price setting between LLF and HLF fuels	PRLH
OilTechMaxFrac[NR17]	-	0.15	0.15	Expert judgement	"endatreg/data/enoil/tmaxfr.cal"	Technical Maximum (fraction) which can be produced from reserve	
OilTechnLT[NR17](t)	year	15.00	15.00	Expert judgement	"endatreg/scen/engen/oiltelt.cal"	Technical lifetime of all [crude] oil capital stocks	TLT
LFEconLT[NR17](t)	year	5.00	5.00	Expert judgement	"endatreg/scen/engen/oileclt.cal"	Economic lifetime of all liquid fuel capital stocks	ELT
OilExplExo[NR17](t)	GJ	0.00	4.0E+10		"endatreg/data/enoil/oilexpl.dat"	Exogenous exploration rate for oil (additional to investment-driven exploration) (not used)	
OilTRCapOutRatio_i[NR17]		3.60	4.00	Calibration	"endatreg/data/enoil/oiltrcor.ini"	Oil capital output ratio for transport/refining	
DifTransport[NR17,NR17](t)		1.00	2.00	Calibration	"endatreg/scen/enoil/diftrans.scn"	Difficulty matrix for interregional trade	WFTC
distance[NR17,NR17](t)	1000 km	0.10	24.45	Data	"endatreg/data/enoil/oildist.dat"	Distance matix for interregional trade	D
TradeBiasMultOil(op)		1.00	10.00	Calibration	"endatreg/data/engen/trbiamul.dat"		
TradeBiasMultBLF(op)		1.00	10.00	Calibration	"endatreg/data/enoil/blftrbia.dat"		
TRElasBLF[NR17]		3.00	3.00	Expert judgement	"endatreg/data/enoil/blftrel.dat"	Sensitivity to prices in interregional BLF trade	λ
TRElasOil[NR17]		5.00	5.00	Expert judgement	"endatreg/data/enoil/oiltrel.dat"	Sensitivity to prices in interregional oil trade	λ
shockoil[NR17](t)		0.00	5.33	Calibration	"endatreg/data/enoil/shockoil.scn"	Additional factor on prices to mimic historic price shocks	
OligoMult		0.30	0.30	Calibration	"endatreg/data/enoil/olimult.dat"	Additional factor on prices for oligopolic regions	β
OliTrsh		0.70	0.70	Calibration	"endatreg/data/enoil/olitrsh.dat"	Determines who is oligopolic region	
BLFDemoFrac[NR17](t)	-	0.00	0.05	Calibration	"endatreg/scen/enoil/blfdemo.scn"	Exogenously forced BLF as fraction of LLF demand	
BLFTarget[NR17](t)	-	0.00	0.00		"endatreg/scen/enoil/blftarg.scn"	Exogenously forced BLF as fraction of LLF demand	
BLFPvalue[NR17](t)	-	0.90	0.95	Calibration/expert judgement	"endatreg/scen/enoil/blfpvalp.scn"	Progress ratio, costs declines for doubling of BLF production	π
BLFPvalueConv[NR17](t)	-	0.85	0.90	Calibration/expert judgement	"endatreg/scen/enoil/blfpvalc.scn"	Progress ratio, costs declines for doubling of BLF conversion (ethanol etc.)	π
BLFtranscostpkm(t)		105.00	135.00	Calibration/expert judgement	"endatreg/scen/enoil/blftrcst.scn"	Transport costs for BLF	TC
BLFTransfFrac[NR17]	-	0.05	0.05	Expert judgement	"endatreg/scen/enoil/blftrans.scn"	Transformation and distribution losses as a fraction of domestic BLF demand	τ
OilTransFrac[NR17](t)	-	0.00	0.34	Historical data	"endatreg/scen/enoil/oiltrans.scn"	Transformation and distribution losses as a fraction of domestic oil demand	τ
OilLearnExpTR(t)	-	0.90	0.90	Calibration	"endatreg/scen/enoil/oiltrpvl.scn"	Progress ratio, costs declines for doubling of oil production for transport/refining	π

OilPValue[NR17](t)		0.70	0.97	Calibration	“endatreg/scen/enoil/oilpval.scn"	Learning factor for oil production	π
BunkerInt[NR17](t)	-	0.00	0.35	Historical data	“endatreg/scen/enoil/bnkint.scn"	Use of oil for bunkers	
BLFFracDemFut[NR17](t)		0.00	0.00		“endatreg/scen/enoil/fracimbl.scn"	BLF import scenario in case of no endogenous trade modelling	
BLFFracSupFut[NR17](t)		0.00	0.00		“endatreg/scen/enoil/fracexbl.scn"	BLF export scenario in case of no endogenous trade modelling	
OilFracSupFut[NR17](t)		0.00	0.58		“endatreg/scen/enoil/fracexps.scn"	Oil import scenario in case of no endogenous trade modelling	
OilFracDemFut[NR17](t)		0.00	1.00		“endatreg/scen/enoil/fracimpd.scn"	Oil export scenario in case of no endogenous trade modelling	
OilFracDemConstr[NR17](t)		0.00	1.00	Calibration	“endatreg/scen/enoil/mximolfr.scn"	Constraints on oil import	
BLFFracDemConstr[NR17](t)		0.00	1.00	Calibration	“endatreg/scen/enoil/mximblfr.scn"	Constraints on BLF import	
transcost(t)	$/GJ-km	34.00	34.00	Calibration/data	“endatreg/scen/enoil/transcos.scn"	Transport costs for oil	TC
premblf[NR17]	-	0.50	0.50	Calibration	“endatreg/scen/enoil/prtrblf.scn"	multiplier on regionally produced blf in trade module	
premoil[NR17]	-	0.62	1.53	Calibration	“endatreg/scen/enoil/prtroil.scn"	multiplier on regionally produced oil in trade module	
OilExpConstMult[NR17](t)		1.00	100.00	Calibration	“endatreg/scen/enoil/oilexpmx.scn"	Constraints on oil exports	
Datgas (for GF submodel)							
BGFYieldFact_i[NR17]	GJ/ha	200.00	230.00	TES	“endatreg/data/engen/yieldfac.ini"	Initial yield for biofuel production plantages	$Yield_{bio}$
BGFDesGrossMargin[NR17]		0.20	0.20	Expert judgement	“endatreg/data/engas/bgfdesgm.cal"	BioGaseousFuel BGF Desired Gross Margin for producers	
BGFMShareAdjTime[NR17]		5.00	5.00	Expert judgement	“endatreg/data/engas/bgfadjt.cal"	Adjustment parameter to delay the market penetration of BLF	
BGFCORInit[NR17]	$/GJ	14.50	14.50	Calibration	“endatreg/data/engas/bgfcor.ini"	Initial capital-output ratio for Biomass production	BGFCOR
BGFConvCOR_i[NR17]		65.00	65.00	Calibration	“endatreg/data/engas/bgfcorco.ini"	Initial capital-output ratio for conversion of biofuels to BGF	$BGFCOR_{conv}$
BGFLearnCum_i[NR17]	GJ	4.5E+06	4.5E+06	Calibration	“endatreg/data/engas/bgfcuml.ini"	Initial value for cumulated gaseous biofuel production for learning by doing simulation	$BGFCumLearn_{tL}$
BGFTechnLT[NR17](t)	year	15.00	15.00	Expert judgement	“endatreg/scen/engen/bgftelt.cal"	Technical lifetime of BGF capital stocks	TLT
BGFTimeSL[NR17]	year	1970.00	1970.00		“endatreg/data/engas/bgftimes.cal"	Year at which the learning in BGF production starts	TL
GasBGFLogitPar[NR17]		4.00	4.00	Expert judgement	“endatreg/data/engas/bgflogpr.cal"	Multinomial logit parameter which determines price difference based BLF market penetration (zero means that price differences have no role, high means important)	$-\lambda$
GasProdDeplMult[NR17](gg)	-	0.00	126.28	Rogner	“endatreg/data/engas/gaspdplm.dat"	Production - depletion multiplier for gas production	GasDeplM
GasProdCum_i[NR17]	GJ	1.1E+05	3.4E+11	Estimate	“endatreg/data/engas/gasprcum.ini"	Initial cumulated gas production used for calculating the learning factor	GasPCum
GasDesGrossMargin[NR17]		0.20	0.20	Expert judgement	“endatreg/data/engas/gasdesgm.cal"	Desired Gross Margin for Natural Gas production	DGM
GasResource_i[NR17]	GJ	4.7E+11	2.0E+14	Rogner + prod90/95	“endatreg/data/engas/resource.ini"	Initial gas resource base	GasRB
GasCost_i[NR17]		0.27	5.00	Historical data	“endatreg/data/engas/gascost.ini"	initial gas production costs	
GasRPRDes[NR17]	year	25.00	30.00	Calibration	“endatreg/data/engas/rprdes.cal"	Desired reserve production ratio for gas	RPR_{des}
DemSupPriceMult(op)		0.20	3.50	Calibration	“endatreg/data/engas/demsuppm.dat"	multiplier on prices as function of demand and supply of natural gas	
EPIPGas[NR17](ga)		1.00	2.00	Davidsen/calibration	“endatreg/data/engas/epipgas.cal"	Multiplier determining the exploration effort in Natural Gas as function of expected price vs. costs (first column) (Davidsen)	
GasTechMaxFrac[NR17]	-	0.15	0.15	Expert judgement	“endatreg/data/engas/tmaxfr.cal"	Technical Maximum (fraction) which can be produced from reserve	

GasTechnLT[NR17](t)	year	15.00	15.00	Expert judgement	“endatreg/scen/engen/gastelt.cal"	Technical lifetime of all gas capital stocks	TLT
GasEconLT[NR17](t)		5.00	5.00	Expert judgement	“endatreg/scen/engen/gaseclt.cal"	Economic liftetime of all gas capital stocks	ELT
GasTRCapOutRatio_i[NR17]		5.60	6.40	Calibration	“endatreg/data/engas/gastrcor.ini"	Capital output ratio for transport and distribution of NG to end-user	
DifTransport[NR17,NR17](t)		1.00	1.60	Calibration	“endatreg/scen/engas/diftrans.scn"	Difficulty matrix for international transport	WFTC
distance[NR17,NR17](t)		0.15	24.45	Data	“endatreg/data/engas/gasdist.dat" 1000 km	Distance matix	D
PREMMult(op)		1.00	10.00		“endatreg/data/engen/trbiamul.dat"		
PREMMultBGF(op)		1.00	10.00		“endatreg/data/engas/bgftrbia.dat"		
TRElasGas[NR17]		5.00	5.00	Expert judgement	“endatreg/data/engas/gastrel.dat"	Sensitivity to price differences in gas trade	λ
TRElasBGF[NR17]		3.00	3.00	Expert judgement	“endatreg/data/engas/bgftrel.dat"	Sensitivity to price differences in BLF trade	λ
shockgas[NR17](t)		0.00	2.67	Calibration	“endatreg/data/engas/shockgas.scn"	Exogenous price shock to include impact of oil crises	
OligoMult		0.30	0.30	Calibration	“endatreg/data/engas/olimult.dat"	Additional rent for oligopolic producers	β
OliTrsh		0.00	0.00	Calibration	“endatreg/data/engas/olitrsh.dat"	Identifies oligopolic producerts	
BGFDemoFrac[NR17](t)		0.00	0.05	Calibration	“endatreg/scen/engas/BGFdemo.scn"	Exogenously forced BGF as fraction of LLF demand	
BGFAddLearn[NR17](t)		0.00	0.00	Calibration	“endatreg/scen/engas/bgfpee.scn"	Exogenously forced BGF as fraction of LLF demand	
BGFPvalue[NR17](t)	-	0.90	0.95	Calibration/data	“endatreg/scen/engas/BGFpvalp.scn"	Learning rate for BGF	π
BGFPvalueConv[NR17](t)	-	0.85	0.90	Calibration/data	“endatreg/scen/engas/BGFpvalc.scn"	Progress ratio, costs declines for doubling of BGF conversion (ethanol etc.)	π
BGFtranscostpkm(t)		125.00	162.00		“endatreg/scen/engas/bgftrcst.scn"	Transport costs per km for biofuels	TC
BGFTransfFrac[NR17]	-	0.05	0.05	Calibration	“endatreg/scen/engas/BGFtrans.scn"	Transform and distribution losses for BGF	τ
GasTransFrac[NR17](t)	-	0.00	2.64	Calibration	“endatreg/scen/engas/gastranf.scn"	Transformation and distribution losses as a fraction of domestic Gas demand	τ
GasPvalueTR(t)		0.91	0.95		“endatreg/scen/engas/gastrpvl.scn"	Learning rate for gas transport and refining	π
GasPvalue[NR17](t)		0.86	0.95	Calibration	“endatreg/scen/engas/gaspval.scn"	Learning rate for gas production	π
GasFracSupFut[NR17](t)		0.00	0.58		“endatreg/scen/engas/fracexps.scn"	Gas export scenario in case of no endogenous trade modelling	
GasFracDemFut[NR17](t)		0.00	1.00		“endatreg/scen/engas/fracimpd.scn"	Gas import scenario in case of no endogenous trade modelling	
BGFFracDemFut[NR17](t)		0.00	0.00		“endatreg/scen/engas/fracimbl.scn"	BGF export scenario in case of no endogenous trade modelling	
BGFFracSupFut[NR17](t)		0.00	0.00		“endatreg/scen/engas/fracexbl.scn"	BGF import scenario in case of no endogenous trade modelling	
GasFracDemConstr[NR17](t)		0.00	1.00		“endatreg/scen/engas/mximgsfr.scn"	Import contsraints for gas in case of endogenous trade modelling	
BGFFracDemConstr[NR17](t)		1.00	1.00		“endatreg/scen/engas/mximblfr.scn"	Import constraints for BGF in case of endogenoous trade modelling	
transcost(t)	$/GJ-km	441.40	683.45	Info + calibration	“endatreg/scen/engas/transcos.scn"	Transport costs per km	TC
GasToLNG(t)		1.72	2.53	Info + calibration	“endatreg/scen/engas/gastolng.scn"	Additional costs for coversion NG to LNG	α
premBGF[NR17]		0.00	0.00	Calibration	“endatreg/scen/engas/prtrbgf.scn"	!multiplier on regionally produced BGF in trade module	
premgas[NR17]		0.00	0.21	Calibration	“endatreg/scen/engas/prtrgas.scn"	multiplier on regionally produced Gas in trade module	
GasExpConstMult[NR17](t)	!%	0.00	100.00	Calibration	“endatreg/scen/engas/gasexpmx.scn"	Export constraint	