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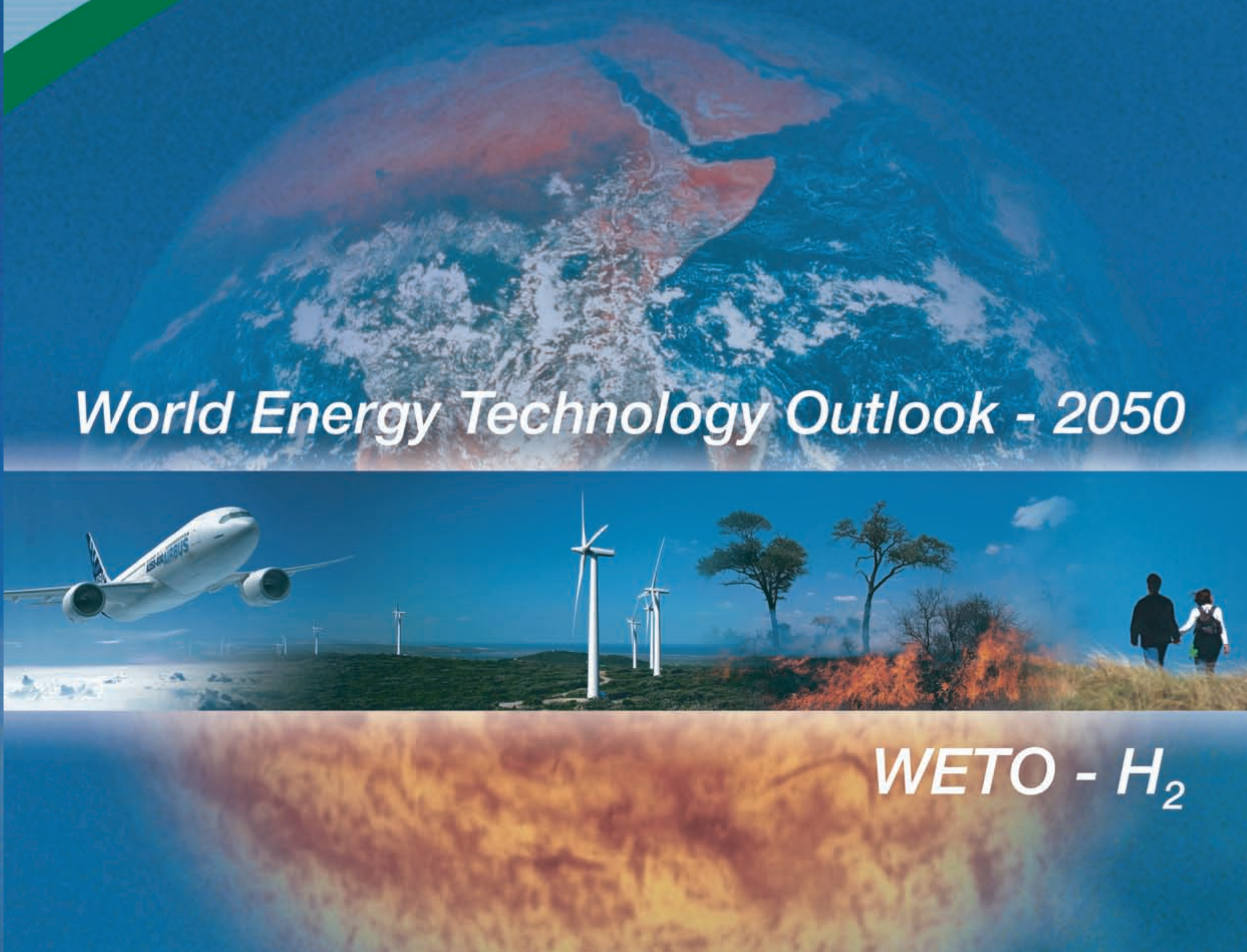

WETO - H_2

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World Energy Technology Outlook - 2050

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World Energy Technology Outlook – *WETO* H_2

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FOREWORD

As the age of cheap energy resources comes to its end, strong political commitment is needed to preserve European competitiveness and to combat climate change. The WETO-H_2 report (*World Energy Technology Outlook-2050*) places the European energy system in a global context. Europe represents today 10% of the world population, 25% of the world GDP and 20% of world energy consumption. Considering the demographic changes and the techno-economic progress made by developing countries, by 2050 these figures will be less than 7%, 15% and 12% respectively.

WETO-H_2 is structured around a business-as-usual case, and features two specific scenarios that reflect the political will of Europe to be at the forefront of the struggle against climate change and to promote new clean energy technologies:

The “reference case” describes the developments of the world energy system up to 2050, and the related CO_2 emissions assuming a continuation of existing economic and technological trends. Without determined action, energy demand will double and electricity demand will quadruple, resulting in an 80% increase in CO_2 emissions.

The “carbon constraint case” explores the consequences of more ambitious carbon emissions policies that aim at the long-term stabilisation of the CO_2 concentration in the atmosphere. Early action is assumed in industrialised countries, while more time is allowed for the emerging and developing countries.

The “hydrogen case” is derived from the “carbon constraint case” but also assumes a series of technology breakthroughs that significantly increase the cost effectiveness of hydrogen technologies, in particular in end use.

The detailed results of the WETO-H_2 report should be of considerable interest for decision and policy makers at different levels. More generally, the report seems to confirm the need for a common energy policy for Europe if it wants to successfully face up to the global energy challenges. The Commission already took first steps by steering the discussion with the Green Paper on “A European strategy for sustainable, competitive and secure energy”. We will need radical progress to tackle simultaneously the issues of European energy security of supply, competitiveness and climate change.

Energy related research is one of several important tools that can help bring about such progress, and the 7th RTD Framework Programme will play its part. Nevertheless, we need to intensify our efforts: European, national and private. If we want Europe to develop a competitive and sustainable energy system in the next decades, we will need determination in putting in place the right policies and in developing and promoting new technologies.

Janez Potočnik
Commissioner for Science and Research

KEY MESSAGES

The WETO-H_2 study has developed a Reference projection of the world energy system and two variant scenarios, a carbon constraint case and a hydrogen case. These scenarios have been used to explore the options for technology and climate policies in the next half-century.

All the projections to 2050 have been made with a world energy sector simulation model – the *POLES model* – that describes the development of the national and regional energy systems, and their interactions through international energy markets, under constraints on resources and climate policies.

The development of the world energy system in the reference projection

The reference projection

The Reference projection describes a continuation of existing economic and technological trends, including short-term constraints on the development of oil and gas production and moderate climate policies for which it is assumed that Europe keeps the lead.

World energy consumption

The total energy consumption in the world is expected to increase to 22 Gtoe per year in 2050, from the current 10 Gtoe per year. Fossil fuels provide 70% of this total (coal and oil 26% each, natural gas 18%) and non-fossil sources 30%; the non-fossil share is divided almost equally between renewable and nuclear energy.

Energy efficiency improvement

The size of the world economy in 2050 is four times as large as now, but world energy consumption only increases by a factor of 2.2. The significant improvement in energy efficiency arises partly from autonomous technological or structural changes in the economy, partly from energy efficiency policies and partly from the effects of much higher energy prices.

North-South balance in energy consumption

Energy demand grows strongly in the developing regions of the world, where basic energy needs are at present hardly satisfied. The consumption in these countries overtakes that of the industrialised world shortly after 2010 and accounts for two thirds of the world total in 2050.

Oil and gas production profiles

Conventional oil production levels off after 2025 at around 100 Mbl/d. The profile forms a plateau rather than the “peak” that is much discussed today. Non-conventional oils provide the increase in total liquids, to about 125 Mbl/d in 2050. Natural gas shows a similar pattern, with a delay of almost ten years.

Oil and gas prices

The prices of oil and natural gas on the international market increase steadily, and reach 110 $/bl for oil and 100 $/boe for gas in 2050[1]. The high prices mostly reflect the increasing resource scarcity.

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[1] In 2005 $

Electricity: the comeback of coal, the take-off of renewable sources and the revival of nuclear energy

The growth in electricity consumption keeps pace with economic growth and in 2050, total electricity production is four times greater than today. Coal returns as an important source of electricity and is increasingly converted using new advanced technologies. The price of coal is expected to reach about 110 $/ton in 2050[2]. The rapid increase of renewable sources and nuclear energy begins after 2020 and is massive after 2030; it implies a rapid deployment of new energy technologies, from large offshore wind farms to "Generation 4" nuclear power plants[3].

CO_2 emissions

The deployment of non-fossil energy sources to some extent compensates for the comeback of coal in terms of CO_2 emissions, which increase almost proportionally to the total energy consumption. The resulting emission profile corresponds to a concentration of CO_2 in the atmospheric between 900 to 1000 ppmv in 2050. This value far exceeds what is considered today as an acceptable range for stabilisation of the concentration.

The European energy system in the reference projection

Energy demand trends

Total primary energy consumption in Europe increases only a little from 1.9 Gtoe / year today to 2.6 Gtoe / year in 2050. Until 2020, the primary fuel-mix is rather stable, except for a significant increase in natural gas consumption. Thereafter the development of renewable energy sources accelerates and nuclear energy revives. In 2050 non-fossil energy sources, nuclear and renewable provide 40% of the primary energy consumption, much above the present 20%. The consumption of electricity keeps pace with economic growth; the market for electricity remains dynamic because of new electricity uses, especially in the Information and Communication Technologies.

CO_2 emissions

This combination of modest climate policies and new trends in electricity supply results in CO_2 emissions that are almost stable up to 2030 and then decrease until 2050. At that date CO_2 emissions in Europe are 10% lower than today.

Electricity production

Because of relatively strong climate policies, European electricity production is 70% decarbonised in 2050; renewable and nuclear sources provide 60% of the total generation of electricity and a quarter of thermal generation is equipped with CO_2 capture and storage systems.

Hydrogen production

Hydrogen develops after 2030, with modest although not negligible results: it provides in 2050 the equivalent of 10% of final electricity consumption.

The carbon constrained world energy system

The carbon constraint case

This scenario explores the consequences of more ambitious carbon policies that aim at a long-term stabilisation of the concentration of CO_2 in the atmosphere close to 500 ppmv by

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2 Or about 22$ per barrel of oil equivalent

3 The scenario assumes that economic and societal obstacles to nuclear can be overcome.

2050. Early action is assumed in Annex B countries, while more time is allowed for the emerging and developing countries.

A "Factor 2" reduction in Europe

In this carbon constraint case, global emissions of CO_2 are stable between 2015 and 2030 (at about 40% above the 1990 level) and decrease thereafter; however, by 2050, they are still 25% higher than in 1990. In the EU-25, emissions in 2050 are half the 1990 level; on average they fall by 10% in each decade.

An accelerated development of non-fossil fuels

By 2050, annual world energy demand is lower than in the Reference case by 3 Gtoe / year. By 2050, renewables and nuclear each provides more than 20% of the total demand; renewable sources provide 30% of electricity generation and nuclear electricity nearly 40%. Coal consumption stagnates, despite the availability of CO_2 capture and storage technologies. By 2050, the cumulative amount of CO_2 stored form now to 2050 is six times the annual volume of emissions today.

Energy trends in Europe

In Europe, the total consumption of energy is almost stable until 2030, but then starts to increase[4]. This is in a sense a statistical phenomenon arising from the high primary heat input of nuclear power. Renewable sources provide 22% and nuclear 30% of the European energy demand in 2050, bringing the share of fossil fuels to less than 50%. Three quarters of power generation is based on nuclear and renewable sources and half of thermal power generation is in plants with CO_2 capture and storage. Hydrogen delivers a quantity of energy equivalent to 15% of that delivered by electricity. By 2050, half of the total building stock is composed of low energy buildings and a quarter of very low energy buildings[5]. More than half of vehicles are low emission or very low emission vehicles (e.g. electricity or hydrogen powered cars).

The world energy system in the H_2 case

The hydrogen scenario

The hydrogen scenario is derived from the carbon constraint case, but also assumes a series of technology breakthroughs that significantly increase the cost-effectiveness of hydrogen technologies, in particular in end-use. The assumptions made on progress for the key hydrogen technologies are deliberately very optimistic.

Total energy demand

Although the total energy demand in 2050 is only 8% less than in the Reference case, there are significant changes in the fuel mix. The share of fossil fuels in 2050 is less than 60%; within this share, the demand for coal drops by almost half compared to the Reference case, and this despite the lower cost assumed for CO_2 capture and storage. The share of nuclear and renewable energy increases, especially between 2030 and 2050; this behaviour is partly caused by the high carbon values across the world and partly by the increased demand for hydrogen.

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[4] This increase is mainly linked to the strong penetration of nuclear, as due to the comparably low efficiency of nuclear power plants a given amount of electricity from nuclear requires more primary energy input than the same of amount of electricity coming from fossil fuels or renewables

[5] Buildings with a reduction by a factor of 2 (low) to 4 (very low) from the consumption of present buildings

Electricity production

The move to a hydrogen economy induces further changes in the structure of generation and the share of nuclear reaches 38%. Thermal electricity production continues to grow and is associated with CO_2 capture and storage systems; in 2050, 66% of electricity generation from fossil fuels is in plants equipped with CCS against 12% in the Reference case.

Hydrogen production and use

The use of hydrogen takes-off after 2030, driven by substantial reductions in the cost of the technologies for producing hydrogen and the demand-pull in the transport sector. From 2030 to 2050, production increases ten-fold to 1 Gtoe / year. By 2050, hydrogen provides 13% of final energy consumption, compared to 2% in the Reference case. The share of renewable energy in hydrogen production is 50% and that of nuclear is 40%.

Around 90% of hydrogen is used in transport. By 2050, the consumption of hydrogen in transport is five times as high as in the Reference case, with a share of 36% of the consumption of the sector. Hydrogen is used in 30% of passenger cars and about 80% of these are powered by fuel cells; 15% are hydrogen hybrid vehicles and 5% are hydrogen internal combustion engines.

The European energy system in the H_2 case

Total energy demand

Nuclear energy provides a third of the total energy demand in Europe. Oil, natural gas and renewables each provides roughly 20% and coal 6%.

Electricity production

The share of fossil fuels in power generation decreases steadily and significantly. The use of CO_2 capture and storage systems develops strongly; by 2050, more than 50% of thermal electricity production is from plants with CO_2 capture and storage.

Hydrogen production and use

The production of hydrogen increases rapidly after 2030 to reach 120 Mtoe by 2050, or 12% of world production. Hydrogen provides 7% of final energy consumption in Europe, against 3% in the Reference case. In Europe, hydrogen is produced mainly from the electrolysis of water using nuclear electricity. The share of hydrogen produced from renewables is also substantial (40% in 2050). About three quarters of the hydrogen produced in Europe go to the transport sector.

INTRODUCTION

The WETO-H_2 study has developed a Reference projection of the world energy system to test different scenarios for technology and climate policies in the next half-century; it has a particular focus on the diffusion of hydrogen as a fuel. This Reference projection adopts exogenous forecasts for population and economic growth in the different world regions and it makes consistent assumptions for the availability of fossil energy resources and for the costs and performances of future technologies. It uses a world energy sector simulation model – the POLES model – to describe the development to 2050 of the national and regional energy systems and of their interactions through international energy markets, under constraints on resources and from climate policy.

Two variant scenarios are considered in this report: a Carbon Constraint case and a hydrogen scenario. The Carbon Constraint case reflects a state of the world with moderately ambitious climate targets, aiming at an emission profile that is compatible in the long-term with concentration levels below 550 ppmv for CO_2. This scenario is not intended to depict the climate policy of the EU that is now in preparation and that will be presented to the UNFCCC “post-2012” negotiation process; it draws on preceding studies of international climate policies with the POLES model, in particular the European Greenhouse gas Reduction Pathways study[6].

Taken together, the Reference projection and the Carbon Constraint case indicate the major changes to expect in the structure and development of the world energy system in different policy contexts. Compared to the previous WETO-2030 study, the present projections, with the horizon of 2050, clearly show the consequences of the twin constraints of finite fossil fuel resources and restrictions on greenhouse gas emissions. The image of the world provided by WETO-H_2 makes apparent the need for radical changes to energy systems.

The hydrogen scenario considers alternative technological and socio-economic pathways that illustrate possible ways of incorporating hydrogen into the world energy system. It implies a certain number of technology breakthroughs to make hydrogen technologies, mainly on the end-use side, more cost effective.

This report first presents the common set of assumptions used in this study, then the results of the Reference projection for the world and for Europe. The third chapter analyses the consequences for energy systems and technologies of the Carbon Constraint case. Chapter 4 discuss the state of the art of hydrogen technologies and presents the results of the hydrogen scenario.

A special analysis has been added to explore around the POLES least-cost solution what the risk-reward balance might be. It relies on the finance technique of mean-variance portfolio theory.

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6 *Greenhouse gas Reduction Pathways, policymakers’ summary:* http://europa.eu.int/comm/environment/climat/pdf/pm_summary2025.pdf

CHAPTER 1 DRIVERS AND CONSTRAINTS IN WORLD ENERGY TO 2050

The Reference projection in the WETO-H_2 study provides an image of the energy scene to 2050 as resulting from the continuation of on-going trends and structural changes in the world economy. This projection has been developed with the POLES modelling system that provides a tool for the simulation and economic analysis of world energy scenarios under environmental constraints. It is not a General Equilibrium, but a Partial Equilibrium Model, with a dynamic recursive simulation process. From the identification of the drivers and constraints in the energy system, the model allows to describe the pathways for energy development, fuel supply, greenhouse gas emissions, international and end-user prices, from today to 2050.

The approach combines a high degree of detail in the key components of the energy systems and a strong economic consistency, as all changes in these key components are largely determined by relative price changes at sectoral level. The model identifies 46 regions of the world, with 22 energy demand sectors and about 40 energy technologies – now including generic "very low energy" end-use technologies. Therefore, each scenario can be described as the set of economically consistent transformations of the initial Reference case that is induced by the introduction of policy constraints.

The main exogenous inputs to the Reference projection relate to: world population and economic growth as the main drivers of energy demand; oil and gas resources as critical constraints on supply and the future costs and performances of energy technology that define the feasible solutions. In all cases, the projected trends extrapolate existing structural changes; this in no way implies, as is illustrated below, a uniform development of the world economic and energy system.

An important aspect of the projections performed with the POLES model is that they rely on a framework of permanent competition between technologies with dynamically changing attributes. The expected cost and performance data for each critical technology are gathered and examined in a customised database that organises and standardises the information in a manner appropriate to the task.

Finally, although the model does not calculate the macro-economic impacts of mitigation scenarios, it does produce robust economic assessments based on the costs of implementation of new technologies and that benefit from a rigorous examination of the engineering and scientific fundamentals.

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1.1 The drivers of world economic growth

In this study, the world economy is projected to grow at 3%/yr until 2030 and then slows to an average 2%/yr between 2030 and 2050. The slower growth in the two later decades is partly a consequence of lower per capita GDP growth, in all regions except the Middle East and Africa, and partly a consequence of a falling rate of growth of population – even a decrease in some regions.

Table 1 sets out the data.

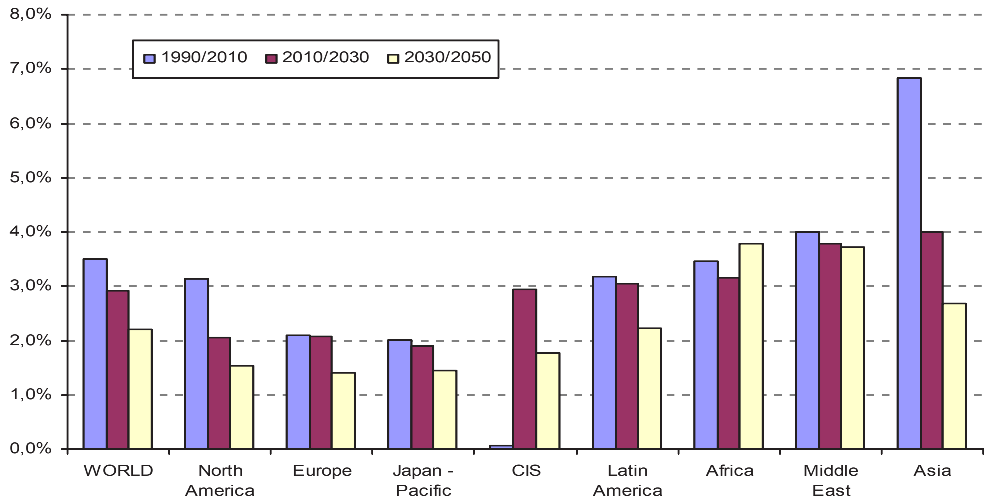
Table 1: World population and economic growth in WETO-H_2 projections

	1990	2001	2010	2030	2050	Annual change (%/year) 1990/10	2010/30	2030/50
Key Indicators								
Population (Billions)	5,2	6,1	6,8	8,1	8,9	1,3%	0,9%	0,5%
GDP (Billions €05)	27 800	39 100	55 000	97 800	151 600	3,5%	2,9%	2,2%
Per capita GDP (€05/cap)	5 300	6 400	8 100	12 100	17 100	2,1%	2,0%	1,7%

The rate of future economic growth is broadly similar across industrialised regions; it is around 2%/yr from 2010 to 2030 and 1.5%/yr from 2030 to 2050. As illustrated in

Figure 1, growth is faster in developing regions: it is between 3 and 4%/yr in Africa and the Middle East over the period and a little less in Latin America; in Asia it falls steeply from the current 7%/yr to 4%/yr between 2010 and 2030 and to less than 3%/yr in 2050. This largely reflects the end of the rapid catch-up process currently experienced by Asian economies and the economic slowdown consequent on the ageing of the population in China.

Figure 1: Economic growth, world and main regions (%/yr)



Box 1: WETO-H_2 population and GDP projections

The demographic forecasts come from the UN. The original work on economic scenarios was performed by the CEPII (Centre d'Etudes Prospectives et d'Informations Internationales), a research centre of the French Government specialising in international economic analysis, modelling and forecasting.

The GDP forecasts are the result of a neo-classical growth model with exogenous technological progress and an explicit consideration of the role of human capital. The main assumption of the model is the convergence in labour productivity towards a long-term equilibrium in a closed economy. The size of the active population being exogenous, the forecast depends on three key factors: physical capital, human capital and the level of technology incorporated in labour. The physical capital is a function of the investment rate. The human capital is a function of the school enrolment, linked to the GDP per capita. Labour productivity in the various regions converges to a common value because of an assumption of a decreasing marginal output of the physical and the human accumulated capital. These relations are expressed in the formula:

$$GDP = K^{a} \times H^{b} \times (A \times L)^{(1-a-b)}$$

with: *K = physical capital, function of investment rate*

H = human capital, function of school enrolment (linked to GDP per capita)

L = active population (exogenous from UN projections)

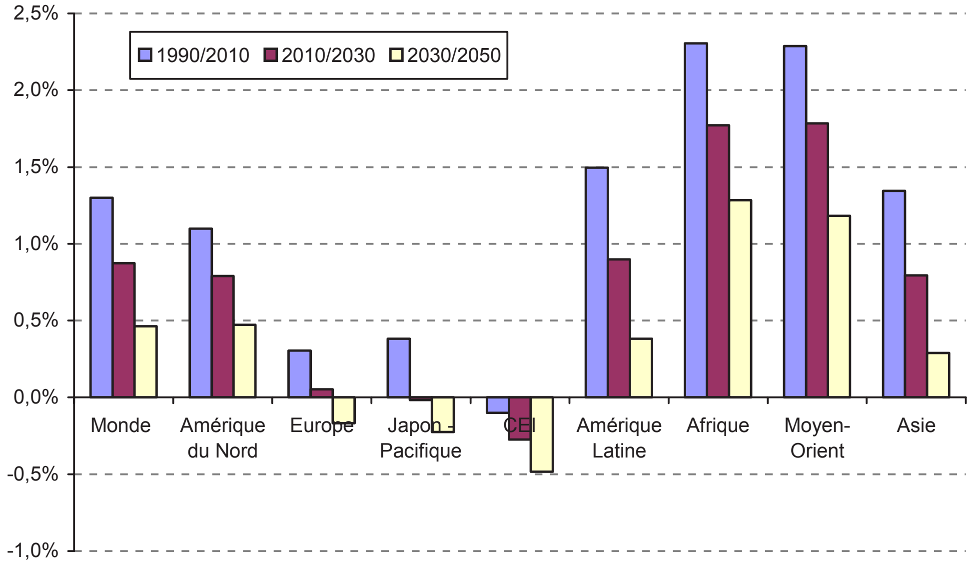
A = technology level incorporated in labour

Investment rates and school enrolment differ by country and the growth of the technology level incorporated in labour is higher for developed countries.

The extension of the economic projection to the 2050 horizon for this study was based on the hypothesis of a decrease in per capita income growth when the level of per capita income increases. This means that per capita GDP growth rate is lower in high-income economies than in the developing regions, once they have taken the road to development (see Figure 3). This eventually brings some economic convergence between mature and emerging economies.

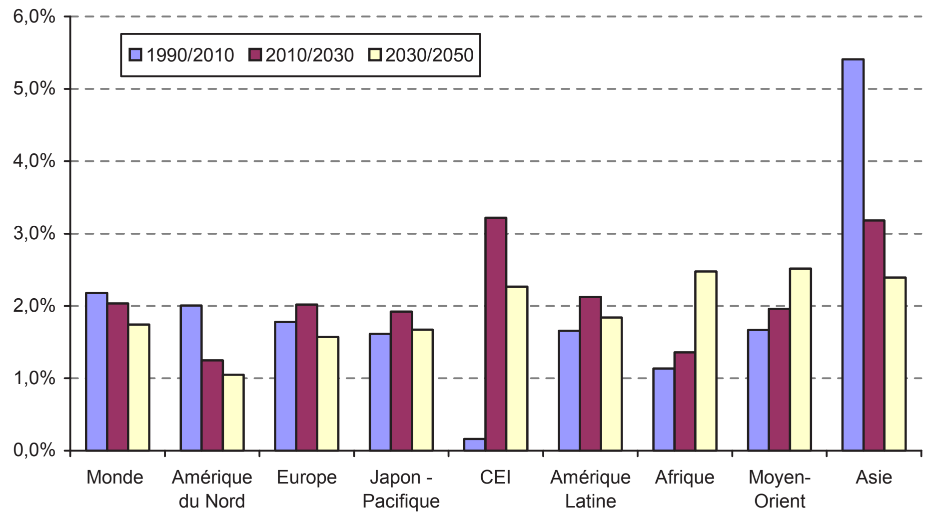
Regional variations in the trend of economic growth derive in part from the underlying population dynamics shown in Figure 2. By 2030, the growth of population is negative in Europe, the Pacific OECD and the CIS. North and Latin America and Asia have low positive rates of growth. After 2030, Africa and the Middle East are the only regions where growth exceeding 1%/yr.

Figure 2: Population growth, world and main regions (%/yr)



The second key driver of economic growth is the growth in per capita GDP that in the long-term increases the mobilisation of labour and global productivity. The average growth rate in per capita GDP across the world falls only slowly over the period and it is consistent with studies of economic growth in the long-term, which point to a secular trend of 2%/yr for average productivity growth. As shown in Figure 3, reductions in per capita GDP growth are most marked in North America (although GDP per capita in this region remains the highest throughout the period) and in Asia, where it is more than halved, from the present impressive 5.5%/yr.

Figure 3: Per capita GDP, world and main regions (%/yr)



This pattern of economic and demographic growth moderates in the long-term the inequalities in income across the world. Africa remains the most backward region; by 2050, the per capita GDP is 8% of that of North America, against 7% today. In 2050 Africa is the only region with an average GDP per capita less than one quarter of that of North America whereas today all regions in transition and in development are below this threshold (Table 2). In 2050, the average per capita income in all developing regions except Africa is about 15 000 €, slightly more than that of Europe in 1990 (including central Europe).

Table 2: Per capita GDP, by world region (€2005/year PPP)

	1990	2000	2010	2030	2050
WORLD	5 300	6 400	8 100	12 100	17 100
North America	23 800	29 200	35 400	45 400	56 000
Europe	13 700	16 200	19 500	29 100	39 800
Japan - Pacific	18 700	21 000	25 800	37 600	52 500
CIS	7 000	4 800	7 300	13 700	21 400
Latin America	5 100	6 100	7 100	10 800	15 500
Africa	1 700	1 900	2 100	2 800	4 500
Middle East	4 400	5 400	6 100	9 000	14 800
Asia	1 700	3 100	4 800	9 000	14 400

1.2 World fossil fuel resources

The assumptions about oil and gas resources are critical because present market behaviour and a series of recent studies[7] suggest that access to supplies to meet future increase in demand may be difficult. Any energy outlook for the long-term has to deal with the possibility of “peak oil” and “peak gas” that some geologists expect soon. The consequent increase in prices may profoundly influence the development of competing energy technologies and reshape the future energy system. WETO-H_2 gives special attention to the evaluation of oil and gas resources; Box 2 sets out the procedures for accounting and calculation. The Institut Français du Pétrole (IFP) reviewed the assumptions concerning Ultimate Recoverable Resources[8], discoveries, reserves and cumulative production and recovery rates.

Box 2: The modelling of oil and gas reserves and production

The POLES model accounts for oil and gas reserves and calculates production for every key producing country or region. This is done in three stages.

Firstly, the model estimates the cumulative amount of oil and gas discovered as a function of the Ultimate Recoverable Resources and the cumulative drilling effort in each region. The amount of URR is not held constant as is usually assumed, but is calculated by revising the value for the base year, as estimated by the United States Geological Survey, according to a recovery ratio that improves over time and increases with the price of the resource. While the recovery rate is differentiated across regions, the world average amounts to 35% today and, due to the price-driven technology improvements, increases to around 50% in 2050. This provides the significant resource base extension that is shown in Figure 4.

Secondly, the model calculates remaining reserves as the difference between the cumulative discoveries and the cumulative production for the previous period (see below Figure 5). In this manner, the model maintains a dynamic inventory of exhaustible resources in which reserves increase if, and only if, new discoveries compensate for current production. The accounting is described by the formula:

$$R_{t+1} = R_t + DIS_t - P_t$$

(where R = reserves, DIS = discoveries, P = production, subscript t = year of account)

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7 See in particular the *Oil and Gas Journal*, Feb. 21 and Mar. 7, 2005, and IMF, April 2005, *World Economic Outlook*: http://www.imf.org/external/pubs/ft/weo/2005/01/pdf/chapter4.pdf

8 The core assumptions used in POLES for the URR, for instance in WETO-2030, are based on the USGS median estimates for oil and for gas in each producing region (i.e. 50% probability of occurrence)

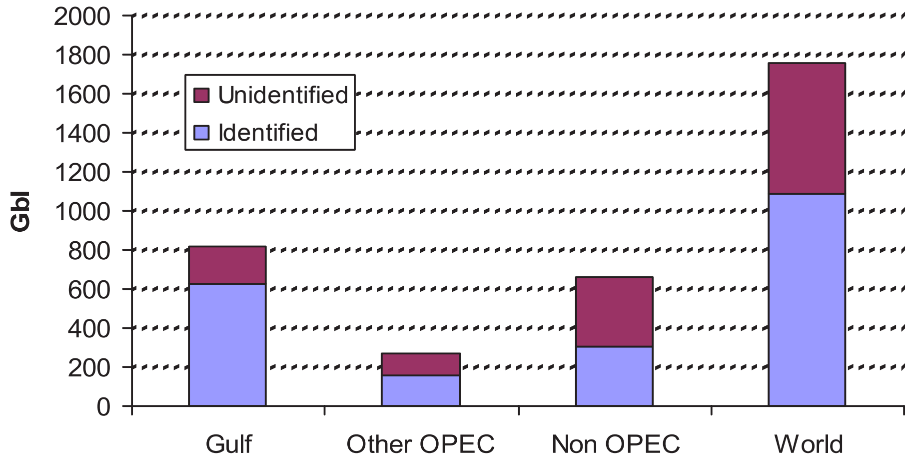
Finally, the model calculates the production. In the case of oil, the formulation differs among regions of the world. In the "price-taker" regions (i.e. Non-OPEC) it is resulting from an endogenous Reserves-to-Production ratio that decreases over time and the calculated remaining reserves in the region; the "swing-producers", mostly located in the Middle East, then make up the balance between the demand and supply.

For natural gas, the production in each key producing country is derived from the combination of the demand forecast and of the projected supply infrastructures in each region (pipelines and LNG facilities).

This approach describes the fundamental parameters and dynamics of resource development. It predicts "peak-oil" when reserves decrease proportionally more rapidly than the R/P ratio. The timing and the profile of "peak-oil" depends on the interaction between the price behaviour of supply and demand and technical progress upstream (see below Figure 10).

Cumulative production of oil today is around 900 Gbl. The assumption of the WETO-H_2 study is that there are 1 700 Gbl remaining, of which almost 1 100 Gbl has been discovered. Of these 1 700 Gbl, about 1 000 Gbl (including identified and unidentified resources) are in OPEC countries. The remaining recoverable resources represent 60 years of present production of conventional oil (Figure 4).

Figure 4: Remaining oil resources, key regions



The POLES oil and gas module simulates technological progress in exploration and production of oil and gas. Progress has been rapid since the seventies, in particular through spill over from information and communication technologies. The main impact is to improve the success of exploratory drilling and to increase recovery rates across the world. The POLES model simulates improved recovery by linking the Ultimate Recoverable Resources (URR) directly to the contemporary recovery rate.

Figure 5: Ultimate Recoverable Resources, cumulative discoveries and production

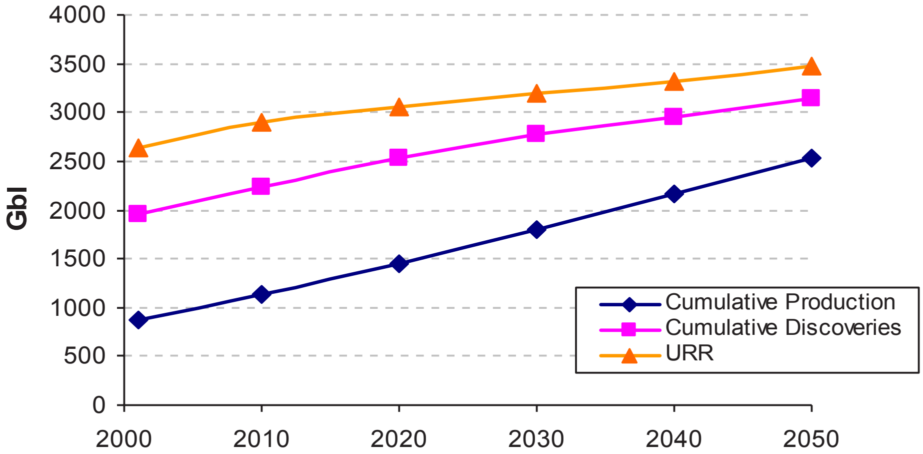


Figure 5 presents the results of the simulation of the discovery and production of oil. The volume of Ultimately Recoverable Resources increases in the period because of improved recovery rates; cumulative discoveries depend on the exploration effort. The development of reserves is visible in the Figure, because reserves are the difference between total cumulative discoveries and cumulative production. This process of reserve development and extension explains how total Ultimate Recoverable Resources estimated by the USGS are extended from 2 600 Gbl today to nearly 3 500 Gbl in 2050; this has an important influence on the supply and demand balance for oil to 2050.

1.3 Technology portfolios in the WETO-H_2 scenarios

Technological change is critical to the management of strong constraints on resources and on emissions. In any long-term energy outlook, it is essential to visualize technological breakthroughs and radical innovations. The WETO-2030 mainly envisaged incremental improvements in large-scale power generation and in renewable technologies. The WETO-H_2 scenarios incorporate new energy technology portfolios, including:

- Hydrogen production through chemical, thermo-chemical or electrical routes
- Carbon capture and storage options as add-ons to plants burning fossil fuel to make electricity or hydrogen
- Distributed electricity production, with or without cogeneration, from fossil fuel, renewable energy or hydrogen
- Very low emission vehicles with new power systems and carrier concepts, including cars powered by electricity or hydrogen
- Low and very low energy buildings with significantly improved thermal performances (meaning a reduction by a factor of 2 to 4 from the consumption of present buildings in each region); these can even be “positive energy buildings” when photovoltaic systems are integrated into the design

Projections of the economic, physical and environmental performance have been organised in a database known as TECHPOL[9].

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9 This was developed in the framework of the FP6 SAPIENTIA and CASCADE-MINTS projects and also in the CNRS Energy Programme

Table 3 lists the energy technologies that are included in the study. The inclusion of a technology in the TECHPOL database and in the POLES model implies no judgement of its competitiveness and prospects. This will depend on many factors, including the relative prices of the primary fuels and the carbon value. The POLES technology portfolios seek to identify options that will participate in the "inter-technology competition" process until 2050 and will be candidates for increased R&D and "technology-push" policies. These portfolios compare to other attempts to identify the scope of energy technologies to combat climate change: for instance, the "technology wedges" approach[10] identifies 15 major technology options that for most of them are included in the POLES portfolios.

Table 3: Energy technologies considered in the POLES model

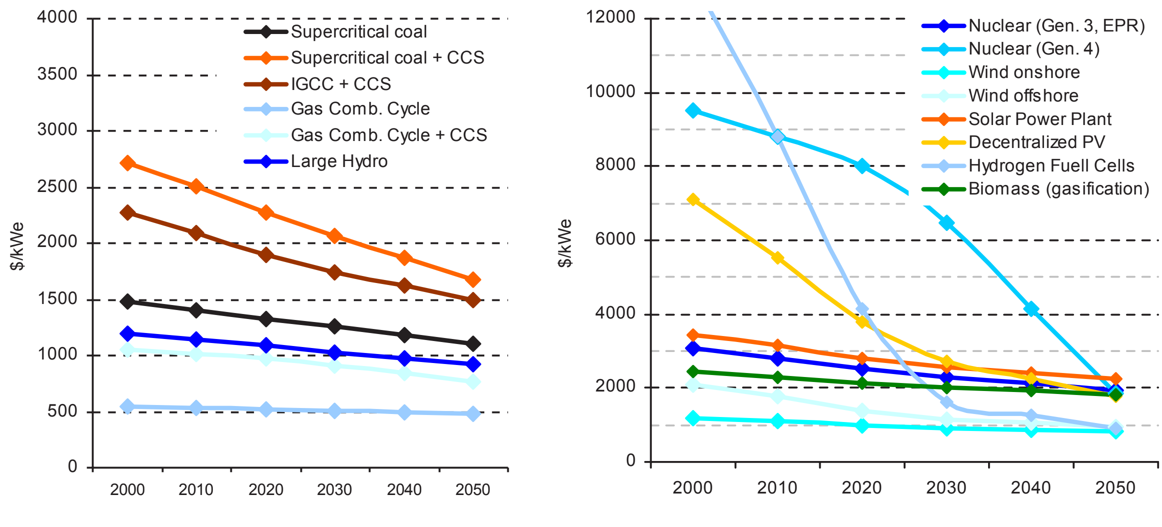
Large Scale Power Generation	
	Hydroelectricity
	Light-water nuclear reactor (including EPR)
	New nuclear design (Generation 4)
	Pulverised coal, supercritical, with/without CO2 capture
	Integrated coal gasification, with/without CO2 capture
	Coal conventional thermal
	Lignite conventional thermal
	Gas conventional thermal
	Gas turbine
	Gas turbine in combined cycle, with/without CO2 capture
	Oil conventional thermal
	Oil fired gas turbine
Renewable Energy Sources	
	Small hydro power (<10 MWe)
	Onshore wind power
	Offshore wind power
	Solar thermal power
	Biomass (woodfuels, electricity from wastes, biofuels)
	Biomass gasification for power generation
Distributed Power Generation	
	Combined heat and power
	Stationary fuel-cells, natural gas
	Stationary fuel-cells, hydrogen
	Building integrated photovoltaic systems
	Photovoltaic systems for rural electrification
Hydrogen Production	
	Gas steam reforming, with/without CO2 capture
	Coal partial oxidation, with/without CO2 capture
	Biomass pyrolysis
	Solar high-temperature thermolysis
	Nuclear high-temperature thermolysis
	Water electrolysis, dedicated nuclear power plant
	Water electrolysis, dedicated wind power plant
	Water electrolysis, baseload electricity

[10] See S. Pacala and R. Socolow, Stabilization Wedges: Solving the Climate Problem for the Next 50 Years with Current Technologies *Science*, Vol 305, Issue 5686, 968-972, 13 August 2004, http://www.sciencemag.org

Very Low Emission Vehicles / Buildings
Internal combustion engine (including hybrid)
Pluggable hybrid
Electric, battery
Gas fuel-cell vehicle
Hydrogen fuel-cell vehicle
Hydrogen internal combustion engine
Low energy building
Very low energy building

In the next decades, inter-technology competition will depend on three set of variables: i. the particular investment and O&M cost and the performance (e.g. efficiency) of each technology; ii. the primary fuel cost; iii. the carbon value or penalty. Any energy projection has to anticipate change in these fundamentals of competition between technologies, as they will determine the shape of the future energy system. Figure 6 illustrates the assumptions made in this study for fourteen technologies that are of particular interest in the TECHPOL database. It shows that a significant cost reduction of 20 to 40% is still anticipated for many technologies, including relatively conventional ones. Still larger reductions might be achieved in some of the frontier technologies of today, such as offshore wind, hydrogen fuel cells and Generation 4 nuclear plants.

Figure 6: Overnight investment cost for power technologies in the TECHPOL database



Source: TECHPOL database

The above figures summarise the expectations of experts about progress in the capital cost of technologies over the next decades. Two caveats should be observed:

- First, investment cost is an important component of total generation cost, but the costs of primary fuel and CO_2 emission may be comparable or greater. For technologies like wind or solar, the low availability factors (of 20 to 30%) are also critical in comparing technologies.
- Second, these anticipated costs are based on current knowledge and are uncertain; chapter 3 explores the consequences of more favourable prospects for hydrogen technologies.

Critical assumptions

Population

World population is expected to grow at a decreasing rate to 8.9 billions in 2050. After 2030, the population in several regions of the world decreases – including Europe and China. The global population stabilises in the second half of the century.

Economic growth

The rate of economic growth in industrialised regions converges to under 2%/yr in the very long-run. Growth in Asian emerging economies falls significantly after 2010, while conversely it accelerates in Africa and the Middle East. As a result, global economic growth is expected progressively to slow from 3.5%/yr in the 1990-2010 period to 2.9%/yr between 2010 and 2030 and then 2.2%/yr until 2050. Total world GDP in 2050 is four times the present GDP.

Oil resources

Nowadays, the availability of oil and gas resources in the next decades is increasingly questioned.. The accumulated production of oil to date is 900 Gbl. The assumption in this study is that there remain almost 1 100 Gbl of identified reserves and slightly more than 600 Gbl of resources that have not yet been identified. Higher recovery rates through technological progress are expected to extend the Ultimate Recoverable Resource base from 2 700 Gbl today to 3 500 Gbl in 2050.

Energy technologies

Technology development will be critical in the shaping the future energy system. A thorough examination of the technical possibilities for the next 50 years suggests new portfolios of energy technologies will challenge conventional ones based on fossil and renewable sources with electricity as a main carrier. It is indispensable to explore the role in future energy systems of carbon capture and storage, options for producing and using hydrogen, diversified distributed electricity systems and end-use technologies with very low energy and/or very low emissions.

Climate policies

International arrangements for managing climate change are still in negotiation and the detailed outcome is unpredictable. However, any projection of the world energy system has to account for at least “minimum” climate policies. These are included in the Reference projection through a low carbon penalty or “carbon value”, differentiated by world regions, i.e. higher in the industrialised than in the developing ones.

Access to oil and gas resources

The geo-politics of the international energy markets are a vital consideration for sound long-term energy projections; a sound representation of the economic behaviour without these influences is not sufficient. The Reference projection accounts for some of these aspects by partially constraining the development of oil production capacity in the Middle East.

CHAPTER 2 ENERGY DEVELOPMENT AND CO_2 EMISSIONS

The WETO-H_2 Reference case describes the economic and technological fundamentals that determine the dynamics of the world energy system; it also includes elements of policy or political development that are likely to occur in the period. It reflects the geo-political conjuncture that dominates the short and medium-term availability and price of world oil; it also reflects a minimum degree of political initiative in climate policy in all regions of the world. The Reference case accordingly visualizes a world adjusting to constraints on access to oil and gas and on emissions of CO_2.

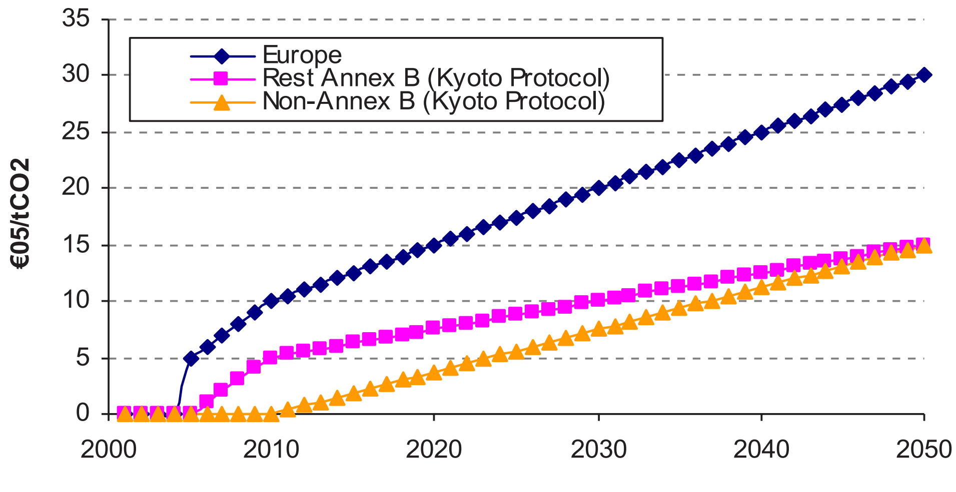
2.1 The geo-political and climate policy context

The Reference case represents the "minimum" climate policies by an exogenous carbon value (corresponding either to a tax or to a permit price) that modifies the investment and consumption decisions of the economic agents. It assumes that Europe keeps the lead in climate policies, although in the Reference case these policies are developed in a minor key. The carbon value varies by region to indicate different levels of commitment:

- In Europe a carbon value of 10 €/tCO_2[11] is assumed in 2010, in line with estimates provided for the European Emission Trading System[12]; the value increases linearly to 20 €/tCO_2 in 2030 and 30 €/tCO_2 in 2050 (i.e. 110 €/tC).
- In the rest of the Annex B countries a more modest policy is assumed with a carbon value starting at 5 €/tCO_2 in 2010 and staying subsequently at half the level that pertains in Europe, so ending at 15 €/tCO_2 in 2050.
- In the emerging and developing non-Annex B countries, moderate climate policies are progressively introduced after 2010 also reaching a carbon value of 15 €/tCO_2 in 2050.

Figure 7 shows the development of the carbon value over time by region.

Figure 7: The exogenous carbon value in the Reference projection



[11] All prices hereafter are expressed in € or in $ of 2005

[12] See the *Kyoto Protocol Implementation* study for DG Environment with the POLES model: http://europa.eu.int/comm/environment/climat/pdf/kyotoprotocolimplementation.pdf

Some limited geopolitical constraints to world oil development are present in the model. The WETO-H_2 study adopts the view that recent developments on the oil market – with prices at more than twice their level of the mid-nineties – do not only reflect a conjuncture of exceptionally high demand and limited supply, but signal important changes in market behaviour. There are no longer any significant reserve margins of production capacity, suggesting that the tightness in supply will persist. This is not a consequence of insufficient reserves, but of restricted access. Access is constrained in the crucial OPEC countries by inadequate investment in producing capacity and in non-OPEC countries by unexpected technical and political obstacles, (with to some extent the exception of the CIS).

Box 3: International energy price dynamics in the POLES model

A principal feature of the POLES model is that it estimates international prices for oil, gas and coal, based on an explicit description of the fundamentals of each international market and a detailed representation of the reserve and resource constraints (see Box 2)

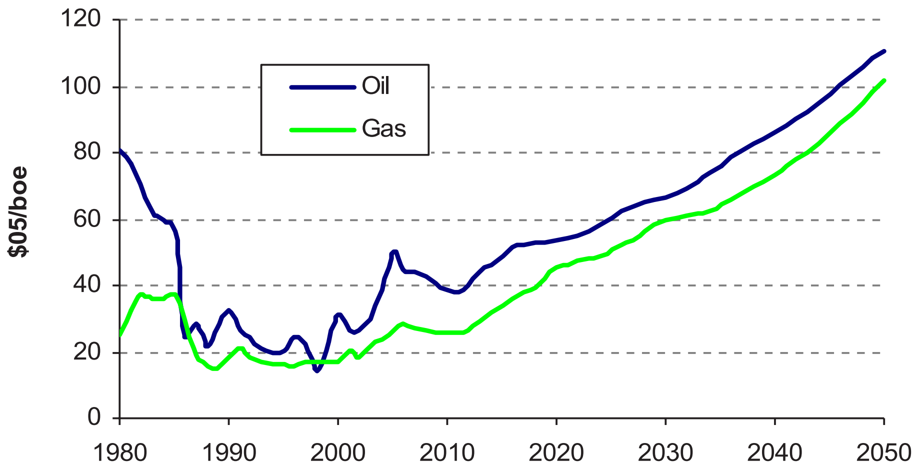
The model calculates a single world price; the oil market is described as "one great pool". It depends in the short-term on variations in the rate of utilisation of capacity in the Gulf countries and, more importantly, in the medium and long-term on the average Reserve-to-Production ratio across the world.

The price of gas is calculated for each regional market; the price depends on the demand, domestic production and supply capacity in each market. There is some linkage to oil prices in the short-term, but in the long-term, the main driver of price is the variation in the average Reserve-to-Production ratio of the core suppliers of each main regional market. As this ratio decreases for natural gas as well as for oil, gas prices follow an upward trend that is similar in the long-term to that of oil.

The price of coal is also estimated for each regional market as the average price of the key suppliers on each market, weighted by their market shares. The average price of the key suppliers is derived from variations in mining and operating costs (that are a function of the increase in per capita GDP and of a productivity trend) and from the capital and transport costs (both depending on the simulated production increases, as compared to a "normal" expansion rate of production capacity).

Examination of the policies for oil development and for foreign investment in the OPEC countries indicates that although there are highly profitable opportunities, in practice access is constrained. The massive and rapid increase in the oil production capacities of OPEC needed to balance the world energy system will not be easy to achieve. This may even induce, in the medium-term, stronger price volatility than the Reference scenario exhibits; successive price-shocks may limit demand and encourage alternative energy development.

Figure 8: Prices of oil and gas from the Reference projection



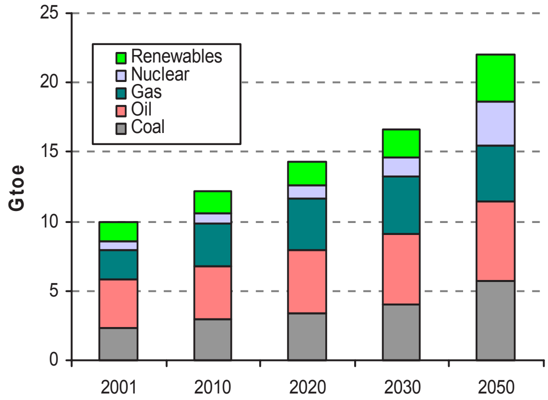
A full description of this behaviour is hard to incorporate in a long-term model. A partial representation is present in the Reference case, in the assumption of a low responsiveness of capacity development in OPEC to an increase in the price of oil; with the mechanisms of oil price formation included in the model, this low responsiveness leads to higher prices than would otherwise occur. Figure 8 illustrates the resulting trajectory of prices: the price of oil rises to 2006, falls briefly to 40 $/bl towards 2010 and then increases to more than 60 $/bl in 2030 and to nearly 110 $/bl in 2050 as resource constraints become determinant. This price level is needed, not so much to stimulate supply alternatives, which are in most cases already competitive, but to curb the trend in world oil demand, which would otherwise be unsustainable.

This trend in the prices of oil and gas create a structural cost advantage for coal. Resources of coal are much larger than of oil and gas; they are dispersed and often located in large consuming countries. Consequently, the absolute increase in coal price, expressed in terms of oil equivalent, is expected to be less than for hydrocarbons. In the Reference projection, coal prices roughly double from the current level, which is similar to the relative change expected for oil; but in terms of oil equivalent the price of coal is still only 22 $/bl in 2050 and this creates a huge cost advantage compared to oil and gas.

2.2 The world energy balance and emission profile

The world energy system that results from this analysis reveals the significant structural changes needed to accommodate the constraints on resource and emissions.

Figure 9: World primary energy demand



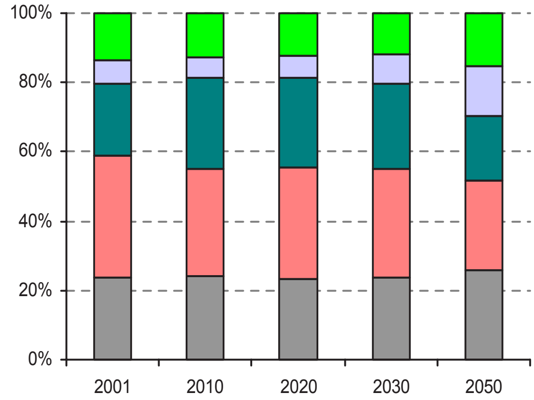


Table 4 lists the main results that reveal the structural consequences of these constraints. In summary, the principal outcomes of the Reference case are:

- World GDP quadruples between now and 2050, despite relatively low economic growth rates towards the end of the period. The energy intensity of the world economy falls to about half of the 2001 value, because of structural change, autonomous efficiency improvements and higher prices. Consequently, world energy consumption roughly doubles from 10 Gtoe today to about 22 Gtoe in 2050.
- The production of conventional oil reaches a peak before 2030 and that of natural gas between 2040 and 2050. This is in spite of the positive effect of technological progress on oil and gas recovery rates and of the corresponding resource extension. The peaking of production limits the contribution of conventional oil and of gas to world 2050 energy supply; oil provides 5 Gtoe – plus more than one Gtoe from non-conventional oil; natural gas provides 4 Gtoe.
- The contribution of non-fossil energy sources increases strongly; by the end of the period the contribution of nuclear energy increases by a factor of four; use of hydroelectricity and biomass doubles; the contribution of wind and solar electricity exceeds by 70% that of hydroelectricity. These sources amount to a non-fossil supply of 6 Gtoe in 2050, of which slightly more than 50% is renewable.
- Coal provides the balance of the world energy supply; its contribution is slightly less than 6 Gtoe in 2050. Compared to the current 2.4 Gtoe the figure is impressive; it reflects the relative abundance of coal and the resulting price advantage in the long-term. This revival of coal has significant environmental impacts, but these are to some extent limited by carbon capture and storage. In spite of relatively low carbon values, this technology already reduces emissions by 6% in 2050.
- Emissions of CO_2 from energy activities more than double over the period. This profile is consistent with that found for the 6 Kyoto GHGs in the Greenhouse Reduction Pathways study made with the POLES and IMAGE models[13]. The result is preoccupying because the trajectory would probably lead to a concentration of CO_2 above 1000 ppmv and therefore to a temperature increase of more than 3 °C in 2100. Policies with limited ambition do not solve the climate change problem.

[13] *Greenhouse gas Reduction Pathways, policymakers' summary*, op.cit.: http://europa.eu.int/comm/environment/climat/pdf/pm_summary2025.pdf

Table 4: Reference projection: key indicators, energy and CO_2 emissions

WORLD	1990	2001	2010	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators								
Gross Inland Cons/GDP (toe/M$95)	290	236	205	157	134	-1,7%	-1,3%	-0,8%
Gross Inland Cons/capita (toe/cap)	1,6	1,6	1,8	2,1	2,5	0,4%	0,7%	0,9%
Electricity Cons/capita (kWh/cap)	1 832	2 077	2 554	3 688	5 529	1,7%	1,9%	2,0%
Transport fuels per capita (toe/cap)	0,3	0,3	0,3	0,3	0,3	0,0%	0,4%	0,5%
CO_2 emissions/capita (tCO_2/cap)	3,8	3,9	4,3	4,8	5,0	0,5%	0,6%	0,2%
% of renewables in Gross Inland Cons	13,4	13,5	12,8	12,0	15,3	-0,2%	-0,3%	1,2%
% of renewables in electricity	20,1	18,7	18,2	20,6	25,0	-0,5%	0,6%	1,0%
Primary Production (Mtoe)	**8 834**	**9 836**	**12 346**	**16 853**	**22 276**	1,7%	1,6%	1,4%
Coal, lignite	2 207	2 408	2 937	3 976	5 678	1,4%	1,5%	1,8%
Oil	3 234	3 487	3 951	5 385	5 964	1,0%	1,6%	0,5%
Natural gas	1 708	1 929	3 164	4 075	4 084	3,1%	1,3%	0,0%
Nuclear	525	671	739	1 425	3 185	1,7%	3,3%	4,1%
Hydro, geothermal	216	232	275	357	417	1,2%	1,3%	0,8%
Biomass and wastes	939	1 101	1 261	1 462	2 261	1,5%	0,7%	2,2%
Wind, solar	0	7	21	174	686	21,9%	11,2%	7,1%
CO_2 Emissions ($MtCO_2$)	**20 161**	**23 566**	**29 055**	**38 749**	**44 297**	1,8%	1,4%	0,7%
of which:								
Electricity generation	7 433	8 932	10 562	13 747	16 065	1,8%	1,3%	0,8%
Industry	4 653	4 812	6 045	7 656	7 971	1,3%	1,2%	0,2%
Transport	3 982	5 056	5 461	6 815	7 263	1,6%	1,1%	0,3%
Household, Service, Agriculture	3 191	3 196	4 128	6 488	7 891	1,3%	2,3%	1,0%
CO_2 Sequestration (Mt CO_2)	0	0	0	271	2 545	na	na	11,9%

2.3 Oil and gas production profiles in the Reference projection

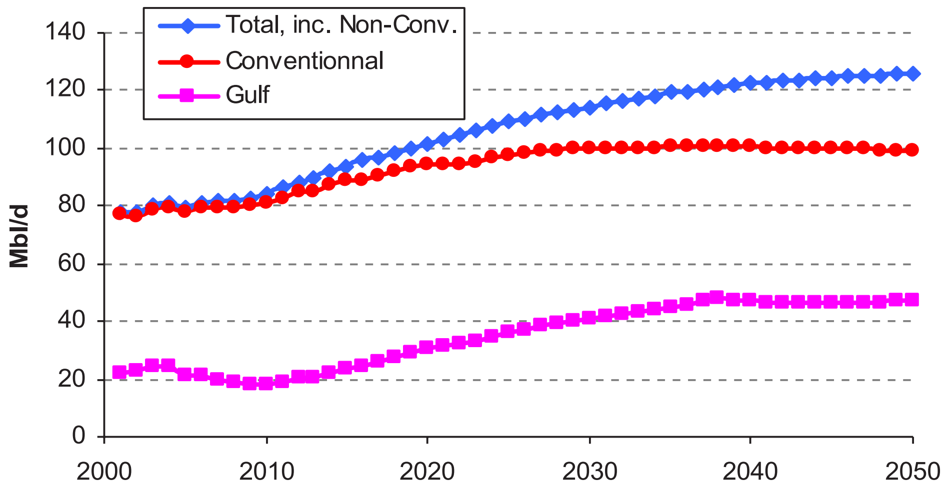
The profile of oil production is an important feature of any long-term energy scenario. Because of its intrinsic properties of easy transport, storage and use, oil has been for many decades the “swing” energy source for balancing energy supply and demand. For that reason, the price of oil often serves as a reference price for other energy sources.

The Reference projection suggests that this balancing role cannot continue. According to the simulation, the world is emerging from a twenty-year period of relatively cheap and abundant oil that began after the second oil shock. In the view of many observers and more recently for many insiders of the oil industry, the oil market in the next decade will undergo successive waves of structural change that can be summarised as follows[14]:

- In the short-term, market behaviour will be much influenced by the lack of surplus production capacity and by the peak in production from non-OPEC countries (that might be delayed by some production increase from the CIS).
- In the medium-term, the critical concern will be the extension of OPEC’s countries production capacities well beyond their historic maximum (i.e. approximately 32 Mbd).
- In the long-term, the peak in OPEC and Gulf production will constrain the consumption of oil, even if non-conventional oil is developed strongly (as in the Reference case).

[14] *Oil and Gas Journal*, February and March 2005, op. cit.

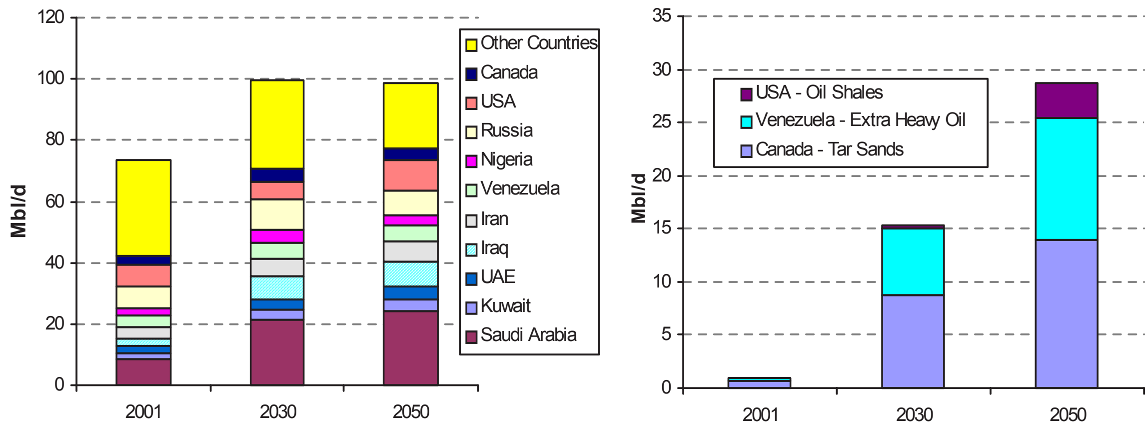
Figure 10: World production profile for conventional and non-conventional oil



The oil production profile in the WETO-H_2 Reference case, as illustrated in Figure 10, is largely consistent with this prognosis for the world oil system:

- Until 2010, non-OPEC production increases slightly because of developments in the CIS; after that year non-OPEC production declines.
- The production of conventional oil in the world reaches a plateau at 100 Mbd in 2030 and then is stable until 2050; this occurs despite a rapid increase of capacity in the Gulf after 2010.
- Production in both the Gulf and the rest of OPEC doubles from now until 2040 and then almost stabilises until 2050.
- Production of non-conventional oil, mostly from extra-heavy oil and tar sands, becomes competitive; it provides nearly 28 Mbd in 2050, comparable to about 60% of the increase in total oil consumption from today to 2050.

Figure 11: Main producers of conventional oil (left) and non-conventional oil (right)



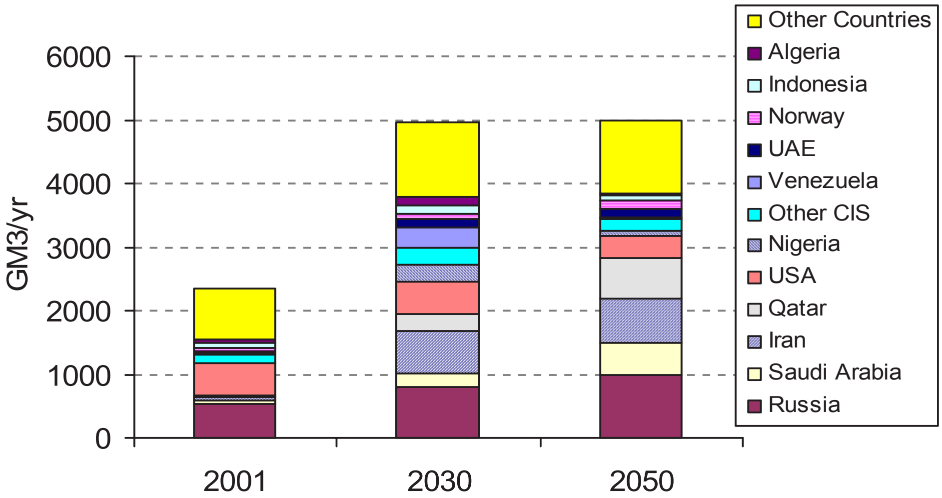
The pattern of oil production in the Reference projection is shown in Figure 11 and can be summarised as follows:

- Non-OPEC production of conventional oil peaks in 2010; world production peaks in 2030 and OPEC production in 2040. In terms of capacity, non-OPEC production loses 4 Gbl/year between today and 2050; OPEC production gains 26 Gbl/year, mainly in the Gulf region.
- Non-conventional oil provides a new supply of 26 Gbl/year.
- The balance of these changes is an increase of 48 Gbl/year in total world production between today and 2050, equal to 60% of present capacity.

Natural gas production shows similar behaviour in Figure 12, with a peak that occurs about ten years after the peak in conventional oil. Production diversifies until 2030, and then there follows a new wave of concentration as limited resources constrain output in many producing countries towards 2050.

- In 2010, four countries produce more than 250 Gm3: Russia, the USA, Indonesia and Algeria.
- In 2030, there are nine such producers: Russia, Iran, Qatar, the USA, Nigeria, the rest of the CIS, Venezuela, Indonesia and Algeria.
- In 2050, there are only five: Russia, Iran, Saudi Arabia, Qatar and the USA.

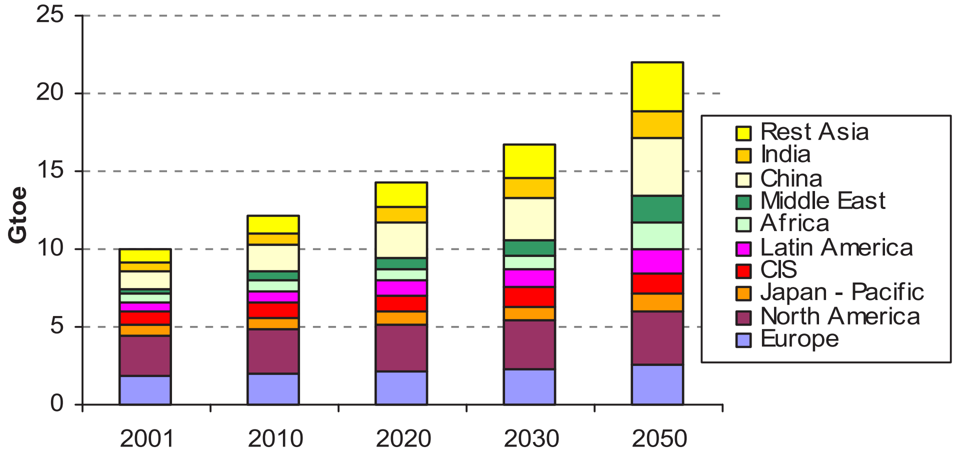
Figure 12: Principal producers of natural gas



2.4 Primary energy consumption by region and inter-regional energy trade

By 2050, the energy consumption of today's industrialised countries (including the CIS countries) will increase by a factor of 1.4; in the developing world, consumption will increase by a factor of 3.5. Shortly after 2010, the consumption of the developing countries exceeds that of the present industrialised countries. The present group of developing countries consume two-thirds of world energy in 2050 (Figure 13).

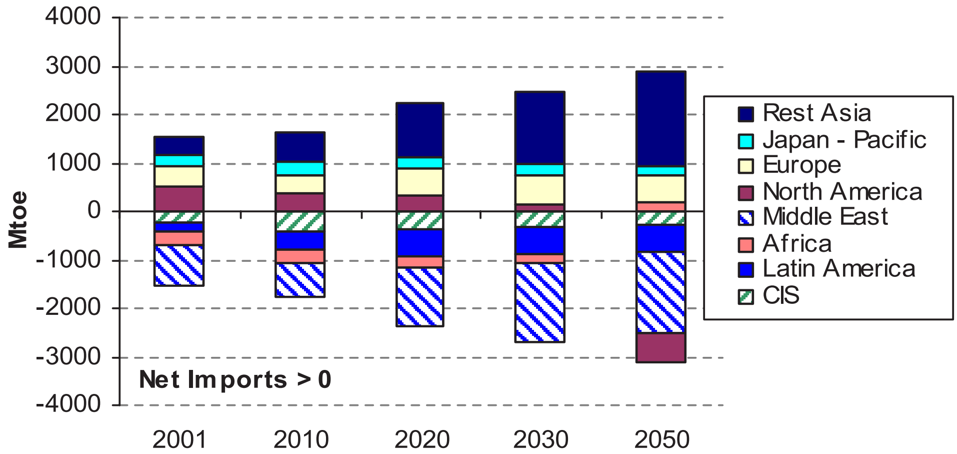
Figure 13: World primary energy consumption, by region



The 1.7%/yr increase in world energy consumption to 2050 appears low, but the cumulative consequences are large. International trade in oil increases from 1.5 Gtoe today to more than 2.5 Gtoe in 2030 and 3 Gtoe in 2050 (

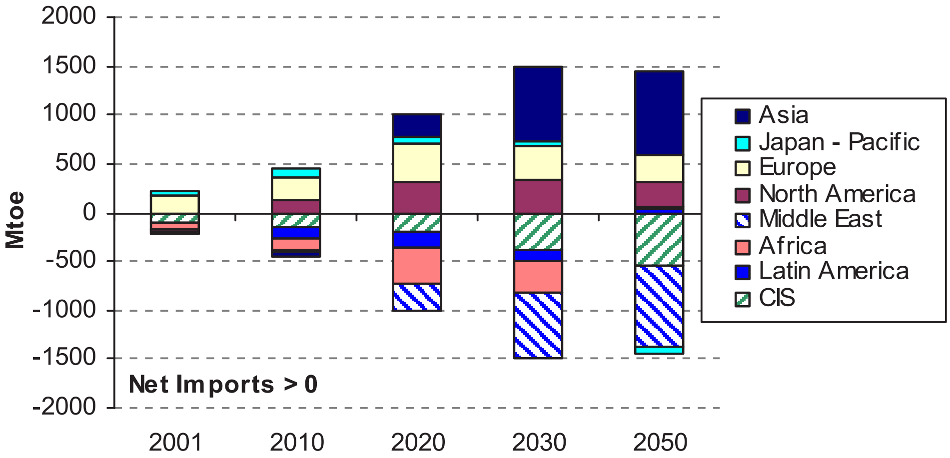
Figure 14); this is a consequence of some increase in consumption, but also of the concentration of production in the OPEC countries and more particularly the Gulf. In 2050, four regions are net exporters of oil. The Middle East has more than half of total exports; the other regions are the CIS, Latin America and, surprisingly, North America, largely because Canada becomes a major supplier of non-conventional oil.

Figure 14: International oil trade



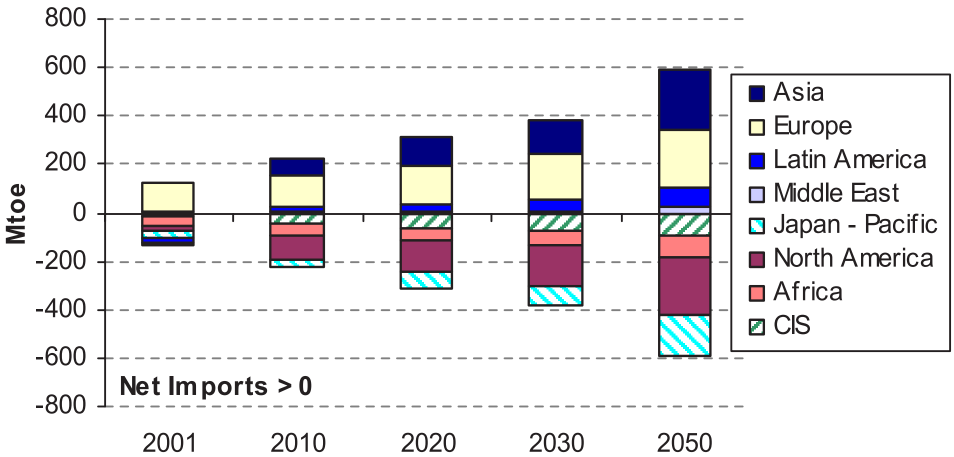
Inter-regional trade in gas increases considerably as shown in Figure 15, from 0.2 Gtoe today to 1.5 Gtoe in 2030, but stabilises after that date. These figures exclude intra-regional trade. The Middle East and the CIS are by far the largest exporters in 2050. The principal importing regions in 2050 are Asia, Europe and to a lesser extent North America; Africa is self-sufficient in oil and gas supply.

Figure 15: International gas trade



Coal trade increases throughout the period to five times the volume today (Figure 16). The high volume of trade reflects the strong return of coal in a context of relative scarcity of oil and gas at high prices and only moderate GHG emission constraints. The four main exporting regions are North America, the Pacific, Africa and the CIS. Because of the rapid growth in consumption, Asia becomes a net importer early in the period.

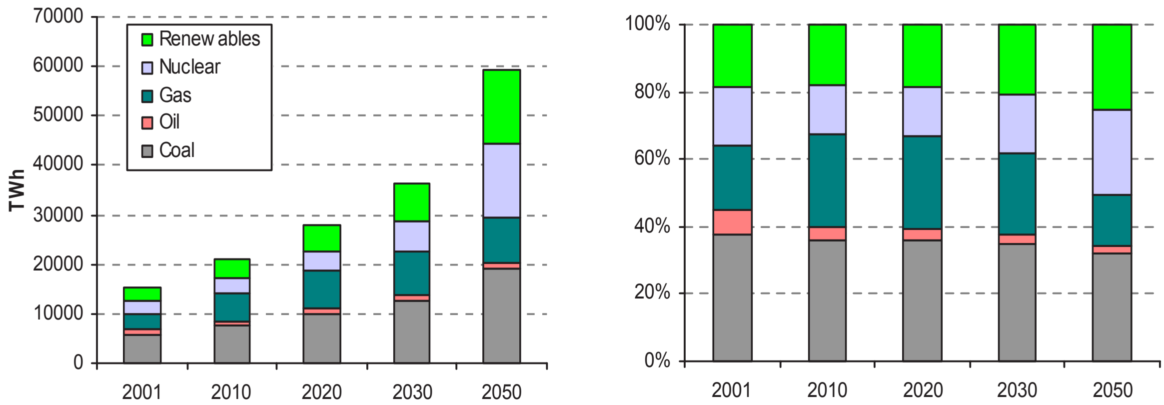
Figure 16: International coal trade



2.5 The development of electricity

The generation of electricity in the world increases nearly four-fold from 15 500 TWh/year today to 60 000 TWh/year by 2050 (Figure 17). The share of thermal generation increases until 2020 because other sources cannot match the growth in demand. Generation from nuclear and hydro sources increases only slowly; generation from renewable resources grows strongly, exceeding 10%/yr until 2030 for wind and 15%/yr after 2010 for solar, but from a low base it cannot match demand growth in volume. After 2020 nuclear electricity increases rapidly and by 2050 the share of fossil-based electricity falls to 50%. This is significant structural change for a Reference case.

Figure 17: World electricity production



Box 4: Investment and operating decisions in the electricity sector

The shape and volume of the electrical load and the cost and performance of available generating technologies determine investment in the power sector.

Table 3 *lists the power plant technologies; the capital costs and performance characteristics of each technology are stored in the TECHPOL database and the fuel costs are endogenous to the model. The model simulates the total electricity demand and load curve to a t+10 years horizon by extrapolation.*

Levelised costs are calculated for each technology at six reference load factors from 730 to 8760 hours. Capacity expansion in each national system is then assumed to be defined by the least-cost investment to meet the expected load duration curve at t+10, taking into account existing plants. Primary electricity sources, such as hydro and nuclear electricity, supply the base-load. Other technologies compete to supply the remainder of the base-load and the rest of the load curve.

After the capacity expansion is determined the model then calculates the production mix of electricity from the given capacity structure by loading plants in order of their operating cost (the merit order) until the demand is satisfied. Finally, the average production cost is derived from the production mix and the levelised costs of the plants.

The renewable energy module in POLES is essentially a dynamic Fisher-Pry model, with an endogenous economic potential and an endogenous diffusion time-constant. What this means is that the amount of generation from new and renewable technologies is determined by a logistic function that relates the generation to the economic potential and the maturity of the technology through parameters that vary according to the technology's cost-effectiveness. The economic potential is the share of the technical potential that is economically competitive under the conditions simulated in the model. This share is calculated as a function of the average payback period for the investment - the lower is the payback period the larger the share of the technical potential that is economic.

Within the thermal generation, advanced technologies progressively gain the lion's share. In 2050, more than 80% of coal-based power generation is from advanced coal technologies and 70% of gas-based electricity is from combined cycle or cogeneration; oil almost disappears from the electricity sector (Table 5).

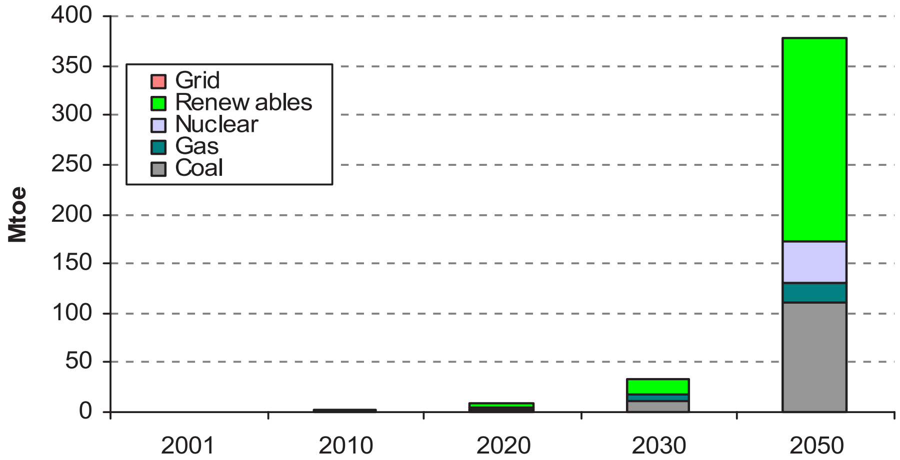
Table 5: World electricity production

					Annual % change		
WORLD	**2001**	**2010**	**2030**	**2050**	**2001/10**	**2010/30**	**2030/50**
Electricity Production (TWh)	**15468**	**21113**	**36295**	**60040**	3,5%	2,7%	2,5%
Thermal, of which :	10074	14669	23809	31584	4,3%	2,5%	1,4%
Coal, lignite	5848	7600	12689	19066	3,0%	2,6%	2,1%
of which advanced coal	0	2022	9122	15964	192,7%	7,8%	2,8%
Gas	2934	5823	8760	9072	7,9%	2,1%	0,2%
of which combined cycle	944	2885	5233	4300	13,2%	3,0%	-1,0%
of which cogeneration (industry)	250	356	865	1954	4,0%	4,5%	4,2%
Oil	1136	804	988	1200	-3,8%	1,0%	1,0%
Biomass	155	442	1372	2246	12,3%	5,8%	2,5%
Nuclear	2653	3049	6328	14866	1,6%	3,7%	4,4%
of which new design	0	0	0	3401	na	na	na
Hydro (large)	2613	3088	3943	4588	1,9%	1,2%	0,8%
Hydro (small)	90	110	205	265	2,3%	3,1%	1,3%
Wind	37	188	1880	6433	19,9%	12,2%	6,3%
Solar	1	7	91	1493	19,7%	13,9%	15,0%
Hydrogen	0	2	39	811	na	15,3%	16,4%

2.6 Hydrogen production and carbon capture and storage

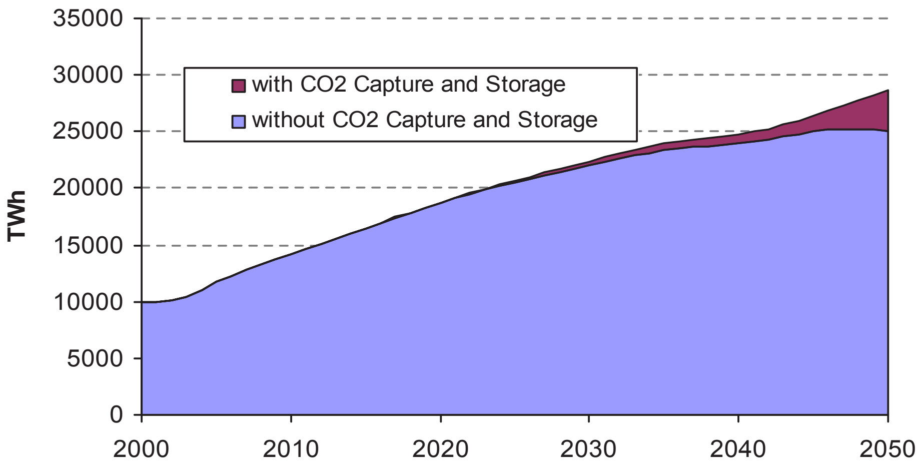
In the Reference case, there is little production of hydrogen. In 2050, it represents only 3% of the total final energy consumption - equivalent to 9% of final electricity consumption. As illustrated in Figure 18, production is mostly from non-fossil fuels, primarily from renewable sources and nuclear. The production from steam reforming of natural gas is limited by high prices and is generally more costly than hydrogen from coal gasification.

Figure 18: Hydrogen energy production by technology



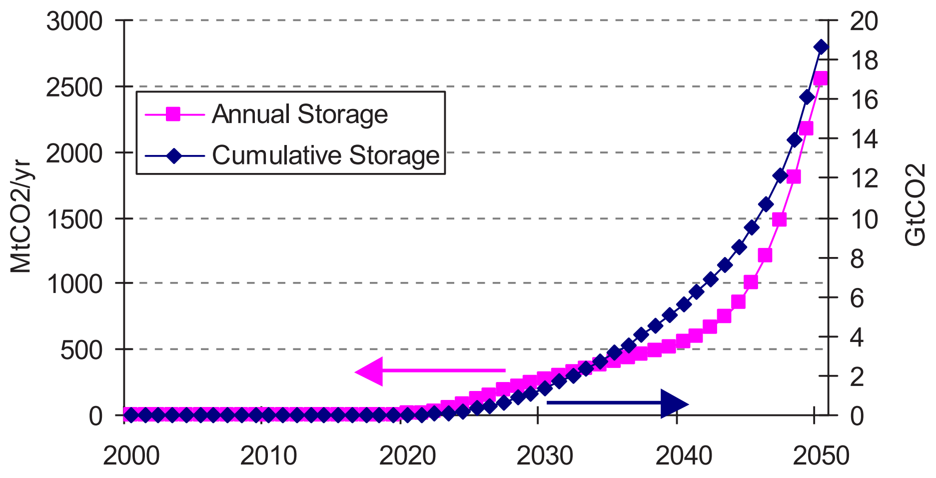
In 2050, 13% of electricity generation comes from plants equipped with carbon capture and storage. Figure 19 shows that CCS only develops after 2040, when the carbon value outside Europe is around 15 €/tCO_2 and when technological progress has reduced the cost of storage.

Figure 19: Carbon capture and storage in thermal electricity production



In 2050, 2.5 Gt of carbon dioxide are captured and stored; this is 5.5% of the gross emissions in that year. In this relatively low carbon constraint case, the cumulative volume stored up to 2050 is 19 Gt (Figure 20), which is slightly less than one year of current emissions.

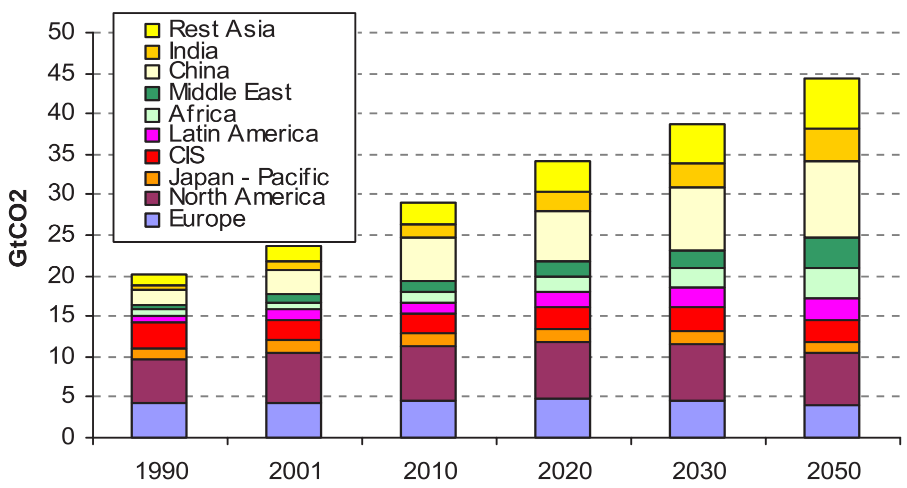
Figure 20: Yearly and total cumulative CO_2 storage



2.7 World CO_2 emissions

The combined effect of all the structural and technological changes in the Reference case is that emissions of CO_2 are 2.25 times greater in 2050 than in 1990 (Figure 21). The CO_2 emissions of Annex B countries increase slowly from the 1990 level of 14.2 Gt to 16.2 Gt in 2030; they then fall again to 14.6 Gt in 2050. This behaviour is a consequence of slow population growth, the high price of energy and to the implementation of climate policies, though moderate they are. In contrast, the increase in non-Annex B regions is dramatic; emissions are 5.9 Gt in 1990 but catch up with Annex B countries between 2010 and 2020 at 15.5 Gt. By 2050, the emissions from non-Annex B countries are 29.7 Gt and amount to two thirds of the world total.

Figure 21: World CO_2 emissions by region



This complex trajectory for CO_2 emissions is composed of distinct trends in industrialised and developing countries:

- The CO2 emissions from industrialised countries are approximately stable. This happens because of the low rate of growth of the population and of the economy, combined with saturation in ownership of energy equipment, the impact of energy price increases on demand and substitution of nuclear and renewable energy in supply.
- The emissions from the developing regions continue to grow. They increase three-fold over the period in spite of - and to an extent because of - the rise in the price of oil and gas. The developing world needs a lot of energy that price rises can only partly contain and the price-induced shift to coal increases the carbon intensity.

2.8 Trends in final energy demand

In order to analyse the long-term trends in energy consumption, final energy demand in each region can be broken down into three categories: thermal energy in industry and buildings, transport fuels and electricity use. Each of these categories is also analysed as providing an essential service to society[15].

Box 5: Final energy demand: activity, price-effects and new low energy solutions

The model projects final energy demand for ten energy-consuming sectors (4 in industry, 3 in transport, plus the residential, services and other sectors) differentiating where appropriate between demand for substitutable fuels (including electricity for thermal uses) and demand for captive uses of electricity.

Two standard equations are used to represent the total fuel demand for each sector and the demand for each individual fuel in the sector. The variation of the total final energy consumption (FC) is a function of:

- *A measure of income or of an activity variable with an associated income elasticity*
- *A short-term price response of demand in the sector to the variation in the average price over the two previous years, expressed as a price elasticity. This short-term effect describes behavioural change and is reversible.*
- *A long-term price effect that is investment-driven and not reversible and that is described by a distributed and lagged price response that depends upon the duration of the price change and a long-term price elasticity.*
- *An autonomous technological trend that varies among countries and sectors; this trend is generally lower than the trends assumed in many top-down models, because these models aggregate many effects that POLES treats explicitly.*

For the substitutable fuels, the resulting final consumption is then shared between the different fuels, according to their relative total user cost and applying a Weibull distribution function.

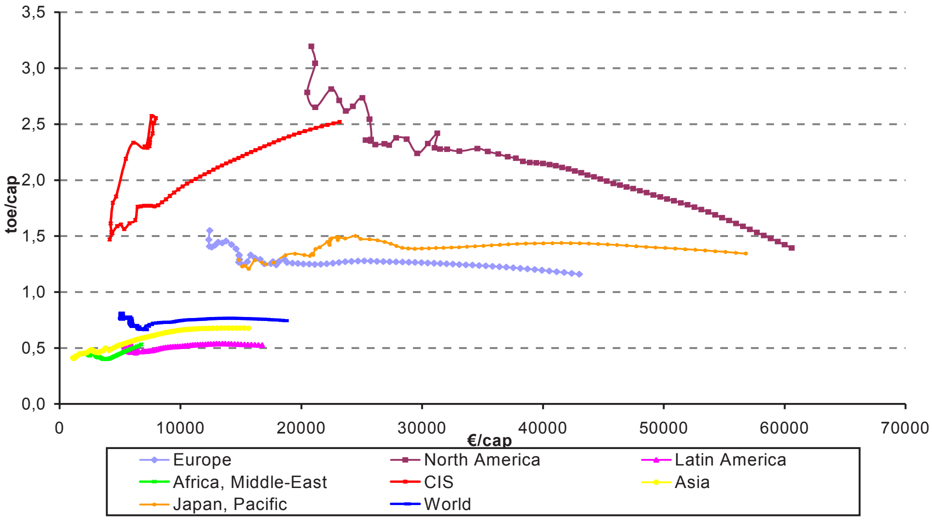
The version of the model used in WETO-H_2 incorporates the diffusion of new low energy or very low energy vehicles and buildings. These new devices progressively substitute for conventional vehicles and buildings as the energy price or carbon value increases. Their diffusion is stimulated by cost-competitiveness, but constrained by stock and renewal effects. The VLE building concept reflects contemporary efforts in many countries to develop zero or even positive energy buildings and the VLE vehicles draws on the efforts of manufacturers to develop hybrid, electric or hydrogen cars.

[15] See in particular works by Jean-Marie Bourdaire at IEA-LTO, *World Energy Outlook 1998* and *World Energy Prospect to 2020: Issues and uncertainties*: http://www.oecd.org/dataoecd/37/55/17738498.pdf

Thermal energy in industry and building

The per capita energy consumption for thermal uses includes the energy used in buildings for comfort and the process heat in industry. At world level, a slight increase between 2010 and 2030 reverses the decreasing trend observed from 1980 until the late 90's. After 2030, there is a slight reduction. As a result, the per capita thermal use in 2050 reverts to the level of 1990 (Figure 22).

Figure 22: Thermal energy and GDP, per capita, 1980-2050



In Europe, after a slight increase until 2020, the per capita level for thermal use decreases moderately and is in 2050 about 10% lower than now. The trend in the Japan and the Pacific region is similar to the trend in Europe. In North America, a more rapid fall than in Europe leads to a certain convergence with the European level. The trend observed in industrialised countries is the result of different influences: a reduction of the energy use in industry, linked to changes in the industry structures towards less intensive industries and a decreasing influence of the industry sector in the economic activity, energy savings in buildings, but also increased comfort[16]. In contrast, the increase in Asia and Latin America until 2030 reflects mainly the growth in manufacturing output. Towards the end of the period, the increase in fuel price results in a much slower progression in these regions.

Transport energy use per capita

The per capita transport energy use increases moderately at world level, by 0.5%/yr on average between 2010 and 2050. For all regions, the period is characterised by high prices of motors fuels[17], particularly by the end of the projection. This moderates the rate of increase of the per capita consumption for transport. Figure 23 shows contrasting patterns in the industrialised and developing regions. The per capita consumption for transport in the industrialised regions stabilises and even falls. In Europe and in the Japan-Pacific region it comes back in 2050 to the present levels; in North America it even falls substantially below the present level. The behaviour in North America reflects the large potential for energy

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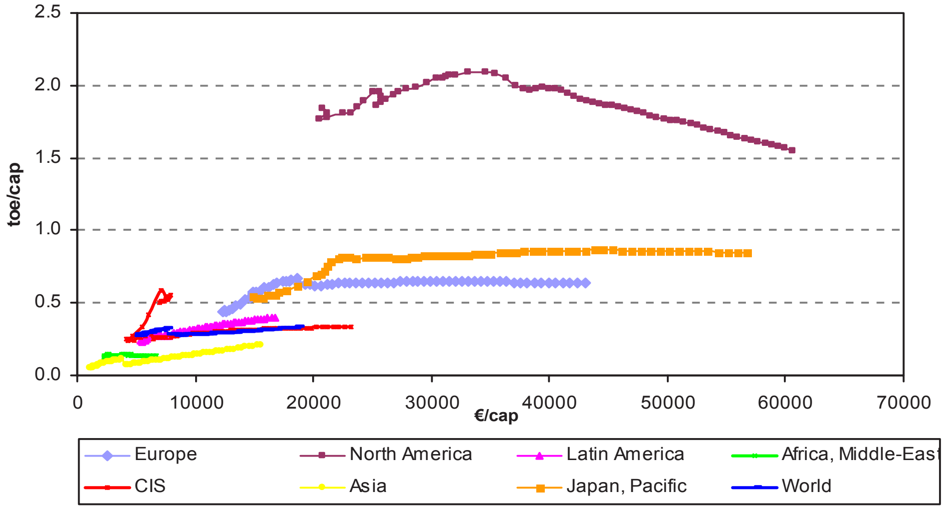
[16] In that respect, a recent study on the EU-15 shows that the consumption per dwelling remained almost stable between 1990 and 2002: all the energy savings have been offset by behavioural and lifestyles changes in ADEME: Energy "Efficiency Monitoring in the EU-15": Paris, 2005

[17] Prices roughly double compared to 2000 in OECD countries and rise even more in non-OECD where taxes are lower and the relative impact of crude prices corresponding greater.

efficiency in vehicles and the existing high level of ownership, which leaves little scope to increase the stock and utilisation of vehicles.

Figure 23: Transport energy use and GDP per capita, 1980-2050



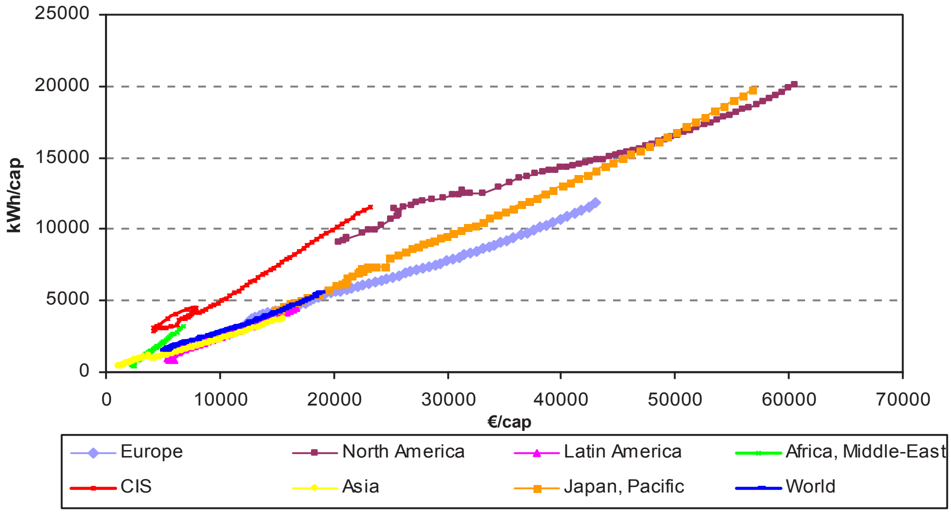
In Europe, there is less possibility to improve the specific consumption of vehicles, which is already lower than in all other regions, but it is likely that the stock of vehicles will increase especially in new member countries and Turkey. These influences partially compensate each other. For most other regions, the average growth in per capita use is between 1 and 2%/yr over the period and even 2.3%/year in Asia.

Electricity use per capita

The per capita demand for electricity in the world increases almost proportionally to income: the rate of growth is 1.9%/yr between 2010 and 2030 and 2%/yr from 2030 to 2050 (Figure 24), compared to an average of 1.7%/yr between 1990 and 2010 and 1.8%/yr over the eighties. The global average disguises different behaviour in the industrialized and developing world.

In the industrialised countries, demand increases at a slower rate than in the past; in the period from 2010 to 2050 it increases at around 0.9%/ year in North America and 2%/yr for the Japan and Pacific region, compared to 1.8%/yr and 3.2%/yr over the eighties.

Figure 24: Electricity use and GDP per capita, 1980-2050



In Europe the slow down is less spectacular, given the high potential of growth in demand from the EU new member states and the accession countries, including Turkey. The estimated rate of growth is 1.9%/ year on average after 2010 compared to 2% in the eighties. This does not mean that there is no improvement in energy efficiency, but rather that there is still a diffusion of new types of electrical appliances, as can be seen at present with ICT appliances. In some countries, electricity replaces fossil fuels for thermal uses, because of the lower cost.

Electricity demand per capita grows much faster in the other regions, especially Asia, Africa and the Middle East (3%/yr on average over the projection period). Ownership of basic household electrical appliances is still far from saturation; there is a diffusion of new end-uses such as air-conditioning and there is growing demand in the productive sectors.

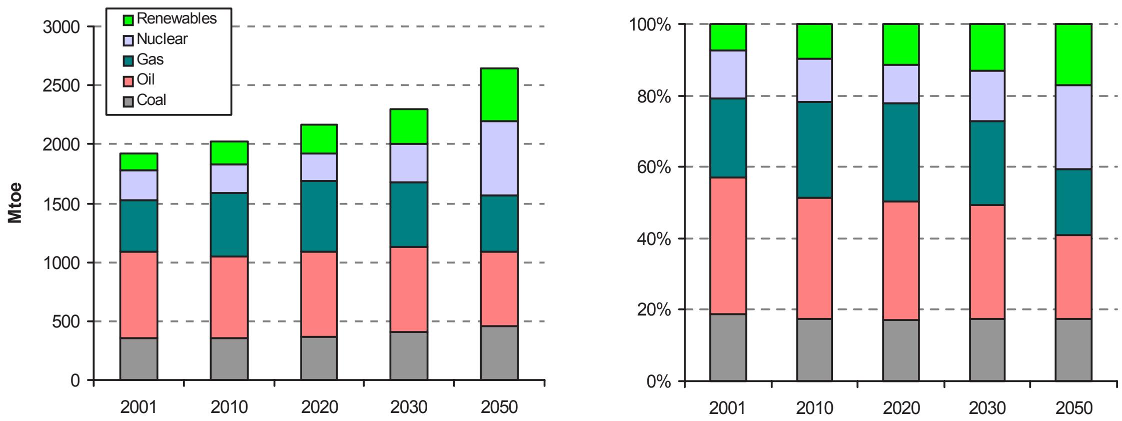
2.9 Europe's primary energy balance

The primary energy consumption in Europe[18] increases moderately over the period from 1.9 Gtoe today to 2.6 Gtoe in 2050; this is slower than elsewhere in the world. The behaviour shows in the energy intensity of GDP that falls throughout the period to less than half of the value in 1990, (Table 6 below).

The consumption of oil and gas is restricted, in particular after 2020, by high prices. By 2030, the consumption of oil and gas in Europe is less than in 1990. Coal use rises slightly but the bulk of the increase in total primary energy consumption comes from renewables and nuclear energy. Renewables increase steadily over the period. Nuclear initially decreases, because of the voluntary phasing-out of nuclear plants in several countries (namely Germany, Belgium and Sweden); but after 2020 it revives and grows at a sustained 3.5%/yr between 2030 and 2050.

[18] Europe, in this study, includes non EU countries, such as Norway and Turkey, but excludes CIS countries partly located in Europe, such as Belarus, Ukraine and Russia.

Figure 25: Primary energy demand in Europe



The combined effect of these structural shifts is that the share of non-fossil energies is stable at around 20% of primary energy consumption until 2020 after which it increases steadily to 40%. These trends have a significant impact on the energy self-sufficiency of Europe:

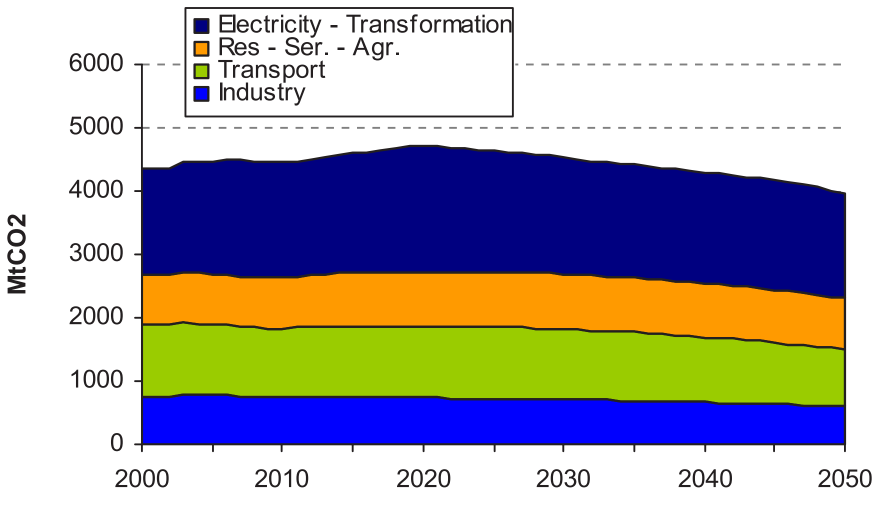
- The ratio of primary production to primary consumption is relatively high between 1990 and 2001; it peaks at 63% in 2010 thanks to an increase in the production of gas (Table 6).
- This ratio falls rapidly between 2020 and 2030 because of falling production in the North Sea and despite the modest increase in demand.
- After 2030, the strong upward trends in nuclear and renewable energies more than compensate for the falling production of hydrocarbons; in 2050, the self-sufficiency ratio recovers to 60%.

Table 6: Energy indicators, primary production and CO_2 emissions for Europe[19]

Europe	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	564	588	599	605	606	586	0,3%	0,1%	-0,2%
GDP (G$95)	8 373	10 312	12 660	15 900	19 079	25 194	2,1%	2,1%	1,4%
Per capita GDP ($95/cap)	14 849	17 533	21 124	26 260	31 496	43 005	1,8%	2,0%	1,6%
Gross Inland Cons./GDP (toe/M$95)	212	186	160	136	120	105	-1,4%	-1,4%	-0,7%
Gross Inland Cons./capita (toe/cap)	3,1	3,3	3,4	3,6	3,8	4,5	0,4%	0,6%	0,9%
Electricity Cons./capita (kWh/cap)	4 206	4 995	5 787	6 896	8 176	11 839	1,6%	1,7%	1,9%
Transport fuels per capita (toe/cap)	0,55	0,65	0,62	0,64	0,65	0,63	0,6%	0,2%	-0,1%
CO2 emissions/capita (tCO2/cap)	7,7	7,4	7,4	7,8	7,5	6,8	-0,2%	0,0%	-0,5%
% of renewables in Gross Inland Cons	5,5	7,5	9,7	11,2	12,9	16,9	2,9%	1,4%	1,4%
% of renewables in electricity	18,2	20,4	21,0	22,9	25,6	25,9	0,7%	1,0%	0,1%
% of primary production in consumption	62,9	62,3	63,3	50,8	50,4	60,3			
Primary Production (Mtoe)	**1 115**	**1 196**	**1 284**	**1 102**	**1 158**	**1 593**	0,7%	-0,5%	1,6%
Coal, lignite	393	240	220	213	218	225	-2,9%	-0,1%	0,2%
Oil	224	313	309	185	113	86	1,6%	-4,9%	-1,4%
Natural gas	190	244	310	226	203	210	2,5%	-2,1%	0,2%
Nuclear	209	254	246	234	326	625	0,8%	1,4%	3,3%
Hydro, geothermal	44	54	55	58	60	63	1,1%	0,4%	0,3%
Biomass and wastes	53	87	131	159	188	283	4,6%	1,8%	2,1%
Wind, solar	0	3	11	27	49	101	29,0%	7,6%	3,7%
Gross Inland Consumption (Mtoe)	**1 773**	**1 921**	**2 029**	**2 168**	**2 299**	**2 642**	0,7%	0,6%	0,7%
Coal, lignite	481	359	354	367	404	458	-1,5%	0,7%	0,6%
Oil	681	734	689	724	727	626	0,1%	0,3%	-0,7%
Natural gas	300	429	541	597	542	484	3,0%	0,0%	-0,6%
Biomass and wastes	53	87	131	159	188	283	4,6%	1,8%	2,1%
Primary electricity	258	313	315	320	436	791	1,0%	1,7%	3,0%
CO2 Emissions (MtCO2)	**4 360**	**4 367**	**4 463**	**4 712**	**4 534**	**3 963**	0,1%	0,1%	-0,7%
of which:									
Electricity generation	1 608	1 519	1 585	1 755	1 623	1 454	-0,1%	0,1%	-0,5%
Industry	961	765	742	738	716	596	-1,3%	-0,2%	-0,9%
Transport	826	1 122	1 093	1 122	1 104	900	1,4%	0,0%	-1,0%
Household, Service, Agriculture	828	800	805	862	868	811	-0,1%	0,4%	-0,3%
CO2 Sequestration (Mt CO2)	0	0	0	9	200	529	na	na	5,0%

Figure 26 shows how these long-term changes in the primary energy balance affect the CO_2 emission profile of Europe. Emissions increase slightly until 2010 in spite of the reductions in the EU 15 required by the Kyoto Protocol; they continue to increase until 2030. Thereafter they fall because of the increase in non-fossil supply. In 2050, the CO_2 emissions of Europe are 10% lower than in 2001.

Figure 26: Energy-related CO_2 emissions in Europe



[19] Europe includes non EU countries, such as Norway and Turkey, but excludes CIS countries

2.10 Europe's final consumption and electricity sector

The final consumption of energy in Europe increases during the period at an average rate of 0.4%/yr. Figure 27 shows the composition of final demand by sector; it reveals a long-term stabilisation of energy consumption in the transport sector. This is an important change in the pattern of demand. In the past thirty years the durable decoupling of an "energy service" from GDP has only been observed for stationary uses of fuels and only temporarily for transport[20], i.e. in the USA after the introduction of the CAFE standards. There are several possible explanations for this new trend in transport including: recent oil price increases; the impact of technological standards; saturation in equipment and in the time-budget for personal transport. In this respect, the Reference case again includes significant structural change.

The Reference case has an inherent tendency to high prices for energy and this triggers important structural change. It suggests that Europe may have entered a second phase of energy decoupling, with electricity remaining the only energy carrier for which demand continues to grow. The third and final phase of decoupling – that of electricity, if it ever happens – is not visible before the 2050 horizon.

Figure 27: Final consumption (left) and electricity consumption (right) by sector in Europe

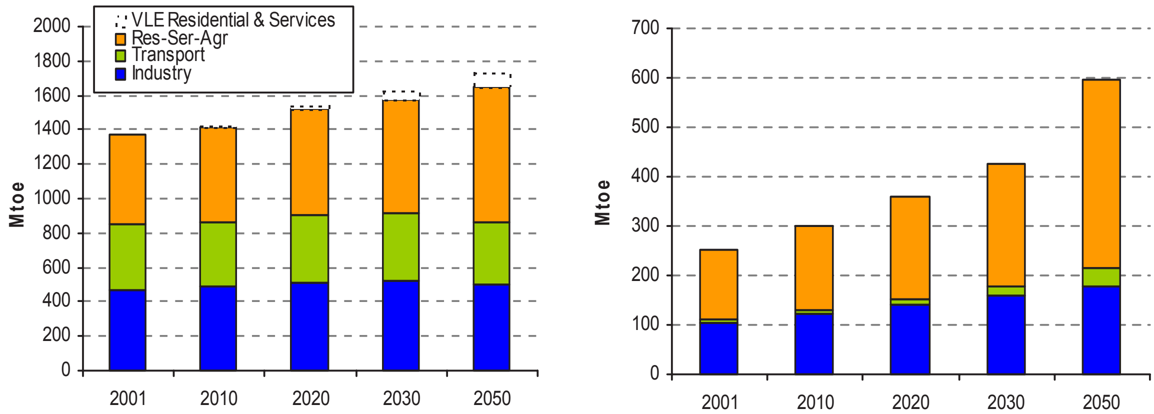


Figure 27 summarises the critical dynamics. The total final consumption of energy increases by 270 Mtoe over the period, almost entirely because of a growth of 260 Mtoe in the residential and tertiary sector, 240 Mtoe of which is electricity. This new pattern in energy demand might be interpreted as the energy dimension of the "third industrial revolution" characterised by the swift development of electricity intensive ICTs (Information and Communication Technologies)[21].

A price-induced diffusion of highly efficient buildings and vehicles also helps restrain demand. By 2050, the market share of low energy buildings is 45% and that of low emission vehicles is 35% (Figure 28).

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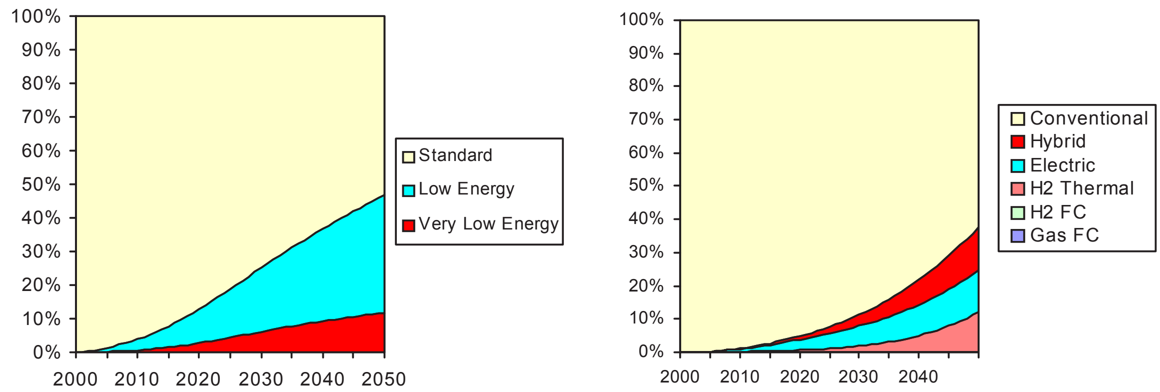
[20] See J.-M. Bourdaire, op. cit.

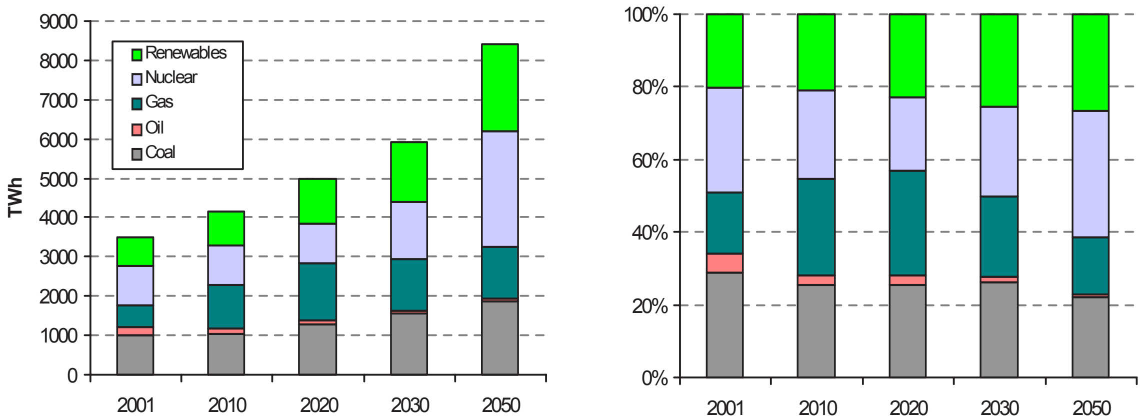
[21] To some extent, the "stationary fuel energy services" can be associated with the first industrial revolution largely based on heavy process industries and infrastructure development (including buildings) while the "mobile fuel services" stem from the second industrial revolution, based on the personal mobility and the oil-automobile nexus.

Figure 28: Low energy buildings (left), Low emission vehicles (right) in Europe



Changes in the origins of generation of electricity are consistent with those identified for primary energy consumption. The development of renewable electricity in Europe almost meets the EU's target of 22% of total power generation by 2010. This share is maintained and it even increases slightly to 25% by 2050. The absolute contribution and the share of nuclear electricity both decrease until 2020, as some second-generation plants are retired. It revives after that date, with the rapid introduction of third and fourth-generation plants. Figure 29 shows that by 2050, more than 60% of electricity in Europe comes from renewable or nuclear energy.

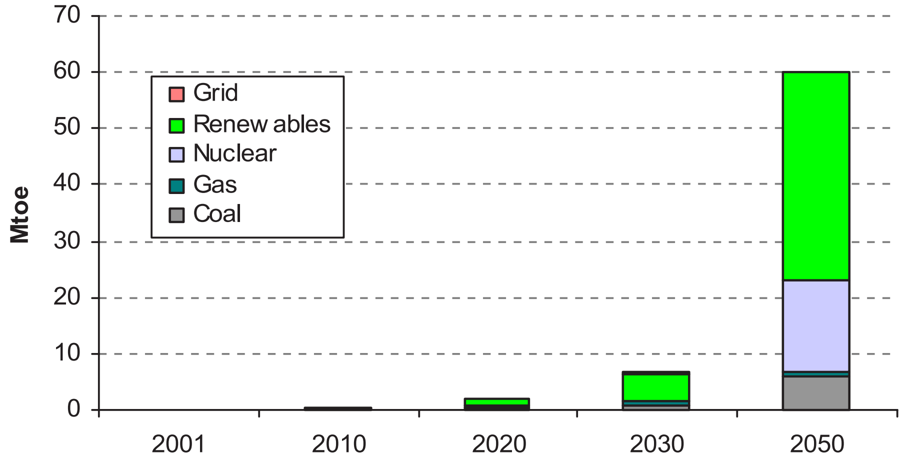
Figure 29: Electricity production and fuel-mix in Europe



2.11 Hydrogen production and carbon capture and storage in Europe

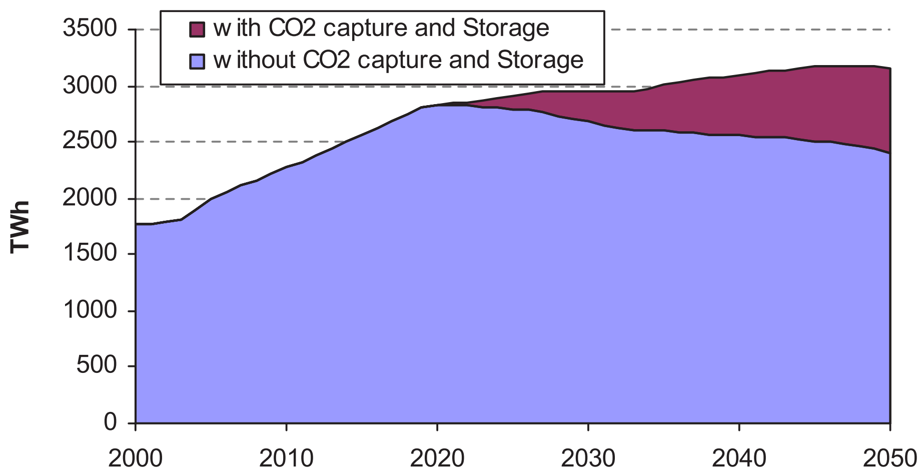
There is little hydrogen production for energy purposes until 2030. Thereafter it begins to penetrate and by 2050, production is 60 Mtoe; this is equivalent to 10% of the final consumption of electricity (Figure 30). The share in European final consumption is slightly above the world average of 9%.

Figure 30: Hydrogen production in Europe



By 2050, carbon capture and storage covers one fourth of total thermal power generation in Europe. The penetration of this technology is stimulated by a carbon value that is higher in Europe than in the rest of the world (Figure 31).

Figure 31: Carbon capture and storage in electricity production in Europe



The sum of these various impacts amounts a significant adjustment of the energy system in Europe, even in the Reference case. The case reveals a modest increase in total energy demand, but a relatively high growth of electricity consumption that with the development of renewables, nuclear and carbon capture and storage results in an almost stable profile for CO_2 emissions (see Figure 26). This profile provides a consistent reference for emission trends in the case of modest climate policies, but it is not consistent with a set of international commitments that would adequately mitigate climate change. Stronger climate policies are needed and are examined in the next chapter.

KEY MESSAGES

The development of the world energy system

World primary energy

The consumption of primary energy in the world is expected to reach 22.3 Gtoe in 2050, from the current 10 Gtoe. Coal and oil (including non-conventional) provide 5.7 and 5.9 Gtoe and natural gas 4.1 Gtoe; renewable and nuclear energy contribute 3.4 and 3.2 Gtoe. This represents a significant structural change in the world fuel-mix, in particular after 2030, when renewable and nuclear energy sources benefit from a sustained development, which translates in a rapid increase of their market share: in 2050, 30% of world energy supply comes from non-fossil sources.

Energy efficiency improvement

While the size of the world economy is multiplied by four in 2050 compared to today, world energy consumption is multiplied only by a factor 2.2. This indicates that significant energy efficiency improvements are already in the Reference projection; they arise both from autonomous technological or structural changes in the economy and from the effects of regularly increasing energy prices and energy efficiency policies .

North-South balance in energy consumption

The growth in energy demand is strong in the developing regions of the world where basic energy needs are at present hardly satisfied. As a result, the energy consumption of developing countries overtakes that of the industrialised ones shortly after 2010; in 2050, it represents two-thirds of the world total.

Oil and gas production profiles

Oil long-term development does not exactly follow the “peak oil” profile that is much discussed today. Rather than a sharp peak, the Reference projection indicates a plateau in conventional oil production, starting from 2025 at a level of about 100 Mbl/d. Thereafter, production of conventional oil is almost stable to 2050. Non-conventional oil plays an important role after conventional oil reaches its maximum and it provides for the increase in total liquids, to 125 Mbl/d in 2050. Natural gas shows a similar pattern, with a delay of almost ten years. As the ratio of reserves to production is higher than for oil, the peak in natural gas occurs at a level that is twice today’s production level, i.e. proportionally much higher than for oil.

Oil and gas prices

The prices of oil and natural gas on the international market increase steadily over the period, to reach 110 $/bl for oil and 100 $/boe for gas in 2050. These price levels reflect both the geo-political constraints that limit in the short run the access to cheap oil and gas and, as time goes, the increasing resource scarcity. Many alternatives to oil and gas may be cost-effective and will be developed at lower price levels, but there is no single “backstop” solution. High prices are required to curb energy demand trends; they are a condition for closing the world energy balance in the absence of a backstop supply option and a strong demand side energy policy.

World electricity and the comeback of coal

The growth in electricity consumption keeps pace with economic growth. In 2050, total electricity production is four times greater than today. Electricity generation is the main – if not the only – avenue for the comeback of coal, which is a significant feature of the Reference projection. Electricity production from coal comes increasingly from new advanced technologies, although the carbon value is not sufficient to induce a significant amount of CO_2 capture and Storage. The coal price is expected to be at 17€/boe in 2050.

The take-off of renewable sources and the revival of nuclear energy

A second key feature of the Reference projection is the rapid increase of renewable sources and nuclear energy. This begins after 2020 and is massive after 2030; it is driven by the sustained growth in electricity demand, which cannot be fully met by the increasing contribution from coal power plants. This implies a massive deployment of new energy technologies, from large offshore wind farms to “Generation 4” nuclear power plants.

CO_2 emissions

This deployment of non-fossil energy options to some extent compensates for the comeback of coal in terms of global CO_2 emissions, which increase by a factor of 2.25 between today and 2050, almost exactly the same as for the total consumption of energy. The resulting emission profile leads to atmospheric concentrations of CO_2 between 900 to 1000 ppmv. This is well outside the range that is today considered consistent with stabilisation of atmospheric temperature.

The “upstream” and “downstream” constraints to energy development

Careful consideration of the drivers and constraints indicates that development of world energy has to respond both to an “upstream” resource constraint – with a growing scarcity for oil and gas – and to a “downstream” environmental constraint – arising from the need to limit emissions. The last, but not the least, message from the Reference case is that compliance with the resource constraint does not necessarily cause compliance with environmental constraint. On the contrary, without strong climate policies the hydrocarbon scarcity promotes a comeback of coal that causes a doubling of total emissions.

The European energy system in the Reference projection

Primary energy balance

The increase in total primary energy consumption in Europe during the projection period is small; it rises from 1.9 today to 2.6 Gtoe in 2050. Until 2020, the primary fuel-mix is quite stable, with a significant increase only in natural gas consumption. Thereafter the development of renewable energy sources accelerates and nuclear energy revives. In 2050 non-fossil energy sources, nuclear and renewable represent 40% of the primary energy consumption, a significant change from the present 20%.

Energy self-sufficiency

The ratio of domestic primary production to primary consumption in Europe is a measure of the energy self-sufficiency. As the output of oil and gas from the North-Sea declines, this ratio falls from more than 60% today to 50% between 2020 and 2030. Thereafter, as non-fossil domestic options penetrate, the ratio rises and again reaches 60% in 2050.

CO_2 emissions

The combination of low-intensity climate policies with a moderate demand increase and new trends in domestic primary supply results in CO_2 emissions that are almost stabilised until 2030 and then decrease until 2050. At that time CO_2 emissions in Europe are 10% lower than today.

Final energy consumption and very low energy (Emission) technologies

Although the consumption of final energy grows only slowly, the consumption of electricity keeps pace with economic growth; this behaviour reflects a market for electricity that remains dynamic because of the diverse electricity uses and new uses, especially in Information and Communication Technologies. The high prices that result from the world context induce a significant penetration of very low energy buildings and Vehicles, which represent 45% of the building stock and 35% of the vehicle fleet in 2050.

CO_2 capture and storage and Hydrogen

In Europe, new power generation technologies and new energy carriers start to appear in the Reference case. This is mainly because the value for carbon is higher than in the rest of the world. It is sufficiently high after 2020 to make CO_2 capture and Storage cost-effective. In 2050, fossil plants with CCS provide one fourth of total thermal generation and electricity from renewable and nuclear sources provides 60%. At that date, European electricity is therefore largely decarbonised, up to 70%. Hydrogen also develops after 2030, with modest although not negligible results. The energy carried by hydrogen in 2050 is the equivalent of 10% of electricity consumption.

CHAPTER 3 IMPACTS OF THE CARBON CONSTRAINT CASE

The Reference projection incorporates a carbon value that broadly reflects existing policies on climate change and intentions as far as they are known; under this assumption the emissions of CO_2 more than double over the period to 2050. This finding suggests that present policies are inadequate and that anthropogenic emissions of greenhouses gases will be a critical constraint on energy policy. The WETO-H_2 study therefore examines an alternative scenario with more severe limits on CO_2 emissions, named the Carbon Constraint case.

3.1 Methodological considerations

There are various ways of intervening in markets to make economic behaviour comply with carbon constraints. A pure economic intervention is to include the value of the carbon constraint (the shadow price) into the energy price to the consumers. A pure regulatory intervention is to impose regulations and standards to limit emissions. It is also possible to combine market instruments with regulations in a mixed approach.

In the WETO-H_2 study, using the POLES model, we represent the carbon constraint in a pure economic way. The carbon constraint is captured by a carbon price that includes the shadow-price of the constraint and that is incorporated in the energy price to the final consumer. There are two consequences:

- a modification of demand in each sector and a change in the allocation of demand among energy carriers determined by the relative price elasticities,
- a modification of the penetration rates of technologies for electricity generation, hydrogen production and low emission buildings and vehicles, according to their associated carbon emissions.

This emphasis on a pure economic approach ensures strong internal consistency of the results in terms of the marginal costs of abatement of carbon across fuels, sectors and regions and the consequences as conveyed through prices. This is valuable in a worldwide exercise of this type. There is a limitation to the approach; the values assumed for price elasticities and costs of competing technologies are robust for the present and the near future, but become fragile for distant time horizons.

3.2 The climate change challenge and greenhouse gas reduction targets

The effect of greenhouse gas emissions on climate over the long and very long-term is still a matter of debate among scientists, and between scientists and policymakers. Some consider that energy policy should address immediately the adverse consequences of climate change through stringent emission targets; others think this is premature. The principal of inter-generational equity that underlies sustainability determines that a critical line must exist beyond which the human, ecologic, economic and social impacts of climate change are unacceptable. These events can be and must be avoided.

The IPCC Special Report on Emission Scenarios

The international community is engaged in trying to determine where the balance lies between the impacts of climate change and the economic and social costs of abatement. The IPCC has developed the SRES scenarios[22] describing different energy futures to support the

[22] See the full report: http://www.grida.no/climate/ipcc/emission/

process of decision and negotiation. The goal is to inform the policy debate and international negotiations, but not to describe a “central” scenario. What appears most important for the IPCC is the ability to evaluate the physical, economic and social consequences of different scenarios for emissions and to identify the underlying relationships, rather than the ability to “discover” and “propose” a preferred solution.

The appropriate profile of future emissions is not obvious. There are three main uncertainties: how emissions of CO_2 will affect the concentration in the atmosphere over time; how the climate will respond to increased greenhouse concentrations and how the socio-economic system will be affected by climate changes. The IPCC examines these matters, but does not formulate targets for emissions. In several OECD countries, it is thought that reductions from the 1990 emissions of 50 to 80% may be needed in the long-term.

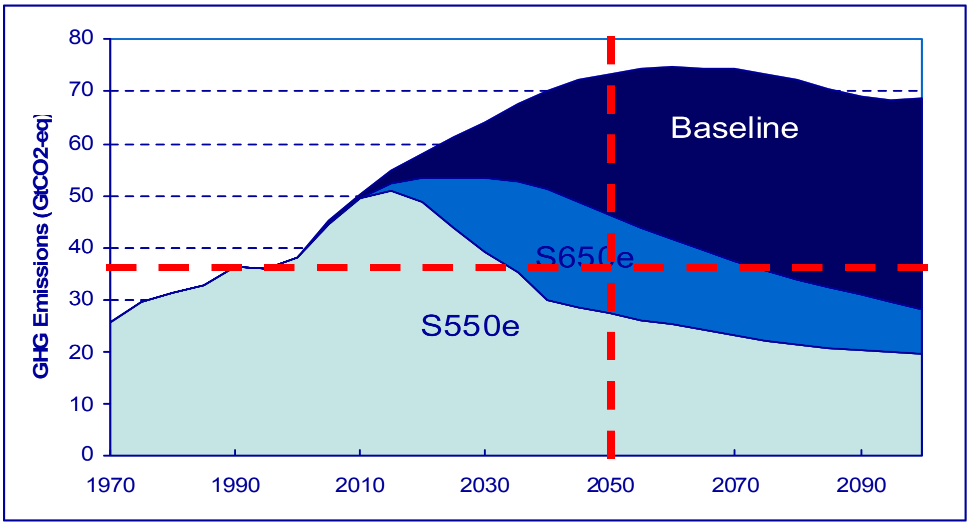
Lessons from the Greenhouse Reduction Pathways and “Factor 4” studies

The Greenhouse Reduction Pathways study, performed for the DG Environment of the European Commission with a set of European models[23], investigated the relationship between carbon emissions and the concentration of GHGs in the atmosphere. It showed that to stabilise atmospheric concentrations of GHGs at 550 ppmv of CO_2 equivalent and therefore to limit the temperature increase at the earth surface to 2°C, the emissions of GHG in the world should stop increasing around 2015, come back under their 1990 level before 2050 and continue to decrease thereafter (see Figure 32). A concentration of 550 ppmv of CO_2 equivalent for the six Kyoto GHGs implies a concentration of approximately 450 ppmv for CO_2 only.

To achieve this world trajectory while allowing for the concurrent development of emerging countries, the GHG emissions of the industrialised countries must fall by approximately a Factor of 4 in 2050, compared to 1990. The study examines two long-term world emission profiles and, through analysis of different arrangements among countries for sharing the burden of reductions, identifies a plausible range of national or regional targets. All arrangements that, from the examination of various criteria, seem potentially acceptable by the different parties indicate that stabilisation at 550 ppmv CO_2eq. requires a Factor 4 reduction in Annex B counties. A Factor 2 reduction is consistent with the 650 ppmv CO_2eq. stabilisation profile.

[23] The POLES, GEM-E3 and IMAGE models, see LEPII-EPE et al. (2003), *Greenhouse Reduction Pathways in the UN-FCCC process up to 2025,* EU-DG Environment, http://europa.eu.int/comm/environment/climat/studies.htm

Figure 32: Greenhouse Gas reduction profiles



Some European countries, including the United Kingdom, France, Germany and the Netherlands, are investigating reductions of GHG emissions by a Factor 3 or 4 in 2050 compared to 1990. This is some measure of the effort required from industrialised countries to stabilise the concentration of CO_2 in the atmosphere at 450 ppm after 2050, while leaving the possibility for developing countries to converge towards similar levels of GHG per capita worldwide before 2100.

These preliminary studies have explored what Factor 4 strategies might mean for technology and social organisation. The questions addressed include, for example: what technologies are required and when; how should they be deployed in the market; how should transport and production systems be organised? Two types of insights are expected from these studies:

- Whether the Factor 4 reduction is feasible, taking into account the present and expected availability of the technologies, the intensity of the changes in the social organisation and the time needed to implement the changes.
- What policies and measures are needed and what incentive structure should be designed and implemented to foster the changes in technology and organisation.

Several conclusions can be drawn about technology. Technological innovation envisaged today could achieve Factor 4 reductions, but it is doubtful that R&D institutions and industry can bring them to market at the right time and at competitive conditions. Factor 4 would require in many cases radical innovations and high-cost technologies that would equate to a carbon value, or shadow-price of the carbon constraint, of several hundred euros per ton of CO_2. Some technology may introduce other concerns about sustainability, for example with nuclear energy, or may require large amounts of land, as is the case for renewables. Some new technologies could stimulate detrimental behavioural change (e.g. “rebound effects” in energy consumption).

Conclusions can also be drawn from these studies about the organisational and behavioural implications of Factor 4 policies. Because of the uncertainties and costs of the new technologies, significant changes in mentalities, behaviours and organisations will be needed to accommodate them. Some changes may require policy actions that disadvantage individuals or parts of the economy and conflict with economic and social priorities. There is insufficient evidence at present to determine whether the macro-economic impacts of these policies would be negative or positive: innovation may in the long-term have a positive impact, but the medium-term cost of implementation would probably be negative. Given the poor present state of knowledge, the balance is uncertain.

Insights from the VLEEM study

In the VLEEM project[24], the challenge is contemplated from the future, using a “back-casting” approach. An important conclusion is that the concentration of CO_2 in the atmosphere has to be stabilised at some time, or the climate system will become completely unstable. At some time in the next century, the emission of CO_2 from fossil fuel combustion has to fall to a very low level, corresponding to the natural system uptake. This establishes an ultimate goal, but the practical targets will be set by international negotiation and will depend on the overall political situation, the geographical distribution of impacts, the trends in economic disparities across the world and the progress in scientific evidence and understanding. If it becomes clear that some extreme weather phenomena, such as the floods in Central Europe in 2002, the heat wave in 2003, or the hurricanes in 2005 are associated with anthropogenic greenhouse gas emissions, then the adoption of stringent emission goals is more likely.

The formula adopted in the VLEEM study to quantify reduction profiles is similar to that used in the existing international negotiations (i.e. the Kyoto Protocol up to 2008-2012). Instead of fixing an absolute limit to global emissions or per capita emissions, a continuous emission reduction effort is assumed that is expressed as a percentage reduction in the volume of emissions every ten years. These reductions are imposed on every country once it has reached a certain level of development. For industrialised countries (i.e. the OECD + the CIS), the target is to reduce the GHG emissions related to energy by 10% every 10 years on average, starting in 1990. The weaker constraint between 1990 and 2008-2012 in the Kyoto Protocol is assumed in the WETO-H_2 study to be compensated by higher constraints after 2012. For developing countries, the same effort is imposed once the country has reached a GDP/capita at purchasing power parity that is equivalent to the average level of industrialised countries in 1990.

3.3 The WETO-H_2 Carbon Constraint case: Factor 2 reductions in 2050 for Annex B countries

There was some hesitation in the formulation of the carbon constraint case in this study. It was initially intended to adopt the “Factor 4” perspective and to investigate the consequences for the EU-25. This would have been consistent with the EU objective of limiting the increase of the average surface temperature to a rise of 2°C from pre-industrial values. For reasons examined above, and taking into consideration the high carbon values resulting from other Factor 4 studies, it was concluded that strengthening of the basic relationships and model structure was a pre-requisite for realistic descriptions of the implementation of Factor 4 scenarios.

It was therefore judged preferable in WETO-H_2 to simulate a less stringent set of emission constraints requiring a 50% or “Factor 2” reduction from 1990 for Europe and for the other Annex B countries. This is consistent with original idea of the Wuppertal Institute (doubling production within 50 years while halving the energy and material input, and thus reducing by a factor of 4 the *energy/material intensity* of GDP), and with the VLEEM study (reducing by 10% every 10 years the GHG emissions of the industrialised countries).

The aim of the WETO-H_2 Carbon Constraint case (CCC) is not to explore options for sharing the burden of reductions among countries; this is a matter for international climate negotiations[25]. The simulation of the Carbon Constraint case is based simply on a set of carbon values that describe the expected intensity and timing of the emission reduction policies in the different regions of the world, with a clear distinction between the Annex B and non-Annex B countries. For Annex B countries, the carbon value starts from the value for Europe in the Reference case of 10 €/tCO_2 in 2010 and increases linearly to 200 €/tCO_2 in 2050. For Non-Annex B regions, the carbon value starts at 10 €/tCO_2 in 2020 and increases

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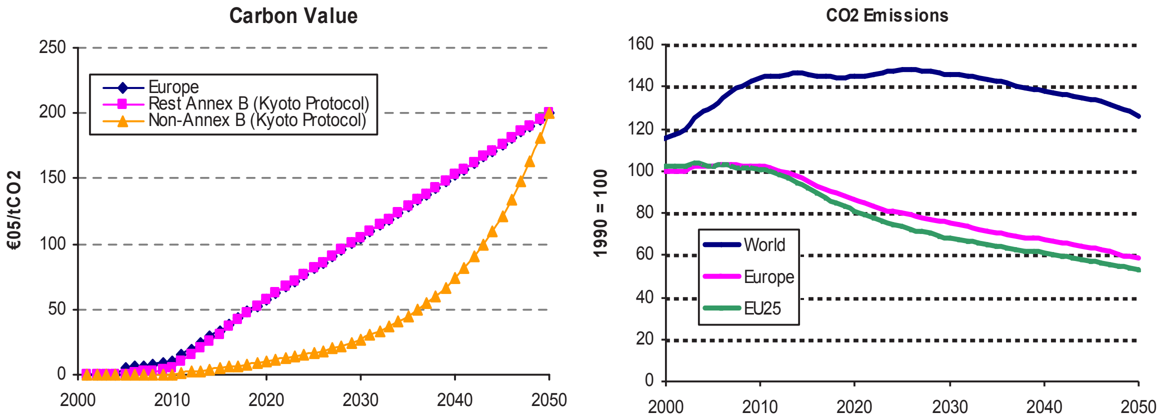
24 Developed for DG Research: http://www.vleem.org/index.html

25 For options for burden-sharing see the Greenhouse Gas Reduction Pathways, op. cit.

at a constant rate slightly above 10%/yr, to catch up with the 200 €/tCO_2 in 2050, see Figure 33.

The resulting programme of emission reductions in the world is not economically optimal, because until 2050 the marginal abatement costs differ between regions. Nor does it account for the North-South financial transfers associated with the Kyoto flexibility mechanisms. The Carbon Constraint case simply describes an abatement programme in which Annex B countries – consistent with their historic responsibility and current capacity – engage in an early action that provides most of the needed reductions in emissions; there are only small purchases of emission credits from Non-Annex B countries. Non-Annex B countries delay by ten to twenty years their efforts.

Figure 33: Carbon value in the CCC (left) and CO_2 emission profiles (right)

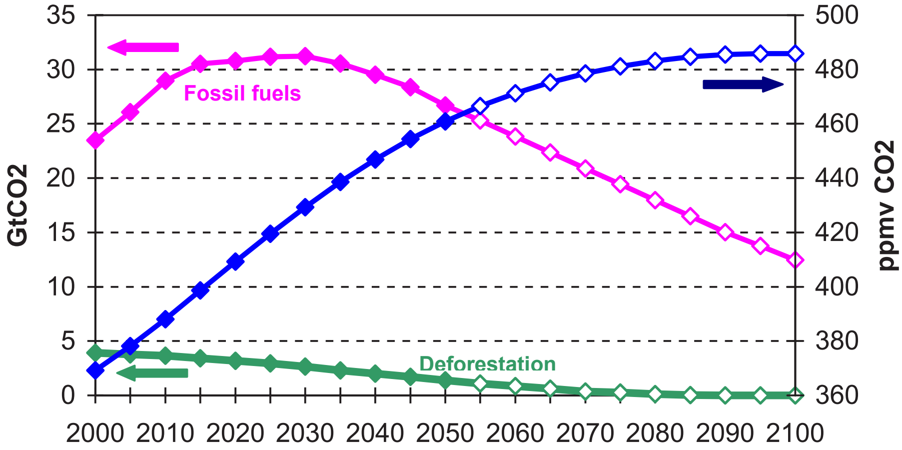


The Carbon Constraint case is an extension of a similar case in the first WETO study to 2030, with a stronger constraint from 2020 to produce the rapid stabilisation and decrease in world emissions that is necessary to meet the targets for stable concentration.

The profile of world emissions rises until 2015, then is flat until 2025, and subsequently falls away to a level in 2050 that is only 25% superior to that of 1990, see Figure 33. World emissions stabilise when the carbon value in the Annex B countries reaches approximately 25 €/tCO_2 and then begin to decline almost ten years later, when this carbon value is reached in developing countries. The corresponding profile for the EU 25 is consistent with the VLEEM perspective: by 2020, emissions are 80% of those in 1990 and then they decrease by 10% over each decade; the Factor 2 reduction is achieved in 2050.

This may lead-provided that emissions follow the right trajectory after 2050- to a stabilisation of the atmospheric concentration of CO_2 alone at a value below 500 ppmv. Indeed the introduction of the Carbon Constraint case emission profile in the MAGICC model results in a concentration level slightly above 480 ppmv in 2100 (see Figure 34).

Figure 34: CO_2 emissions and resulting atmospheric concentrations



Source: MAGICC model[26]

The profile is ambitious both for the world and for Europe, but it is less stringent than the profile needed to give a high probability of meeting the EU climate target of "less than 2°C more than pre-industrial average temperatures".

3.4 Impacts on world primary energy

The supply of primary energy to the world in the CCC is shown in Figure 35. The main points are:

- World primary energy supply falls from 22.5 Gtoe in the Reference case to 19 Gtoe. More efficient use of energy and behavioural changes in energy demand are important elements in emission reductions. Their importance is underestimated in these figures for two reasons: first, a part of the low-cost demand reductions is already included in the Reference case through a (low) carbon value; second, there is a higher share of nuclear energy in the CCC, which results in a lower efficiency of the overall electricity generation system.
- At 3.8 Gtoe in 2050, the supply of gas is almost unaffected in the CCC; higher efficiency of use is compensated by the substitution of gas for higher-carbon fuels. Oil is more affected; supply falls from 6 Gtoe in the Reference case to 4.9 Gtoe. Oil and gas demand peak in the CCC, but at lower levels than in the Reference case, despite lower producer prices; this is because of the high prices to the user caused by the high value of carbon. An important result is that oil reserves in 2050 are higher in the CCC than in the Reference case (525 compared to 425 Gbl), showing that the scenario is more sustainable also in terms of oil resources.
- Coal suffers most in the Carbon Constraint case and the resurgence detected in the Reference case no longer occurs, despite the deployment of carbon capture and storage technologies. Coal supply increases modestly until 2030 then declines; in 2050 it is 2.6 Gtoe, only 20% more than today.
- Until 2020 and despite steady progress, renewable and nuclear energy only maintain their share of world energy supply; subsequently they develop rapidly to 4.0 and 4.3 Gtoe respectively, because of the high carbon value. Their combined share in world energy supply increases from 20% in 2030 to more than 40% in 2050.

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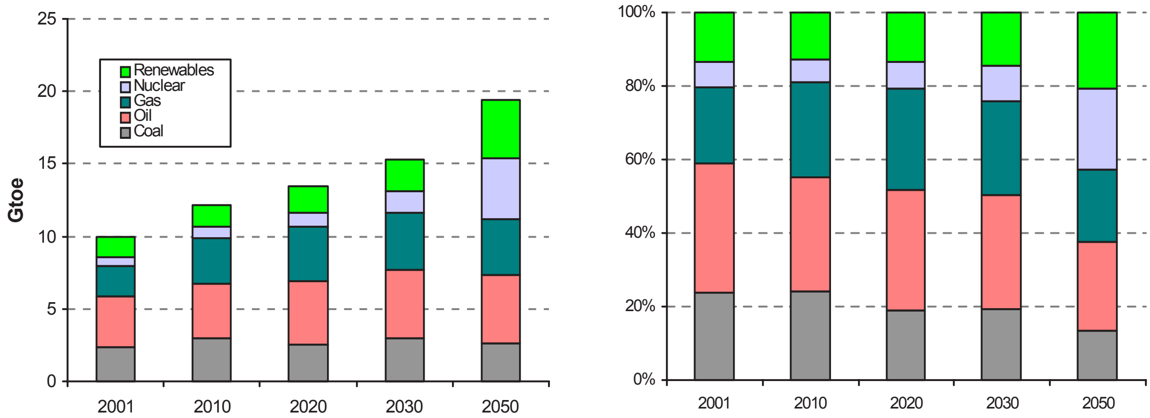
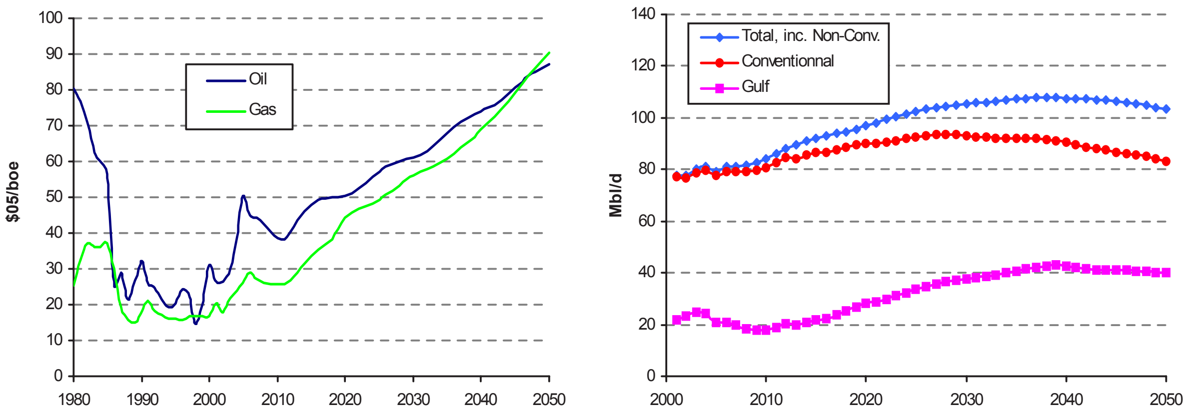
[26] The emission values beyond 2050 are extrapolated. The concentrations have been calculated using the MAGICC 4.1 climate model, including climate feedbacks on the carbon cycle, from Wigley, T.M.L. (2003) 'MAGICC/SCENGEN 4.1: Technical Manual', National Center for Atmospheric Research, Boulder, CO, USA.

Figure 35: World primary energy demand – CCC



Because of the lower demand, the international prices for oil and for gas are lower in the CCC than in the Reference case. In 2050 they are nearly equal at about 90 $/boe, compared to 111 and 102 $/boe in the Reference (Figure 36). This is because the high carbon value that intervenes between the end-user price and the producer price. The reduction in the use of fossil fuels caused by the high carbon values moderates the scarcity and high producer prices detected in the Reference case. The result shows that a strong climate policy significantly alleviates the oil and gas resource challenge.

Figure 36: Oil production and international prices – CCC

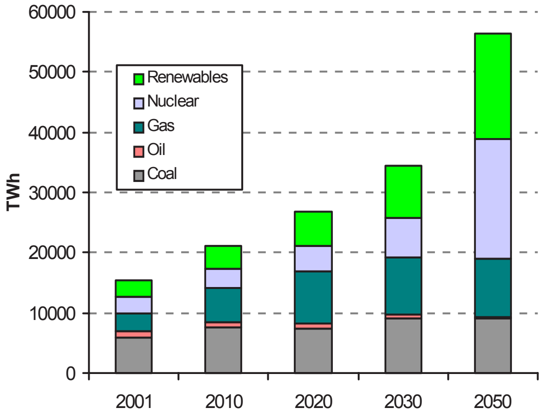


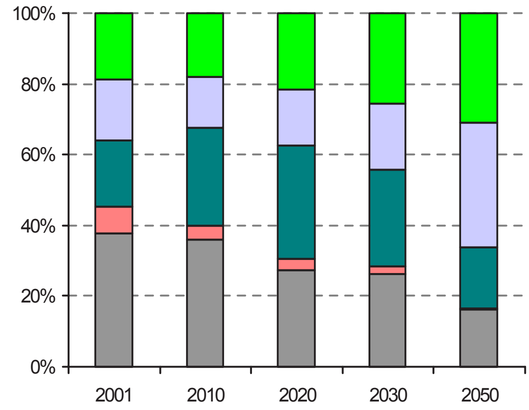
The effects of the CCC on trade of oil and natural gas are small, but international trade of coal is dramatically reduced. After 2030, the diffusion of non-fossil fuels accelerates and trade in coal falls from 600 Mtoe in the Reference case to 160 Mtoe in the CCC.

3.5 Impacts on the electricity sector and on energy conversion

The contribution and share of electricity from non-fossil sources considerably increases in the CC scenario; more than 30% of world electricity comes from renewable and almost 40% from nuclear energy, as shown in Figure 37. This implies the construction of 180 new nuclear units of 1200 MW, of which 80 units from generation 4, plus the replacement of the existing ones. Consequently, the consumption of electricity in the world falls by less than 10% as compared to the reference scenario when the stronger CO_2 emission constraint is imposed. This limited response is because electricity generation shifts to low-carbon substitutes for fossil fuels and achieves a cost-advantage in new markets, especially transport. This partially offset the increase in efficiency in the end-uses of electricity.

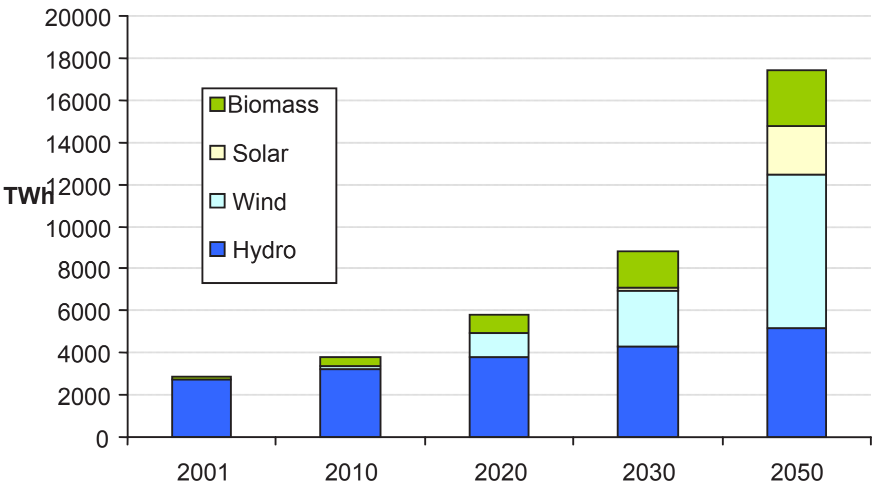
Figure 37: World electricity production – CCC





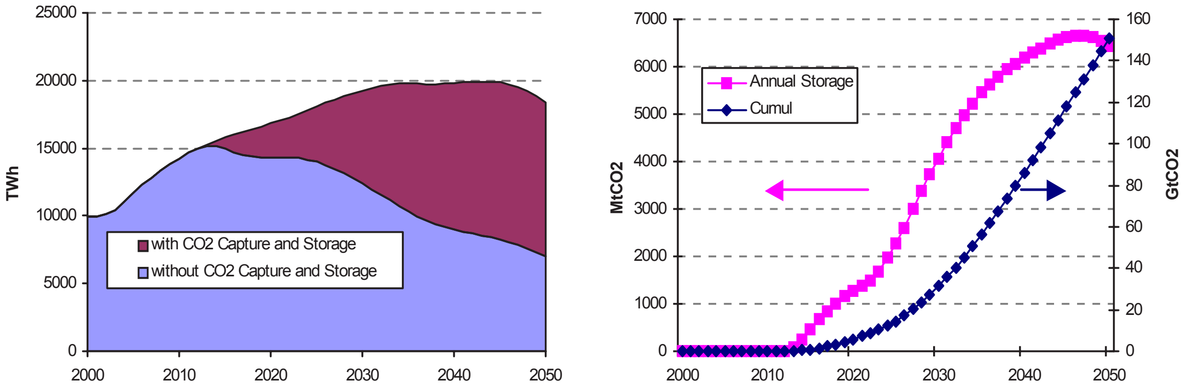
Incremental generation in renewable electricity comes mainly from biomass and wind power. In 2030 each provides about one fourth of a total that is still dominated by large hydro (Figure 38); after 2030 the share of wind-power grows more rapidly because of the deployment of offshore plants. In 2050, 42% of renewable electricity and 13% of total electricity comes from wind and the amount exceeds that from large hydro. Solar electricity begins to be appreciable from 2030; it is generated by thermodynamic power plants and by photovoltaic systems integrated into buildings. After 2040, photovoltaic systems on buildings become important and they produce three times more electricity in 2050 than the thermal systems.

Figure 38: World renewable electricity – CCC



The CCC induces more rapid development of generation in power plants with carbon capture and storage (CCS) than does the Reference case; they appear by 2015 when the carbon value reaches 25 €/tCO_2 in the Annex B countries. The share of CCS plants in thermal generation in 2050 compared to the Reference case is 62% instead of 12%. The annual storage of CO_2 is 6.5 Gt/yr, or 20% of total gross emissions. Cumulative storage by 2050 is almost eight times higher than in the Reference case.

Figure 39: World thermal electricity and carbon capture and storage – CCC



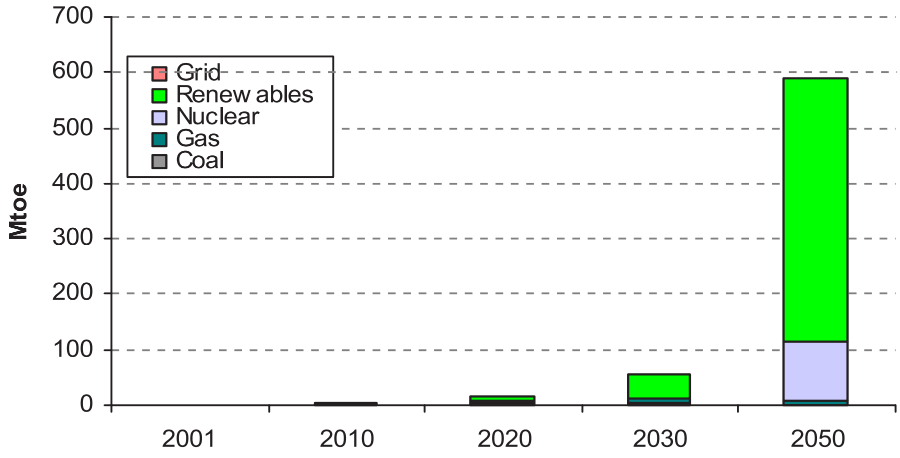
Carbon capture and storage is significant in the Carbon Constraint scenario. It is adopted in each region when the carbon value reaches approximately 25 €/tCO_2. This is the case after 2015 for Annex B regions and just before 2030 in the developing regions. With the assumptions on the costs of technology and primary fuel that characterise this scenario, the 25 €/tCO_2 is a fine trigger for the deployment of CCS.

Despite this, and unexpectedly, the annual quantity of CO_2 captured peaks in 2040. There are two reasons for this:

- In a power plant with CCS, between 10 and 20% of the CO_2 produced is not captured and is lost to the atmosphere. In high carbon value scenarios, these losses constitute a strong cost penalty that reduces competitiveness with respect to non-fossil options.
- The cost of CO_2 transport and storage infrastructure increases as more carbon is stored because the lowest cost geological options are filled first. The extra cost of the facilities reinforces the loss of competitiveness by the end of the period.

In CCC, 60% more hydrogen is produced in the world than in the Reference case. The structure of production is also altered because the production of hydrogen from fossil fuels is no longer economic despite the possibility of CCS, (Figure 40).

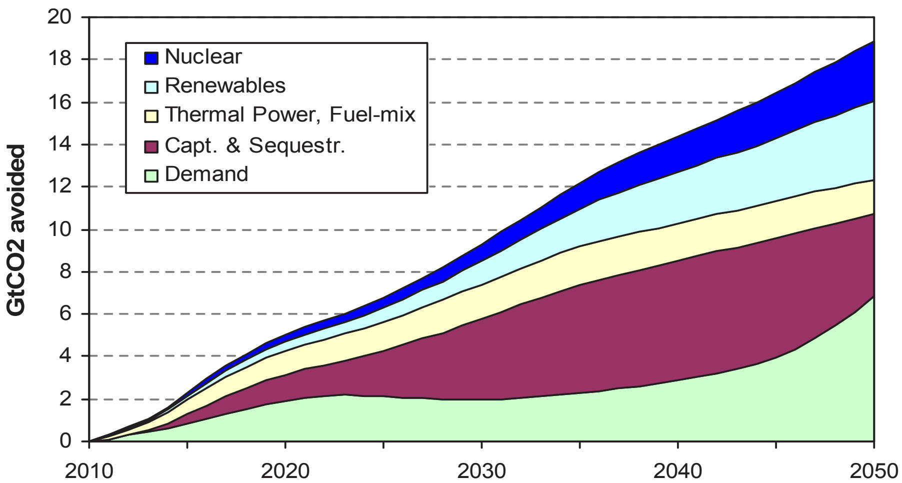
Figure 40: World hydrogen production – CCC



3.6 Responses to the carbon constraint, world level

The world energy system responds to the carbon constraint through five main options: energy-efficiency, change in fossil fuel mix, increased renewable energy, nuclear energy and carbon capture and storage. In the Carbon Constraint case, the total abatement of CO_2 in the world increases almost linearly by 0.5 $GtCO_2$ each year after 2010 and reaches a total abatement of 19 $GtCO_2$/yr in 2050. Figure 41 shows how this emission reduction from the Reference is composed from changes in: i. final demand – both energy-efficiency and fuel-mix; ii. capture and Storage; iii. fuel-mix effect in power generation; iv. nuclear and v. renewable energy.

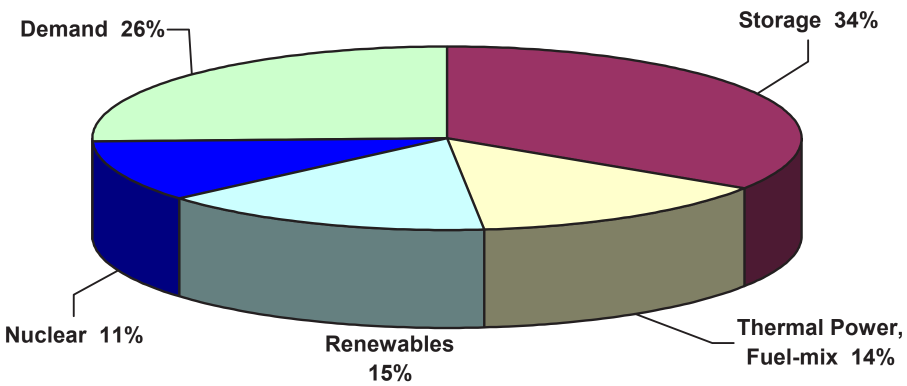
Figure 41: World CO_2 emission reductions by main option (CCC versus Reference)



The contributions of nuclear and renewable energy increase regularly over the period. A shift in the mix of fuels used for thermal power generation towards less carbon intensive fuels – mostly substitution of gas to coal – is important in the short-term, as these substitutions in many cases do not even need new investment. After 2020, their contribution to CO_2 abatement is almost stabilised. The impact of CO_2 capture and Storage follows an uneven path; after a first wave between 2010 and 2015, when the carbon value reaches 25 €/t CO_2 in Annex B countries, the adoption of CCS accelerates after 2025, when the carbon value approximates a similar level in non-Annex B countries. Between 2030 and 2040, CCS represents 4 to 5 Gt CO_2/yr, accounting for almost 40% of world emission reductions each year. Thereafter, the importance of CCS in abatement decreases both in share and in volume, because the high costs of transport and storage impair the competitiveness of the technology. Higher efficiency and a less carbon intensive mix of fuels in final use are the main options before 2020 and after 2040 when the potential for CCS is largely saturated.

When the contributions of the different options in abatement are computed over the period from 2010 – 2050, CCS has the largest share followed by changes in energy consumption, use of renewables, changes in the thermal power fuel-mix and use of nuclear energy. This ranking needs to be carefully interpreted because CCS appears to some extent to be a transitional solution and the rather small share of nuclear energy has to be assessed against the already significant development of nuclear energy in the Reference case.

Figure 42: Share in total cumulative CO_2 reductions from 2010 to 2050, world



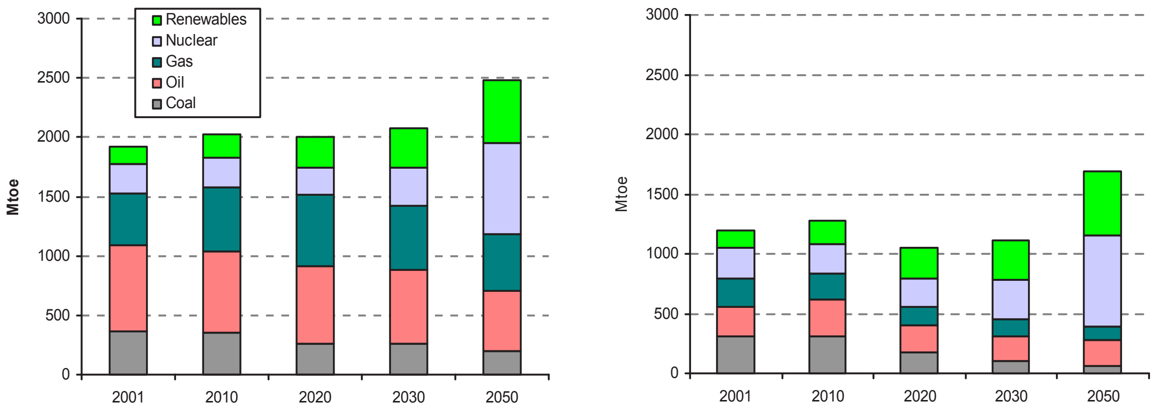
3.7 The Carbon Constraint case in Europe

The Carbon Constraint alters the pattern of energy development in Europe in several ways. The most noticeable consequence is the stabilisation of primary energy supply and final energy consumption up to 2030 at 2.0 Gtoe and 1,4 Gtoe, followed by increases of 20% and 5% between 2030 and 2050 (Figure 43 and Figure 44). The rates of growth of primary and final energy are different because of the preponderance of nuclear energy in electricity generation; the production of nuclear heat must be included in the primary energy supply and this is proportionally larger than for fossil fuels.

The share of fossil fuels in primary supply falls to 70% in 2030, compared with 80% today, but then the rate of decline accelerates and it drops to less than 50% in 2050. The volumes and shares of coal and oil drop considerably over the period. The share of natural gas, which is today more than 20%, rises to 30% in 2020, but then falls back below 20% in 2050.

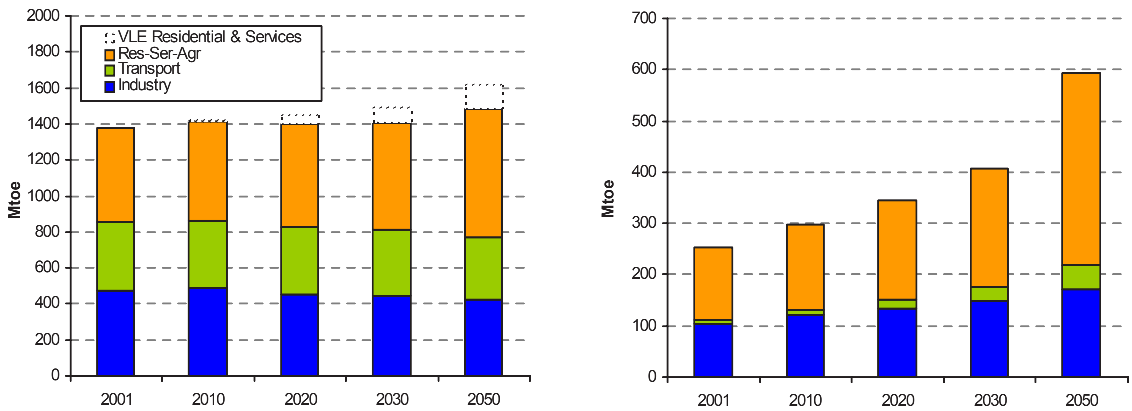
The trends in indigenous production and self-sufficiency in the CCC are similar to the Reference case, with an initial decrease up to 2030 as North Sea oil production falls away, followed by an upsurge, from renewable and nuclear power after 2030. The extent of self-sufficiency in 2050 is higher in the CCC, reaching 68% in 2050 compared with 62% today and only 60% in the Reference projection.

Figure 43: European primary energy supply (left) and production (right) – CCC



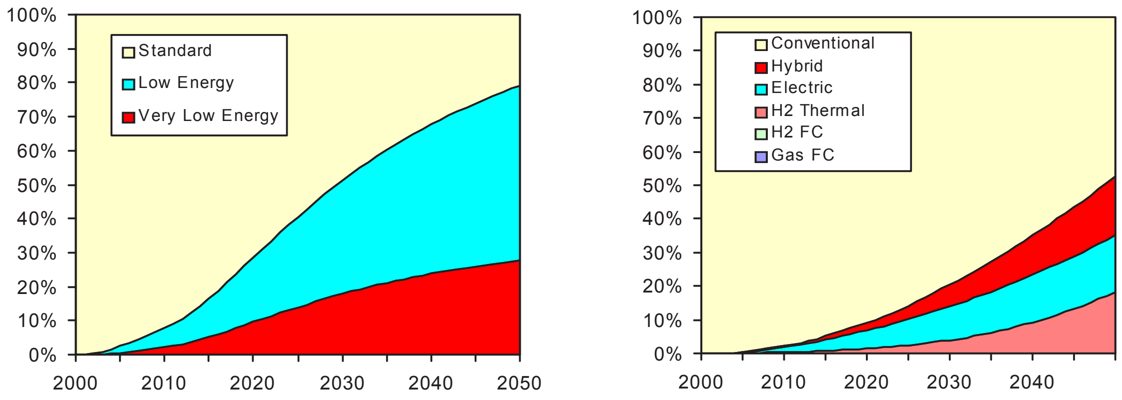
Final energy consumption is nearly stable in transport and industry, but the consumption in the residential and service sector increases towards the end of the period, despite the adoption of low and very low energy buildings. Electricity is the only carrier significantly to increase market share, partly because it substitutes for more CO_2 intensive energy carriers and partly because of demand from Information and Communication Technologies in households and services.

Figure 44: Final energy (left) and electricity by sector (right) in Europe – CCC



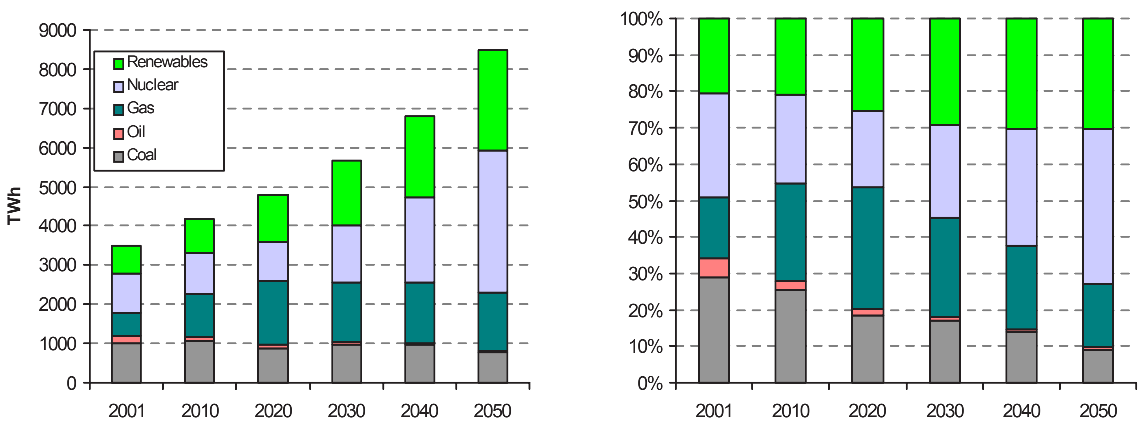
The CCC is characterised by wide diffusion of low and very low energy buildings with half of the building stock in the low Energy category by 2050, and one fourth in the very low energy category. This is a remarkable given the slow turnover of the building stock and implies substantial thermal retrofitting throughout the period. Low emission vehicles also diffuse rapidly, although the penetration by the end of the period is lower than for low energy buildings; the joint market share of for hybrid, electric and hydrogen cars is 45%.

Figure 45: Low energy buildings and vehicles in Europe – CCC



The total of electricity consumption is almost unchanged from the Reference case to the CCC, but there is a big difference in the origin of generation. Starting from a balanced fuel-mix today, the electricity sector passes through a series of structural changes. Because of the slow turnover of plants in the power system, these changes are only noticeable after 2020, despite the earlier introduction of high carbon values.

Figure 46: Electricity production and fuel-mix in Europe – CCC

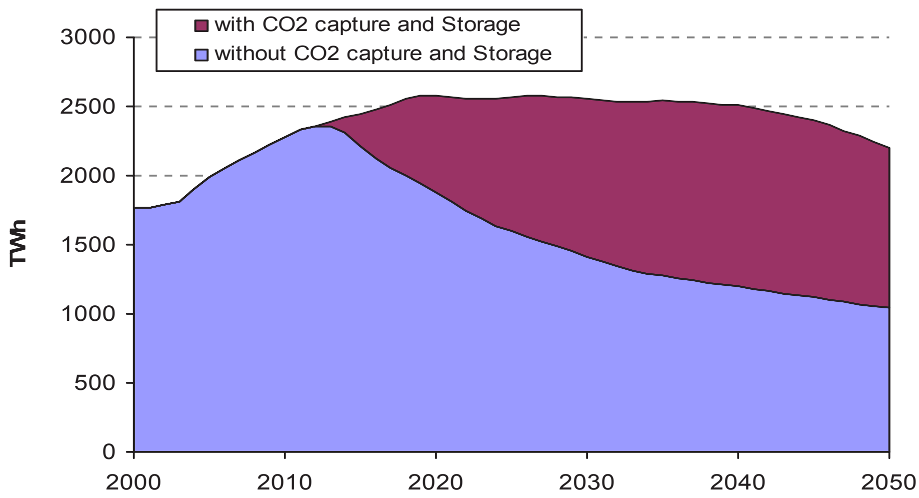


The dynamics of European electricity production are shown in Figure 46. The main points are:

- Until 2020, gas penetrates strongly into the electricity market. Use of coal, despite the carbon constraint, is stable in volume although its share declines
- Between 2020 and 2040, the volumes of generation from coal and natural gas are stable but oil almost disappears from electricity production. Of the 2 200 TWh still produced by thermal power plants in 2050 (i.e. one quarter of the total) more than one-half is produced in plants that incorporate facilities for Carbon capture (Figure 49).
- Both the absolute and relative contributions of nuclear energy reach a minimum in 2020, with the retirement of the last plants of the second generation, developed in the seventies and built in the eighties. Thereafter, nuclear generation increases rapidly as third and later fourth generation plants enter production. By 2050, the contribution of nuclear exceeds 40% of total electricity production in Europe, compared to 30% today.

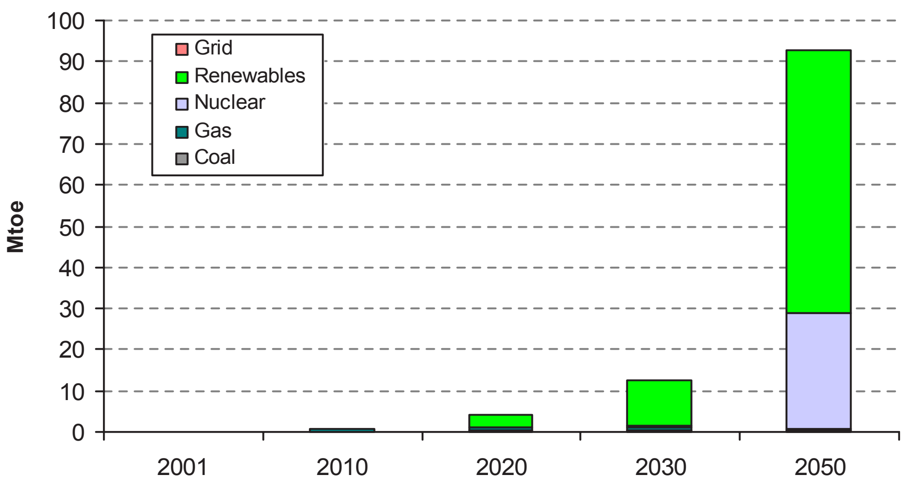
- The volume of renewable electricity grows steadily over the period; its share increases from slightly more than 20% in 2010 to 30% in 2050.

Figure 47: Thermal electricity production in Europe – CCC



The effect of the CCC on the production of hydrogen in Europe is much as for the world; production increases 50% compared to the Reference case, from 60 to 90 Mtoe; this is equivalent to 15% of electricity consumption in Europe. There is no hydrogen production from fossil fuels, despite the possibility of carbon capture and storage; in 2050, two thirds of hydrogen is produced from renewable sources and one third from nuclear.

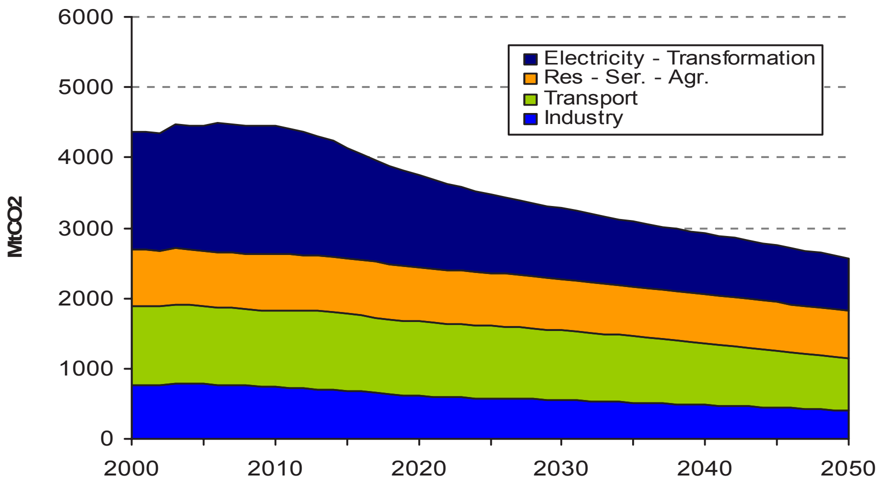
Figure 48: Hydrogen production in Europe – CCC



The combination of these structural changes in the long-term reduces emissions of CO_2 compared to 1990 levels by 50% for the EU25 and by 40% for the whole European region.

The same carbon value applies in all sectors and therefore the marginal costs of emission reduction in each sector are equal. The emission profiles in the sectors are consequently differentiated according to their specific Marginal Abatement Cost curves (Figure 49); reductions from the 1990 level exceed 50% for industry and power generation, but only 35% for transport and 20% in the residential and services sector.

Figure 49: Sectoral energy-related CO_2 emissions – CCC

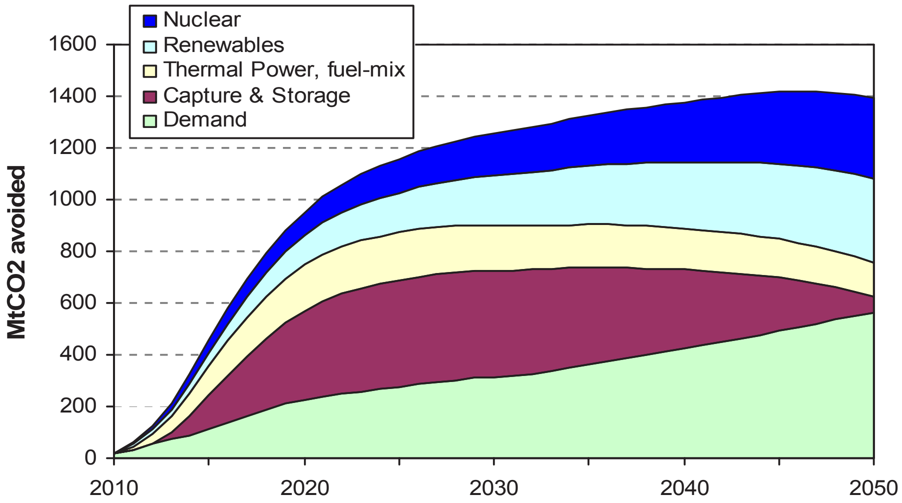


These emission profiles are aggregate results for a least-cost reduction programme in Europe as a whole, as would arise either from a uniform carbon tax or from a European market for emission quotas. In the latter case, the profiles would represent the outcome of trading, which must be distinguished from the initial allocation of quotas. The details of any allocation scheme will affect transfers within the region and across sectors, but not the aggregate profiles. The design of an allocation scheme would need to account for many different matters including industrial performance and the competitiveness of the European economy.

3.8 Responses to the carbon constraint in Europe

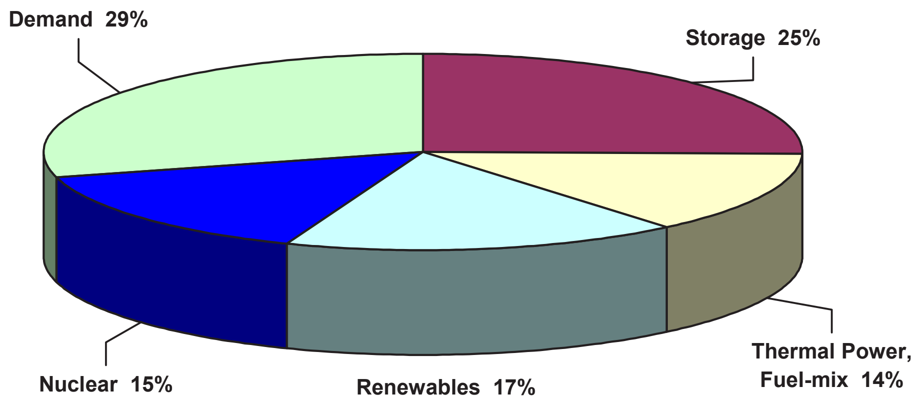
The profile of further abatement in Europe in response to the carbon constraint, over and above the abatement in the Reference case, is shown in Figure 50; it has interesting features. The volume of additional reductions initially increases rapidly to about 1 $GtCO_2$/yr in 2020, but thereafter grows only slowly and peaks shortly before 2050. Abatement from end-use options increases steadily over the period; the contribution of CCS increases before 2020 and decreases after 2030, again illustrating the important, but transitional character of this option. Changes in the mix of fuels for power generation is important in the short-term; renewable and nuclear energy are increasing deployed throughout the projection.

Figure 50: CO_2 emission reductions in Europe by main option (CCC versus Reference)



In Europe, the major part of the accumulated abatement in the 2010-2050 period is from end-use options, followed by CCS, renewables, nuclear energy and finally changes in the thermal power fuel-mix (Figure 51). The balanced outcome illustrates the fact that stringent emission reduction policies will have to combine all of the five strategic options, with the proportion of each one basically depending of its long-run marginal development cost.

Figure 51: Share in total cumulative reductions from 2010 to 2050 in Europe



KEY MESSAGES

The carbon constrained world energy system

Stabilisation of concentrations with early action in Annex B countries

The Carbon Constraint case in the WETO-H_2 study does not describe a specific EU climate policy, because this is still under definition. It simply intends to explore the consequences of ambitious carbon policies aiming at a long-term stabilisation of CO_2 concentrations in the range of 500 to 550 ppmv. The CCC recognises that Annex B countries have a greater historic responsibility and more capacity to combat climate change than developing countries. It is assumed that they adopt “early action” policies, represented by Carbon Values that increase rapidly to 200 €/tCO_2 in 2050. More time is allowed for Non-Annex B countries and this delayed effort is represented as a trajectory of Carbon Value that catches-up with Annex B only in 2050.

A “Factor 2” reduction in Europe

Global emissions in CCC are stable between 2015 and 2030, but fall thereafter. By 2050 they are 25% more than in 1990. The onset of the stabilisation and falling stages correspond to the crossing of the threshold of 25 €/tCO_2 in Annex B and non-Annex B countries. The threshold is crossed just before 2015 for Annex B and before 2030 for Non-Annex B regions. In the EU25, emissions in 2050 are half the 1990 level; on average they fall by 10% for each decade. More stringent policies, such as Factor 4, should be examined, but will require radical structural changes.

An accelerated development of non-fossil fuels

By 2050, primary energy supply in the world is reduced from 22 Gtoe in the Reference case to 19 Gtoe in the CCC. Part of the improvement in final energy efficiency is masked in these figures by the high contribution of nuclear energy (with higher primary heat input than fossil fuels). Because of the early action in Annex B, the primary fuel mix changes rapidly after 2010 and by 2050 the structure is much altered; renewables and nuclear each provide more than 20%. In contrast to the resurgence of coal that is observed in the Reference case, coal consumption in CCC stagnates, despite the availability of carbon capture and storage technologies.

Lower demand and lower international prices for fossil fuels

The carbon constraint affects the oil production profile; “peak oil” occurs earlier and at a lower level of production. In turn, this gives lower international prices for oil and natural gas; 25% lower for oil and 10% for gas. This finding indicates that the CCC leads to a more sustainable management of non-renewable resources.

The decarbonisation of electricity production

Electricity consumption in the CCC is only 10% less than in the Reference case, because the increasingly low-carbon electricity substitutes for more carbon-intensive carriers. In 2050, renewable sources provide 30% of electricity generation and nuclear electricity nearly 40%. The revival of nuclear is rapid in Annex B countries after 2020.

Impacts on carbon capture and storage and Hydrogen

Carbon capture and storage displays a surprising profile with a peak in 2045 equivalent to 20% of gross emissions of CO_2, followed by a decline. The decline is caused by the cost penalty of residual CO_2 emissions from CCS facilities and by the increasing cost of storage as the cheapest options are filled. By 2050, cumulative storage is already 6 times current annual emissions. Hydrogen production is stimulated by the carbon constraint and is 60% higher than in the Reference case, but the origin of production changes radically. Because of the high Carbon Value, technologies using fossil fuels such as steam methane reforming and coal partial oxidation are no longer cost-effective.

The carbon constrained European energy system

An enhanced energy self-sufficiency for Europe

In Europe, the total of primary energy supply is almost stable until 2030, but then increases, largely because of the high primary heat input of nuclear power. Primary production decreases until 2025, tracking production from the North Sea, but then increases again as nuclear and renewable power generation become economic. After 2020, the “energy self-sufficiency ratio” begins to rise and by 2050, two thirds of the energy consumed in Europe is indigenous. Total final consumption is almost stable throughout the period, because increases in the residential-service sector compensate for reductions in industry and transport. Electricity consumption increases steadily, noticeably in transport.

The importance of very low energy end-use technologies

The CCC assumes a high carbon value and consequently provokes structural change compared to the Reference case. The main changes are in the adoption of low energy buildings and low emission vehicles. By 2050, one-half of the total building stock is composed of low energy buildings and one quarter of very low energy buildings. More than one-half of vehicles are low emission or very low emission vehicles.

A deep decarbonisation of power and hydrogen generation

Renewable sources provide 22% and nuclear 30% of Europe’s total primary energy supply, allowing fossil fuel to be less than 50% of European supply in 2050 - a major achievement. Three quarters of power generation is based on nuclear and renewable sources, while carbon capture and storage covers half of remaining thermal power generation. Hydrogen delivers energy equivalent to 15% of that delivered by electricity, based on non-fossil sources.

The necessity of combining all zero or low CO_2 options

The Carbon Constraint case describes a Factor 2 scenario for Europe in a consistent world context. It shows that ambitious climate policies increase the long-term sustainability of world oil and gas resource use and enhance energy self-sufficiency in Europe. It also demonstrates that ambitious CO_2 emission reduction policies require an intensified development of each of five critical clusters of energy technologies: energy-efficiency, renewable energy, nuclear power, changes in thermal power fuel-mix and carbon capture and storage.

CHAPTER 4 TOWARDS A HYDROGEN ECONOMY

The Reference projection described in Chapter 1 shows that the world faces a hard challenge to create energy systems that are secure, that limit climate change and that permit sustainable development. New energy technology will be a vital part of the response.

Hydrogen is often proposed as a future energy carrier. An objective of the WETO-H_2 project is to design and evaluate alternative technological and socio-economic pathways to illustrate possible ways of incorporating hydrogen into the global energy system.

Design and analyse of such pathways leads to a better understanding of the mechanisms that might trigger the use of hydrogen as an energy carrier in parallel with electricity, oil products and natural gas. These triggers might be technological, economical, environmental or political. The objective of this study is not to determine their pre-requisites, but simply to identify the initiating mechanisms for coherent technological clusters, described as pathways, in such a way that the fulfilment of a minimum set of conditions would facilitate the development of a specific path towards the so-called "*hydrogen economy*".

The conceptual construction of these pathways requires a categorisation that may be to some extent arbitrary. The concept of "*hydrogen economy*" itself, interpreted as a technico-economic steady state, is unclear since we can imagine alternative specifications for such a system. Therefore, the defined pathways are characterised not only by a given path, but also by a long-term stable technico-economic regime, as well as by the speed of penetration of the hydrogen technologies into the market.

Section 3.1 presents the state of technology in the different stages of the hydrogen chain from production, through transport and storage to use. It examines also the extent of commercialisation and the prospects for R&D of hydrogen technologies. Section 3.2 provides a qualitative and quantitative description of the practical hydrogen pathways considered in this study. In Section 3.3, the necessary technology breakthroughs for the hydrogen pathways are presented as well as the conditions under which these breakthroughs can materialise. Finally, Section 3.4 discusses the consequences of the technological breakthroughs and pathways on the deployment of hydrogen in Europe and in the world and the changes with regard to energy demand and related CO_2 emissions.

4.1 State of hydrogen technology

Hydrogen is the most common element in the universe but, on earth, it does not exist in significant quantities except in combination with other elements. It is combined with oxygen in water and with carbon in natural gas, oil, coal or biomass. Hydrogen has been produced and used for industrial purposes for over one hundred years. The largest producers of hydrogen are the chemical and petroleum industries.

'Hydrogen energy'[27] does not yet exist; the introduction of hydrogen as an energy carrier will be an enormous and continuing task, but concerns about climate change and energy security have brought hydrogen to the forefront of energy research and policy worldwide, especially in Europe. The transition to a hydrogen economy faces many technical, economic and social challenges in production, distribution and storage infrastructure, conversion and final use. This chapter describes the present state of the art of the principal hydrogen technologies and the strategy of stakeholders with respect to the different stages of the hydrogen chain.

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[27] I.e. Hydrogen used as an energy carrier like electricity or as a transport fuel like diesel and gasoline.

4.1.1 Production of hydrogen

There are no natural deposits of hydrogen on earth; it needs to be produced from other energy sources. Hydrogen in nature is strongly bonded to other elements; these bonds must be broken to produce elemental hydrogen and this takes considerable energy. There are several ways of doing this; some processes are already in commercial use while others are being developed or still under research. Hydrogen can be produced from a diverse array of feedstocks, including water, using electricity or by thermal processes. Hydrogen is produced today from steam reforming of natural gas (or LPG), by gasification of coal and heavy fuel oils or by electrolysis of water.

Other production technologies are being researched. Photoelectrolysis proceeds by the direct conversion of sunlight into hydrogen. In photobiological processes, hydrogen is produced as a by-product of the metabolism of organisms[28]. In thermochemical processes water is decomposed into hydrogen and oxygen at high temperature; the necessary heat can come from nuclear or solar energy.

Based on a detailed survey of many studies of hydrogen production, five hydrogen production technologies or group of technologies have been selected and included in the POLES model, they are: steam reforming of natural gas; gasification of coal; gasification of biomass; electrolysis of water and thermolysis. These technologies are considered the most representative and promising for large-scale hydrogen production over the next fifty years. Each technology is briefly described below including its performance in terms of costs, emissions, feasibility, scale and logistics.

Steam reforming of natural gas

In this process, natural gas is reacted with steam at high temperature (700-1000 °C) in the presence of a catalyst to produce hydrogen, carbon monoxide and carbon dioxide. A subsequent water gas shift reaction between carbon monoxide and steam increases the amount of hydrogen and converts most of the carbon monoxide to carbon dioxide. The carbon dioxide is then separated from the mixture by an absorption or membrane process giving moderately pure hydrogen.

Steam reforming of natural gas is at present the lowest cost route to hydrogen and the most common method in commercial use. The process could be used in conjunction with the existing natural gas infrastructure to produce hydrogen where it is to be used. Steam reformers are well understood and easily scaleable. Hydrogen produced in large plants with capacities between 20 000 Nm^3/h and 350 000 Nm^3/h may be distributed either as a compressed gas by pipeline and in trucks or as liquefied hydrogen in trucks. Many decades of operation in industrial installations have demonstrated an excellent safety record for these production and transport systems.

Small-scale reformers, in capacities from 100 to 20 000 Nm^3/h, can be located close to the point of use. In this case, hydrogen would probably be distributed as gas. Liquefying hydrogen at small-scale steam reformers is technically feasible, but is costly and needs a lot of space. Small-scale reformers suitable for hydrogen production at hydrogen filling stations are either downscaled large systems or auto-thermal reformers - a combination of gasification and steam reforming that is more compact, but has a slightly lower efficiency. In recent years, the cost of small-scale steam reformers has fallen and the reliability and efficiency have improved. Most commercial plants are purpose-designed; series production has not yet been established.

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[28] The EU projects “SolarH” and “BioHydrogen” support research in these areas.

Because of the scalability, hydrogen production from natural gas is an interesting option for transport applications. Large and medium scale production plants are suitable for large fleets of road vehicles, for air and ship transport and for trains. Decentralised plants are suitable for filling stations for passenger cars, for small fleets of road vehicles and for trains. Hydrogen production from natural gas is not suitable for applications with a very low hydrogen throughput.

Reforming depends on the availability of natural gas. This means that the plants should be located close to natural gas pipelines with adequate capacity, or on sites where LNG can be made available in sufficient quantity. The European Union is particularly well placed in this respect with its widespread natural gas pipeline network and the projected development of LNG facilities. In the long-term, beyond 2030-2040, restricted supplies of natural gas will limit its potential as a main source of hydrogen fuel for transport. The current natural gas consumption in the EU is close to the current consumption of road transport fuels; it is doubtful that incremental gas will be able to compensate for the projected decline in oil products.

Another disadvantage of making hydrogen from natural gas is that the process emits CO_2. Well-to-Tank emissions[29] of greenhouse gases (essentially carbon dioxide) from this route are estimated at 90 to 150 g/MJ[30]. Because of economies of scale and logistics related to the transport and storage of CO_2, carbon capture and storage (CCS) systems are only feasible for large-scale hydrogen production plants.

Finally, the comparative advantage of steam reforming depends on the final use of the hydrogen. For instance, the proton exchange membrane fuel cells (PEMFC) that is most suitable for transport is sensitive to impurities in the hydrogen fuel, especially to sulphur and carbon monoxide (CO). Sulphur is found in coal and hydrocarbons and carbon monoxide is a by-product of steam reforming. Hydrogen from reforming intended for use in PEMFC must be processed further to remove carbon monoxide. This is not required when hydrogen is used in internal combustion engines or solid oxide fuel cells that are rather insensitive to CO.

Steam reforming of natural gas is at present the cheapest way of producing hydrogen. With a price of gas between 2 and 4 €/GJ, the cost of hydrogen from large-scale plants is from 5 to 8 €/GJ. These figures do not include carbon capture and storage (CCS). CCS would add about 20% to the cost[31]. The cost of production also depends on the size of the reformer; according to the Institute for Energy and Environment [IE, 2004], the ratio of costs from a small-scale (1 000 Nm^3/h) and a large-scale (150 000 Nm^3/h) steam reformer is between 2 and 3 (without carbon storage).

Steam reforming of natural gas is not only the cheapest way of producing hydrogen today, but also at present prices it would also be the most cost effective path for supplying hydrogen to passenger cars in an established market. The cost of supplying compressed gaseous hydrogen to a car (i.e. the well-to-tank cost) depends on both the production and distribution concepts. In a well-established market, large-scale natural gas reforming with pipeline transport to the filling stations is the most cost effective option. Provided that the filling

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29 I.e. emissions resulting from the production and distribution of a transport fuel to the point of use (hydrogen, diesel, etc.). The emissions related to the use of the fuel in a vehicle are referred to as Tank-to-Wheel emissions.

30 The lower figure corresponds to the production of gaseous hydrogen from the reforming of the mix of natural gas in the EU in central plant and to the delivery by pipeline to the filling station for onboard storage pressure of 70 MPa; the upper figure assumes the production of liquid hydrogen from the reforming of natural gas in central plants and the delivery by truck to the filling station.

31 The figure holds for a hydrogen plant capacity of 150 000 Nm^3/h [IE, 2004]. These costs correspond to gas prices before the high rises in 2005 (present price are around 6€/GJ).

stations are within a radius of 50 km of the production plant and the production of hydrogen is 180,000 toe per year, then the cost of supply is estimated to lie between 14 and 18 €/GJ (without CO_2 capture and storage). For longer distances, the costs will rise considerably. Production of hydrogen on site is more expensive (19-22 €/GJ) and delivery of liquid hydrogen from a central plant would be about 25 €/GJ.

To provide perspective, the production cost of distillate motor fuels at present is between 5 and 7 €/GJ, but the final price for European consumers, including taxes, is around 1 €/litre, i.e. 30 €/GJ.

Coal gasification

Partial oxidation, or gasification, is a process that decomposes a solid carbonaceous feedstock into gases and a residue. In a modern gasifier, coal reacts with steam at high temperature and pressure with controlled amounts of air or oxygen. Under these conditions, water is decomposed to hydrogen and the carbon in the coal is converted to carbon monoxide and carbon dioxide. To increase the proportion of hydrogen, the gaseous product may then be subjected to the water-gas shift reaction whereby carbon monoxide and steam are converted to carbon dioxide and hydrogen. The hydrogen is then separated. Within this class of process there are three distinct concepts; two exclusively produce hydrogen and the third produces both hydrogen and electricity.

The first concept is the conventional large-scale system using wet gas cleaning. Of the gasification systems in use in conventional facilities, the entrained flow bed gasifier is the most suitable for hydrogen production because it has a higher carbon conversion and higher hydrogen yields than the fixed-bed or fluidised-bed gasifiers.

The second concept, for the medium and long-term is an advanced large-scale systems using hot gas cleaning and membrane separation technology. The gas cleaning takes place at a temperature of about 350 to 650ºC. The hydrogen separation is more efficient than in the conventional wet gas cleaning process: neither water-gas shift converters nor further purification steps are needed. However, this concept is still at the research and development level.

The third concept is polygeneration of hydrogen and electricity based on the Integrated Gasification Combined Cycle (IGCC). The process resembles conventional gasification, but integrates a combined cycle gas turbine to generate electricity. IGCC systems are already commercially available in capacities from 200 to 800 MW_e. Although based on a well-known technology, the combined production of hydrogen and electricity still requires technological improvement. A commercial polygeneration system may be available between 2015 and 2020. The polygeneration concept also offers the prospect of flexible operation that can shift the balance of output between hydrogen and electricity and allow fossil fuel power generation better to adapt to a large penetration of intermittent renewable sources in the future.

Coal gasification is a promising option for hydrogen production, but mainly in large plants. Existing conventional systems have a capacity of about 130 000 Nm^3/h of hydrogen and over. The high complexity of the technology and the integration of carbon capture and storage systems make small-scale production plants unattractive on both economic and environmental grounds. There is a need for R&D to overcome these problems. The priorities are: to down-scale the gasifier; to improve the heat transfer after the gasifier; to improve the gas cleanup; to achieve more favourable gas composition; to improve the combustion in gas turbines; to improve the waste water treatment and the air-separation processes. For these reasons, small-scale production of hydrogen from coal is not considered in this study.

The availability of coal will not limit the potential for coal gasification for some decades. World coal reserves will last for several centuries, but coal production in Europe is expected to decline, making the region depend on imports. There might be concern that this dependence will impair security of the EU energy supply; the concern should be allayed by the relatively uniform distribution of coal resources in the world and the historical evidence of stable prices on the world market for coal.

A second potential constraint on coal gasification is that it emits large volumes of carbon dioxide. If climate change is a constraint then, hydrogen production from coal is only environmentally viable in combination with carbon capture and storage. It is interesting to compare the Well-to-Tank emissions[32] of the coal-based hydrogen to those from steam reforming of natural gas. Hydrogen production from coal emits between 50 and 250 g/MJ depending on the level of CCS (see 4.1.2). The emission from steam reforming of natural gas is 90 g/MJ without carbon capture and storage.

Finally, as with steam reforming, partial oxidation of coal produces impurities of which the most significant are sulphur and carbon monoxide; these must be removed if hydrogen is used in proton exchange membrane fuel cells (see infra).

Based on a coal price of 1.5 €/GJ, the cost of producing hydrogen on a large scale by the gasification of coal without carbon capture and storage is between 8 and 10 €/GJ[33], depending on the technology. CCS will increase the cost by up to 20% [Tzimas and Peteves, 2005]. The cost of supply to the user is estimated at 19 to 21 €/GJ if filling stations are within 50 km of the production plant. Methane and other hydrocarbons can also be partially oxidised to make hydrogen; the production cost is higher than for either the gasification of coal or the steam reforming of natural gas.

According to IE [2004], the capital costs of the conventional and advanced systems at large scale are similar, but the operation and maintenance (O&M) costs are 50% higher for the advanced concept. Carbon capture and storage will increase the capital cost of the conventional system by about 15% and the O&M costs by 80%; comparable figures are not available for the advanced concept. Costs for polygeneration are significantly higher than for the hydrogen-focused concepts; the ratio of costs is approximately 2.5 for both capital and O&M costs. The cost penalty of CCS is less dramatic; it is about 6% on the capital cost and about 50% on the O&M costs.

Biomass gasification

Biomass is an important option for substituting for fossil fuels. The principal advantage is that over the cycle of growth and use there is no net emission of carbon dioxide. Biomass can in principle be gasified the same way as coal. A wide variety of biomass sources can be used to produce hydrogen (e.g. wood, forestry by-products, straw and municipal solid waste) and the dispersion of these sources may permit hydrogen production plant to be at or near the point of use, with the possibility of reducing costs.

Biomass is a more complex and variable feedstock than coal and the process of gasification needs to be adapted accordingly. The high content of volatile material (about 80% compared to 30% for coal) and the low density of biomass compared to coal will influence the design of the reactor. The problems with the volatile components can be managed in a two-step

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32 Reported emission figures assume the delivery of gaseous hydrogen by pipeline to the filling stations.

33 The figure holds for a hydrogen plant capacity of 150 000 Nm^3/h [IE, 2004]

gasification process. In the first step, the biomass is pyrolysed in the absence of air, producing pyrolytic oil and water. The pyrolytic vapours are then reformed with steam to produce a hydrogen-rich gas. The process can be implemented in a single reactor (with a fixed or fluidised bed) or in a two-stage reactor, depending on the nature of the biomass raw material.

An advantage of the two-step biomass pyrolysis/gasification process with respect to the single-step gasification process is that the pyrolysis can be performed on a different site from the gasification. Pyrolytic oil would be produced close to the biomass resources and then transported to the hydrogen consuming sites for gasification.

Gasification of biomass offers some important potential advantages over gasification of fossil fuels, such as a high concentration of hydrogen in the gas produced, but there are many problems associated with the complex chemistry and wide range of properties of the feedstock. The currently achievable quality of raw gas is below the requirements for hydrogen supply although it is adequate for electricity generation. Even with the best-controlled and most favourable feedstock, a gas cleaning/conditioning system is essential for hydrogen production. The technical complexity of the gas cleaning means that larger-scale operation is needed for hydrogen production that for power generation. Only biomass gasification for hydrogen production on a large scale is at present conceivable.

At present, biomass gasification systems are designed and operated to produce raw gas for heat and power production. No system available in Europe is technically mature and run under commercial conditions for hydrogen production. There is a large potential for process optimisation, research and development. Many of the research and development issues are similar to those in coal gasification. High temperature gas processing, including reforming of hydrocarbons and the optimisation of the water-gas shift need to be further investigated.

Beyond 2020, overall efficiencies up to 65% could be expected. Co-production of hydrogen and electricity in an IGCC system could have similar advantages to those described for coal gasification.

The hydrogen production costs of the one and two-stage processes are similar. Present estimates lie between 9 and 12 €/GJ, with a slight advantage for the two-stage route. Both the investment costs and the cost of the feedstock are uncertain. The investment cost is uncertain because there is no commercial process of hydrogen production for biomass gasification and because there is a high potential to reduce costs as the technology matures that is hard to assess. The cost of the feedstock dominates the variable costs and varies widely depending on the type of biomass and its availability. Improved processes with higher conversion efficiency have a potential to reduce the part of feedstock costs in the whole, but this tendency may be partially offset by additional costs for biomass pre-processing. Based on these expectations, the cost of hydrogen from gasification of biomass would not be competitive with most concepts using fossil fuels and CCS (see supra) assuming fossil fuel prices at current levels.

Electrolysis of water

Electrolysis of water is the decomposition of water into hydrogen and oxygen by passage of an electric current. Hydrogen gas collects at the negative cathode and oxygen gas at the positive anode. After steam reforming of natural gas, electrolysis of water is the most common method of hydrogen production and many years of industrial operation have demonstrated excellent safety. Electrolysis is easily scalable; units with capacities from 1 kW_e (corresponding to a hydrogen production of about 250 Nm^3/h) to 150 MW_e (35 000 Nm^3/h) are commercially available.

During the last 10 to 15 years, electrolysis has made significant technical progress; efficiency has been improved and operation has been achieved with fluctuating power input (e.g. wind electricity). A trend to higher pressures can also be observed; new electrolysers are typically operated at between 1 and 3 MPa in order to avoid the first compression stage for hydrogen transport. Advanced technologies promise improved performance and simplified maintenance, but have not yet demonstrated long periods of operation.

Recently, research and development efforts have focused on advanced electrolysers of MW-sized units and on small-scale units for producing hydrogen on site. These small-scale units are between 130 and 270 kWe power input (i.e. 30-60 Nm^3/h capacity range) and over the last five years have become more reliable. The major advantage of producing hydrogen on site compared to large-scale production schemes is that it eliminates the need for hydrogen transport. Based on the above small-scale developments, several manufacturers are investigating electrolysis systems for hydrogen refuelling stations to supply compressed gaseous hydrogen to road vehicles and other mobile applications.

The main disadvantage of water electrolysis is that it requires large amounts of electricity. Efforts are being made to increase the efficiency and reduce electricity use. For instance, electrolysers operated at temperatures between 700 and 1000°C and at high pressure are more efficient, but work on these systems is still at the R&D stage.

The benefits of water electrolysis, compared to the thermo-chemical conversion of primary energy, are the lower capital cost and the modular nature. Electrolysers can operate without loss of efficiency at almost any scale and can be adjusted to the hydrogen demand and to the electricity supply. Another advantage is that the process gives very pure hydrogen. This is important when hydrogen is used in Proton Exchange Membrane (PEM) fuel cells that are sensitive to the small quantities of CO present in hydrogen produced from biomass or fossil fuels. The production by electrolysis, although more expensive than other routes, avoids additional costs at the fuel cell.

The cost of hydrogen production by electrolysis is dominated by the cost of electricity; this is around 30% of the total production cost using coal and nuclear electricity and up to 80% using offshore wind. Electrolysis is only economically feasible where electricity can be generated cheaply, for example from off-peak electricity from the grid or when there is excess electricity production from intermittent wind or solar sources. Nitsch [2003] and the IE [2004] have estimated the production cost of hydrogen by electrolysis from a plant with a capacity of 1000 Nm^3/h and 20 years technical life. They calculate a cost of about 22 to 25 €/GJ using base load electricity from coal or nuclear, at about 30-50 €/GJ using wind electricity and between 90 and 450 €/GJ for more costly renewable sources (e.g. photovoltaics and high temperature solar thermal generation)[34].

The emissions of greenhouse gases from electrolysis depend upon the source of the electricity used. If the electricity is from nuclear or renewable sources, then the hydrogen is free from emissions. If the electricity is from fossil fuels, then the CO_2 emissions will be significant. Consequently, the Well-to-Tank emissions of greenhouse gases can lie within a wide range. The range starts close to 0 g/MJ, when gaseous hydrogen is produced by electrolysis on site using wind-based electricity, and goes up to 240 g/MJ, for hydrogen from central electrolysis plant using electricity generated from the EU fuel mix, liquefied and then delivered by truck to filling stations.

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[34] The estimates are based on anticipated improvements in stack design combined with higher efficiency.

Thermolysis and thermo-chemical cycles

When water is heated to above 2500 °C it decomposes into hydrogen and oxygen. There are severe materials problems in working at this temperature. The process temperature can be reduced by combining the direct decomposition with electrolysis or with a chemical cycle. The combination with electrolysis is known as steam electrolysis or high-temperature electrolysis. The advantage of the process over conventional electrolysis is that some of the energy needed to split the water is added as heat instead of electricity, the heat may be cheaper than electricity and this reduces the cost.

Thermolysis can also be coupled with chemical reactions in order to split the water at lower temperatures. Intermediates are added to the water to facilitate the splitting; they are consumed in the process, but can be recovered and regenerated and reused. The series of reactions is referred to as a thermo-chemical cycle[35]. There are many possible water-splitting cycles, but only few are more efficient than electrolysis. Research efforts focus on the development of low cost and high efficient processes that are commercially viable.

The sulphur-iodine (S-I) cycle is promising; it requires temperatures above 850°C, but offers high efficiency. In thermo-chemical cycles the chemical reactions scale by volume, whereas in electrolysis they scale rather by surface area; therefore economies of scale favour the thermo-chemical route. It has been proposed to achieve large-scale production using heat from a nuclear reactor. The process is being researched and developed in Europe[36], Japan and the United States.

Another promising cycle is the ZnO/Zn process; this is suitable for solar heat because it does not require high temperature gas-separation and has an energy conversion efficiency of about 29%. As with other thermo-chemical cycles, the ZnO/Zn process requires handling copious streams of solid materials. Further development work is currently focused on solar chemical reactor modelling and on designing a better quench method for recovering Zn.

Hydrogen production from solar thermolysis is still at an experimental stage, but according to the available literature and information from well-reported projects, the capital cost would be around 3 500 €/kWh. Learning effects and technological spillovers might diminish this figure. Such a capital-intensive technology would give high costs for the production of hydrogen, above 50 €/GJ.

4.1.2 CO_2 capture and storage (CCS)

When hydrogen is produced from coal, oil or natural gas, carbon dioxide is emitted and must be managed. Carbon capture and storage (CCS) is one option; it is a process by which carbon dioxide is separated and stored indefinitely. The requirement is similar for both hydrogen production and electricity generation. It is likely that in the first phase, hydrogen will be produced mainly from fossil fuels; CCS is therefore important for a hydrogen economy. CCS is challenging in terms of cost, potential, reliability and safety; these topics are the subject of R&D projects financed notably by the 5th and 6th EU Framework Programmes.

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35 There are other technologies under research with aim to reduce the temperature, e.g. hybrid thermal/electrolytic decomposition processes, direct catalytic decomposition. However, they are still at a very early stage of development.

36 For instance, the European HYTHEC research project under the 5th EU framework programme is devoted to the S-I thermo-chemical cycle.

Hydrogen and CO_2 can be separated by chemical solvent scrubbing, physical solvent scrubbing, absorption, membranes, cryogenics, chemical looping combustion and ceramic membrane separation. In pre-combustion capture and in steam reforming of natural gas, the water-gas shift reaction generates a hydrogen-rich synthesis gas and a quite concentrated CO_2 stream at high pressure from which the CO_2 can be easily extracted. There are established chemical processes for this and advanced concepts with reactive membranes are being developed. Economies of scale are significant and the separation of CO_2 is only efficient in large-scale centralised units providing hydrogen in large amounts (see supra).

CO_2 abatement from 70% and 90% can be achieved for steam reforming of natural gas. For coal gasification it is about 90%. Use of CCS reduces Well-to-Tank GHG emissions from 250 g/MJ to about 50 g/MJ for hydrogen produced from coal, and from 90 g/MJ to about 30 g/MJ for hydrogen produced from natural gas.

Once captured, the CO_2 must be stored permanently. Possibilities include: geological storage (i.e. injecting CO_2 into empty underground coal, oil or gas fields or into saline aquifers); ocean storage (although there is great uncertainty as to the storage time and environmental impact of this option) and mineral and biological storage (combining chemically CO_2 with naturally occurring minerals such as magnesium silicate). Geological storage potential has been assessed in the US, Canada and Australia and is being assessed in the EU.

Studies suggest that CCS would increase the hydrogen supply costs at filling stations by 25 to 30%; some studies indicate even higher costs. The cost of the fuel is the principal component in this extra cost when hydrogen is produced from natural gas while the capital cost is the most important component when hydrogen is produced from coal.

4.1.3 Hydrogen transport and distribution

Besides the technological, economic and environmental challenges related to the production of hydrogen, the transition to a hydrogen economy requires solutions for the transport and distribution of hydrogen from centralised production sites to points of use. The transport and distribution of hydrogen is especially important when hydrogen is produced in large centralised plants. When hydrogen is produced on site (e.g. at filling stations) the transport and distribution of hydrogen is less important; in this case, the energy flow to make the hydrogen comes from the existing distribution infrastructures for natural gas or electricity.

Hydrogen is transported either as a compressed gas (CGH_2) or as a liquid (LH_2). The energy-to-mass ratio of hydrogen is quite high[37], but its energy content per unit volume is modest[38], so it must either be compressed or liquefied to transport, as well as to be a practical fuel for mobile applications. Compression and liquefaction require substantial energy and this affects the economics of hydrogen use.

Hydrogen can be transported and distributed safely with available technology. Steel bottles and pipelines have been use to transport gaseous hydrogen for more than half a century with excellent safety records. Hydrogen has been liquefied on an industrial scale since the 1960s when large liquefaction plants were built in the US and in Europe for the space programmes. Cryogenic tankers for the transport of liquid hydrogen by road have been developed recently and some already operate in Europe.

Despite this experience, the introduction of hydrogen on a large scale in energy systems poses new challenges and requires significant R&D (e.g. for materials) to solve technical problems, to reduce costs and to ensure safety. There is an active European research

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37 0.11 GJ/kg compared to 0.045 GJ/kg for natural gas.

38 0.01 GJ/m3 compared to 0.036 GJ/m3 for natural gas.

programme among industry and research institutions. The NaturalHy research project[39], financed by the European Commission, is seeking to identify the critical limits of a system in which hydrogen is distributed mixed with natural gas in existing pipeline networks and then separated at the point of use. The project involves European gas companies and gas research institutes. The system would permit a smooth and short-term introduction of hydrogen at relatively low cost by using the existing widespread natural gas network. It would avoid huge investments in new pipelines dedicated to hydrogen. European research also addresses the issues of safety, regulations, codes and standards that are particularly important in relation to the transport and distribution of hydrogen.

Distribution of gaseous hydrogen (CGH_2)

Gaseous hydrogen can be transported in pressurised bottles[40] (typically at 20 to 30 MPa), in tube-trailers (typically at 20 MPa) and through pipelines. In distribution pipelines, the pressure is between 0.01 and 2 MPa, while for long distance transport the pressure can range between 1.1 and 30 MPa.

Hydrogen has been transported by pipeline up to 300 km for many decades. More than 1 000 km of industrial hydrogen pipelines are in operation worldwide, mainly in the USA and in Europe (France, Germany and Belgium). It is the most appropriate and lowest cost mode of transport at high capacity over a long distance. The two main components of cost are capital and operation.

The main elements of the capital cost are the pipes and the compressors and the main operating cost is running the compressors. Pipeline capital costs are quantified per unit length and increase linearly with the pipeline diameter. Because of the physical properties of hydrogen and because it reacts with the steel used in modern natural gas pipelines, the pipelines for hydrogen are more complex and costly than for natural gas. The pumping cost is higher than for natural gas because of the lower volumetric energy density of hydrogen; more gas must be transported to deliver a certain amount of energy. Either the hydrogen must be moved at a greater speed, requiring more compression power and energy[41], or the diameter of the pipeline must be greater. Consequently, CGH_2 pipelining would cost, per unit of energy, 1.5 to 2 times as much as natural gas. Better operating efficiency is expected from the use of higher input pressures (typically 2 to 3 MPa) from high-pressure water electrolysers or gasifiers. This could reduce the hydrogen compression at the beginning of the pipeline by a factor of up to 5.

Because of the huge cost of a new pipeline system dedicated to hydrogen, there is much effort addressed to find ways of using existing or new natural gas pipelines. There are three main lines of research: (1) the conversion of existing hydrocarbon pipelines to hydrogen service, (2) the use of mixtures of hydrogen and natural gas in existing natural gas pipelines (e.g. NaturalHy project)[42] and (3) the construction of new natural gas pipelines that are hydrogen compatible. The first two options need, above all, careful metallurgical and risk analysis. The third option implies incremental capital costs for a pipeline that is oversized in diameter and pressure capability that may be difficult to justify during the period of natural gas service. It is being considered for the new Northeast Asia natural gas pipeline system connecting Russia, China and Japan.

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39 See http://www.naturalhy.net

40 Single bottles, bundles or bundle trailers.

41 About 3.5 times higher compression energy is required for transporting the same energy equivalent.

42 In this case, H_2 should be separated at the point of use.

It is likely that in the transition period, hydrogen will be carried by trucks. Bottles made of composite materials operating at 30 MPa have been in service for ten years. Tube-trailer transport of compressed gaseous hydrogen is currently suitable up to about 6 000 Nm³; it has low energy efficiency and this limits its application to short distances (i.e. below 200 km) and to small volumes and frequencies).

The cost of delivering compressed hydrogen depends strongly on the mode of transport and on the distance. According to available studies, the distribution cost by truck is from 10 to 30 €/GJ and by pipeline from 6 to 20 €/GJ. However, they may reach considerably lower levels if the required investments in infrastructure are put in place [Castello and Tzimas]. The large range reflects the variation with distance and the weak experience in large-scale hydrogen transport and distribution. It is likely that learning effects and economies of scale will reduce the cost in the future.

Distribution of liquid hydrogen (LH_2)

Liquid hydrogen can only be delivered by truck and by rail. A truck can carry more hydrogen as a liquid than as a compressed gas because the liquid is denser. Today, LH_2 can be transported in cryo-containers or in trailers in sizes between 41 m³ and 53 m³ at temperatures of about 20°K (i.e. - 253°C). A 40 m³ LH_2 trailer transports about five times as much hydrogen as a 21 m³ CGH_2 tube trailer.

Even liquid hydrogen has a low density and the tanker must be heavily insulated so only around 2 000 to 4 000 kg could be delivered by a single trailer; this is enough to fill 400 to 800 vehicles. Today, there are less than 20 large LH_2 trailers in Europe; in a mature hydrogen system, the economies of series would reduce costs by 30% to 50%.

The cost of delivering liquefied hydrogen by truck at present is between 1 and 3 €/GJ. This is much less than the cost of transporting gaseous hydrogen (see supra), but liquefaction itself is energy intensive; about one third of the energy of gaseous hydrogen is lost in liquefaction.

Hydrogen filling stations

Hydrogen can be delivered to filling stations in four main ways: by LH_2 or CGH_2 trailers; by on-site generation through reforming of natural gas or electrolysis of water, or by pipeline. Trailer and pipeline delivery are comparable to conventional supply pathways for liquid fuel or compressed natural gas (CNG). On-site production of hydrogen is an alternative approach that uses existing infrastructure for the distribution of natural gas or electricity.

A supply system for LH_2 would be similar to present arrangements for petroleum products. Fuel is made at a central site, the liquefier, usually adjacent to the hydrogen production plant. LH_2 is delivered to the filling station in trailers or containers and stored on the site either in the original containers or in cylindrical, stationary facilities.

With a submerged cryogenic pump, LH_2 can be transferred to the 100-140 litre tank of typical hydrogen passenger car in less than 3 minutes. LH_2 refuelling can be achieved either by fully robotised refuelling interfaces or by manual refuelling interfaces. The dimensions and weight of these interfaces are comparable to advanced CNG and gasoline refuelling nozzles in use today.

To deliver liquefied hydrogen as compressed gas ($LCGH_2$) the LH_2 is gasified and compressed by a submerged cryogenic pump delivering gas at the required storage pressure up to 70 MPa. When refuelling with cryogenic gas there is no need to compensate for temperature by over-pressurisation as is done for CGH_2 refuelling. $LCGH_2$ refuelling for CGH_2 vehicles is preferred when both LH_2 and CGH_2 are dispensed from the same filling station. High pressure CGH_2 refuelling has advanced significantly in recent years; $LCGH_2$ refuelling or cryogenic cooling of CGH_2 with liquid nitrogen (at about -200 °C) is no longer necessary for fast CGH_2 refuelling.

Generation of hydrogen fuel on site offers a novel path for supply of fuel that does not require access to an upstream supply of hydrocarbons. Any independent fuel provider can purchase natural gas or electricity for hydrogen production and sell hydrogen to its clients. This opens the sector to new players and provides new business opportunities.

On-board compressed hydrogen storage (see infra) requires refuelling stations able to supply hydrogen at pressures above 70 MPa (for cars) or above 35 MPa (for buses or utility vehicles). This in turn requires adequate compressors and storage devices at the station, sized to match the demand patterns. Several stations are now in operation and are testing different forms and pressures of hydrogen. Stations are being demonstrated in Europe (in the framework of the CUTE project), the United States, Japan and Singapore. Commercial stations were built in Reykjavik (Iceland) already in the spring of 2003. It is mainly oil suppliers who are active in this stage of the hydrogen chain.

4.1.4 Hydrogen storage

Hydrogen can be stored in small and large quantities either by compressing or liquefying the gas, or by binding it physically or chemically to a storage material.

Small amounts of hydrogen gas can be stored in bottles or tubes, larger amounts in gasometers and very large amounts in underground aquifers, salt caverns or depleted oil or gas deposits. Liquid storage is feasible in small volumes in so-called cryostats, in medium size volumes in cylindrical storages of ten to hundred cubic meters or in larger spherical or cylindrical storages of several thousands of cubic meters.

Physical storage is possible in metal hydrides. Metal hydrides can store relatively large volumes of gas at moderate pressure and with good energy efficiency. Unfortunately, most metal hydrides are dense and the storage systems are therefore heavy. High temperature hydrides show the best gravimetric storage densities of up to 8% by weight, but because of their release temperatures above 200°C, they are not suitable for mobile applications. With low temperature hydrides only low gravimetric densities can be achieved that are also not compatible with mobile applications. Medium temperature hydrides with release temperatures between 100°C and 200°C seem to be best suited to the requirements of vehicles.

Chemical storage in so-called chemical hydrides (e.g. methyl-cyclohexane, toluene and sodium-borohydride) is a proven concept for the storage of hydrogen in stationary applications but it is not yet developed commercially.

For large-scale mobile applications such as railways, ships and aircraft, liquid hydrogen storage seems to be the only realistic option. Otherwise, the necessary storage volumes would create serious problems of size, weight and cost. The state-of-the-art technologies for hydrogen storage on board road vehicles are compressed and liquid hydrogen storage. More exotic technologies include classical metal hydrides (e.g. low temperature titanium or vanadium) and novel metal hydrides (e.g. high temperature aluminium or magnesium), while future technologies include the adsorption of hydrogen in carbon structures. All these storage methods can also be used in tramways and regional trains as well as in boats and small ships.

A pressure of 35 MPa in CGH_2 storage tanks is regarded as sufficient for most city buses and urban utility vehicles whereas 70 MPa are necessary for passenger cars because of constraints on operating range[43] and space for passengers. Other constraints include the time necessary to fill in the tank (the target is 4 to 5 minutes) and the weight of the tank.

The costs of storage vary widely according to the storage system and materials used. Costs are highest when expensive materials or complicated storage structures are involved. This is the case for containers for liquid hydrogen storage with many insulating layers where complicated production processes are needed. Mass production is critical for achieving acceptable costs of LH_2 storage systems. It is also expected that activated carbon materials at moderate cryogenic temperatures and moderate pressure could reduce costs if these systems perform acceptably in typical uses.

Composite materials are used to manufacture storage vessels for high pressure. The cost of these materials is at present very high, but it is likely that mass manufacturing will reduce costs to acceptable levels for mobile applications. Commercial applications will take place when the first mass manufactured vehicles enter the market, which is expected around 2010. The goal is 200-500 € for a single storage tank compared to 25 000 € today. A prerequisite for such cost reduction is large-scale production of the order of several hundreds of thousands of units per year per manufacturing line.

This review shows that hydrogen storage still faces technical and economic obstacles that must be overcome to achieve the transition to a hydrogen economy. The most mature technology is storage of compressed hydrogen in tanks. Storing liquid hydrogen saves volume, but loses about one third of the energy in liquefaction, and needs to be made more cost effective. Despite the need for further research on hydrogen storage, some systems are already in the market, e.g. several manufacturers offer 70 MPa on-board storage systems for vehicles. European research is actively involved on the issue of hydrogen storage[44].

4.1.5 Conversion and final use

The conversion of hydrogen to electricity in a fuel cell is often seen as a critical element of the hydrogen economy. There are applications for fuel cells for power generation (stationary FC often with heat recovery) and in the transport sector (mobile FC). Hydrogen can also be used in an internal combustion engine like gasoline or diesel.

Fuel cells combine oxygen and hydrogen electrochemically to produce water, electricity and heat. They are often classified by the electrolyte they employ; this determines the chemical reactions that take place in the cell, the catalyst required, the temperature range in which the cell operates, the fuel required and other factors. There are several types of fuel cells under development, each with its own limitations and potential applications. Some promising concepts in commercial application are: Alkaline FC (AFC); Proton Exchange Membrane FC (PEMFC); Phosphoric Acid FC (PAFC); Molten Carbonate FC (MCFC) and Solid Oxide FC (SOFC). The main characteristics are summarised in the table below.

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[43] An autonomy of 600 km is currently targeted.

[44] See for instance the StorHy (www.storhy.net) and NessHy projects.

Table 7: Classification of fuel cells according to temperature and electrolyte

Type	Temperature (°C)		Electrolyte	State of H_2	Use	
	Typical value	Range			Stationary	Transport
Low temperature fuel cells						
Alkaline fuel cell (AFC)	80	60-120	Potassium hydroxide	Liquid	Yes (up to 120 kW)	Yes (cars, spacecrafts, boats, small ships)
Proton exchange membrane fuel cell (PEMFC)	80	50-120	Polymer membrane	Solid	Yes (up to 250 kW)	Yes (trains, cars, boats, small ships, military ships)
Medium temperature fuel cells						
Phosphoric acid fuel cell (PAFC)	200	160-220	Phosphoric acid	Liquid	Yes (kW & MW range)	-
High temperature fuel cells						
Molten carbonate fuel cell (MCFC)	650	620-660	Alkali-carbonates	Liquid	Yes (kW & MW range)	Yes (military ships)
Solid oxide fuel cell (SOFC)	950	800-1000	Ceramic oxide	Solid	Yes (up to 100 kW)	Yes (auxiliary power units)

Stationary Fuel Cells

Three types of fuel cells are appropriate for stationary applications: PEMFC, PAFC, and SOFC. The PAFC is considered the ‘first generation’ of modern fuel cells. Tested in the 1970s, PAFC is one of the most mature fuel cell technologies and the first to be used commercially. PAFC is commercially available in the kW range and in the MW range. It is the type of fuel cell that is most produced and installed worldwide, especially in the 200 kW size. PAFC is 40% efficient in power generation and up to 85% in co-generation. A disadvantage of PAFC is that the power density is low; this means it has a relatively large volume and weight and high cost.

PEMFC delivers more power for a given volume or weight of fuel cell than PAFC and so is more compact and lightweight, but, like PAFC, PEMFC use a costly platinum catalyst. From an industrial perspective, PEMFC has the extra advantage that it can be used for both mobile and stationary applications, offering economies of scale in research and development.

SOFC is a high temperature fuel cell that is well suited to combined heat and power applications in industry and to public power supply. SOFC is around 50-60% efficient in generating electricity and can achieve 80 to 85% total efficiency in cogeneration. Operating at high temperatures, SOFC does not need a precious metal catalyst; this is an advantage in cost compared to PAFC and PEMFC. Solid oxide fuel cells are at a relatively early stage of development, but the high efficiency offers a good incentive for more R&D effort.

The capital cost at present of a fuel cell for cogeneration in, say, a small housing estate is between 6 000 and 10 000 €/kW, including gas pre-processing, cell stack and inverter. Economies of series and learning effects should reduce future costs. According to the Deployment Strategy formulated by the European Hydrogen & Fuel Cell Technology Platform[45], with reasonable assumptions the investment cost might reach 2 000 €/kW for micro-CHP systems and 1 000 €/kW for industrial or commercial CHP. Although the threshold of profitability is still remote, it will be easier to reach for stationary applications systems than for vehicles.

Most stationary FC devices operating today use natural gas or alcohol, and incorporate a reformer to produce hydrogen; the energy balance at the reformer is better with cleaner and hydrogen rich fuels. Hydrocarbon mixtures are not so technically suitable, but this option can play a strategic role in transition when a full hydrogen infrastructure will not be available. Fuel cells are the most promising option for hydrogen use in power generation because they have high conversion efficiency (above 80% compared to 30-35% in open cycle turbines and to about 60% in combined cycle turbines). Their ability to substitute for conventional heat and electricity generation technologies will depend on two critical factors: the capital cost, which is still too high, and the lifetime, which is still too short (less than 40,000 working hours).

Research projects, either private or co-funded by the European Commission, aim not only to improve the performance and costs of different types of stationary fuel cells, but also to explore the feasibility of such systems in real world conditions. An example is the Virtual FC Power Plant EC project conducted by a German heating company with nine European research and industrial partners. The main objective was to transform a ‘laboratory’ FC technology into an operating technology. It resulted in 29 micro plants operating in Germany, Netherlands, Spain, and Portugal. These are interconnected decentralised residential micro-CHPs installed in multi family houses, small enterprises and public facilities for individual heating, cooling and electricity production. These plants have produced so far 160 MWh of electricity and 300 MWh of heat.

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[45] https://www.hfeurope.org/677/687/HFP_DS_Report_AUG2005.pdf

Fuel Cells for mobile applications

The main mobile applications of fuel cells are for transport and for powering portable devices such as mobile phones, radios and laptop computers. Fuel cells could gradually replace conventional batteries in portable applications. The fuel could be hydrogen, methanol or ethanol. The biggest advantage of a fuel cell would be a longer operating time than a conventional battery. For such low energy consumption applications, the potential for greenhouse gas reduction is low.

Fuel cells can be adapted to most transport modes. For road vehicles, development efforts focus on PEMFCs. This is one of the most promising technologies for the transport sector; they are compact and lightweight compared to other types of fuel cells; they operate at relatively low temperatures, around 80°C and this allows them to start quickly and to respond rapidly to changes in the demand for power. PEMFCs have been proposed or developed for use in trams, trains, boats and small ships and for auxiliary power in cars and trucks. High temperature solid oxide and molten carbonate fuel cells are suitable for marine use; in military ships they offer tactical benefits and in large ships they increase thermal efficiency, especially combined with gas turbines. AFC are suitable for niche applications in boats and small ships. Fuel cells with much higher power density than now are needed for there to be prospects for propulsion of aircraft.

Car manufacturers are active in research and demonstration of fuel cells. EC research programmes also support R&D of fuel cells for transport[46]. Most demonstration vehicles that are powered by fuel cells are the result of partnerships between a fuel cell manufacturer and a car manufacturer. This is because of the high level of R&D expenditures needed to produce a new model of car or a fuel cell. Fuel cell manufacturers provide fuel cells and technology support to the car manufacturers, but in most cases, they also operate in other markets. Most manufacturers construct and sell not only PEM fuel cells, fuel cell engines, fuel cell components and electric drive systems for transport applications, but also portable and stationary fuel cell power generators and power electronics for power generation.

Reliable up-to-date data on the costs of fuel cell vehicles are scarce. Several cost estimates were published by the automotive industry, fuel cell manufacturers and research centres in the mid-nineties. As fuel cell cars approach commercialisation, little information is made public about detailed technological advances and manufacturing costs. According to available studies, however, current manufacturing costs are still higher than cost-goals for commercialisation and highly dependent on manufacturing volumes. An increase in production from 500 to 500 000 cars per year would halve the unit costs [DTI, 2002].

The cost of using fuel cell vehicles is dominated by the fixed cost. The variable cost, even with the present cost structure, is lower for FC vehicles than for conventional ones. Assuming a hydrogen price of 40 €/GJ and a gasoline price of 30 €/GJ and specific consumptions of PEMFC vehicles and standard internal combustion vehicles of 0.0014 GJ/km and 0.0023 GJ/km, the corresponding variable costs are around 0.055 €/km and 0.070 €/km.

The comparison is more difficult when fixed costs are included. Specific PEM costs for the power train of fuel cell vehicles may today be between 8 000 and 12 000 €/kW. The additional cost of hydrogen storage and fuel handling may be 60 €/kW for a H_2-fuelled vehicle and 3 000 €/kW for FC vehicles fuelled by compressed natural gas with an on-board reformer. These cost estimates translate into a total levelised cost per kilometre of about 3.5 €/km for the

[46] See for instance the Fuero project (programme of car manufacturers on fuel cells systems and component in vehicles); the Hyfleet-Cut project (demonstration programme for buses); the Hychain-Minitrans project (minibuses, light duty vehicles and scooters); the Zeroregio project (demonstration programme aiming at 5% H2 fuel in Frankfurt and Mantua in 2020); the Hytran project (new FC prototype aiming at 55% efficiency by 2015); the Felicitas project (heavy trucks).

PEMFC vehicle, 4.5 €/km for the on-board natural gas reforming FC vehicle and 0.25 €/km for the standard gasoline ICE vehicle. The calculations assume an average annual mileage of 15 000 km per year.

Mass production and learning effects are expected to reduce future costs. The European Hydrogen & Fuel Cell Technology Platform foresees specific costs of the PEMFC power train falling to around 100 €/kW by 2020, for an overall production of 150 000 vehicles a year. Levelised costs of a FC vehicle covering a distance of 15 000 km per year, could then lie between 0.2 and 0.3 €/km, assuming the hydrogen price also falls from 40 €/GJ to 20 €/GJ.

Hydrogen internal combustion engine (ICE-H_2)

The use of hydrogen for transport is not dependent on fuel cells; hydrogen can also be burnt in internal combustion engines (ICE), similar to gasoline engines, but modified to account for the different combustion properties of hydrogen. This is a promising route to a first demand for hydrogen in transport. It is a low risk and cost option because it starts from current vehicle technology and permits a progressive shift to hydrogen. There is a long experience of ICE using gasoline and diesel and this experience may be adapted to hydrogen. For this reason, ICEs fuelled by hydrogen could reach economical and technical maturity sooner than fuel cells and could create a first demand for hydrogen supply and distribution that will help to develop hydrogen refuelling stations and transport infrastructures. Various car manufacturers are working on the hydrogen ICE concept (ICE-H_2), but each is developing different types of vehicles with their own specifications.

The additional production cost of ICE-H_2 vehicles compared to standard ICE vehicles burning fossil fuel is between 50% and 80%, assuming some improvement in the overall thermal efficiency of the engine.

Hydrogen hybrid vehicles (Hybrid-H_2)

Another promising prospect for hydrogen in transport is its use in hybrid vehicles. Hybrid vehicles are already at a commercial stage; they comprise a standard power train with an electric engine powered with a battery. Each engine delivers approximately half of the total car power. At full power, both engines operate jointly delivering the total power of a standard vehicle. The batteries are recharged by the braking energy recuperated in the wheels (Prius-like hybrid) or from the grid (plug-in hybrid). In urban use, the vehicle operates as an electric car and the batteries are fuelled directly from the alternator of the ICE.

In the hybrid-H_2 vehicle, the electric engine is coupled with a hydrogen-fuelled ICE or a hydrogen-fuelled FC. Because the coupling with an electric engine enables use of smaller ICE engines or FC systems, the cost of the total power train is reduced. The fixed costs could be approximately half those of a PEMFC vehicle. This advantage may facilitate the mass commercialisation of the technology and stimulate cost reductions through learning.

To conclude this section, the following table gives an overview of the application of hydrogen technologies to the various transport modes.

Table 8: Overview of fuel cells and transport applications

	CGH_2	LH_2	PEMFC	SOFC	AFC	H_2-ICE
Car/van/bus propulsion	+	+	+		Niche	+
Long-haul truck	-	(±)	+		-	(+)
Car/van/bus/truck auxiliary power units	(±)	(±)	+	+	-	-
Small motor vehicle (scooter, bike, etc.)	+	-	+		(+)	+
Urban rail	+	+	+		-	(+)
Boat/small ship	+	±	+		+	+
Large ship	-	(+)	(+)	(+)	-	+
Ship auxiliary power units	(±)	+	+	+	(-)	(-)

+ means applicable; - means not applicable; ± means applicable under specific circumstances. Parenthesis indicates that the assessment is preliminary and requires validation through feasibility studies or prototypes. GT means Gas Turbine and SIGT means Steam Injection Gas Turbine.

4.2 Hydrogen technology pathways

Based on the previous description of hydrogen and fuel cell technologies, two different and contrasting pathways have been elaborated that could lead to the penetration of hydrogen, mainly into the market for transport fuels. Each pathway describes a route to a coherent and plausible hydrogen energy system. The two pathways are not mutually exclusive. The principal difference between them lies in the way hydrogen is produced; this in turn is determined mainly by the energy resources available in the different world regions. The first pathway assumes centralised hydrogen production from fossil fuels and the second assumes that hydrogen is made mainly from electricity. Although the critical defining characteristics relate to the supply of hydrogen, there are also differences in the way that the demand for hydrogen develops in each case and in the general evolution of world energy markets.

The primary assumptions in the construction of each pathway concern the performance and costs of the two methods of making hydrogen that most stakeholders consider the main alternatives, i.e. thermo-chemical conversion of primary energy and electrolysis of water. There is an associated set of assumptions in each case concerning the performance and costs of hydrogen conversion, the evolution of prices for fossil fuel and electricity and the development of dedicated hydrogen infrastructures. Current and projected figures used in the two pathways are derived from published analyses of the outlook for fuel cells and hydrogen technology, as well as from specific technico-economic assessments recently made by JRC/IPTS [2003; 2004].

The available information permits the definition of two coherent pathways and their potential technical, economic and environmental benefits. It also permits the main obstacles and boundary conditions for wide-scale introduction of hydrogen and fuel cells to be identified. The boundary conditions are decisive for the practical implementation of the pathways. Five issues that are critical to the introduction of hydrogen in transport can be identified:

The cost of fuel cell vehicles and the cost of hydrogen as a fuel are expected to continue to fall in the future as a result of constant technical improvement, towards the perhaps optimistic goal of 50-100 €/kW for fuel cells. A crucial condition for the reduction in cost is that economies of scale are achieved the production of both vehicles and fuel. The cost of hydrogen compared to conventional or other transport fuels is the main determinant of success in the market. The boundary condition for hydrogen to have a competitive advantage is that *high oil prices* should be combined with either *low natural gas prices or low electricity prices*.

- Fuel cells and hydrogen vehicles have some intrinsic advantages over conventional technologies; fuel cells offer significant benefits for auxiliary power units and in some niche markets. These benefits are not in themselves sufficient to determine user choice. Significant penetration of hydrogen and fuel cells depends on ***comparable performance at comparable cost, with accessible and reliable infrastructure***.

- Provision of hydrogen distribution and storage is an important challenge. A wide network of refuelling stations is essential, but needs a critical mass of demand for hydrogen to be viable. It is indispensable that the ***cost of hydrogen distribution is kept low*** and that its ***introduction is massive***, so that the investment can be justified.

- There may be significant environmental benefits from hydrogen, depending on the primary energy used for its production. Hydrogen from electrolysis only benefits the global environment if the electricity used for the electrolysis is generated from carbon-free fuel. Hydrogen from reforming fossil fuel is roughly neutral to the global environment unless the efficiency of fuel cells is much improved. The introduction of hydrogen in transport would therefore only benefit the global environment in the case of

low cost renewables for electricity generation or in the case of ***high-performance fuel cells combined with low prices of natural gas or biofuels*****.**

- The commitment of industry could be influenced by policy. The key industrial stakeholders (car manufacturers, refineries and fuel providers, infrastructure providers, fleet managers) will invest in a new technology only if the future market prospects are clear. The role of policy makers should therefore be to ***decrease uncertainty through suitable and timely policy measures, legislation and standards***. Appropriate legislation could also influence user choices, by promoting the use of hydrogen, by penalising CO_2 emissions or by limiting the use of conventional technologies in certain areas.

4.2.1 Pathway n°1: Centralised fossil fuel-based hydrogen production

This first pathway envisages that hydrogen is produced from hydrocarbons and coal and then is distributed as a fuel for both transport and electricity generation, including combined heat and power. The largest use is for transport. The main assumption is that a market for hydrogen develops relatively rapidly in some economies of the OECD, driven by low cost technologies to produce hydrogen from fossil fuel. These technologies (steam reforming natural gas and coal gasification) are already relatively mature and are today the cheapest way to produce hydrogen. In this pathway, hydrogen would be produced mainly in centralised production units, mimicking power generation. Natural gas reforming would dominate at first but would be rapidly substituted by coal gasification with carbon dioxide capture and storage, which should be a well-established practice by 2020.

To create the necessary stimulus to demand in the short-term, this pathway assumes a rapid decline in the cost of both fuel cells and hydrogen from 2005 to 2010. It also assumes that the price of electricity exceeds the price in the Reference projection throughout this period, because of high carbon values and/or inadequate generation from renewable energy and nuclear in some parts of the world. A large part of the initial demand for hydrogen is for power generation using stationary fuel cells, mainly for CHP in industry. The remaining part is used in the transport sector, first for internal combustion vehicles (ICE-H_2) and/or captive fuel cell (FC) vehicle fleets (urban buses etc), then also for private FC vehicles. The crucial assumption is that electricity from stationary fuel cells generated using hydrogen from fossil fuel is cost-effective with advanced coal power plants.

The use of hydrogen in stationary applications stimulates learning effects that further reduce the cost of fuel cells until FC vehicles eventually compete with ICE-H_2 in the transport market. These technologies depend on long-lived and costly investments that exhibit strong economies of scale. It must be assumed that the demand for hydrogen grows rapidly from the start in order that these investments are financially viable. Hydrogen is used increasingly for electricity and CHP, as well as transport, and becomes an important universal energy carrier. Hydrogen eventually has a dual role; it enters the energy system both upstream and in parallel to electricity; it is simultaneously a *final energy carrier* (for a growing share in transport) and *an intermediate carrier* (for a limited, but stable share in a partly decentralised power generation sector).

The dynamics of the penetration of hydrogen into the transport sector are critical to this pathway. The initial demand comes mainly from captive fleets; it is channelled through internal combustion engines working on hydrogen (both in simple and hybrid engines) and is driven by financial incentives such as tax exemptions. Policy instruments are the prevailing drivers up to 2010-2015. From 2020, learning effects bring the cost of fuel cells to a level where FC vehicles (again, simple FC and hybrid designs) are competitive.

Affordable transport of hydrogen is important in a centralised system of production. In the early stages, the preferred means of transport and distribution is by road using special trucks; the cost is from 10 to 20 €/GJ and is competitive up to about 500-800 km. Subsequently, a pipeline system develops to move hydrogen from production sites to distribution hubs (see Table 9).

In short, the long-term state at the end of this pathway is a system fuelled largely by coal and characterised by high hydrogen and electricity prices as a consequence of high carbon values. This stimulates efficient use of hydrogen and provides incentives for a significant and long-term penetration of fuel cell technologies.

4.2.2 Pathway n°2: Electricity-based hydrogen production

This second pathway assumes that hydrogen is produced mainly by electrolysis and is used almost entirely for transport, initially in internal combustion engines; there is no significant demand for power and CHP, except for stationary fuel cells in some niche markets. The hydrogen is made at first from reforming natural gas; subsequently a parallel production of hydrogen from electrolysis develops using off-peak nuclear and then renewable electricity. The crucial technical breakthroughs required in this pathway are the development of cheap electrolysers and a significant reduction in the long-term in the cost of carbon-free electricity from nuclear and renewable energy. This pathway leads to an energy system relying essentially on cheap and carbon-free electricity that simultaneously play the role of *final energy carrier* and *intermediate energy carrier* for the transport sector.

The transport technologies are expected to develop in a similar manner to the first pathway, but the market for ICE-H_2 is expected to last longer, extending beyond 2030. Tax exemption and subsidies are required to foster the development of expensive hydrogen-based motor engines.

This scheme does not require as rapid an improvement in FC technologies as was postulated for the first pathway, at least at the beginning of the period. It would require in the medium-term, a relatively high share of nuclear power in the generation of electricity, part of which will be dedicated to hydrogen production. Ultimately, this pathway depends on the availability of low-cost renewable energy and is likely to develop at a slower pace than the first.

The table below summarises and compares the critical aspects of the two paths.

Table 9: Main driving factors in the two hydrogen pathways

	Pathway N°1	Pathway N°2
	"Centralised Fossil fuel-based Hydrogen Production"	"Electric-based Hydrogen Production"
H_2 production	• Rapid development of low-cost techniques of coal gasification with CO_2 sequestration • Centralised reforming of natural gas • On-site reformers at filling stations •	• Development of on-site electrolysis • Low-cost off-peak electricity • Rapid growth of affordable carbon-free electricity
Distribution	• Liquid hydrogen road trailers and rail cars / containers • Pipelines for hydrogen gas • Natural gas grid for reforming on site • Pyrolytic oil road trailers for on-site biomass gasification •	• Electric grid for electrolysis on site • H_2 distribution over short distances and in small quantities, mainly by road trailers and rail cars/ containers
Storage & Availability	• Initially limited availability of H_2 (infrastructure limitations) • Initially limited range (on-board storage limitations) •	• Potentially unlimited H_2 availability (on-site electrolysis) • Storage issues resolved by time of mass introduction
Stationary applications	• H_2 used extensively for power generation • Early improvement in lifetime and durability of high-temperature FCs • FC CHP market niches rapidly occupied •	• Improved lifetime and durability of high-temperature FCs • Industrial and residential niche markets develop after transport applications
Transport applications	• Cost of IC-H_2 engines soon competitive with standard ICV • Improvements in hybrid technologies • Large-scale introduction of FCs in the medium-term: cost of power-train declines by a factor of 100: life of stack exceeds 6000 hrs •	
Infrastructure & investment	• Infrastructure: natural gas and H_2 distribution networks • CO_2 storage •	• Non-fossil based carbon-free electricity production

4.2.3 Quantitative assumptions

The analysis of the costs of the relevant technologies presented in section 3.1 concludes that many of them are at present far from the market. This section identifies the reductions in cost that are required to make the hydrogen pathways possible.

The development of processes to produce hydrogen at reasonable cost from both fossil and non-fossil fuels is a pre-requisite for a hydrogen economy. An appropriate reference for the cost of hydrogen is the expected cost of motor fuels such as gasoline or diesel. The consumer price of gasoline in the EU is at present around 1 €/l, equivalent to 30 €/GJ. The price for diesel is slightly lower, around 25 €/GJ. These figures include taxes that account between 60% and 80% of the final price. The production cost of gasoline in the EU is between 6 and 10 €/GJ.

Both pathways envisage extensive use of hydrogen in transport that should stimulate cost reductions through mass production and economies of scale. In decentralised paths to production of hydrogen, many identical components will be required (e.g. electrolysers, filling nozzles, flow meters etc.). These components exist already and are manufactured, but not yet mass-produced. Increasing market penetration will also allow for larger installations (e.g. larger hydrogen filling stations for privately owned cars) that will have lower unit costs through economies of scale.

At current prices for distillate fuels, hydrogen in large-scale use could compete if it were taxed less than gasoline and diesel, as is now the case for natural gas used for automotive fuel. The price of fossil fuels, especially oil and natural gas, is expected to remain high and even to rise, while the cost of renewable energies is decreasing steadily because of continuing commercialisation, [WETO, 2003]. Both developments are difficult to project precisely because they depend on many factors, some of which are political. Nonetheless, it is likely that the cost advantage of fossil energy will continue to decrease and that renewable energy sources will eventually be cheaper. Consequently, the cost of hydrogen production from fossil fuel will increase while the costs from renewable-based production will decrease. At the same time, the costs of conventional automotive fuels will also increase. These effects are to some extent included in the cost estimates presented in the table below. The picture is qualitatively similar for all segments of the transport market, although the price differentials between conventional automotive fuels and hydrogen differ in each segment.

The table below summarises, for the different stages of the hydrogen chain, the cost reductions required for proposed pathways to be viable. The technological breakthroughs that are needed are discussed in the next section.

The cost assumptions match, although sometimes displaced in time, the forecasts/targets of the European Fuel Cell & Hydrogen Technology Platform (EFCHTP)[47]

Both hydrogen technology pathways are present in the hydrogen scenario (see section 4. 4). They are assigned to each country or world region according to its present energy market structure, natural resources endowment and policy options endorsed.

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[47] http://ec.europa.eu/research/energy/nn/nn_rt/nn_rt_hlg/article_1261_en.htm

Table 10: Main cost assumptions regarding the hydrogen pathways

Technology	Today	2025 Pathway n°1	2050 Pathway n°1	2025 Pathway n°2	2050 Pathway n°2
Carbon capture and storage (CCS) (€/tCO_2)	20 - 30	4 - 8	3 - 6	8 - 16	6 - 12
Hydrogen from coal gasification (without CCS) (€/GJ)	8 - 10	7 - 9	3 - 5	8 - 10	6 - 7
Hydrogen from reforming of natural gas (without CCS) (€/GJ)	5 - 8	5 - 6	4 - 5	5 - 6	4 - 5
Cost of electrolyser (€/Nm^3/d)	120	100	80	80	60
PEM fuel cell (€/kW)	8 000 – 6 000	400	40	800	100
High temperature fuel cell (€/kW)	10 000 – 8 000	800	200	2 000	400
Nuclear based electricity (€/GJe)	10 - 12	7 - 8	4 - 5	4 - 5	3 - 4
Renewable average electricity (€/GJe)	30 - 60	20 - 40	10 - 20	10 - 20	5 - 10
ICE-H_2 (€/kW)	100	80	60	40	40
H_2 transportation/storage cost(¹) (Compressed gas - truck)(€/GJ)	14 - 22	6	3	8	4
H_2 transportation/storage costs¹ (Pipeline)(€/GJ)	10 - 15	3	2	4	3
(¹) 5000 kg/hr, 800 km					

4.3 Breakthroughs in hydrogen technology and priorities for research

The previous sections demonstrate that with the present and foreseeable costs of hydrogen technology and prices for fossil fuels the necessary economic conditions for a large-scale use of hydrogen in Europe will not be met in the near-term. Specific technological bottlenecks are identified in section 3.1 that hinder the penetration of hydrogen into the market. Breakthroughs in these technologies would accelerate deployment.

Several clusters of technologies are determinant. Some clusters relate to the production and distribution of hydrogen and are defining characteristics of the two alternative pathways described previously. Others, for example fuel cell technology, determine whether the use of hydrogen is cost-effective and are fundamental to the entire hydrogen concept.

4.3.1 Production of hydrogen

In the production of hydrogen, the challenges are:

- To reduce the cost of hydrogen to the user, especially from carbon-free electricity, to a competitive level; at present the cost is 3 to 8 times that of conventional fuels
- To reduce the cost of decentralised hydrogen production.

The important clusters of technologies concern:

- CO2 capture and storage
- Gasification
- Electrolysis
- Renewable power
- Alternative routes for the production of hydrogen

The first two clusters are especially relevant to the centralised fossil fuel-based hydrogen production pathway. The second is also important for biomass gasification. The last three are primarily required in the electricity-based hydrogen production pathway.

Capture and storage of CO_2

For hydrogen to become a viable part of the response to the challenge of climate change, its production from fossil fuels must be combined with CO_2 capture and storage; this will increase the cost. As noted in section 3.1, the capture and storage of CO_2 would raise the production cost of hydrogen from coal or natural gas by about 20%.

The capture and storage of CO_2 from steam reforming of natural gas is restricted to large-scale centralised production and is not cost-effective for small, decentralised hydrogen production or for compact reformers on site. Consequently, it is not appropriate to the pathway with early build-up of a refuelling infrastructure for hydrogen, although it might be applicable to large-scale supply for ships and aircraft from 2015/2020.

The amount of CO_2 that can be stored is limited by the availability of suitable structures. The best structures are in depleted oil and gas reservoirs or aquifers. In Europe, the most favourable oil and gas fields are in Norway, the United Kingdom, the Netherlands and Denmark. Suitable aquifers suitable are likely to exist in most European countries. In most cases, the ratio of proven storage capacity to the annual CO_2 emissions from the power sector is between 30 and 100 years. The cost of CO_2 transport and disposal depends on the geology of the site, but is generally low relative to the cost of capture; a large part of the geological potential could be developed at between 3 and 10 €/tCO_2, including transport to the structure and injection into the reservoir, but excluding the cost of capture. Estimates of the current overall cost of capture and storage route are between 30 and 50 €/t CO_2; the mid-term target adopted by the European Commission is to bring this down to 20 €/t CO_2.

The cost-effectiveness of capture and storage is improved if the CO_2 is put to use. If CO_2 is stored in producing oil reservoirs then it may increase the reservoir drive and give an economic benefit through enhanced oil recovery (EOR). CO_2 may also be used for recovery of coal-bed methane by injecting gas into coal strata that cannot be mined. Enhanced oil recovery with CO_2 is proven in large permeable structures in the US and Canada, but the economic feasibility in the less permeable and more faulted structures of the North Sea has not been fully demonstrated. The potential and economic feasibility of the use of CO_2 for recovery of coal-bed methane is still to be proven. In any case, the amount of CO_2 that could be used is small compared to the amount that needs to be captured.

Gasification

The production of hydrogen from coal is proven and tested in a pre-commercial phase. Production from biomass and waste is possible, but fully operational systems are yet to be demonstrated. Conversion efficiencies must be increased to make the process more cost-effective, both in terms of hydrogen yield per mass unit of feedstock and in terms of thermodynamic efficiency. It is also important to improve the quality of the hydrogen-rich gas produced. The properties of the gas determine what it can be used for without further treatment and the way in which it can be transported and distributed.

It is critical to clarify whether it is practical to split gasification between two sites conducting an initial pyrolysis and final gasification. The first process could be carried out in large centralised plants and delivers easily transportable pyrolytic oil that can subsequently be gasified in small, decentralised units; this separation reduces the requirement for transport of hydrogen. The viability of single-step processes will depend on the availability of safe, reliable and economic technologies for transport and distribution of hydrogen.

In any case, hydrogen production based on gasification is only economically viable in relatively large, regional installations. These would be more cost-effectiveness if they could accept a range of feedstocks, so that coal and biomass could be gasified in the same facility. Fuel cells operating on biogas obtained from waste in installations such water treatment plants, landfills, and food-processing sites (100 - 500 kWe) are proven. Integrated applications, with on-site co-production of hydrogen and electricity should be promoted to support the development of economically viable decentralised systems in the initial phase unrestricted by an undeveloped infrastructure for distribution and delivery.

Electrolysis

The electrolysis of water is a well-established process to produce hydrogen in the medium and long-term; it has been used in industry for many years. The consumption of electricity is high and the cost of electricity is from 70 to 90% of the total cost of production. This pathway to hydrogen depends on low-cost, carbon-free electricity from nuclear or renewable sources.

The annualised cost of capital is a small part of the total cost of electrolytic hydrogen. Even if significant reductions in capital cost are achieved, they will not be determinant for the adoption of this pathway. Improvements in lifetime, efficiency and reliability are more important; these can be induced through learning effects.

Renewable power

The main advantage of renewable energy sources is their abundance, inexhaustibility and widespread distribution. The disadvantage, especially for the production of electricity, is their variable and diffuse nature. Backup generation of electricity is needed for large-scale generation for the grid. Hydrogen has the advantage over electricity as an energy carrier in an energy sector dominated by renewables that the problem of intermittency with many renewable energy sources can be managed by adjusting the production of hydrogen and by storage. Most renewable energy technologies are adapted to generate electricity.

Production of hydrogen by electrolysis is a good approach to use renewable energy for transport. Transport is a critical sector for the environment because it is expected to grow rapidly at world level and is dominated at present by petroleum products.

There is a wide range of renewable energy sources in various states of commercial development. Hydropower is a well-established renewable technology that in many cases is cost-effective. Other possibilities are solar energy, geothermal energy, wind energy, biomass and marine energy from tides and waves. The adoption of these technologies has been limited and variable. For electricity generation, they are not yet competitive with coal, gas or nuclear power. In the long-term solar and wind energy are possible sources of electricity for electrolysis and are widely distributed; they are reviewed below.

The two main options for generating electricity from solar energy are photovoltaic cells (PV cells) and solar thermal power plants. The cost of electricity generation from solar energy is high because of the low capacity factor and the low efficiency of the conversion plants. Solar power is intermittent because it is interrupted at night and by clouds. The efficiency of devices varies according to the design and nature, but is generally only 12 to 16%. Solar radiation has low intensity and the conversion devices must be larger than conventional plant for a similar amount of electricity; this problem is exacerbated by low efficiency. Consequently, solar energy requires a lot of land; 1000 MWe of solar capacity needs at least 20 square kilometres of collectors. The problem of land-use is similar for thermal and photovoltaic plants, but the capital cost of photovoltaic systems is higher. The cost of electricity from solar photovoltaic cells is today between 1.00 and 1.50 €/kWh. Electricity from solar thermal plants is produced from 0.18 to 0.30 €/kWh and has a good potential for cost reduction. There are 350 MWe of solar thermal plants in the world; they have produced 80% of the total solar electricity generated to date.

A stand-alone system operating on intermittent renewable energy needs to have energy storage. Energy can be stored as electricity in batteries or as hydrogen. In both cases, there are losses in moving energy in and out of store that lower the overall net efficiency of the system and the storage equipment increases the capital cost. Research is underway to develop cheaper and more efficient solar cells and to link solar systems more efficiently to energy storage.

Wind power also requires backup to cope with calm periods and needs a large area of land. Despite these drawbacks, there is 25 000 MWe of capacity of wind turbines operating across the world. The levelised cost of electricity from wind is now only 10 to 20% above the average cost of production of electricity in Europe (i.e. 0.12 to 0.18 €/kWh compared to 0.10 to 0.13 €/kWh).

Most European countries have some wind potential. The volume of useful offshore wind resources in the EU 25 is estimated at about 900 PJ/a. In 2004, 8 321 MWe of wind power has been installed worldwide, the largest ever annual increase. This is almost all for grid electricity, but there are two pilot projects in Europe to produce hydrogen by electrolysis of water. They are in Greece and in the Canary Islands and are funded under the $RES2H_2$ European Project.

For other renewable energy sources, the situation is more differentiated because it depends on the resources available in the different countries or regions.

Hydropower provides 17.5% of world electricity, Apart from a few countries with large resources, such as Canada where 60% of electricity is from hydropower, the hydro capacity is normally deployed to meet peak-load demand because it can be readily stopped and started. The main advantage of hydroelectric power is its ability to handle high seasonal and daily peak loads.

About 6 000 MWe capacity of electricity generation from geothermal energy is currently operating in the world. There are also prospects in some parts of the world, where the hot mantle is close to the surface, for injecting water underground and for recovering steam to produce electricity.

On some coastlines, where there is a large tidal range such as in France and Russia, the tidal flow can be controlled by barrages and used to generate electricity. Because of the environmental impacts, there is little potential for new large tidal barrages. The location of freestanding turbines in major coastal tidal streams has more potential.

Waves are concentrated wind power. Electrical generators can either be coupled to floating devices or activated by the air displaced by waves in a hollow concrete structure. There are still many technical problems to overcome before a commercially viable process can be envisaged.

These carbon-free renewable sources of energy provide the technical potential for movement along the second pathway to a hydrogen economy as described in the previous section, but costs must fall a long way. An average reduction in cost of about one order of magnitude is necessary to bring renewable-based electrolytic hydrogen close to competition with hydrogen from the reforming of natural gas, even when including the capture and storage of carbon dioxide.

Alternative routes for hydrogen production

Alternative means of producing hydrogen are now under research and development. The thermo-chemical production route was described in section 3.3.1. This consists of splitting water into hydrogen and oxygen in thermo-chemical cycles operating at high temperature. The choice of temperature is the result of a balance between favourable reaction kinetics and aggressive chemical corrosion of containment vessels; catalysts that accelerate the reaction may reduce the need for high temperature materials. An important challenge is to separate the reaction products at high temperature; effective membrane materials must be found. Because of these problems, the technology is far from commercial exploitation and sustained R&D effort on these topics is still needed.

There are interesting possibilities of biological routes to hydrogen. Some single-cell organisms such as algae and microbes produce hydrogen efficiently at ambient temperatures. The molecular processes involve complex protein structures that have only recently been partially identified. These natural mechanisms are the basis for new research initiatives. Converting them into an industrial process is only a concept at present, but if successful could open many possibilities for an economically and environmentally sustainable hydrogen production system.

4.3.2 Hydrogen distribution and storage

A fundamental challenge is to reduce the large share of the cost of distribution and storage within the final cost of hydrogen to the user. The "centralised" versus "decentralised" modes of production require different systems of distribution and storage. Reliance on the network for natural gas may be satisfactory for stationary applications, especially for high-temperature fuel cells that are able to tolerate the quality of hydrogen from on-site reforming. If hydrogen purity is critical then local purification units may be installed; this decentralised solution may partially circumvent the problem of the cost of hydrogen distribution.

Transport is expected to be the largest market for hydrogen and this will require a distribution network dense enough to accommodate the diffuse demand from many dispersed consumers. Supplying hydrogen to this market at reasonable cost and under appropriate conditions is a formidable challenge. It requires huge investments in infrastructure and the development of new procedures for the management and exploitation of the network assets.

A network of pipelines carrying compressed gaseous hydrogen (CGH_2) and connecting production sites with filling stations may be the most cost-effective solution in the long-term. The capital cost would be huge and may delay the investment, but the economies of scale would permit low long-run marginal costs of distribution, even below 1 Euro/GJ. The HyNet Roadmap Report, working from the conclusions of the EC Contact Group on Alternative Fuels, estimates that, depending on the technological choices and implementation strategies, the costs of a pan-European hydrogen network supplying 5 to 9 million vehicles (10 000 hydrogen filling stations) would be between 7 and 14 billion Euros. Initial demonstration projects should be developed around hydrogen mini-grids and selected strategic hydrogen axes.

The second long-distance distribution option is distribution of compressed or liquefied hydrogen in tankers, either by trucks or by rail. This is at present the cheapest way to distribute small quantities of gaseous hydrogen over short and medium distances. There are problems in adapting this approach to liquid hydrogen because of the volatility of hydrogen and the energy losses in liquefaction, but the volumetric energy density of the liquid is higher than for the gas and the process could be economic over long distances.

These two long-distance transport options can co-exist (even for a long while) with decentralised production combined with buffer storage, either with liquid hydrogen reservoirs for short-term buffering and/or with CGH_2 tanks.

The mode of distribution that eventually prevails will be strongly influenced by the type of on-board storage that develops in vehicles, either as liquid or compressed gas. In turn, the type of on-board storage adopted will depend on the way in which motor manufacturers decide to demonstrate hydrogen fleets; space for storage is a more serious constraint on small cars than on buses or trucks. The technology breakthroughs that may change this picture are the development of safe and affordable high-pressure tanks that go beyond the currently tested 350 bars to reach 700 bars and success with alternative storage concepts such as complex metal hydrides.

4.3.3 End-use technologies

Fuel cells

The fuel cell is critical to the hydrogen economy. The fuel cell converts chemical energy into electricity without an intermediate thermodynamic cycle and the associated energy losses. The high conversion efficiency would be a change of paradigm for the energy system. The biggest obstacle is cost; there are subsidiary problems with performance and durability.

The cost of fuel cells in stationary applications for electricity generation and CHP must decrease by more than an order of magnitude, from 8 000 - 10 000 €/kW to 500 €/kW, to give significant market penetration. These reductions are likely to be achieved by mass production, even if some technical problems persist. High temperature fuel cells, like the Solid Oxide Fuel Cell (SOFC) or the Molten Carbonate Fuel Cell (MCFC) are suitable for decentralised power or CHP. They operate today with natural gas and could develop without a hydrogen distribution infrastructure; the fundamental obstacle is the cost.

Transport is the main market for fuel cells in the long-run; in this application, the reduction in cost to compete with internal combustion and hybrid engines is even more demanding. The cost of polymer-based low temperature fuel cells (PEMFCs) is at present between 7 000 and 9 000 €/kW; this must fall nearly two orders of magnitude to 50 to 100 €/kW to be competitive. For this type of fuel cell, the biggest difficulty in reducing costs is the expensive nature of the materials in the fuel cell stack. About 70% of the cost is in the proton exchange membranes, precious metal catalysts, gas diffusion layers, and bipolar plates. Furthermore, the performance of the polymer membranes under the cycling conditions of automotive fuel cells can degrade fast, especially as materials are pushed into higher temperature operating regimes. At present, the mechanisms of degradation are only partially understood. The life of the fuel cell stack is at present less than 2000 hours; this has to at least double.

Among high temperature fuel cells, the SOFC is promising. The solid oxide provides the membrane that transports oxygen ions from the cathode to the anode. Compared to polymer-based fuel cells, the higher operating temperature in the SOFC has advantages, e.g. the possibility to use other fuels than hydrogen, such as hydrocarbons; a longer lifetime under certain conditions and higher efficiency, perhaps up to 85%. A disadvantage is that it is less durable than PEMFC under the extended thermal cycling typical of mobile applications; it is more suitable for applications without such cycling.

The research needs are addressed below, categorised according to the components of the fuel cell, i.e. cathodes, anodes, membranes, membrane electrode assemblies, and bipolar plates.

For **cathodes** and **anodes**, the priorities are to decrease the over-potential of oxygen reduction and to improve the tolerance of impurities. The first topic reflects the unfavourable electrochemical kinetics for the reduction of oxygen, which means that an additional driving force is needed to obtain an adequate current in the cells. The second topic aims to achieve higher tolerance of impurities so that less pure and less costly hydrogen can be used.

For **membranes**, the priorities are to improve cost, strength, durability, and ionic conductivity. Low temperature fuel cells, such as PEMFC, require the polymer electrolytes to be hydrated to operate. Without complex high-pressure systems, hydration is lost above 80ºC, but operation at about 120ºC would facilitate heat transfer from the cell. Polymer membranes are also easily degraded at high power and under thermal cycling. The membranes are also sensitive to ionic impurities produced by corrosion of the metal components. For high temperature fuel cells, such as SOFC, the priority is to develop systems that operate at lower temperatures, to reduce corrosion and thermal stress.

A **membrane-electrode assembly (MEA)** is an array of catalyst particles with transport pathways for electrons, protons, and gases. These three interpenetrating nanoscale networks must be optimised to produce acceptable performance of the electrode. Mass transport limitation within the cathode catalyst layer is a fundamental limiting factor in fuel cells today. If and when better catalysts become available, improving this aspect of MEA will become the next important target.

Finally, other emerging fuel cell technologies could be enabled by discoveries of novel materials. Three potential novel technologies are:

- Intermediate temperature electrolytes (200-500ºC)
  This technology would allow the use of low or non-precious metal catalysts and fuels containing substantial amounts of CO. The candidate material would be an inorganic proton and/or oxide-ion conductor or a hybrid or composite membrane structure.
- Alkaline environment fuel cells
  Alkaline cells are known to be efficient and robust, but they have a low tolerance of impurities and cannot use air as the source of oxygen
- Membrane-free fuel cells
  Membrane-free fuel cells have been demonstrated for low power and short-term use in biological environments. The research challenge is to test whether membrane-free concepts can be developed for high power and long life systems, because the design of the electrodes would be very specific.

Alternative concepts for the hydrogen power train

Widespread demonstration of vehicles with internal combustion engines running on hydrogen could accelerate the penetration of hydrogen as a transportation fuel. This technology is close to technical and economic viability today. Demonstration of a fleet of vehicles could stimulate the rest of the hydrogen-chain to develop.

The hybrid vehicle concept could also be applied to hydrogen-fuelled ICE vehicles. Hybridisation would increase the efficiency of the hydrogen vehicle and demonstrate some environmental benefits compared to present engines and fuels, providing that the source of hydrogen is not carbon-intensive. The benefits would be greater for the more efficient FC vehicle, but hybrid ICE vehicles would show the way.

4.4 Energy development and CO_2 emissions in the H_2 case

The Reference case described in chapter 1 projects present trends in energy demand and hydrogen technologies. The projection shows only a small penetration of hydrogen into the energy system; by 2050, the share of hydrogen in final energy consumption is 2% of the world total and 3% in Europe. The stringent limits on CO_2 emissions in Europe and other Annex B countries introduced in the Carbon Constraint case (see chapter 2) do not much change the prospects for hydrogen. The only substantial difference between the two cases is in the origin of the hydrogen. In the Carbon Constraint case, fossil fuel based H_2 production disappears from the technology mix after 2030, even though there is some possibility of carbon capture and storage.

Given these findings and given the many ongoing initiatives to facilitate and accelerate the development and deployment of cost-competitive hydrogen technologies, it was felt necessary and interesting to elaborate an alternative scenario aiming at a significant market penetration of hydrogen in Europe and the world by 2050. The scenario assumes technological breakthroughs along specific development pathways and adopts similar assumptions for greenhouse gases to those made in the carbon constraint case. The hydrogen scenario is therefore also a carbon constraint case and is referred to as the H_2 case.

The H_2 case assumes significant technical change in the transport sector associated with large reductions in cost for fuel cells, hydrogen-fuelled internal combustion engines and hybrid hydrogen engines. This favourable evolution of costs is caused by a strong demand for hydrogen in the transport sector that supports innovation. This activity on the demand side stimulates technical advance in supply that is manifest in the improved performance and lower capital and operating costs of technologies for producing hydrogen. The cost assumptions adopted in the H_2 case are summarised in section 3.2.

The analysis chooses to focus on the use of hydrogen in the transport. There are other possible choices, for instance, technology breakthroughs in batteries or in on-board reformers. They are out of the scope of the present study.

The assumptions on climate change policy in the H_2 case are similar to those made in the Carbon Constraint case and are expressed in the same time-path of carbon values. Because of differences in technical performance and cost in the two cases, the emission profiles of CO_2 also differ. The H_2 case shows slightly higher emissions at the end of the period (see infra) but in both case, the emission profiles are consistent with a trajectory of long-term stabilisation of greenhouse gas emissions at 500 ppmv (see Figure 33).

4.4.1 World primary energy demand

The primary energy demand in 2050 in the H_2 case is 20.3 Gtoe – double the present amount. It is 1.7 Gtoe (8%) less than the Reference, but 0.9 Gtoe more (5%) than in the Carbon Constraint case. The small impact of the carbon constraint on the total amount of primary energy demand suggests that the major element to CO_2 emission reduction strategies is change to the fuel mix. This is supported by the observation that the share of fossil fuels in primary energy demand in 2050 is slightly less than 60% in the H_2 case compared to 70% in the Reference.

By 2050, the annual contribution of oil and gas to the world supply of primary energy is 1 Gtoe (or 10%) less than in the Reference. The volumes of production of oil and gas both peak in the H_2 case, but at lower levels than in the Reference. The maximum production of conventional oil is 97 Mbl/d in 2030 compared to 101 Mbl/d previously.

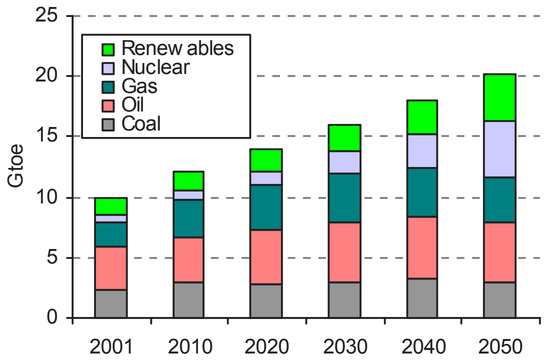
Coal is affected more than other fossil fuels. In contrast to the steady increase in the use of coal in the Reference, in the H_2 case it first increases slightly to 2010 and than stabilises at around 2.9 Gtoe from 2010 to 2050. This dramatic drop of 49% compared to the consumption in 2050 of 5.7 Gtoe in the Reference occurs despite the assumed lower cost of carbon capture and storage.

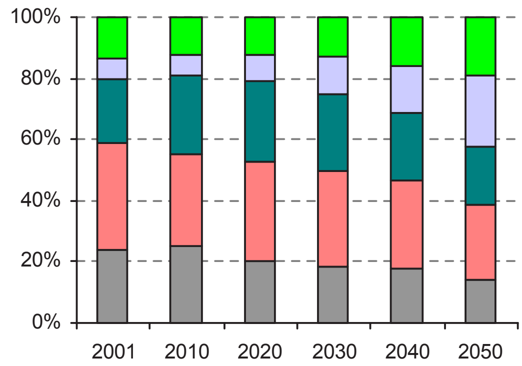
Although the share of fossil fuels in world primary energy demand is comparable in the H_2 and CC cases, the volume of demand of fossil fuel is 0.6 Gtoe lower in the CC case. This difference is evenly shared between coal and oil.

The share of non-fossil energy grows more strongly in the H_2 case than in the Reference; the contributions of nuclear and renewable energy increase seven times and three times respectively by 2050; in that year they contribute 4.7 Gtoe and 3.9 Gtoe. The fastest increase is between 2030 and 2050; it is caused partly by the high carbon values across the world and partly by the rapidly growing demand for hydrogen. In 2050, the share of non-fossil energy in world primary energy demand is 40%, compared to less than 25% in 2030. Nuclear energy makes the main incremental contribution. Compared to the Reference, the incremental volumes of production for nuclear and renewables in 2050 are 1.5 Gtoe (47%) and 0.5 Gtoe (15%).

In the CC case also, the share of non-fossil sources increases to 40% of world primary energy demand by 2050, but the share of nuclear in this demand is slightly less at 52% compared to 55% in H_2.

Figure 52: World primary energy demand (H_2 case)

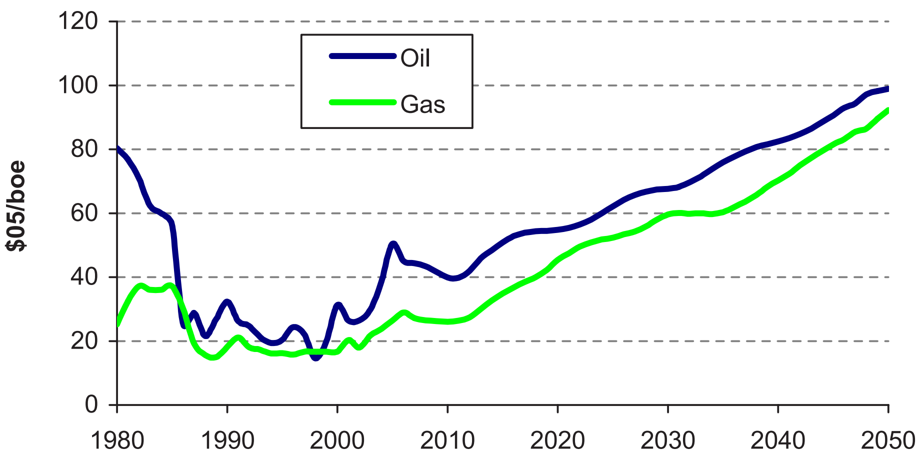




Production of oil (conventional and non-conventional) and gas in the world in 2050 is lower in the H_2 case than in the Reference by 13% and 7% respectively. Consequently, there are larger oil and gas reserves remaining in place at the end of the period. The H_2 case has almost no effect on the distribution of oil and gas production in the world, or on the volumes and regional characteristics of oil and gas trade. The effect on coal trade is dramatic, especially after 2030. Imports by Asia and coal export from the Pacific and Africa fall by more than 80% by 2050.

International oil and gas prices are lower in the H_2 case than in the Reference because of the reduced demand. In 2050, the price is 200 $ of 2005 per barrel for oil and 90 $/bl for gas (Figure 53), against 111 $/bl and 102 $/bl in the Reference. This price development is driven by the increasing carbon values and follows the logic set out in chapter 2 for the CC case.

Figure 53: International fuel prices (H_2 case)

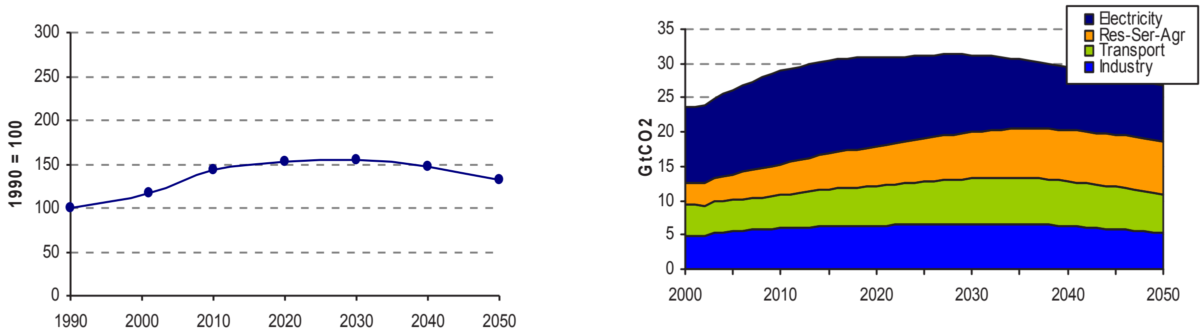


4.4.2 World energy-related CO_2 emissions

Figure 54 shows how the changes in primary energy demand affect world emissions of CO_2. The profile is a consequence partly of the assumed time-paths of carbon values differentiated according to world regions and partly of the assumed cost and performance of hydrogen technologies.

World emissions of CO_2 are somewhat higher in the H_2 case than in the Carbon Constraint case. Between 2020 and 2050, the gap increases from 5 to 6%. This difference is the direct consequence of higher global primary energy demand (see supra) that results from an overall cheaper energy system induced by substantial cost reductions in H_2 technology clusters.

Figure 54: World CO_2 emissions (H_2 case)



Energy-related CO_2 emissions in the world are 32% higher in 2050 than in 1990. They peak in 2030 at about 55% more than in 1990 and then decline. By 2050, emissions return to a level close to that of 2005. From 2000 to 2010, the emissions increase despite the rising carbon values in Europe and other Annex B countries. This happens because the carbon values in non-Annex B countries are very low up to 2020 (between 0 and 10 €/t CO_2) and because of the growing share of these countries in world primary energy demand. Thereafter the rate of growth of CO_2 emissions slows; the volume peaks around 2030 and then falls away from 2030 to 2050 in accordance with the progression of carbon values throughout the world.

In terms of final use, world emissions of CO_2 increase from all sectors compared to 1990. They increase most strongly in the residential and tertiary sectors (+140%), but appreciably in transport (slightly more than 40%) and rather moderately in industry and power generation (around 10%). This evolution changes the share of CO_2 emissions among sectors. In 2050, the above sectors account for 29%, 21%, 20% and 30% respectively of total emissions against 16%, 20%, 23% and 37% in 1990.

Compared to the Reference, world emissions of CO_2 in 2050 fall by 18 Gt (about 40%). Of this reduction some 13 Gt, or about three quarters, is achieved in the generation of electricity; this is 62% less than in the Reference. Emissions from industry and transport also fall substantially, by 33% and 22%. Emissions from the residential and tertiary sectors are not much affected; they are only 2% lower.

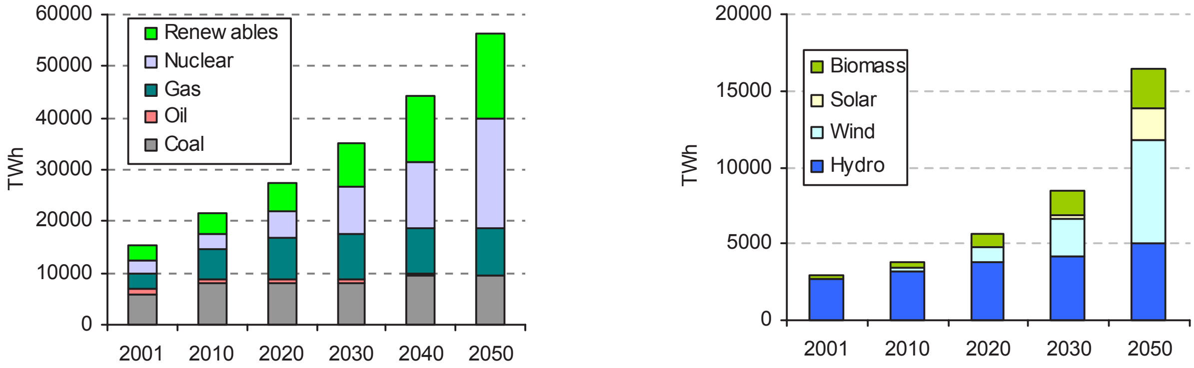
4.4.3 World electricity and hydrogen production

Policies to reduce emissions of CO_2 affect the volume and structure of electricity production in the world. This was shown in Chapter 2 for the Carbon Constraint case; the growth of electricity generation and the share of fossil energy sources were reduced compared to the Reference. Generation in the H_2 case evolves much like in the CC case; it increases on average by 2.7% per year, compared to 2.8% per year in the Reference. By 2050, this amounts to about 5% less generation, or 3 000 TWh/yr.

The move to a hydrogen economy induces further change in the structure of generation. In the CC case, fossil fuels, nuclear and renewable energy each produce about one third of world electricity. In the H_2 case, the share of nuclear increases to 38%, at the expense of both fossil fuels and renewables. Generation of electricity in the world is 56 000 TWh/yr in 2050; of this total, 9 000 TWh/yr comes from coal, 9 000 TWh/yr from hydrocarbons (mainly natural gas), 21 500 TWh/yr from nuclear energy and 16 500 TWh from renewable energy.

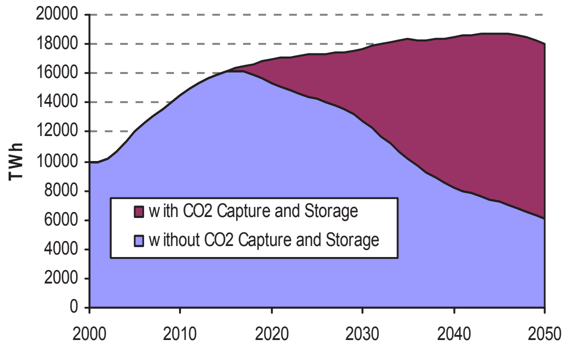
Until 2030, the development of renewable electricity is dominated by large hydro, supplemented by regular increases in wind power and biomass (Figure 55). After 2030, the growth of wind power accelerates so that by 2050, it represents slightly more than 40% of renewable electricity and 12% of global electricity production. The contribution of solar power is significant in 2050, with a market share in renewable electricity of 12%, close to that of biomass.

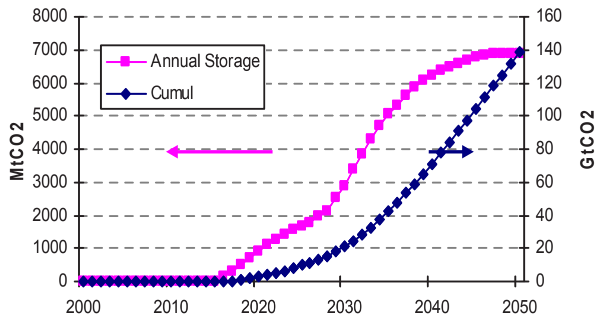
Figure 55: World electricity production (H_2 case)



Despite the remarkable decrease in the share of fossil fuels for electricity production, the volume of production of thermal electricity progresses steadily, although more slowly than the total of electricity production (1.3% compared to 2.7%). This continued growth of thermal electricity is consistent with policies to reduce emissions of CO_2, because it is associated with the development of carbon capture and storage systems (CCS) in centralised power plants. The H_2 case assumes rapid progress in this technology, as represented by the lower costs incorporated in the H_2 scenario. In 2030, 28% of electricity generation from fossil fuels is in plants equipped with CCS against only 2% in the Reference. By 2050, the shares are 66% and 12%. As a result, the cumulative storage of CO_2 is seven times higher in the H_2 case (140 $GtCO_2$) than in the Reference (20 $GtCO_2$).

Figure 56: Carbon capture and storage in thermal electricity production (H_2 case)

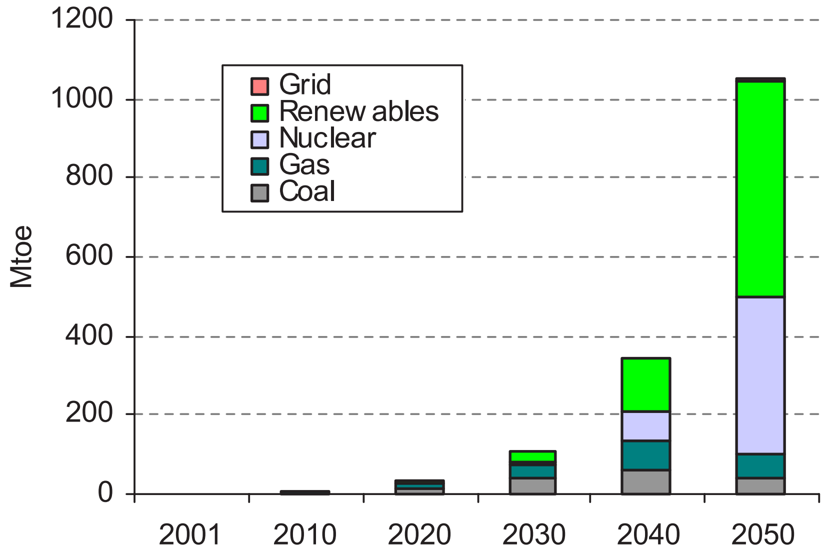




The production of hydrogen in the world takes-off after 2030, driven by substantial reductions in the cost of the technology and the demand-pull of the transport sector. From 2030 to 2050 production increases by a factor of 10 to reach 1 Gtoe. In the Reference, the volume of production is 350 Mtoe/yr at the end of the period. By 2050, hydrogen provides 13% of final energy consumption, compared to 2% in the Reference; this is equivalent to 26% of world electricity consumption, against 7% in the Reference.

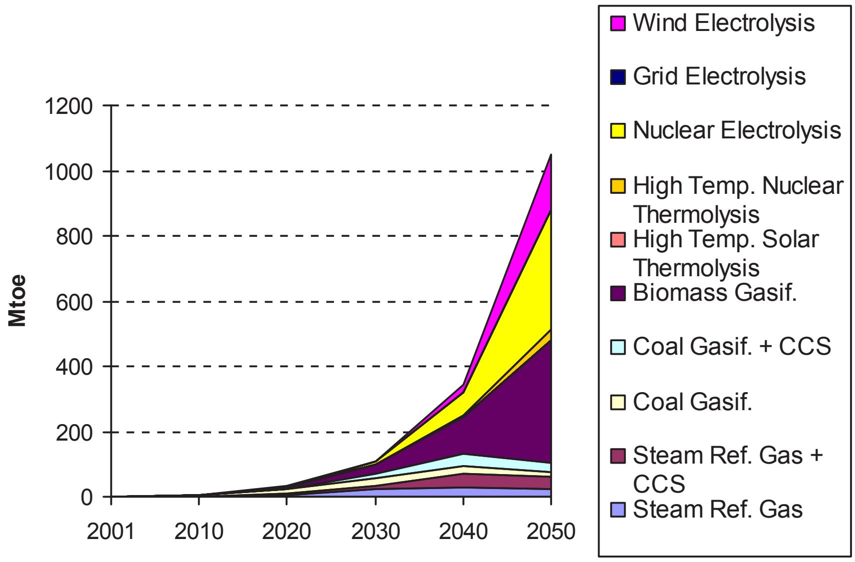
Until 2030, two third of hydrogen production is from fossil fuels, of which about 40% is from steam reforming of natural gas and 60% from coal gasification. Subsequently, because of higher carbon values, the production from non-fossil energy sources increases sharply. By 2050, the share of production from coal and natural gas has fallen to 10%, although the volume is increasing. The share of renewable energy is 50% and of nuclear is 40%.

Figure 57: Fuel mix in world hydrogen production (H_2 case)



Biomass is the dominant source of renewable hydrogen with a share of 70%. The balance is mainly from wind; the share of solar thermal is less than 1%. More than 90% of the production from nuclear electricity is by electrolysis of water. 60% of the production from fossil fuels is from steam reforming of natural gas and 40% is from coal gasification. The change in shares compared to 2030 is a consequence of higher carbon values. Around 65% of plants for hydrogen production using fossil fuels are equipped with CCS facilities in 2050, against 35% in 2030.

Figure 58: Technology mix in world hydrogen production (H_2 case)



It is interesting to compare the shares of fuels used in production of the two energy carriers: electricity and hydrogen. The share of nuclear is similar for the two types of production, about 40%. The second source of electricity production is fossil fuel, whereas for hydrogen it is renewable energy. Production of electricity from renewable energy is about 2.6 times the production of hydrogen from renewables, but the electricity produced from biomass is only half of the hydrogen produced from biomass.

4.4.4 Final energy consumption and energy developments in transport

Final energy consumption in the world by 2050 is 11% lower in the H_2 case than in the Reference. Less energy is used in industry and in the residential and tertiary sectors. Energy consumption in transport and in buildings is similar in the two cases, because the price-induced diffusion of very low energy buildings is balanced by an overall cheaper energy system in the H_2 case.

There is no significant change in the allocation of final energy consumption among sectors and in the market share of fossil fuels and electricity. The largest share of consumption is still in the residential and tertiary sectors (more than 40% of the total) and electricity final consumption increases regularly to reach 30% of total final energy demand in 2050 (compared to 15% now).

There are two major differences between the H_2 case and the Reference (and the Carbon Constraint case); the first one concerns the use of hydrogen and the second one the fuel mix in transport.

The critical finding for hydrogen consumption is that around 90% is used in transport (Figure 59). The 'optimistic' characterisation of hydrogen technology and the assumed demand-pull from transport in the H_2 case contribute to this result. The remaining 10% goes one third to the residential and tertiary sectors and two thirds to fuel cell based CHP in industry. In the

Reference, the above sectors account for 64%, 17% and 19% respectively of total hydrogen consumption.

Figure 59: World final hydrogen consumption by sector (H_2 case)

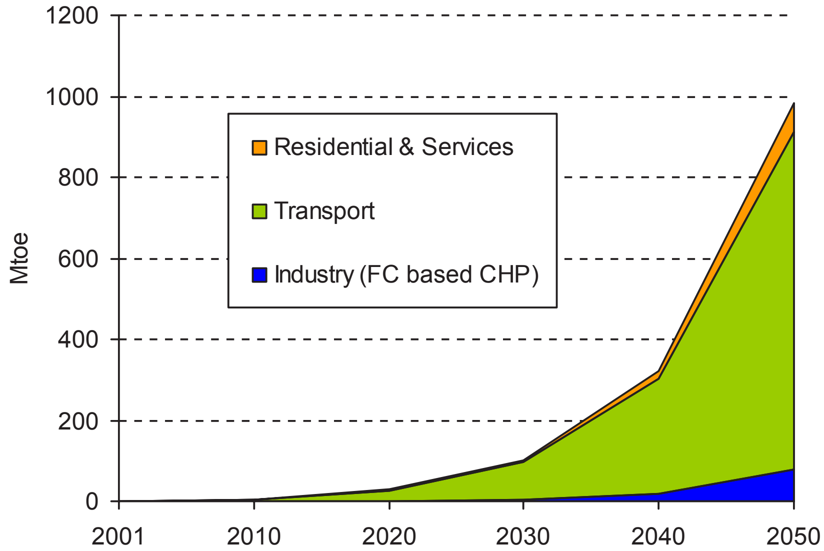
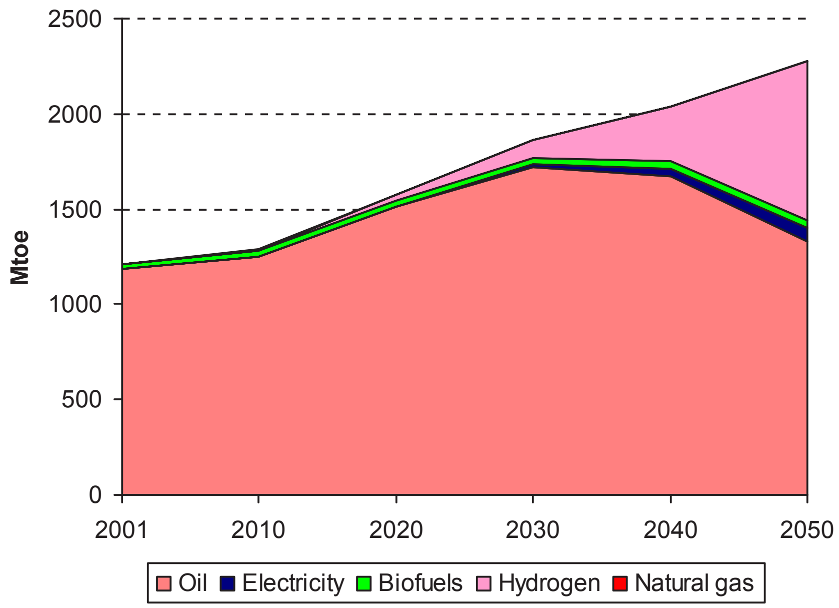


Figure 60 shows how world energy consumption in transport develops in the H_2 case. In 2030, hydrogen takes 5% of the transport market, against 2% in the Reference. Hydrogen as a transport fuel catches a fraction of the market share of petroleum products. The shares of biofuels and electricity remain unaffected in the two cases (in the order of 3% all together). The effect of CO_2 reduction policies on total energy consumption in transport in the H_2 case is small, but perceptible; consumption is 4.5% lower than in the Reference.

Figure 60: World energy consumption in transport (H_2 case)[48]



By 2050, the H_2 case has diverged strongly from the others. Energy consumption in transport is 10% higher than in the Reference because of the large fall in the cost of hydrogen. The consumption of hydrogen has now taken off; it is five times as great as in the Reference, with a market share in transport of almost 36%[49]. The consumption of petroleum products correspondingly falls by 26%. The use of electricity in transport falls by about 3%, because hydrogen-based vehicles displace a part of electric vehicles. The consumption of biofuels changes imperceptibly. The balance of these effects on the fuel mix in transport is: 58% for oil products; 3% for electricity; 2% for biofuels and 37% for hydrogen. The small market share of biofuels is because biomass is used mainly to produce electricity and hydrogen (see supra).

Because the demand-pull for hydrogen in transport is mainly from passenger cars it is interesting to show the evolution of the mix of technologies in this segment of the market (Figure 61). Cars fuelled with hydrogen penetrate steadily from 2010 to 2050. By 2050, hydrogen cars represents 30% of total passenger cars. About 80% are fuel cell cars; 15% are hydrogen hybrid vehicles and 5% are hydrogen internal combustion engines. The shares of the different technologies within the hydrogen market evolve in time in a manner determined by the assumptions underlying the pathways described in chapter 3.2. ICE-H_2 cars start with a share of 18% in 2020 that declines steadily to 5% in 2050. The share of hydrogen-hybrid vehicles increases from around 7% in 2020 to 15% in 2050. Eventually, FC cars dominate, with a share between 75 and 80% of the hydrogen market in passenger cars.

Outside the hydrogen market, the use of electric vehicles increases, although a little less than in the Reference; use of conventional gasoline and diesel cars declines, but is partly compensated by the development of hybrids using gasoline or diesel as complementary fuel.

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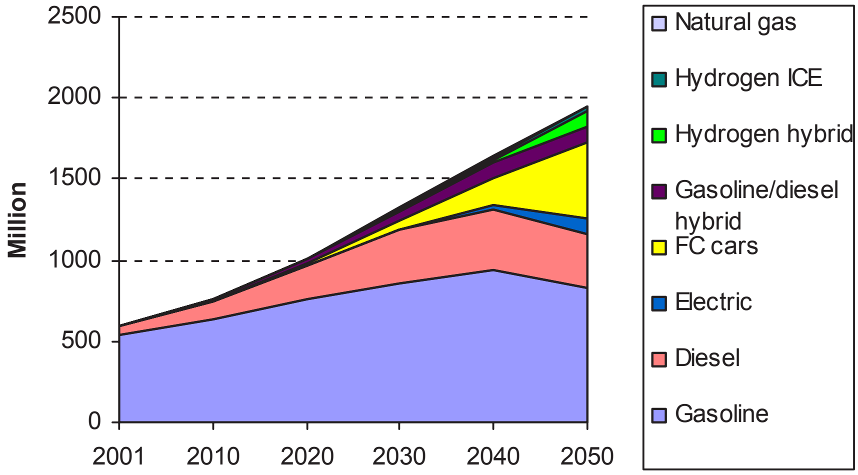
48 The consumption of natural gas does not appear on the graph because it is negligible.

49 In the Reference, the market share of hydrogen in transport was around 8% in 2050.

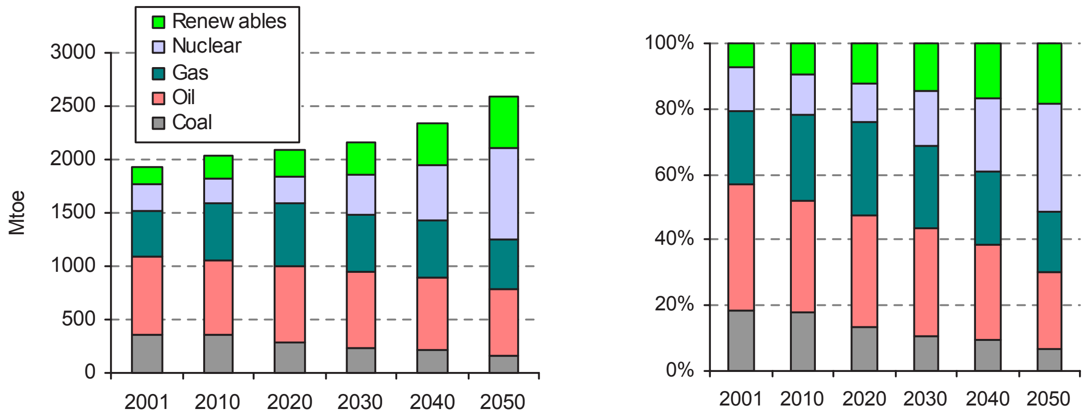
Figure 61: Developments in passenger car technology in the world (H_2 case)[50]



4.4.5 The hydrogen case in Europe

As in the Carbon Constraint case, the H_2 case has significant effect on the dynamics of the energy system in Europe. Primary energy demand increases at a moderate rate up to 2030 (+ 0.4% per year on average) and then somewhat faster from 2030 to 2050 (+ 0.9% per year on average). Consequently, primary energy consumption is 35% higher in 2050 compared to now at 2.6 Gtoe.

Figure 62: Primary energy demand in Europe (H_2 case)

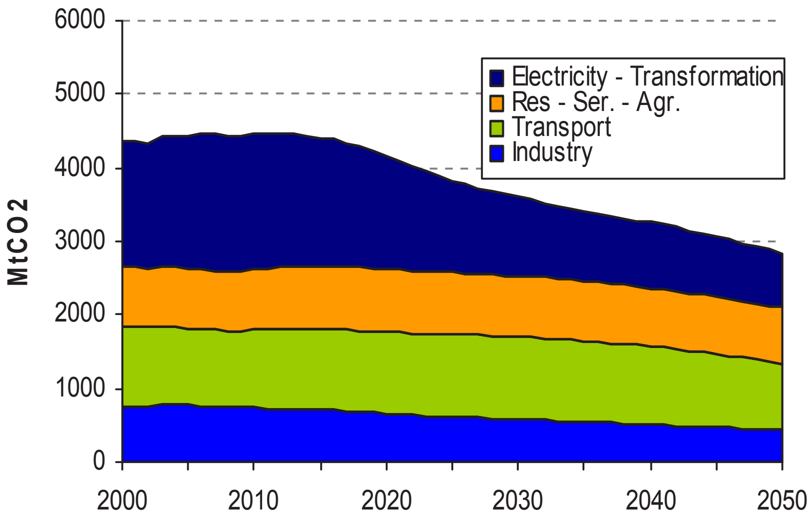


50 Gasoline and diesel car fleet includes cars using biofuels; cars fueled with natural gas do not appear on the graph because their share in the total car fleet is negligible.

This evolution of primary energy demand shows that up to 2030 the main reaction of the European energy system to CO_2 reduction policies is to improve energy efficiency, whereas the main element in the long-term as hydrogen takes off is change in the fuel mix. In 2020 and in 2030, primary energy consumption is 4% and 6% lower than in the Reference, but only 2% lower in 2050, compared to 6% in the CC case. By 2050, there is a significant change in the fuel mix. Already in the Carbon Constraint case there is a marked progression of nuclear and renewable energy sources at the expense of fossil fuels, especially coal; this is complemented in the H_2 case by a deeper penetration of nuclear and an additional fall in the use of coal. Consequently, in 2050, nuclear energy provides one third of the primary energy consumption in Europe. Oil, natural gas and renewables each provide roughly one fifth and coal 6%.

Emissions of CO_2 fall steadily, but they are slightly higher in the H_2 case than in the Carbon Constraint case; this is for the same reasons described for world emissions in section 4.4.2. By 2050, CO_2 emissions are 35% lower than now, against a 40% reduction in the CC case. The difference arises from the transport sector that has similar emissions in the H_2 and Reference cases.

Figure 63: Energy-related CO_2 emissions in Europe (H_2 case)

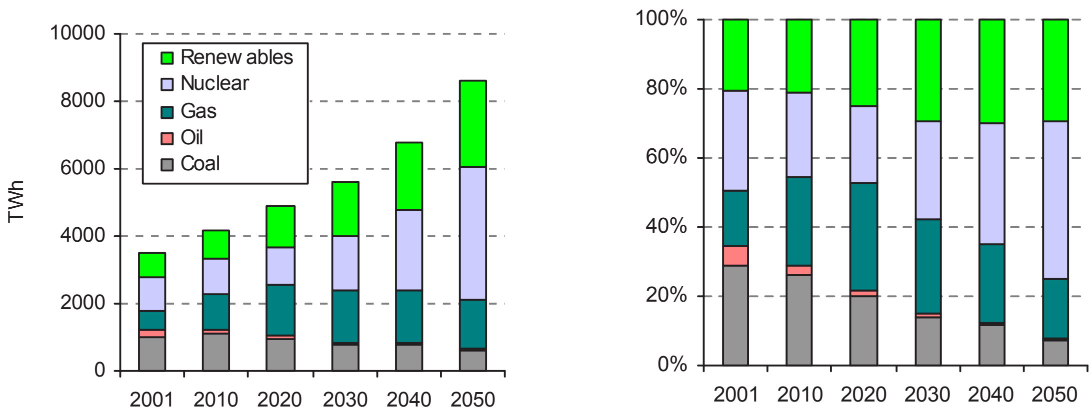


Electricity generation in Europe grows strongly from 2030 to 2050. Electricity generation increases on average by 2.1% per year compared to 1.8% in the Reference; consequently, and despite a slower evolution in the H_2 case before 2030, about 200 TWh/yr more electricity is needed by 2050.

The fuel mix in power generation changes markedly compared to the balanced structure of the Reference. As in the Carbon Constraint case, the share of fossil fuels decreases steadily and significantly after 2020. This is especially true for coal; in the H_2 case coal has 7% of generation in 2050, against 9% and 22% in the CC and Reference cases. By 2050, electricity production from coal is 40% less than now. Natural gas maintains a market share of around 17% to 2050, as it does in the CC and Reference cases; this amounts to more than twice the current volume of electricity generation from natural gas.

The use of CCS systems develops greatly from 2020 to 2050 because of the carbon constraint and cost reductions and despite the drop in thermal electricity. By 2050, more than 50% of thermal electricity production in Europe is from plant with CCS, almost evenly allocated between coal and natural gas. Because of the smaller share of coal in generation, the result is that CCS covers 70% of generation from coal and 40% of generation from natural gas.

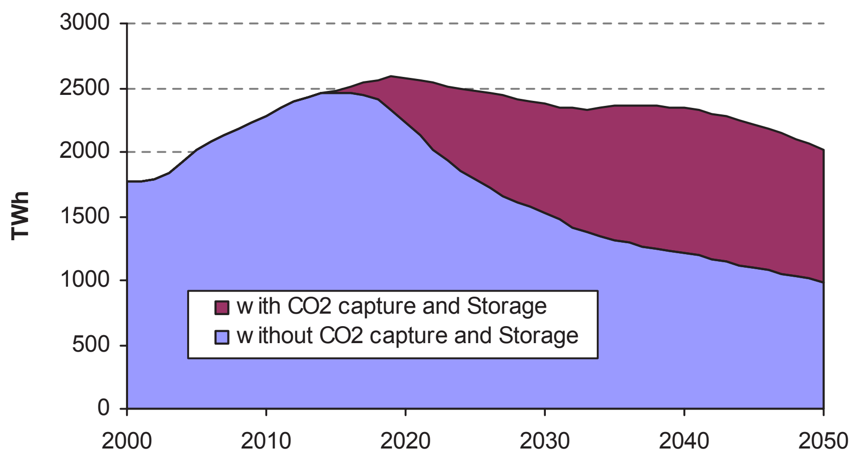
Figure 64: Electricity production and fuel mix in Europe (H_2 case)



Generation of electricity from nuclear energy falls in both absolute and relative terms from now to 2020, but thereafter increases rapidly, especially during the last ten years of the period. By 2050, nuclear provides 4 000 TWh/yr, almost half of the electricity produced in Europe and four times the present amount.

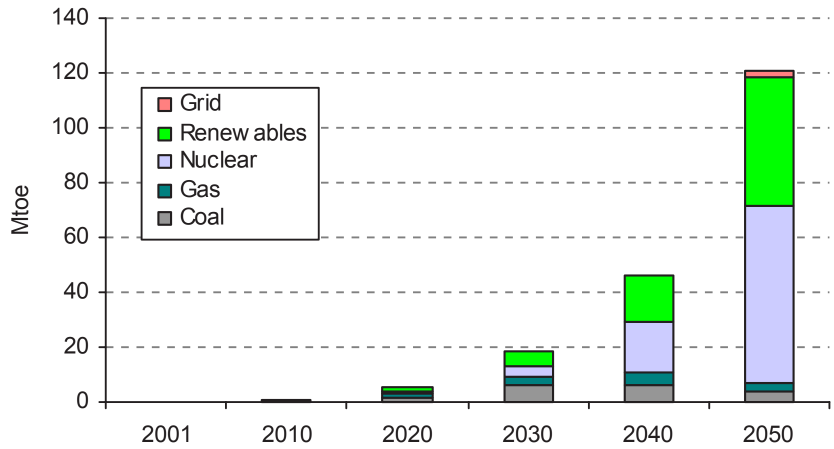
Renewable electricity grows continuously over the period and has a share of 30% of generation in 2050. Ensuring about one third of renewable electricity production, wind power takes the lead in 2050, followed by hydro (30%), solar PV and biomass (36% together).

Figure 65: Development of CCS in European thermal electricity production (H_2 case)



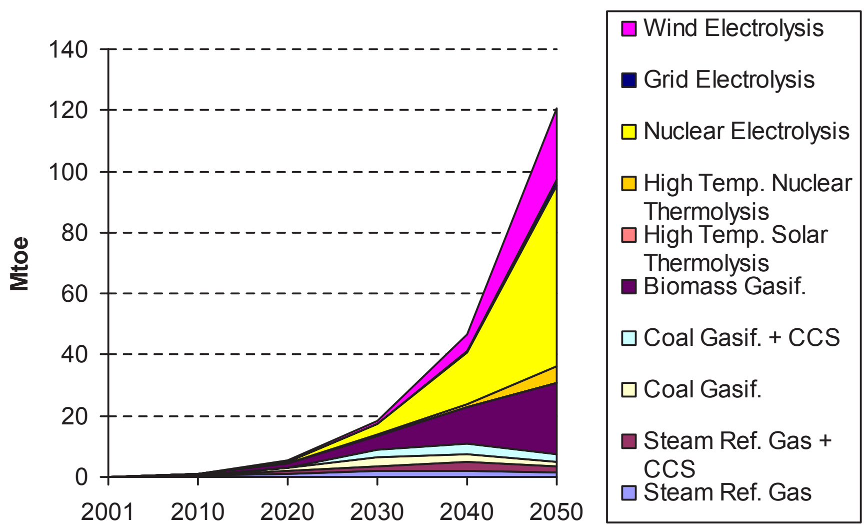
The production of hydrogen in the H_2 case increases rapidly after 2030 to reach 120 Mtoe/yr by 2050; this is 12% of world hydrogen production. Hydrogen provides 7% of final energy consumption in Europe, against 3% in the Reference; it is equivalent to one fifth of electricity consumption in Europe. This behaviour is broadly similar to that observed worldwide.

Figure 66: Fuel mix in hydrogen production in Europe (H_2 case)



The origin of the hydrogen used in Europe is somewhat different from that elsewhere. In Europe, hydrogen is produced mainly from the electrolysis of water using nuclear electricity; elsewhere it is mainly from renewable sources. Nevertheless, the share of renewables in Europe is not negligible and by 2050 represents 40% of total hydrogen production, evenly allocated between wind and biomass (Figure 67). This compares to 50% worldwide.

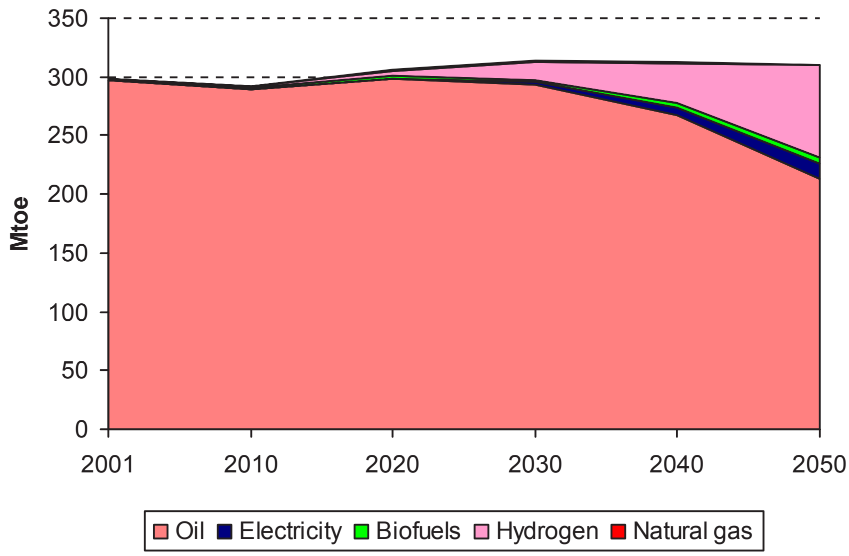
Figure 67: Technology mix in hydrogen production in Europe (H_2 case)



In 2050, about three quarter of the hydrogen produced in Europe goes to transport; this is less than the 90% share worldwide. The remaining quarter is allocated 20% to the residential and tertiary sectors and 5% to fuel cell based CHP in industry. Energy consumption in transport is projected to be stable from 2001 to 2050, showing only a 4% increase over 49 years. The penetration of hydrogen into the transport market implies a fall in the share of petroleum products. The demand for biofuels and electricity also increases, although less than for hydrogen. By 2050, gasoline, diesel and other petroleum products represent 70% of total energy consumption in transport; this is 30% below the volume now.

The mix of technologies for hydrogen cars reflects that described for the world. By 2050, 80% of the H_2 passenger car fleet are fuel cell cars; 15% are hydrogen hybrid cars and 5% are hydrogen internal combustion engines.

Figure 68: Energy consumption in transport[51] in Europe



[51] The consumption of natural gas does not appear on the graph because it is negligible.

KEY MESSAGES

Drivers and constraints in the H_2 case

Hydrogen technologies

The Reference case is characterised by business-as-usual trends in cost and performance data for hydrogen technologies. It shows a small penetration of hydrogen into the energy system; by 2050, the share of hydrogen in final energy consumption is 2% of the world total and 3% for Europe. Given the many ongoing initiatives to facilitate and accelerate the development and deployment of cost-competitive hydrogen technologies, an alternative scenario – the H_2 case – was elaborated. The H_2 scenario assumes technological breakthroughs based on the indicative targets outlined by the International Platform for the Hydrogen Economy.

These breakthroughs show that improvements in technical performance and costs are predominantly required in the distribution and consumption segments of the hydrogen economy. Fuel cell technologies have to undergo a decrease in cost by a factor 100 to become competitive. The technical and economic characteristics of the transport and distribution of hydrogen must also be improved significantly. On the production side, fossil fuel based technologies are already close to the competitiveness threshold.

Climate policy

The assumptions on climate policy are similar to those made in the Carbon Constraint case and are expressed in the same time-path of carbon values. However, the emission profiles of CO_2 differ because of differences in technical performance and cost in the two cases.

The world energy system in the H_2 case

Primary energy demand

The primary energy demand in 2050 is 1.7 Gtoe (8%) less than the Reference and change to the fuel mix is significant. The share of fossil fuels in 2050 is slightly less than 60% in the H_2 case compared to 70% in the Reference. Coal is affected more than other fossil fuels. The demand for coal drops dramatically by 49% in 2050 compared to the Reference despite the assumed lower cost of carbon capture and storage. The share of nuclear and renewable energy grows more strongly in the H_2 case than in the Reference. The fastest increase is between 2030 and 2050; it is caused partly by the high carbon values across the world and partly by the rapidly growing demand for hydrogen.

CO2 emissions

World emissions of CO_2 in 2050 fall by 18 Gt (about 40%) compared to the Reference. Of this reduction, about three quarters are achieved in the generation of electricity. This result shows that the deployment of hydrogen in the world energy system is compatible with ambitious climate policies consistent with a trajectory of long-term stabilisation of greenhouse gas emissions at 550 ppmv. World emissions of CO_2 are, however, somewhat higher in the H_2 case than in the Carbon Constraint case. Between 2020 and 2050, the gap is from 5 to 6%. This difference is the direct consequence of slightly higher global primary energy demand that in turn results from an overall cheaper energy system.

Electricity production

The growth of electricity generation and the share of fossil energy sources are reduced compared to the Reference. Generation in the H_2 case evolves much like in the Carbon Constraint case. The move to a hydrogen economy induces further change in the structure of generation; the share of nuclear increases to 38%, compared to 33% in the CC case, at the expense of both fossil fuels and renewables. The volume of production of thermal electricity continues to grow because it is associated with the development of carbon capture and storage (CCS) systems. In 2050, 66% of electricity generation from fossil fuels is in plants equipped with CCS against 12% in the Reference.

Hydrogen production

The production of hydrogen in the world takes-off after 2030, driven by substantial reductions in the cost of the technology and the demand-pull in the transport sector. From 2030 to 2050 production increases by a factor of 10 to reach 1 Gtoe. By 2050, hydrogen provides 13% of final energy consumption, compared to 2% in the Reference and the share of production from coal and natural gas is only 10%, although the volume is increasing. The share of renewable energy is 50% and of nuclear is 40%.

Energy consumption in transport

The critical finding for hydrogen consumption is that around 90% is used in transport. The ‘optimistic’ characterisation of hydrogen technology and the demand-pull from transport assumed in the H_2 case contributes to this result.

By 2050, the consumption of hydrogen in transport is five times as great as in the Reference, with a share of 35% of the energy consumption of the sector. Hydrogen cars represents 30% of total passenger cars: about 80% are fuel cell cars; 15% are hydrogen hybrid vehicles and 5% are hydrogen internal combustion engines.

The European energy system in the H_2 case

Primary energy demand and CO_2 emissions

As at world level, the H_2 case has significant effect on the dynamics of the energy system in Europe. Primary energy demand in 2050 is 2% lower than in the Reference and there is a significant change in the fuel mix. Nuclear energy provides one third of the primary energy consumption in Europe. Oil, natural gas and renewables each provide roughly one fifth and coal 6%. Emissions of CO_2 fall steadily and are 35% lower than now.

Electricity and hydrogen production

Electricity generation in Europe grows strongly from 2030 and 2050. It increases on average by 2.1% per year compared to 1.8% in the Reference. The fuel mix in power generation changes markedly compared to the balanced structure of the Reference. The share of fossil fuels decreases steadily and significantly. The use of CCS systems develops greatly; by 2050, more than 50% of thermal electricity production is from plants with CCS.

The production of hydrogen increases rapidly after 2030 to reach 120 Mtoe/yr by 2050; this is 12% of world hydrogen production. Hydrogen provides 7% of final energy consumption in Europe, against 3% in the Reference. In Europe, hydrogen is produced mainly from the electrolysis of water using nuclear electricity. Nevertheless, the share of renewables is not negligible and by 2050 represents 40% of total hydrogen production.

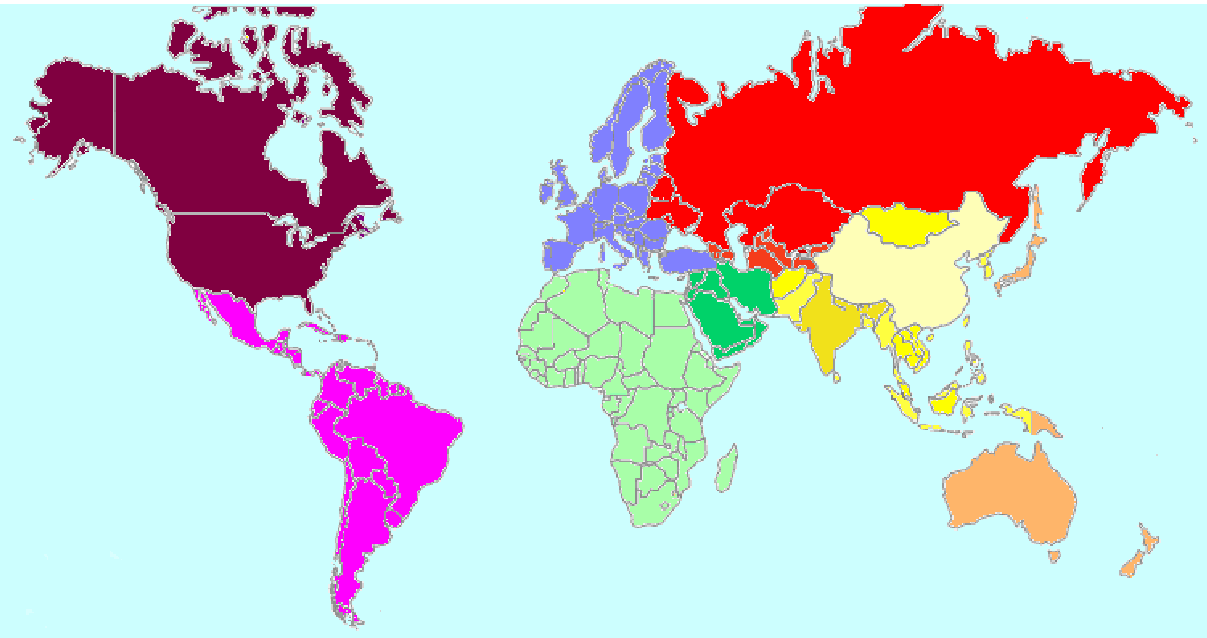
Energy consumption in transport

In 2050, about three quarter of the hydrogen produced in Europe goes to transport. Energy consumption in transport is projected to be stable from 2001 to 2050, showing only a 4% increase over 49 years. The mix of hydrogen technologies for hydrogen passenger cars reflects that described for the world.

ANNEXES

1. Definition of POLES Regions

WORLD BREAKDOWN IN WETO-H_2



Europe: Albania, Austria, Belgium, Bosnia-Herzegovina, Bulgaria, Croatia, Czech Republic, Cyprus, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Latvia, Lithuania, Luxembourg, Macedonia, Malta, Netherlands, Norway, Poland, Portugal, Romania, Serbia & Montenegro, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey, United Kingdom

CIS (Community of Independent States): Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyz Rep., Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, Uzbekistan

North America: USA, Canada

Latin America: Central America (including Mexico), South America and Caribbean

Japan, Pacific: Japan, Australia, New Zealand, Papua New Guinea, Fiji, Kiribati, Samoa (Western), Solomon Islands, Tonga, Vanuatu

Asia:

China

India

Rest of Asia: Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia, China, Hong-Kong, India, Indonesia, Lao, Macao, Malaysia, Maldives, Myanmar, Mongolia, Nepal, North Korea, Pakistan, Philippines, Thailand, Singapore, South Korea, Sri Lanka, Taiwan, Vietnam.

Africa, Middle East:

Africa: North Africa (Algeria, Tunisia, Morocco, Libya, Egypt) and Sub-Saharan Africa

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

OTHER REGIONS

EU25 (European Union 25): Austria, Belgium, Czech Republic, Cyprus, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, United Kingdom

OECD: Australia, Austria, Belgium, Canada, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Spain, Slovak Republic, South Korea, Sweden, Switzerland, Turkey, United Kingdom, USA

***OPEC* (*Organization of Petroleum Exporting Countries*)**: Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates, Venezuela

OPEC Middle East: Iran, Iraq, Kuwait, Qatar, Saudi Arabia, United Arab Emirates

Gulf: Bahrain, Iran, Iraq, Kuwait, Oman, Qatar, Saudi Arabia, United Arab Emirates, Yemen

2. WETO-H_2 projections by region

World

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	5245	6113	6792	7496	8082	8864	1.3%	0.9%	0.5%
GDP (G$95)	29880	42224	59524	81559	105930	164090	3.5%	2.9%	2.2%
Per capita GDP ($95/cap)	5697	6907	8764	10880	13107	18513	2.2%	2.0%	1.7%
Gross inland cons/GDP (toe/M$95)	290	236	205	176	157	134	-1.7%	-1.3%	-0.8%
Gross inland cons/capita (toe/cap)	1.6	1.6	1.8	1.9	2.1	2.5	0.4%	0.7%	0.9%
Electricity cons/capita (kWh/cap)	1832	2077	2554	3064	3688	5529	1.7%	1.9%	2.0%
Transport fuels per capita (toe/cap)	0.3	0.3	0.3	0.3	0.3	0.3	0.0%	0.4%	0.5%
CO2 emissions/capita (tCO2/cap)	3.8	3.9	4.3	4.6	4.8	5.0	0.5%	0.6%	0.2%
% of renewables in gross inland cons	13	13.5	12.8	12.1	12.0	15.3	-0.2%	-0.3%	1.2%
% of renewables in electricity	20	18.7	18.2	18.7	20.6	25.0	-0.5%	0.6%	1.0%
Primary Production (Mtoe)	**8834**	**9836**	**12346**	**14532**	**16853**	**22276**	1.7%	1.6%	1.4%
Coal, lignite	2207	2408	2937	3371	3976	5678	1.4%	1.5%	1.8%
Oil	3234	3487	3951	4771	5385	5964	1.0%	1.6%	0.5%
Natural gas	1708	1929	3164	3723	4075	4084	3.1%	1.3%	0.0%
Nuclear	525	671	739	926	1425	3185	1.7%	3.3%	4.1%
Hydro, geothermal	216	232	275	320	357	417	1.2%	1.3%	0.8%
Biomass and wastes	939	1101	1261	1352	1462	2261	1.5%	0.7%	2.2%
Wind, solar	0	7	21	69	174	686	21.9%	11.2%	7.1%
Gross Inland Consumption (Mtoe)	**8654**	**9950**	**12195**	**14348**	**16647**	**22047**	1.7%	1.6%	1.4%
Coal, lignite	2201	2352	2937	3371	3976	5678	1.5%	1.5%	1.8%
Oil	3089	3487	3951	4771	5385	5964	1.2%	1.6%	0.5%
Natural Gas	1679	2082	3164	3723	4075	4084	3.2%	1.3%	0.0%
Biomass and wastes	940	1101	1261	1352	1462	2261	1.5%	0.7%	2.2%
Others	745	911	1035	1316	1955	4289	1.7%	3.2%	4.0%
Final Consumption (Mtoe)	**6267**	**7102**	**8302**	**9755**	**11129**	**13739**	1.4%	1.5%	1.1%
by source									
Coal, lignite	869	670	913	1052	1193	1377	0.3%	1.3%	0.7%
Oil	2553	2950	3376	4071	4624	5172	1.4%	1.6%	0.6%
Gas	985	1137	1345	1544	1680	1610	1.6%	1.1%	-0.2%
Electricity	826	1092	1492	1975	2563	4215	3.0%	2.7%	2.5%
Biomass and wastes	855	1004	926	855	791	867	0.4%	-0.8%	0.5%
Heat	179	249	250	251	253	257	1.7%	0.1%	0.1%
Hydrogen	0	0	1	7	24	241		15.9%	12.1%
by sector									
Industry	2416	2639	3180	3666	4093	4649	1.4%	1.3%	0.6%
Transport	1432	1717	1869	2143	2399	2929	1.3%	1.3%	1.0%
Household, Service, Agriculture	2418	2746	3253	3946	4637	6162	1.5%	1.8%	1.4%
Electricity Generation (TWh)	**11859**	**15468**	**21113**	**27993**	**36295**	**60040**	2.9%	2.7%	2.5%
Thermal, of which :	7609	10074	14669	19507	23809	31584	3.3%	2.5%	1.4%
Coal	4422	5848	7600	10025	12689	19066	2.7%	2.6%	2.1%
Gas	1705	2934	5823	7799	8760	9072	6.3%	2.1%	0.2%
Biomass and wastes	150	155	442	757	1372	2246	5.6%	5.8%	2.5%
Nuclear	2013	2653	3049	4004	6328	14866	2.1%	3.7%	4.4%
Hydro+Geothermal	2231	2703	3198	3717	4148	4853	1.8%	1.3%	0.8%
Solar	1	1	7	14	91	1493	12.1%	13.9%	15.0%
Wind	4	37	188	746	1880	6433	21.4%	12.2%	6.3%
Hydrogen	0	0	2	5	39	811		15.3%	16.4%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**2**	**8**	**32**	**378**		15.7%	13.1%
Coal	0	0	1	3	12	111		16.2%	11.9%
Renewables	0	0	0	3	15	206		20.5%	14.0%
Nuclear	0	0	0	0	0	41		17.1%	28.0%
CO2 Emissions (MtCO2), *of which :*	**20161**	**23566**	**29055**	**34206**	**38749**	**44297**	1.8%	1.4%	0.7%
Electricity generation	7433	8932	10562	12246	13747	16065	1.8%	1.3%	0.8%
Industry	4653	4812	6045	6910	7656	7971	1.3%	1.2%	0.2%
Transport	3982	5056	5461	6206	6815	7263	1.6%	1.1%	0.3%
Household, Service, Agriculture	3191	3196	4128	5431	6488	7891	1.3%	2.3%	1.0%
CO2 Sequestration (Mt CO2)	0	0	0	10	271	2545			11.9%

NB : Oil consumption in international bunkers is accounted for in gross inland consumption at world level (but not at regional levels). The related emissions are included in the world total CO_2 emissions ($MtCO_2$).

Europe

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	564	588	599	605	606	586	0.3%	0.1%	-0.2%
GDP (G$95)	8373	10312	12660	15900	19079	25194	2.1%	2.1%	1.4%
Per capita GDP ($95/cap)	14849	17533	21124	26260	31496	43005	1.8%	2.0%	1.6%
Gross inland cons/GDP (toe/M$95)	212	186	160	136	120	105	-1.4%	-1.4%	-0.7%
Gross inland cons/capita (toe/cap)	3	3.3	3.4	3.6	3.8	4.5	0.4%	0.6%	0.9%
Electricity cons/capita (kWh/cap)	4206	4995	5787	6896	8176	11839	1.6%	1.7%	1.9%
Transport fuels per capita (toe/cap)	0.5	0.6	0.6	0.6	0.6	0.6	0.6%	0.2%	-0.1%
CO2 emissions/capita (tCO2/cap)	7.7	7.4	7.4	7.8	7.5	6.8	-0.2%	0.0%	-0.5%
% of renewables in gross inland cons	6	7.5	9.7	11.2	12.9	16.9	2.9%	1.4%	1.4%
% of renewables in electricity	18	20.4	21.0	22.9	25.6	25.9	0.7%	1.0%	0.1%
Primary Production (Mtoe)	**1115**	**1196**	**1284**	**1102**	**1158**	**1593**	0.7%	-0.5%	1.6%
Coal, lignite	393	240	220	213	218	225	-2.9%	-0.1%	0.2%
Oil	224	313	309	185	113	86	1.6%	-4.9%	-1.4%
Natural gas	190	244	310	226	203	210	2.5%	-2.1%	0.2%
Nuclear	209	254	246	234	326	625	0.8%	1.4%	3.3%
Hydro, geothermal	44	54	55	58	60	63	1.1%	0.4%	0.3%
Biomass and wastes	53	87	131	159	188	283	4.6%	1.8%	2.1%
Wind, solar	0	3	11	27	49	101	29.0%	7.6%	3.7%
Gross Inland Consumption (Mtoe)	**1773**	**1921**	**2029**	**2168**	**2299**	**2642**	0.7%	0.6%	0.7%
Coal, lignite	481	359	354	367	404	458	-1.5%	0.7%	0.6%
Oil	681	734	689	724	727	626	0.1%	0.3%	-0.7%
Natural Gas	300	429	541	597	542	484	3.0%	0.0%	-0.6%
Biomass and wastes	53	87	131	159	188	283	4.6%	1.8%	2.1%
Others	258	313	315	320	436	791	1.0%	1.7%	3.0%
Final Consumption (Mtoe)	**1263**	**1377**	**1419**	**1519**	**1578**	**1647**	0.6%	0.5%	0.2%
by source									
Coal, lignite	156	82	79	80	83	82	-3.3%	0.2%	-0.1%
Oil	575	648	618	649	658	570	0.4%	0.3%	-0.7%
Gas	235	288	312	317	291	238	1.4%	-0.3%	-1.0%
Electricity	204	253	298	359	426	596	1.9%	1.8%	1.7%
Biomass and wastes	44	60	63	64	64	76	1.8%	0.1%	0.9%
Heat	50	47	48	49	50	53	-0.2%	0.2%	0.3%
Hydrogen	0	0	0	2	5	31		13.6%	9.8%
by sector									
Industry	493	472	488	511	519	495	-0.1%	0.3%	-0.2%
Transport	308	381	373	388	392	371	1.0%	0.2%	-0.3%
Household, Service, Agriculture	462	525	558	619	667	780	1.0%	0.9%	0.8%
Electricity Generation (TWh)	**2845**	**3489**	**4168**	**4991**	**5932**	**8608**	1.9%	1.8%	1.9%
Thermal, of which :	1540	1823	2384	3003	3217	3588	2.2%	1.5%	0.5%
Coal	1070	1006	1054	1279	1551	1860	-0.1%	1.9%	0.9%
Gas	230	577	1109	1436	1319	1337	8.2%	0.9%	0.1%
Biomass and wastes	15	51	108	170	258	328	10.4%	4.5%	1.2%
Nuclear	801	1006	1017	1012	1447	2931	1.2%	1.8%	3.6%
Hydro+Geothermal	503	633	643	672	697	738	1.2%	0.4%	0.3%
Solar	0	0	0	2	17	344	15.5%	23.8%	16.3%
Wind	1	27	123	301	545	817	28.8%	7.7%	2.1%
Hydrogen	0	0	0	1	9	190		22.4%	16.2%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**0**	**2**	**7**	**60**		14.6%	11.7%
Coal	0	0	0	0	1	6		13.9%	9.9%
Renewables	0	0	0	1	5	37		19.4%	10.6%
Nuclear	0	0	0	0	0	16			26.7%
CO2 Emissions (MtCO2), *of which :*	**4360**	**4367**	**4463**	**4712**	**4534**	**3963**	0.1%	0.1%	-0.7%
Electricity generation	1608	1519	1585	1755	1623	1454	-0.1%	0.1%	-0.5%
Industry	961	765	742	738	716	596	-1.3%	-0.2%	-0.9%
Transport	826	1122	1093	1122	1104	900	1.4%	0.0%	-1.0%
Household, Service, Agriculture	828	800	805	862	868	811	-0.1%	0.4%	-0.3%
CO2 Sequestration (Mt CO2)	0	0	0	9	200	529			5.0%

CIS

							Annual % change		
	1990	**2001**	**2010**	**2020**	**2030**	**2050**	**1990/10**	**2010/30**	**2030/50**
Key Indicators									
Population (Millions)	281	281	276	270	261	237	-0.1%	-0.3%	-0.5%
GDP (G$95)	2139	1463	2164	3041	3860	5488	0.1%	2.9%	1.8%
Per capita GDP ($95/cap)	7608	5204	7852	11263	14797	23174	0.2%	3.2%	2.3%
Gross inland cons/GDP (toe/M$95)	635	633	457	359	311	252	-1.6%	-1.9%	-1.0%
Gross inland cons/capita (toe/cap)	5	3.3	3.6	4.0	4.6	5.8	-1.5%	1.2%	1.2%
Electricity cons/capita (kWh/cap)	4438	3084	4114	5530	7318	11585	-0.4%	2.9%	2.3%
Transport fuels per capita (toe/cap)	0.5	0.2	0.3	0.3	0.3	0.3	-3.4%	0.9%	0.3%
CO2 emissions/capita (tCO2/cap)	11.9	8.3	8.8	10.2	11.3	11.7	-1.5%	1.3%	0.2%
% of renewables in gross inland cons	3	3.3	4.9	4.8	5.5	15.1	2.7%	0.6%	5.2%
% of renewables in electricity	15	19.1	18.5	15.8	15.8	26.4	1.2%	-0.8%	2.6%
Primary Production (Mtoe)	**1637**	**1226**	**1603**	**1738**	**1973**	**2294**	-0.1%	1.0%	0.8%
Coal, lignite	301	197	230	269	327	397	-1.3%	1.8%	1.0%
Oil	583	400	594	614	585	498	0.1%	-0.1%	-0.8%
Natural gas	659	543	675	745	899	1005	0.1%	1.4%	0.6%
Nuclear	55	54	56	57	97	186	0.1%	2.8%	3.3%
Hydro, geothermal	20	20	21	22	23	23	0.3%	0.3%	0.0%
Biomass and wastes	19	11	27	30	41	144	1.8%	2.1%	6.4%
Wind, solar	0	0	0	0	2	42		21.0%	17.9%
Gross Inland Consumption (Mtoe)	**1359**	**926**	**990**	**1090**	**1199**	**1382**	-1.6%	1.0%	0.7%
Coal, lignite	289	176	182	209	252	300	-2.3%	1.6%	0.9%
Oil	416	183	178	233	257	228	-4.1%	1.8%	-0.6%
Natural Gas	562	482	525	539	528	460	-0.3%	0.0%	-0.7%
Biomass and wastes	19	11	27	30	41	144	1.8%	2.1%	6.4%
Others	72	74	77	79	121	251	0.3%	2.3%	3.7%
Final Consumption (Mtoe)	**978**	**611**	**656**	**751**	**820**	**912**	-2.0%	1.1%	0.5%
by source									
Coal, lignite	139	58	52	55	64	64	-4.8%	1.1%	0.0%
Oil	322	126	157	195	217	208	-3.5%	1.6%	-0.2%
Gas	279	187	186	211	213	199	-2.0%	0.7%	-0.3%
Electricity	107	75	97	128	164	236	-0.5%	2.6%	1.8%
Biomass and wastes	19	9	7	6	4	46	-4.7%	-2.4%	12.4%
Heat	111	156	156	156	156	156	1.7%	0.0%	0.0%
Hydrogen	0	0	0	0	1	3		14.8%	9.5%
by sector									
Industry	492	257	275	296	306	301	-2.9%	0.6%	-0.1%
Transport	147	67	72	80	82	80	-3.5%	0.7%	-0.2%
Household, Service, Agriculture	339	287	309	375	431	531	-0.5%	1.7%	1.1%
Electricity Generation (TWh)	**1727**	**1252**	**1557**	**1995**	**2482**	**3458**	-0.5%	2.4%	1.7%
Thermal, of which :	1283	800	1075	1487	1764	1804	-0.9%	2.5%	0.1%
Coal	431	252	295	489	671	836	-1.9%	4.2%	1.1%
Gas	584	508	695	882	928	787	0.9%	1.5%	-0.8%
Biomass and wastes	21	3	39	52	107	150	3.1%	5.2%	1.7%
Nuclear	212	215	232	246	432	869	0.5%	3.1%	3.6%
Hydro+Geothermal	233	237	249	261	266	268	0.3%	0.3%	0.0%
Solar	0	0	0	0	0	3		1.0%	12.8%
Wind	0	0	0	1	18	489		26.8%	18.0%
Hydrogen	0	0	0	0	2	23		9.5%	14.0%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**0**	**0**	**1**	**6**		12.5%	11.1%
Coal	0	0	0	0	0	4		18.7%	13.7%
Renewables	0	0	0	0	0	1			14.9%
Nuclear	0	0	0	0	0	1			
CO2 Emissions (MtCO2), *of which :*	**3343**	**2331**	**2437**	**2742**	**2958**	**2782**	-1.6%	1.0%	-0.3%
Electricity generation	1330	763	771	856	930	847	-2.7%	0.9%	-0.5%
Industry	866	444	477	518	535	367	-2.9%	0.6%	-1.9%
Transport	398	187	200	221	225	199	-3.4%	0.6%	-0.6%
Household, Service, Agriculture	644	397	419	536	626	759	-2.1%	2.0%	1.0%
CO2 Sequestration (Mt CO2)	0	0	0	0	0	103			

North America

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	277	316	345	376	404	444	1.1%	0.8%	0.5%
GDP (G$95)	7146	10003	13225	16432	19843	26887	3.1%	2.0%	1.5%
Per capita GDP ($95/cap)	25778	31614	38341	43693	49146	60584	2.0%	1.2%	1.1%
Gross inland cons/GDP (toe/M$95)	299	252	216	183	158	127	-1.6%	-1.5%	-1.1%
Gross inland cons/capita (toe/cap)	8	8.0	8.3	8.0	7.8	7.7	0.4%	-0.3%	-0.1%
Electricity cons/capita (kWh/cap)	10999	12064	14030	14898	16274	20063	1.2%	0.7%	1.1%
Transport fuels per capita (toe/cap)	1.9	2.1	2.0	1.9	1.8	1.6	0.1%	-0.5%	-0.7%
CO2 emissions/capita (tCO2/cap)	19.0	19.6	19.5	18.6	17.6	14.5	0.1%	-0.5%	-1.0%
% of renewables in gross inland cons	6	6.2	8.2	9.9	12.3	15.6	1.4%	2.0%	1.2%
% of renewables in electricity	19	14.6	14.0	15.9	20.8	26.9	-1.5%	2.0%	1.3%
Primary Production (Mtoe)	**1926**	**2040**	**2451**	**2473**	**2854**	**3998**	1.2%	0.8%	1.7%
Coal, lignite	582	611	640	723	862	1272	0.5%	1.5%	2.0%
Oil	527	494	627	688	895	1445	0.9%	1.8%	2.4%
Natural gas	505	555	738	561	467	324	1.9%	-2.3%	-1.8%
Nuclear	178	224	211	203	245	425	0.8%	0.7%	2.8%
Hydro, geothermal	63	49	53	57	61	66	-0.9%	0.7%	0.4%
Biomass and wastes	70	105	178	223	285	342	4.7%	2.4%	0.9%
Wind, solar	0	2	5	18	39	124	14.2%	11.4%	5.9%
Gross Inland Consumption (Mtoe)	**2139**	**2525**	**2862**	**3008**	**3145**	**3419**	1.5%	0.5%	0.4%
Coal, lignite	488	576	535	592	693	1033	0.5%	1.3%	2.0%
Oil	847	992	1005	1031	1016	836	0.9%	0.1%	-1.0%
Natural Gas	491	578	876	884	806	592	2.9%	-0.4%	-1.5%
Biomass and wastes	70	105	178	223	285	342	4.7%	2.4%	0.9%
Others	242	275	269	278	345	615	0.5%	1.3%	2.9%
Final Consumption (Mtoe)	**1450**	**1714**	**1843**	**1957**	**2037**	**2073**	1.2%	0.5%	0.1%
by source									
Coal, lignite	62	44	40	39	39	45	-2.2%	-0.1%	0.7%
Oil	768	907	920	950	957	826	0.9%	0.2%	-0.7%
Gas	324	363	384	390	368	270	0.9%	-0.2%	-1.5%
Electricity	262	328	416	482	565	766	2.3%	1.5%	1.5%
Biomass and wastes	30	60	70	82	88	80	4.3%	1.2%	-0.5%
Heat	3	12	12	13	13	13	7.2%	0.1%	0.1%
Hydrogen	0	0	0	2	7	72		16.2%	12.3%
by sector									
Industry	468	539	548	563	579	575	0.8%	0.3%	0.0%
Transport	533	655	679	707	719	689	1.2%	0.3%	-0.2%
Household, Service, Agriculture	449	520	616	688	740	809	1.6%	0.9%	0.4%
Electricity Generation (TWh)	**3701**	**4474**	**5592**	**6481**	**7560**	**10337**	2.1%	1.5%	1.6%
Thermal, of which :	2411	3012	4069	4742	5316	6064	2.7%	1.3%	0.7%
Coal	1782	2088	1963	2407	2944	3976	0.5%	2.0%	1.5%
Gas	391	694	1835	2018	1836	1408	8.0%	0.0%	-1.3%
Biomass and wastes	90	78	132	169	417	598	1.9%	5.9%	1.8%
Nuclear	685	885	872	877	1088	2014	1.2%	1.1%	3.1%
Hydro+Geothermal	602	571	614	666	711	764	0.1%	0.7%	0.4%
Solar	1	0	0	1	13	308	-10.0%	28.9%	17.2%
Wind	3	6	37	195	428	1115	13.3%	13.0%	4.9%
Hydrogen	0	0	0	0	4	73		24.8%	15.6%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**0**	**2**	**8**	**90**		16.5%	12.6%
Coal	0	0	0	2	6	68		18.9%	12.5%
Renewables	0	0	0	0	1	15		21.9%	12.7%
Nuclear	0	0	0	0	0	6			33.3%
CO2 Emissions (MtCO2), *of which :*	**5263**	**6198**	**6713**	**6991**	**7099**	**6427**	1.2%	0.3%	-0.5%
Electricity generation	2128	2668	2797	2968	3087	2937	1.4%	0.5%	-0.2%
Industry	791	697	611	563	534	496	-1.3%	-0.7%	-0.4%
Transport	1499	1942	2017	2082	2078	1688	1.5%	0.2%	-1.0%
Household, Service, Agriculture	657	695	754	799	779	611	0.7%	0.2%	-1.2%
CO2 Sequestration (Mt CO2)	0	0	0	1	13	639			21.3%

Japan, Pacific

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	150	157	161	162	161	154	0.4%	0.0%	-0.2%
GDP (G$95)	3026	3583	4497	5474	6558	8731	2.0%	1.9%	1.4%
Per capita GDP ($95/cap)	20234	22775	27864	33713	40770	56786	1.6%	1.9%	1.7%
Gross inland cons/GDP (toe/M$95)	182	181	162	143	131	118	-0.6%	-1.0%	-0.5%
Gross inland cons/capita (toe/cap)	4	4.1	4.5	4.8	5.4	6.7	1.0%	0.9%	1.1%
Electricity cons/capita (kWh/cap)	6186	7496	8927	10750	13283	19795	1.9%	2.0%	2.0%
Transport fuels per capita (toe/cap)	0.7	0.8	0.8	0.8	0.9	0.8	0.8%	0.3%	-0.1%
CO2 emissions/capita (tCO2/cap)	8.5	10.1	10.3	10.1	10.3	9.3	0.9%	0.0%	-0.5%
% of renewables in gross inland cons	5	3.8	4.9	5.7	7.3	13.9	0.0%	2.0%	3.3%
% of renewables in electricity	15	11.3	11.0	13.6	17.5	22.5	-1.5%	2.4%	1.3%
Primary Production (Mtoe)	**255**	**352**	**418**	**532**	**651**	**1067**	2.5%	2.2%	2.5%
Coal, lignite	113	178	189	228	272	390	2.6%	1.8%	1.8%
Oil	38	40	34	36	39	34	-0.5%	0.7%	-0.7%
Natural gas	24	28	48	63	77	166	3.6%	2.4%	3.9%
Nuclear	53	81	112	161	201	334	3.8%	3.0%	2.6%
Hydro, geothermal	14	12	13	14	15	15	-0.7%	0.7%	0.1%
Biomass and wastes	12	12	21	23	30	81	2.8%	1.8%	5.0%
Wind, solar	0	1	2	7	18	47		12.6%	5.0%
Gross Inland Consumption (Mtoe)	**551**	**648**	**726**	**783**	**861**	**1027**	1.4%	0.9%	0.9%
Coal, lignite	112	154	161	160	186	217	1.8%	0.7%	0.8%
Oil	294	296	287	285	273	226	-0.1%	-0.2%	-0.9%
Natural Gas	63	92	131	133	137	106	3.8%	0.2%	-1.3%
Biomass and wastes	12	12	21	23	30	81	2.8%	1.8%	5.0%
Others	69	94	126	182	233	396	3.1%	3.1%	2.7%
Final Consumption (Mtoe)	**382**	**466**	**481**	**513**	**553**	**598**	1.2%	0.7%	0.4%
by source									
Coal, lignite	45	46	44	42	44	37	-0.1%	0.0%	-0.9%
Oil	222	268	261	266	263	232	0.8%	0.0%	-0.6%
Gas	25	39	44	47	54	44	2.8%	1.1%	-1.1%
Electricity	80	101	124	150	184	262	2.2%	2.0%	1.8%
Biomass and wastes	8	9	7	5	4	11	-0.7%	-2.3%	4.9%
Heat	2	2	2	2	2	3	0.0%	1.1%	1.5%
Hydrogen	0	0	0	0	1	10		14.2%	9.7%
by sector									
Industry	173	200	203	214	233	244	0.8%	0.7%	0.2%
Transport	103	130	130	135	138	130	1.1%	0.3%	-0.3%
Household, Service, Agriculture	106	136	149	164	182	224	1.7%	1.0%	1.0%
Electricity Generation (TWh)	**1047**	**1292**	**1654**	**2004**	**2461**	**3624**	2.3%	2.0%	2.0%
Thermal, of which :	705	831	1037	1073	1194	1210	1.9%	0.7%	0.1%
Coal	212	364	444	506	631	723	3.8%	1.8%	0.7%
Gas	216	341	487	480	460	352	4.2%	-0.3%	-1.3%
Biomass and wastes	17	5	25	37	65	105	1.8%	4.9%	2.4%
Nuclear	202	320	461	696	893	1551	4.2%	3.4%	2.8%
Hydro+Geothermal	139	140	147	162	169	171	0.3%	0.7%	0.1%
Solar	0	1	0	1	18	239		28.9%	13.7%
Wind	0	1	9	72	179	301		15.9%	2.6%
Hydrogen	0	0	0	1	9	152		25.2%	15.4%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**0**	**1**	**3**	**31**		16.7%	12.8%
Coal	0	0	0	0	1	4		13.0%	9.8%
Renewables	0	0	0	0	2	20		19.2%	11.7%
Nuclear	0	0	0	0	0	8			32.7%
CO2 Emissions (MtCO2), *of which :*	**1277**	**1591**	**1665**	**1648**	**1657**	**1437**	1.3%	0.0%	-0.7%
Electricity generation	487	582	675	650	643	537	1.6%	-0.2%	-0.9%
Industry	318	357	336	337	349	296	0.3%	0.2%	-0.8%
Transport	280	384	383	395	394	327	1.6%	0.1%	-0.9%
Household, Service, Agriculture	162	217	205	199	188	154	1.2%	-0.4%	-1.0%
CO2 Sequestration (Mt CO2)	0	0	0	0	58	159			5.2%

Africa, Middle-East

							Annual % change		
	1990	2001	2010	2020	2030	2050	1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	755	983	1190	1439	1692	2177	2.3%	1.8%	1.3%
GDP (G$95)	1754	2643	3598	5087	7019	14703	3.7%	3.4%	3.8%
Per capita GDP ($95/cap)	2.3	2.7	3.0	3.5	4.1	6.8	1.3%	1.6%	2.5%
Gross inland cons/GDP (toe/M$95)	0.4	0.3	0.3	0.3	0.3	0.2	-0.4%	-1.1%	-0.6%
Gross inland cons/capita (toe/cap)	0.8	0.9	1.0	1.0	1.1	1.6	1.0%	0.5%	1.9%
Electricity cons/capita (kWh/cap)	577	781	972	1251	1589	3177	2.6%	2.5%	3.5%
Transport fuels per capita (toe/cap)	0.12	0.13	0.12	0.13	0.14	0.19	0.0%	0.5%	1.5%
CO2 emissions/capita (tCO2/cap)	1.6	1.9	2.3	2.6	2.8	3.6	1.9%	0.9%	1.2%
% of renewables in gross inland cons	31	26	17	11	8	13	-3.0%	-3.5%	2.4%
% of renewables in electricity	13	10	9	8	9	23	-1.6%	-0.2%	4.7%
Primary Production (Mtoe)	**1616**	**2051**	**2331**	**3647**	**4698**	**5853**	1.8%	3.6%	1.1%
Coal, lignite	104	132	184	240	313	524	2.9%	2.7%	2.6%
Oil	1171	1417	1346	2023	2520	2677	0.7%	3.2%	0.3%
tural gas	149	281	602	1210	1661	1945	7.2%	5.2%	0.8%
Nuclear	2	3	4	16	55	260	2.5%	14.6%	8.1%
Hydro, geothermal	6	8	11	13	15	19	2.8%	1.6%	1.3%
Biomass and wastes	183	209	184	144	127	314	0.0%	-1.8%	4.6%
Wind, solar	0	1	1	2	8	115		11.6%	14.2%
Gross Inland Consumption (Mtoe)	**620**	**857**	**1182**	**1477**	**1863**	**3493**	3.3%	2.3%	3.2%
Coal, lignite	76	114	146	195	265	465	3.3%	3.0%	2.9%
Oil	237	305	393	545	723	1200	2.6%	3.1%	2.6%
tural Gas	115	217	444	562	670	1119	7.0%	2.1%	2.6%
Biomass and wastes	183	209	184	144	127	314	0.0%	-1.8%	4.6%
Others	9	12	16	31	78	394	3.0%	8.3%	8.4%
Final Consumption (Mtoe)	**469**	**673**	**763**	**937**	**1157**	**2053**	2.5%	2.1%	2.9%
by source									
Coal, lignite	19	17	28	36	48	85	1.8%	2.8%	2.9%
Oil	189	256	325	450	585	953	2.7%	3.0%	2.5%
Gas	46	124	141	160	180	262	5.8%	1.2%	1.9%
Electricity	37	66	100	155	231	595	5.0%	4.3%	4.8%
Biomass and wastes	177	209	169	135	109	129	-0.2%	-2.2%	0.8%
Heat	0	1	1	1	1	1	2.6%	0.0%	0.0%
Hydrogen	0	0	0	1	3	30		16.7%	13.1%
by sector									
Industry	135	233	252	294	350	601	3.2%	1.6%	2.7%
Transport	93	132	147	187	233	408	2.4%	2.3%	2.8%
Household, Service, Agriculture	242	308	363	456	574	1044	2.1%	2.3%	3.0%
Electricity Generation (TWh)	**552**	**953**	**1384**	**2151**	**3207**	**8167**	4.7%	4.3%	4.8%
Thermal, of which :	472	845	1238	1917	2698	5240	4.9%	4.0%	3.4%
Coal	174	248	403	638	931	1736	4.3%	4.3%	3.2%
Gas	145	335	612	944	1284	2472	7.5%	3.8%	3.3%
Biomass and wastes	0	0	0	2	30	285		34.4%	11.9%
Nuclear	8	11	15	69	244	1213	2.9%	15.0%	8.3%
Hydro+Geothermal	72	97	128	151	175	227	2.9%	1.6%	1.3%
Solar	0	0	1	2	31	457		19.4%	14.3%
Wind	0	0	1	11	54	869		19.8%	14.9%
Hydrogen	0	0	1	1	5	161		10.1%	19.1%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**0**	**1**	**3**	**55**		14.5%	14.8%
Coal	0	0	0	0	0	4		7.9%	12.6%
Renewables	0	0	0	0	1	32		20.1%	18.8%
Nuclear	0	0	0	0	0	2			23.4%
CO2 Emissions (MtCO2), *of which :*	**1209**	**1855**	**2757**	**3673**	**4729**	**7757**	4.2%	2.7%	2.5%
Electricity generation	442	620	810	1135	1514	2518	3.1%	3.2%	2.6%
Industry	268	500	556	657	786	1112	3.7%	1.7%	1.7%
Transport	268	395	441	555	679	1040	2.5%	2.2%	2.2%
Household, Service, Agriculture	118	222	405	642	891	1637	6.4%	4.0%	3.1%
CO2 Sequestration (Mt CO2)	0	0	0	0	0	188			

Latin America

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	435	520	585	649	700	756	1.5%	0.9%	0.4%
GDP (G$95)	2393	3410	4474	6210	8145	12658	3.2%	3.0%	2.2%
Per capita GDP ($95/cap)	5502	6557	7645	9569	11636	16754	1.7%	2.1%	1.8%
Gross inland cons/GDP (toe/M$95)	198	180	167	155	140	120	-0.8%	-0.9%	-0.8%
Gross inland cons/capita (toe/cap)	1	1.2	1.3	1.5	1.6	2.0	0.8%	1.2%	1.1%
Electricity cons/capita (kWh/cap)	1147	1489	1814	2343	2919	4489	2.3%	2.4%	2.2%
Transport fuels per capita (toe/cap)	0.3	0.3	0.3	0.3	0.3	0.4	0.4%	1.2%	0.8%
CO2 emissions/capita (tCO2/cap)	2.1	2.4	2.5	2.9	3.2	3.3	0.8%	1.4%	0.1%
% of renewables in gross inland cons	28	24.2	27.6	24.7	24.1	33.0	-0.1%	-0.7%	1.6%
% of renewables in electricity	65	58.6	54.7	47.5	48.7	53.3	-0.9%	-0.6%	0.5%
Primary Production (Mtoe)	**626**	**835**	**1229**	**1615**	**1791**	**1971**	3.4%	1.9%	0.5%
Coal, lignite	22	41	18	26	37	48	-0.9%	3.5%	1.3%
Oil	394	523	690	903	987	1040	2.8%	1.8%	0.3%
Natural gas	75	114	308	437	458	277	7.3%	2.0%	-2.5%
Nuclear	3	8	6	11	34	103	3.2%	8.9%	5.7%
Hydro, geothermal	38	48	56	67	77	95	1.9%	1.6%	1.1%
Biomass and wastes	94	101	150	168	182	339	2.4%	1.0%	3.2%
Wind, solar	0	0	0	2	16	69		22.3%	7.4%
Gross Inland Consumption (Mtoe)	**474**	**614**	**748**	**960**	**1144**	**1524**	2.3%	2.1%	1.4%
Coal, lignite	20	28	36	58	84	128	3.0%	4.3%	2.1%
Oil	244	314	300	367	428	475	1.0%	1.8%	0.5%
Natural Gas	75	116	200	287	322	315	5.0%	2.4%	-0.1%
Biomass and wastes	94	101	150	168	182	339	2.3%	1.0%	3.2%
Others	42	55	63	80	127	267	2.1%	3.6%	3.8%
Final Consumption (Mtoe)	**359**	**465**	**529**	**663**	**786**	**990**	2.0%	2.0%	1.2%
by source									
Coal, lignite	12	15	17	18	21	17	1.8%	0.9%	-1.1%
Oil	187	240	237	295	349	385	1.2%	2.0%	0.5%
Gas	38	57	90	125	147	140	4.4%	2.5%	-0.2%
Electricity	43	67	91	131	176	292	3.8%	3.3%	2.6%
Biomass and wastes	80	87	94	94	92	134	0.8%	-0.1%	1.9%
Heat	0	0	0	0	0	0		0.0%	0.0%
Hydrogen	0	0	0	1	2	22		16.5%	11.6%
by sector									
Industry	151	196	218	262	295	320	1.8%	1.5%	0.4%
Transport	109	148	159	201	239	302	1.9%	2.1%	1.2%
Household, Service, Agriculture	99	121	153	201	252	368	2.2%	2.5%	1.9%
Electricity Generation (TWh)	**612**	**959**	**1291**	**1848**	**2475**	**4083**	3.8%	3.3%	2.5%
Thermal, of which :	206	376	608	1002	1241	1669	5.6%	3.6%	1.5%
Coal	21	42	77	194	324	542	6.8%	7.4%	2.6%
Gas	60	153	399	636	704	768	9.9%	2.9%	0.4%
Biomass and wastes	6	9	48	81	124	275	10.8%	4.8%	4.1%
Nuclear	12	30	25	49	150	475	3.6%	9.3%	5.9%
Hydro+Geothermal	393	553	655	780	893	1105	2.6%	1.6%	1.1%
Solar	0	0	0	0	1	28		8.0%	16.1%
Wind	0	0	2	17	188	768		26.0%	7.3%
Hydrogen	0	0	0	0	2	37		11.2%	16.5%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**0**	**1**	**3**	**30**		15.7%	12.2%
Coal	0	0	0	0	1	7		15.8%	9.2%
Renewables	0	0	0	0	1	21		21.2%	14.2%
Nuclear	0	0	0	0	0	2			22.8%
CO2 Emissions (MtCO2), *of which :*	**918**	**1268**	**1440**	**1911**	**2265**	**2484**	2.3%	2.3%	0.5%
Electricity generation	242	276	305	473	577	700	1.2%	3.2%	1.0%
Industry	226	307	332	392	439	330	2.0%	1.4%	-1.4%
Transport	301	411	410	519	614	684	1.6%	2.0%	0.5%
Household, Service, Agriculture	108	142	188	263	334	452	2.8%	2.9%	1.5%
CO2 Sequestration (Mt CO2)	0	0	0	0	0	45			

Asia

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	2783	3267	3635	3995	4258	4511	1.3%	0.8%	0.3%
GDP (G$95)	5048	10810	18906	29416	41426	70429	6.8%	4.0%	2.7%
Per capita GDP ($95/cap)	1814	3309	5201	7363	9728	15612	5.4%	3.2%	2.4%
Gross inland cons/GDP (toe/M$95)	344	227	193	165	148	122	-2.8%	-1.3%	-1.0%
Gross inland cons/capita (toe/cap)	1	0.8	1.0	1.2	1.4	1.9	2.4%	1.8%	1.4%
Electricity cons/capita (kWh/cap)	388	721	1168	1660	2232	3785	5.7%	3.3%	2.7%
Transport fuels per capita (toe/cap)	0.0	0.1	0.1	0.1	0.1	0.2	2.7%	2.5%	2.1%
CO2 emissions/capita (tCO2/cap)	1.4	1.8	2.6	3.1	3.6	4.3	3.4%	1.6%	0.8%
% of renewables in gross inland cons	31	25.1	17.5	14.5	12.3	12.6	-2.8%	-1.7%	0.1%
% of renewables in electricity	21	15.9	15.9	16.7	17.1	19.6	-1.4%	0.4%	0.7%
Primary Production (Mtoe)	**1657**	**2136**	**3031**	**3424**	**3728**	**5500**	3.1%	1.0%	2.0%
Coal, lignite	693	1009	1455	1672	1949	2823	3.8%	1.5%	1.9%
Oil	297	299	351	322	245	185	0.8%	-1.8%	-1.4%
Natural gas	107	164	483	480	310	158	7.8%	-2.2%	-3.3%
Nuclear	24	47	103	244	467	1252	7.6%	7.8%	5.1%
Hydro, geothermal	30	41	66	88	106	136	4.0%	2.4%	1.2%
Biomass and wastes	507	577	571	604	608	758	0.6%	0.3%	1.1%
Wind, solar	0	0	2	13	41	188		17.1%	7.9%
Gross Inland Consumption (Mtoe)	**1738**	**2459**	**3658**	**4861**	**6136**	**8561**	3.8%	2.6%	1.7%
Coal, lignite	735	947	1523	1791	2091	3078	3.7%	1.6%	2.0%
Oil	369	680	947	1401	1753	2142	4.8%	3.1%	1.0%
Natural Gas	73	169	447	720	1069	1008	9.5%	4.5%	-0.3%
Biomass and wastes	507	577	571	604	608	758	0.6%	0.3%	1.1%
Others	54	87	170	345	614	1575	5.9%	6.6%	4.8%
Final Consumption (Mtoe)	**1365**	**1796**	**2611**	**3414**	**4198**	**5466**	3.3%	2.4%	1.3%
by source									
Coal, lignite	435	409	653	784	893	1047	2.1%	1.6%	0.8%
Oil	290	506	859	1266	1595	1998	5.6%	3.1%	1.1%
Gas	37	79	188	293	427	459	8.4%	4.2%	0.4%
Electricity	93	203	365	570	818	1469	7.1%	4.1%	3.0%
Biomass and wastes	497	569	515	468	428	390	0.2%	-0.9%	-0.5%
Heat	13	31	31	31	31	31	4.4%	0.0%	0.0%
Hydrogen	0	0	0	1	6	73		18.1%	13.8%
by sector									
Industry	504	742	1198	1525	1811	2112	4.4%	2.1%	0.8%
Transport	139	205	308	446	595	949	4.1%	3.3%	2.4%
Household, Service, Agriculture	723	850	1105	1443	1791	2405	2.1%	2.4%	1.5%
Electricity Generation (TWh)	**1374**	**3049**	**5467**	**8522**	**12179**	**21764**	7.1%	4.1%	2.9%
Thermal, of which :	994	2387	4258	6285	8381	12008	7.5%	3.4%	1.8%
Coal	732	1847	3364	4511	5638	9394	7.9%	2.6%	2.6%
Gas	78	326	686	1403	2229	1948	11.5%	6.1%	-0.7%
Biomass and wastes	0	9	90	246	370	504		7.3%	1.6%
Nuclear	92	187	426	1056	2074	5812	8.0%	8.2%	5.3%
Hydro+Geothermal	288	473	763	1025	1237	1581	5.0%	2.4%	1.2%
Solar	0	0	5	7	10	114		3.6%	13.1%
Wind	0	2	15	148	468	2074	35.8%	19.0%	7.7%
Hydrogen	0	0	1	1	9	175		13.0%	16.2%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**0**	**2**	**7**	**105**		16.8%	14.2%
Coal	0	0	0	1	2	18		15.5%	11.9%
Renewables	0	0	0	1	4	81		22.2%	16.2%
Nuclear	0	0	0	0	0	6			29.7%
CO2 Emissions (MtCO2), *of which :*	**3791**	**5956**	**9580**	**12529**	**15506**	**19448**	4.7%	2.4%	1.1%
Electricity generation	1197	2504	3620	4409	5373	7072	5.7%	2.0%	1.4%
Industry	1224	1742	2990	3705	4297	4772	4.6%	1.8%	0.5%
Transport	411	615	918	1312	1721	2425	4.1%	3.2%	1.7%
Household, Service, Agriculture	675	724	1353	2131	2801	3467	3.5%	3.7%	1.1%
CO2 Sequestration (Mt CO2)	0	0	0	0	0	881			

3. WETO-H_2 projections by region - Carbon Constraint Case

World

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	5245	6113	6792	7496	8082	8864	1.3%	0.9%	0.5%
GDP (G$95)	29880	42224	59524	81559	105930	164090	3.5%	2.9%	2.2%
Per capita GDP ($95/cap)	5697	6907	8764	10880	13107	18513	2.2%	2.0%	1.7%
Gross inland cons/GDP (toe/M$95)	290	236	205	165	144	118	-1.7%	-1.7%	-1.0%
Gross inland cons/capita (toe/cap)	1.6	1.6	1.8	1.8	1.9	2.2	0.4%	0.3%	0.7%
Electricity cons/capita (kWh/cap)	1832	2077	2557	2934	3500	5268	1.7%	1.6%	2.1%
Transport fuels per capita (toe/cap)	0.3	0.3	0.3	0.3	0.3	0.3	0.0%	0.1%	0.3%
CO2 emissions/capita (tCO2/cap)	3.8	3.9	4.3	3.9	3.6	2.9	0.5%	-0.8%	-1.2%
% of renewables in gross inland cons	13	13.5	12.8	13.6	14.5	20.7	-0.2%	0.6%	1.8%
% of renewables in electricity	20	18.7	18.1	21.6	25.5	30.2	-0.5%	1.7%	0.8%
Primary Production (Mtoe)	**8834**	**9836**	**12338**	**13634**	**15488**	**19614**	1.7%	1.1%	1.2%
Coal, lignite	2207	2408	2939	2567	2935	2617	1.4%	0.0%	-0.6%
Oil	3234	3487	3939	4550	4959	4895	1.0%	1.2%	-0.1%
Natural gas	1708	1929	3165	3710	3921	3825	3.1%	1.1%	-0.1%
Nuclear	525	671	739	977	1452	4257	1.7%	3.4%	5.5%
Hydro, geothermal	216	232	275	327	368	441	1.2%	1.5%	0.9%
Biomass and wastes	939	1101	1261	1398	1603	2745	1.5%	1.2%	2.7%
Wind, solar	0	7	21	104	250	836	21.9%	13.3%	6.2%
Gross Inland Consumption (Mtoe)	**8654**	**9950**	**12187**	**13459**	**15298**	**19426**	1.7%	1.1%	1.2%
Coal, lignite	2201	2352	2939	2567	2935	2617	1.5%	0.0%	-0.6%
Oil	3089	3487	3939	4550	4959	4895	1.2%	1.2%	-0.1%
Natural Gas	1679	2082	3165	3710	3921	3825	3.2%	1.1%	-0.1%
Biomass and wastes	940	1101	1261	1398	1603	2745	1.5%	1.2%	2.7%
Others	745	911	1034	1409	2071	5533	1.7%	3.5%	5.0%
Final Consumption (Mtoe)	**6267**	**7102**	**8290**	**9202**	**10197**	**11801**	1.4%	1.0%	0.7%
by source									
Coal, lignite	869	670	913	921	941	648	0.3%	0.2%	-1.9%
Oil	2553	2950	3364	3849	4227	4239	1.4%	1.1%	0.0%
Gas	985	1137	1340	1418	1506	1443	1.6%	0.6%	-0.2%
Electricity	826	1092	1494	1892	2432	4015	3.0%	2.5%	2.5%
Biomass and wastes	855	1004	926	856	790	855	0.4%	-0.8%	0.4%
Heat	179	249	250	251	253	257	1.7%	0.1%	0.1%
Hydrogen	0	0	3	15	48	345		15.2%	10.3%
by sector									
Industry	2416	2639	3181	3372	3628	3627	1.4%	0.7%	0.0%
Transport	1432	1717	1866	2052	2250	2635	1.3%	0.9%	0.8%
Household, Service, Agriculture	2418	2746	3243	3778	4320	5539	1.5%	1.4%	1.3%
Electricity Generation (TWh)	**11859**	**15468**	**21139**	**26851**	**34587**	**57812**	2.9%	2.5%	2.6%
Thermal, of which :	7609	10074	14696	17656	20942	21683	3.3%	1.8%	0.2%
Coal	4422	5848	7606	7348	9114	9016	2.7%	0.9%	-0.1%
Gas	1705	2934	5840	8641	9438	9640	6.4%	2.4%	0.1%
Biomass and wastes	150	155	442	836	1684	2649	5.6%	6.9%	2.3%
Nuclear	2013	2653	3048	4224	6449	19862	2.1%	3.8%	5.8%
Hydro+Geothermal	2231	2703	3198	3806	4284	5128	1.8%	1.5%	0.9%
Solar	1	1	7	18	213	2326	12.1%	18.9%	12.7%
Wind	4	37	188	1141	2642	7336	21.4%	14.1%	5.2%
Hydrogen	0	0	2	6	56	1477		17.4%	17.8%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**4**	**17**	**61**	**585**		15.4%	11.9%
Coal	0	0	1	2	2	2		3.6%	-1.0%
Renewables	0	0	1	10	49	469		23.5%	12.0%
Nuclear	0	0	0	0	1	107		15.3%	30.0%
CO2 Emissions (MtCO2), *of which :*	**20161**	**23566**	**29027**	**29180**	**29460**	**25459**	1.8%	0.1%	-0.7%
Electricity generation	7433	8932	10577	8892	7413	4454	1.8%	-1.8%	-2.5%
Industry	4653	4812	6046	6159	6400	4837	1.3%	0.3%	-1.4%
Transport	3982	5056	5439	5861	6184	5850	1.6%	0.6%	-0.3%
Household, Service, Agriculture	3191	3196	4103	5162	5953	6617	1.3%	1.9%	0.5%
CO2 Sequestration (Mt CO2)	0	0	0	1275	4064	6442			2.3%

NB : Oil consumption in international bunkers is accounted for in gross inland consumption at world level (but not at regional levels). The related emissions are included in the world total CO_2 emissions ($MtCO_2$).

Europe

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	564	588	599	605	606	586	0.3%	0.1%	-0.2%
GDP (G$95)	8373	10312	12660	15900	19079	25194	2.1%	2.1%	1.4%
Per capita GDP ($95/cap)	14849	17533	21124	26260	31496	43005	1.8%	2.0%	1.6%
Gross inland cons/GDP (toe/M$95)	212	186	160	126	109	98	-1.4%	-1.9%	-0.5%
Gross inland cons/capita (toe/cap)	3	3.3	3.4	3.3	3.4	4.2	0.4%	0.1%	1.1%
Electricity cons/capita (kWh/cap)	4206	4995	5790	6625	7813	11799	1.6%	1.5%	2.1%
Transport fuels per capita (toe/cap)	0.5	0.6	0.6	0.6	0.6	0.6	0.6%	-0.1%	-0.2%
CO2 emissions/capita (tCO2/cap)	7.7	7.4	7.4	6.2	5.4	4.4	-0.2%	-1.6%	-1.1%
% of renewables in gross inland cons	6	7.5	9.8	12.9	15.9	21.3	2.9%	2.5%	1.5%
% of renewables in electricity	18	20.4	21.0	25.4	29.2	29.1	0.7%	1.7%	0.0%
Primary Production (Mtoe)	**1115**	**1196**	**1283**	**1050**	**1109**	**1688**	0.7%	-0.7%	2.1%
Coal, lignite	393	240	220	160	153	113	-2.9%	-1.8%	-1.5%
Oil	224	313	309	174	103	61	1.6%	-5.3%	-2.6%
Natural gas	190	244	310	225	201	216	2.5%	-2.1%	0.3%
Nuclear	209	254	246	233	322	770	0.8%	1.4%	4.4%
Hydro, geothermal	44	54	55	59	61	64	1.1%	0.5%	0.3%
Biomass and wastes	53	87	131	169	213	338	4.6%	2.5%	2.3%
Wind, solar	0	3	11	31	56	126	29.0%	8.3%	4.2%
Gross Inland Consumption (Mtoe)	**1773**	**1921**	**2023**	**2005**	**2075**	**2479**	0.7%	0.1%	0.9%
Coal, lignite	481	359	354	255	257	192	-1.5%	-1.6%	-1.4%
Oil	681	734	685	659	624	514	0.0%	-0.5%	-1.0%
Natural Gas	300	429	538	598	541	472	3.0%	0.0%	-0.7%
Biomass and wastes	53	87	131	169	213	338	4.6%	2.5%	2.3%
Others	258	313	314	324	440	961	1.0%	1.7%	4.0%
Final Consumption (Mtoe)	**1263**	**1377**	**1412**	**1402**	**1408**	**1483**	0.6%	0.0%	0.3%
by source									
Coal, lignite	156	82	79	58	54	36	-3.3%	-1.9%	-1.9%
Oil	575	648	614	595	569	471	0.3%	-0.4%	-0.9%
Gas	235	288	309	288	255	206	1.4%	-1.0%	-1.1%
Electricity	204	253	298	345	407	594	1.9%	1.6%	1.9%
Biomass and wastes	44	60	63	63	64	79	1.8%	0.1%	1.0%
Heat	50	47	48	49	50	53	-0.2%	0.2%	0.3%
Hydrogen	0	0	1	4	10	45		13.1%	8.0%
by sector									
Industry	493	472	488	456	447	425	-0.1%	-0.4%	-0.3%
Transport	308	381	372	372	366	342	0.9%	-0.1%	-0.3%
Household, Service, Agriculture	462	525	552	574	595	716	0.9%	0.4%	0.9%
Electricity Generation (TWh)	**2845**	**3489**	**4170**	**4806**	**5673**	**8803**	1.9%	1.6%	2.2%
Thermal, of which :	1540	1823	2387	2768	2884	2673	2.2%	0.9%	-0.4%
Coal	1070	1006	1054	882	969	781	-0.1%	-0.4%	-1.1%
Gas	230	577	1112	1611	1545	1492	8.2%	1.7%	-0.2%
Biomass and wastes	15	51	108	192	315	361	10.4%	5.5%	0.7%
Nuclear	801	1006	1017	1006	1432	3612	1.2%	1.7%	4.7%
Hydro+Geothermal	503	633	643	681	706	746	1.2%	0.5%	0.3%
Solar	0	0	0	3	29	593	15.5%	27.2%	16.4%
Wind	1	27	123	347	608	859	28.8%	8.3%	1.7%
Hydrogen	0	0	0	1	15	321		25.2%	16.6%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**1**	**4**	**13**	**93**		13.9%	10.5%
Coal	0	0	0	0	0	0		4.5%	-1.2%
Renewables	0	0	0	3	11	64		20.0%	9.1%
Nuclear	0	0	0	0	0	28		14.2%	27.8%
CO2 Emissions (MtCO2), *of which :*	**4360**	**4367**	**4445**	**3760**	**3278**	**2566**	0.1%	-1.5%	-1.2%
Electricity generation	1608	1519	1586	1100	804	582	-0.1%	-3.3%	-1.6%
Industry	961	765	742	609	552	407	-1.3%	-1.5%	-1.5%
Transport	826	1122	1086	1055	988	742	1.4%	-0.5%	-1.4%
Household, Service, Agriculture	828	800	792	777	731	664	-0.2%	-0.4%	-0.5%
CO2 Sequestration (Mt CO2)	0	0	0	353	609	595			-0.1%

CIS

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	281	281	276	270	261	237	-0.1%	-0.3%	-0.5%
GDP (G$95)	2139	1463	2164	3041	3860	5488	0.1%	2.9%	1.8%
Per capita GDP ($95/cap)	7608	5204	7852	11263	14797	23174	0.2%	3.2%	2.3%
Gross inland cons/GDP (toe/M$95)	635	633	458	311	261	205	-1.6%	-2.8%	-1.2%
Gross inland cons/capita (toe/cap)	5	3.3	3.6	3.5	3.9	4.8	-1.5%	0.4%	1.0%
Electricity cons/capita (kWh/cap)	4438	3084	4117	5351	7005	10864	-0.4%	2.7%	2.2%
Transport fuels per capita (toe/cap)	0.5	0.2	0.3	0.3	0.3	0.3	-3.4%	0.6%	0.2%
CO2 emissions/capita (tCO2/cap)	11.9	8.3	8.8	7.6	7.3	6.5	-1.5%	-1.0%	-0.6%
% of renewables in gross inland cons	3	3.3	4.9	6.0	10.0	18.4	2.7%	3.6%	3.1%
% of renewables in electricity	15	19.1	18.5	17.7	24.7	33.0	1.2%	1.5%	1.5%
Primary Production (Mtoe)	**1637**	**1226**	**1602**	**1589**	**1774**	**1951**	-0.1%	0.5%	0.5%
Coal, lignite	301	197	229	166	191	125	-1.4%	-0.9%	-2.1%
Oil	583	400	594	605	568	441	0.1%	-0.2%	-1.3%
Natural gas	659	543	674	692	795	885	0.1%	0.8%	0.5%
Nuclear	55	54	56	68	119	292	0.1%	3.8%	4.6%
Hydro, geothermal	20	20	21	24	24	24	0.3%	0.5%	0.0%
Biomass and wastes	19	11	27	33	63	130	1.8%	4.3%	3.7%
Wind, solar	0	0	0	0	14	54		34.8%	7.1%
Gross Inland Consumption (Mtoe)	**1359**	**926**	**990**	**945**	**1009**	**1126**	-1.6%	0.1%	0.6%
Coal, lignite	289	176	181	125	143	88	-2.3%	-1.2%	-2.4%
Oil	416	183	178	213	227	205	-4.1%	1.2%	-0.5%
Natural Gas	562	482	526	482	420	334	-0.3%	-1.1%	-1.1%
Biomass and wastes	19	11	27	33	63	130	1.8%	4.3%	3.7%
Others	72	74	77	92	156	369	0.3%	3.6%	4.4%
Final Consumption (Mtoe)	**978**	**611**	**656**	**670**	**714**	**770**	-2.0%	0.4%	0.4%
by source									
Coal, lignite	139	58	52	38	35	24	-4.8%	-1.9%	-2.0%
Oil	322	126	157	173	185	172	-3.5%	0.8%	-0.4%
Gas	279	187	186	174	170	159	-2.0%	-0.4%	-0.3%
Electricity	107	75	98	124	157	221	-0.5%	2.4%	1.7%
Biomass and wastes	19	9	7	6	10	34	-4.7%	1.5%	6.4%
Heat	111	156	156	156	156	156	1.7%	0.0%	0.0%
Hydrogen	0	0	0	0	1	4		13.2%	8.0%
by sector									
Industry	492	257	275	246	245	228	-2.9%	-0.6%	-0.4%
Transport	147	67	72	76	77	73	-3.5%	0.3%	-0.2%
Household, Service, Agriculture	339	287	310	348	392	470	-0.5%	1.2%	0.9%
Electricity Generation (TWh)	**1727**	**1252**	**1559**	**1927**	**2381**	**3261**	-0.5%	2.1%	1.6%
Thermal, of which :	1283	800	1076	1352	1414	963	-0.9%	1.4%	-1.9%
Coal	431	252	295	311	417	231	-1.9%	1.7%	-2.9%
Gas	584	508	696	931	822	547	0.9%	0.8%	-2.0%
Biomass and wastes	21	3	39	62	153	174	3.1%	7.1%	0.7%
Nuclear	212	215	233	295	530	1366	0.5%	4.2%	4.8%
Hydro+Geothermal	233	237	249	273	278	279	0.3%	0.5%	0.0%
Solar	0	0	0	0	0	7		3.0%	14.9%
Wind	0	0	0	5	157	617		41.4%	7.1%
Hydrogen	0	0	0	0	2	29		10.7%	14.3%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**0**	**0**	**1**	**8**		12.4%	10.1%
Coal	0	0	0	0	0	0		4.9%	-0.8%
Renewables	0	0	0	0	1	4			9.6%
Nuclear	0	0	0	0	0	4			29.4%
CO2 Emissions (MtCO2), *of which :*	**3343**	**2331**	**2438**	**2057**	**1900**	**1534**	-1.6%	-1.2%	-1.1%
Electricity generation	1330	763	771	513	369	200	-2.7%	-3.6%	-3.0%
Industry	866	444	477	372	331	182	-2.9%	-1.8%	-2.9%
Transport	398	187	200	208	206	176	-3.4%	0.1%	-0.8%
Household, Service, Agriculture	644	397	419	478	541	611	-2.1%	1.3%	0.6%
CO2 Sequestration (Mt CO2)	0	0	0	161	291	182			-2.3%

North America

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	277	316	345	376	404	444	1.1%	0.8%	0.5%
GDP (G$95)	7146	10003	13225	16432	19843	26887	3.1%	2.0%	1.5%
Per capita GDP ($95/cap)	25778	31614	38341	43693	49146	60584	2.0%	1.2%	1.1%
Gross inland cons/GDP (toe/M$95)	299	252	216	159	131	106	-1.6%	-2.5%	-1.1%
Gross inland cons/capita (toe/cap)	8	8.0	8.3	7.0	6.5	6.4	0.4%	-1.3%	0.0%
Electricity cons/capita (kWh/cap)	10999	12064	14058	13287	14001	17765	1.2%	0.0%	1.2%
Transport fuels per capita (toe/cap)	1.9	2.1	2.0	1.7	1.6	1.3	0.1%	-1.2%	-0.8%
CO2 emissions/capita (tCO2/cap)	19.0	19.6	19.5	12.9	10.4	7.2	0.1%	-3.1%	-1.8%
% of renewables in gross inland cons	6	6.2	8.2	12.6	17.0	25.2	1.4%	3.7%	2.0%
% of renewables in electricity	19	14.6	14.0	22.3	30.5	36.0	-1.5%	4.0%	0.8%
Primary Production (Mtoe)	**1926**	**2040**	**2453**	**2094**	**2279**	**3063**	1.2%	-0.4%	1.5%
Coal, lignite	582	611	641	362	413	421	0.5%	-2.2%	0.1%
Oil	527	494	627	665	797	1079	0.9%	1.2%	1.5%
Natural gas	505	555	739	537	407	311	1.9%	-2.9%	-1.3%
Nuclear	178	224	211	202	218	534	0.8%	0.2%	4.6%
Hydro, geothermal	63	49	53	59	63	67	-0.9%	0.9%	0.3%
Biomass and wastes	70	105	178	233	311	483	4.7%	2.8%	2.2%
Wind, solar	0	2	5	37	70	167	14.2%	14.6%	4.5%
Gross Inland Consumption (Mtoe)	**2139**	**2525**	**2863**	**2616**	**2604**	**2844**	1.5%	-0.5%	0.4%
Coal, lignite	488	576	536	262	286	334	0.5%	-3.1%	0.8%
Oil	847	992	1003	929	857	647	0.8%	-0.8%	-1.4%
Natural Gas	491	578	877	896	800	611	2.9%	-0.5%	-1.3%
Biomass and wastes	70	105	178	233	311	483	4.7%	2.8%	2.2%
Others	242	275	269	298	351	769	0.5%	1.3%	4.0%
Final Consumption (Mtoe)	**1450**	**1714**	**1842**	**1738**	**1704**	**1725**	1.2%	-0.4%	0.1%
by source									
Coal, lignite	62	44	40	18	13	10	-2.2%	-5.5%	-1.3%
Oil	768	907	918	848	795	615	0.9%	-0.7%	-1.3%
Gas	324	363	384	346	301	228	0.8%	-1.2%	-1.4%
Electricity	262	328	417	430	486	678	2.3%	0.8%	1.7%
Biomass and wastes	30	60	70	80	79	73	4.3%	0.6%	-0.4%
Heat	3	12	12	13	13	13	7.2%	0.1%	0.1%
Hydrogen	0	0	1	4	17	109		16.3%	9.8%
by sector									
Industry	468	539	548	478	468	470	0.8%	-0.8%	0.0%
Transport	533	655	679	647	629	588	1.2%	-0.4%	-0.3%
Household, Service, Agriculture	449	520	615	614	607	667	1.6%	-0.1%	0.5%
Electricity Generation (TWh)	**3701**	**4474**	**5603**	**5765**	**6548**	**9407**	2.1%	0.8%	1.8%
Thermal, of which :	2411	3012	4080	3794	4043	3991	2.7%	0.0%	-0.1%
Coal	1782	2088	1966	1097	1208	1415	0.5%	-2.4%	0.8%
Gas	391	694	1842	2390	2281	1841	8.1%	1.1%	-1.1%
Biomass and wastes	90	78	132	187	469	680	1.9%	6.5%	1.9%
Nuclear	685	885	872	871	967	2509	1.2%	0.5%	4.9%
Hydro+Geothermal	602	571	614	687	732	784	0.1%	0.9%	0.3%
Solar	1	0	0	2	68	590	-10.0%	40.1%	11.4%
Wind	3	6	37	409	728	1337	13.3%	16.1%	3.1%
Hydrogen	0	0	0	1	9	196		29.8%	16.8%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**1**	**5**	**20**	**147**		16.7%	10.5%
Coal	0	0	0	1	1	0		0.8%	-1.5%
Renewables	0	0	0	3	18	104		33.7%	9.1%
Nuclear	0	0	0	0	0	43			31.1%
CO2 Emissions (MtCO2), *of which :*	**5263**	**6198**	**6713**	**4839**	**4184**	**3195**	1.2%	-2.3%	-1.3%
Electricity generation	2128	2668	2803	1329	968	757	1.4%	-5.2%	-1.2%
Industry	791	697	611	415	366	333	-1.3%	-2.5%	-0.5%
Transport	1499	1942	2010	1879	1737	1203	1.5%	-0.7%	-1.8%
Household, Service, Agriculture	657	695	753	720	632	485	0.7%	-0.9%	-1.3%
CO2 Sequestration (Mt CO2)	0	0	0	620	941	1072			0.7%

Japan, Pacific

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	150	157	161	162	161	154	0.4%	0.0%	-0.2%
GDP (G$95)	3026	3583	4497	5474	6558	8731	2.0%	1.9%	1.4%
Per capita GDP ($95/cap)	20234	22775	27864	33713	40770	56786	1.6%	1.9%	1.7%
Gross inland cons/GDP (toe/M$95)	182	181	160	131	118	110	-0.6%	-1.5%	-0.4%
Gross inland cons/capita (toe/cap)	4	4.1	4.5	4.4	4.8	6.2	1.0%	0.4%	1.3%
Electricity cons/capita (kWh/cap)	6186	7496	8911	10402	12803	19447	1.8%	1.8%	2.1%
Transport fuels per capita (toe/cap)	0.7	0.8	0.8	0.8	0.8	0.8	0.7%	0.0%	-0.1%
CO2 emissions/capita (tCO2/cap)	8.5	10.1	10.2	7.5	6.7	5.9	0.9%	-2.1%	-0.6%
% of renewables in gross inland cons	5	3.8	5.0	7.6	10.6	17.1	0.1%	3.9%	2.4%
% of renewables in electricity	15	11.3	11.0	18.4	22.9	24.4	-1.5%	3.8%	0.3%
Primary Production (Mtoe)	**255**	**352**	**418**	**474**	**582**	**860**	2.5%	1.7%	2.0%
Coal, lignite	113	178	189	153	179	115	2.6%	-0.3%	-2.2%
Oil	38	40	34	35	37	27	-0.5%	0.4%	-1.5%
Natural gas	24	28	48	71	80	171	3.6%	2.6%	3.9%
Nuclear	53	81	111	160	204	383	3.8%	3.1%	3.2%
Hydro, geothermal	14	12	13	15	15	15	-0.7%	0.9%	0.0%
Biomass and wastes	12	12	21	27	44	98	2.8%	3.6%	4.1%
Wind, solar	0	1	2	13	23	51		14.0%	4.1%
Gross Inland Consumption (Mtoe)	**551**	**648**	**721**	**717**	**774**	**961**	1.4%	0.4%	1.1%
Coal, lignite	112	154	161	99	96	93	1.8%	-2.5%	-0.2%
Oil	294	296	283	262	242	207	-0.2%	-0.8%	-0.8%
Natural Gas	63	92	130	142	150	114	3.7%	0.7%	-1.4%
Biomass and wastes	12	12	21	27	44	98	2.8%	3.6%	4.1%
Others	69	94	126	188	242	449	3.1%	3.3%	3.1%
Final Consumption (Mtoe)	**382**	**466**	**476**	**470**	**490**	**546**	1.1%	0.1%	0.5%
by source									
Coal, lignite	45	46	44	25	19	16	-0.1%	-4.1%	-0.8%
Oil	222	268	257	245	231	200	0.7%	-0.5%	-0.7%
Gas	25	39	43	46	53	46	2.6%	1.1%	-0.7%
Electricity	80	101	124	145	177	257	2.2%	1.8%	1.9%
Biomass and wastes	8	9	7	5	4	10	-0.7%	-2.3%	4.1%
Heat	2	2	2	2	2	3	0.0%	1.1%	1.5%
Hydrogen	0	0	0	1	3	13		13.3%	7.9%
by sector									
Industry	173	200	203	188	197	218	0.8%	-0.2%	0.5%
Transport	103	130	129	129	128	120	1.1%	0.0%	-0.3%
Household, Service, Agriculture	106	136	144	152	165	208	1.6%	0.7%	1.2%
Electricity Generation (TWh)	**1047**	**1292**	**1651**	**1944**	**2377**	**3590**	2.3%	1.8%	2.1%
Thermal, of which :	705	831	1035	939	1027	853	1.9%	0.0%	-0.9%
Coal	212	364	444	328	349	328	3.8%	-1.2%	-0.3%
Gas	216	341	486	535	546	380	4.1%	0.6%	-1.8%
Biomass and wastes	17	5	25	44	112	120	1.8%	7.8%	0.4%
Nuclear	202	320	460	691	905	1767	4.2%	3.4%	3.4%
Hydro+Geothermal	139	140	147	170	176	175	0.3%	0.9%	0.0%
Solar	0	1	0	2	54	293		36.1%	8.8%
Wind	0	1	9	142	203	289		16.6%	1.8%
Hydrogen	0	0	0	1	11	213		26.9%	15.8%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**0**	**1**	**5**	**44**		15.3%	11.7%
Coal	0	0	0	0	0	0		-0.7%	-2.3%
Renewables	0	0	0	1	4	31		19.2%	10.1%
Nuclear	0	0	0	0	0	13			32.0%
CO2 Emissions (MtCO2), *of which :*	**1277**	**1591**	**1650**	**1226**	**1077**	**909**	1.3%	-2.1%	-0.8%
Electricity generation	487	582	674	371	272	221	1.6%	-4.4%	-1.0%
Industry	318	357	336	263	245	221	0.3%	-1.6%	-0.5%
Transport	280	384	381	372	355	278	1.5%	-0.4%	-1.2%
Household, Service, Agriculture	162	217	193	171	152	125	0.9%	-1.2%	-1.0%
CO2 Sequestration (Mt CO2)	0	0	0	140	232	195			-0.9%

Africa, Middle-East

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	755	983	1190	1439	1692	2177	2.3%	1.8%	1.3%
GDP (G$95)	1754	2643	3598	5087	7019	14703	3.7%	3.4%	3.8%
Per capita GDP ($95/cap)	2.3	2.7	3.0	3.5	4.1	6.8	1.3%	1.6%	2.5%
Gross inland cons/GDP (toe/M$95)	0.4	0.3	0.3	0.3	0.3	0.2	-0.4%	-1.2%	-1.1%
Gross inland cons/capita (toe/cap)	0.8	0.9	1.0	1.0	1.1	1.4	1.0%	0.3%	1.3%
Electricity cons/capita (kWh/cap)	577	781	975	1228	1549	2983	2.7%	2.3%	3.3%
Transport fuels per capita (toe/cap)	0.12	0.13	0.12	0.13	0.14	0.17	0.0%	0.5%	1.2%
CO2 emissions/capita (tCO2/cap)	1.6	1.9	2.3	2.4	2.4	2.2	1.9%	0.2%	-0.5%
% of renewables in gross inland cons	31	26	17	11	10	19	-3.0%	-2.7%	3.4%
% of renewables in electricity	13	10	9	8	12	28	-1.6%	1.4%	4.1%
Primary Production (Mtoe)	**1616**	**2051**	**2322**	**3517**	**4454**	**5327**	1.8%	3.3%	0.9%
Coal, lignite	104	132	184	197	250	227	2.9%	1.5%	-0.5%
Oil	1171	1417	1336	1886	2310	2286	0.7%	2.8%	-0.1%
tural gas	149	281	602	1254	1658	1824	7.2%	5.2%	0.5%
Nuclear	2	3	4	20	63	422	2.5%	15.3%	10.0%
Hydro, geothermal	6	8	11	13	15	21	2.8%	1.7%	1.6%
Biomass and wastes	183	209	184	145	145	415	0.0%	-1.2%	5.4%
Wind, solar	0	1	1	2	12	131		13.8%	12.7%
Gross Inland Consumption (Mtoe)	**620**	**857**	**1183**	**1441**	**1796**	**3018**	3.3%	2.1%	2.6%
Coal, lignite	76	114	146	167	224	227	3.3%	2.1%	0.1%
Oil	237	305	393	532	675	872	2.5%	2.7%	1.3%
tural Gas	115	217	444	562	661	930	7.0%	2.0%	1.7%
Biomass and wastes	183	209	184	145	145	415	0.0%	-1.2%	5.4%
Others	9	12	16	35	91	574	3.0%	9.1%	9.7%
Final Consumption (Mtoe)	**469**	**673**	**763**	**914**	**1107**	**1757**	2.5%	1.9%	2.3%
by source									
Coal, lignite	19	17	28	31	35	17	1.8%	1.3%	-3.5%
Oil	189	256	324	440	559	765	2.7%	2.8%	1.6%
Gas	46	124	141	154	173	242	5.8%	1.0%	1.7%
Electricity	37	66	100	152	225	558	5.0%	4.2%	4.6%
Biomass and wastes	177	209	169	135	109	134	-0.2%	-2.2%	1.0%
Heat	0	1	1	1	1	1	2.6%	0.0%	0.0%
Hydrogen	0	0	0	1	4	39		15.5%	11.7%
by sector									
Industry	135	233	252	276	314	423	3.2%	1.1%	1.5%
Transport	93	132	147	185	229	374	2.3%	2.2%	2.5%
Household, Service, Agriculture	242	308	363	453	564	960	2.1%	2.2%	2.7%
Electricity Generation (TWh)	**552**	**953**	**1387**	**2110**	**3144**	**7644**	4.7%	4.2%	4.5%
Thermal, of which :	472	845	1241	1853	2546	3616	5.0%	3.7%	1.8%
Coal	174	248	404	562	789	903	4.3%	3.4%	0.7%
Gas	145	335	613	987	1387	2235	7.5%	4.2%	2.4%
Biomass and wastes	0	0	0	3	80	388		41.1%	8.2%
Nuclear	8	11	15	85	279	1975	2.9%	15.8%	10.3%
Hydro+Geothermal	72	97	128	154	180	246	2.9%	1.7%	1.6%
Solar	0	0	1	2	48	548		22.0%	12.9%
Wind	0	0	1	15	84	968		22.4%	13.0%
Hydrogen	0	0	1	1	6	292		11.1%	21.7%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**0**	**2**	**6**	**83**		14.5%	14.5%
Coal	0	0	0	0	0	0		2.0%	0.0%
Renewables	0	0	0	0	2	75		22.7%	19.2%
Nuclear	0	0	0	0	0	6			28.5%
CO2 Emissions (MtCO2), *of which :*	**1209**	**1855**	**2759**	**3521**	**4114**	**4785**	4.2%	2.0%	0.8%
Electricity generation	442	620	812	1068	1075	742	3.1%	1.4%	-1.8%
Industry	268	500	556	611	689	590	3.7%	1.1%	-0.8%
Transport	268	395	440	545	652	886	2.5%	2.0%	1.5%
Household, Service, Agriculture	118	222	405	635	869	1434	6.4%	3.9%	2.5%
CO2 Sequestration (Mt CO2)	0	0	0	1	287	823			5.4%

Latin America

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	435	520	585	649	700	756	1.5%	0.9%	0.4%
GDP (G$95)	2393	3410	4474	6210	8145	12658	3.2%	3.0%	2.2%
Per capita GDP ($95/cap)	5502	6557	7645	9569	11636	16754	1.7%	2.1%	1.8%
Gross inland cons/GDP (toe/M$95)	198	180	167	154	138	107	-0.8%	-1.0%	-1.3%
Gross inland cons/capita (toe/cap)	1	1.2	1.3	1.5	1.6	1.8	0.8%	1.1%	0.5%
Electricity cons/capita (kWh/cap)	1147	1489	1820	2354	2937	4436	2.3%	2.4%	2.1%
Transport fuels per capita (toe/cap)	0.3	0.3	0.3	0.3	0.3	0.4	0.4%	1.1%	0.3%
CO2 emissions/capita (tCO2/cap)	2.1	2.4	2.5	2.9	3.0	2.2	0.8%	0.9%	-1.4%
% of renewables in gross inland cons	28	24.2	27.6	25.2	25.6	39.0	-0.1%	-0.4%	2.1%
% of renewables in electricity	65	58.6	54.5	47.8	51.2	59.2	-0.9%	-0.3%	0.7%
Primary Production (Mtoe)	**626**	**835**	**1229**	**1600**	**1737**	**1775**	3.4%	1.7%	0.1%
Coal, lignite	22	41	19	23	33	23	-0.8%	2.9%	-1.8%
Oil	394	523	689	874	915	853	2.8%	1.4%	-0.3%
Natural gas	75	114	309	450	466	273	7.4%	2.1%	-2.6%
Nuclear	3	8	6	13	37	100	3.2%	9.4%	5.1%
Hydro, geothermal	38	48	56	67	78	99	1.9%	1.6%	1.2%
Biomass and wastes	94	101	150	171	189	348	2.4%	1.2%	3.1%
Wind, solar	0	0	0	2	20	79		23.5%	7.1%
Gross Inland Consumption (Mtoe)	**474**	**614**	**748**	**956**	**1120**	**1349**	2.3%	2.0%	0.9%
Coal, lignite	20	28	36	54	81	62	3.0%	4.1%	-1.4%
Oil	244	314	299	361	408	364	1.0%	1.6%	-0.6%
Natural Gas	75	116	201	287	307	297	5.0%	2.2%	-0.2%
Biomass and wastes	94	101	150	171	189	348	2.4%	1.2%	3.1%
Others	42	55	63	82	134	278	2.1%	3.9%	3.7%
Final Consumption (Mtoe)	**359**	**465**	**529**	**658**	**767**	**867**	2.0%	1.9%	0.6%
by source									
Coal, lignite	12	15	17	17	17	4	1.8%	0.0%	-6.5%
Oil	187	240	236	290	333	303	1.2%	1.7%	-0.5%
Gas	38	57	90	123	144	123	4.4%	2.4%	-0.8%
Electricity	43	67	92	131	177	288	3.9%	3.3%	2.5%
Biomass and wastes	80	87	94	95	91	116	0.8%	-0.2%	1.2%
Heat	0	0	0	0	0	0		0.0%	0.0%
Hydrogen	0	0	0	1	4	33		15.1%	10.8%
by sector									
Industry	151	196	218	259	284	257	1.8%	1.3%	-0.5%
Transport	109	148	159	199	234	270	1.9%	2.0%	0.7%
Household, Service, Agriculture	99	121	153	200	249	340	2.2%	2.5%	1.6%
Electricity Generation (TWh)	**612**	**959**	**1295**	**1860**	**2495**	**4050**	3.8%	3.3%	2.5%
Thermal, of which :	206	376	612	999	1194	1466	5.6%	3.4%	1.0%
Coal	21	42	77	175	319	289	6.8%	7.3%	-0.5%
Gas	60	153	403	651	658	810	10.0%	2.5%	1.0%
Biomass and wastes	6	9	48	84	141	330	10.8%	5.5%	4.3%
Nuclear	12	30	25	55	163	458	3.6%	9.8%	5.3%
Hydro+Geothermal	393	553	655	784	905	1148	2.6%	1.6%	1.2%
Solar	0	0	0	0	2	43		8.5%	18.0%
Wind	0	0	2	21	229	876		27.2%	6.9%
Hydrogen	0	0	0	0	2	60		11.6%	18.9%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**0**	**2**	**5**	**45**		14.8%	11.6%
Coal	0	0	0	0	1	0		8.5%	-2.6%
Renewables	0	0	0	1	3	41		22.5%	13.1%
Nuclear	0	0	0	0	0	3			26.9%
CO2 Emissions (MtCO2), *of which :*	**918**	**1268**	**1441**	**1880**	**2068**	**1677**	2.3%	1.8%	-1.0%
Electricity generation	242	276	307	462	457	264	1.2%	2.0%	-2.7%
Industry	226	307	332	386	415	228	2.0%	1.1%	-2.9%
Transport	301	411	408	508	583	532	1.5%	1.8%	-0.5%
Household, Service, Agriculture	108	142	188	261	327	391	2.8%	2.8%	0.9%
CO2 Sequestration (Mt CO2)	0	0	0	0	103	276			5.0%

Asia

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	2783	3267	3635	3995	4258	4511	1.3%	0.8%	0.3%
GDP (G$95)	5048	10810	18906	29416	41426	70429	6.8%	4.0%	2.7%
Per capita GDP ($95/cap)	1814	3309	5201	7363	9728	15612	5.4%	3.2%	2.4%
Gross inland cons/GDP (toe/M$95)	344	227	194	162	143	109	-2.8%	-1.5%	-1.4%
Gross inland cons/capita (toe/cap)	1	0.8	1.0	1.2	1.4	1.7	2.4%	1.6%	1.0%
Electricity cons/capita (kWh/cap)	388	721	1169	1642	2192	3655	5.7%	3.2%	2.6%
Transport fuels per capita (toe/cap)	0.0	0.1	0.1	0.1	0.1	0.2	2.7%	2.5%	1.7%
CO2 emissions/capita (tCO2/cap)	1.4	1.8	2.6	3.0	3.0	2.4	3.4%	0.7%	-1.1%
% of renewables in gross inland cons	31	25.1	17.5	15.3	13.6	17.1	-2.8%	-1.2%	1.1%
% of renewables in electricity	21	15.9	15.9	18.1	19.8	23.7	-1.4%	1.1%	0.9%
Primary Production (Mtoe)	**1657**	**2136**	**3031**	**3310**	**3553**	**4951**	3.1%	0.8%	1.7%
Coal, lignite	693	1009	1456	1506	1715	1594	3.8%	0.8%	-0.4%
Oil	297	299	350	312	228	147	0.8%	-2.1%	-2.2%
Natural gas	107	164	483	481	314	145	7.8%	-2.1%	-3.8%
Nuclear	24	47	103	282	489	1756	7.6%	8.1%	6.6%
Hydro, geothermal	30	41	66	91	112	150	4.0%	2.7%	1.5%
Biomass and wastes	507	577	571	621	639	931	0.6%	0.6%	1.9%
Wind, solar	0	0	2	18	56	228		18.8%	7.3%
Gross Inland Consumption (Mtoe)	**1738**	**2459**	**3659**	**4779**	**5920**	**7650**	3.8%	2.4%	1.3%
Coal, lignite	735	947	1524	1605	1848	1621	3.7%	1.0%	-0.7%
Oil	369	680	946	1420	1734	1897	4.8%	3.1%	0.4%
Natural Gas	73	169	448	742	1042	1067	9.5%	4.3%	0.1%
Biomass and wastes	507	577	571	621	639	931	0.6%	0.6%	1.9%
Others	54	87	170	391	656	2134	5.9%	7.0%	6.1%
Final Consumption (Mtoe)	**1365**	**1796**	**2611**	**3349**	**4007**	**4652**	3.3%	2.2%	0.7%
by source									
Coal, lignite	435	409	653	734	768	539	2.1%	0.8%	-1.7%
Oil	290	506	858	1259	1554	1713	5.6%	3.0%	0.5%
Gas	37	79	188	287	410	439	8.4%	4.0%	0.3%
Electricity	93	203	365	564	803	1418	7.1%	4.0%	2.9%
Biomass and wastes	497	569	515	471	432	409	0.2%	-0.9%	-0.3%
Heat	13	31	31	31	31	31	4.4%	0.0%	0.0%
Hydrogen	0	0	0	3	10	103		16.9%	12.6%
by sector									
Industry	504	742	1198	1469	1673	1608	4.4%	1.7%	-0.2%
Transport	139	205	308	443	586	867	4.1%	3.3%	2.0%
Household, Service, Agriculture	723	850	1105	1437	1748	2178	2.1%	2.3%	1.1%
Electricity Generation (TWh)	**1374**	**3049**	**5473**	**8440**	**11969**	**21058**	7.2%	4.0%	2.9%
Thermal, of which :	994	2387	4264	5951	7834	8122	7.6%	3.1%	0.2%
Coal	732	1847	3367	3994	5063	5070	7.9%	2.1%	0.0%
Gas	78	326	689	1536	2198	2334	11.5%	6.0%	0.3%
Biomass and wastes	0	9	90	264	414	596		7.9%	1.8%
Nuclear	92	187	427	1220	2173	8175	8.0%	8.5%	6.8%
Hydro+Geothermal	288	473	763	1056	1307	1750	5.0%	2.7%	1.5%
Solar	0	0	5	8	12	252		4.8%	16.4%
Wind	0	2	15	203	632	2391	35.8%	20.8%	6.9%
Hydrogen	0	0	1	1	11	367		14.2%	19.3%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**1**	**3**	**12**	**164**		16.4%	13.9%
Coal	0	0	0	1	1	1		5.4%	0.8%
Renewables	0	0	0	2	9	151		23.3%	15.3%
Nuclear	0	0	0	0	0	11			33.5%
CO2 Emissions (MtCO2), *of which :*	**3791**	**5956**	**9582**	**11897**	**12839**	**10794**	4.7%	1.5%	-0.9%
Electricity generation	1197	2504	3624	4048	3467	1688	5.7%	-0.2%	-3.5%
Industry	1224	1742	2990	3503	3801	2876	4.6%	1.2%	-1.4%
Transport	411	615	915	1295	1664	2033	4.1%	3.0%	1.0%
Household, Service, Agriculture	675	724	1353	2120	2702	2906	3.5%	3.5%	0.4%
CO2 Sequestration (Mt CO2)	0	0	0	0	1599	3299			3.7%

4. WETO-H_2 projections by region - H_2 Case

World

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	5245	6113	6792	7496	8082	8864	1.3%	0.9%	0.5%
GDP (G$95)	29880	42224	59524	81559	105930	164090	3.5%	2.9%	2.2%
Per capita GDP ($95/cap)	5697	6907	8764	10880	13107	18513	2.2%	2.0%	1.7%
Gross inland cons/GDP (toe/M$95)	290	236	204	171	151	123	-1.7%	-1.5%	-1.0%
Gross inland cons/capita (toe/cap)	1.6	1.6	1.8	1.9	2.0	2.3	0.4%	0.5%	0.7%
Electricity cons/capita (kWh/cap)	1832	2077	2597	3017	3543	5214	1.8%	1.6%	2.0%
Transport fuels per capita (toe/cap)	0.3	0.3	0.2	0.3	0.3	0.3	-0.5%	0.9%	0.5%
CO2 emissions/capita (tCO2/cap)	3.8	3.8	4.3	4.2	3.9	3.1	0.6%	-0.5%	-1.2%
% of renewables in gross inland cons	13	13.5	12.6	12.5	13.0	19.2	-0.3%	0.2%	2.0%
% of renewables in electricity	20	18.7	17.9	20.3	24.2	28.7	-0.6%	1.5%	0.9%
Primary Production (Mtoe)	**8834**	**9836**	**12274**	**14114**	**16174**	**20451**	1.7%	1.4%	1.2%
Coal, lignite	2207	2408	3021	2838	2905	2901	1.6%	-0.2%	0.0%
Oil	3234	3487	3805	4670	5248	5173	0.8%	1.6%	-0.1%
Natural gas	1708	1929	3160	3683	3954	3802	3.1%	1.1%	-0.2%
Nuclear	525	671	765	1176	1991	4688	1.9%	4.9%	4.4%
Hydro, geothermal	216	232	275	323	363	430	1.2%	1.4%	0.8%
Biomass and wastes	939	1101	1227	1328	1482	2526	1.3%	0.9%	2.7%
Wind, solar	0	7	21	95	230	933	22.0%	12.7%	7.3%
Gross Inland Consumption (Mtoe)	**8654**	**9950**	**12128**	**13934**	**15972**	**20253**	1.7%	1.4%	1.2%
Coal, lignite	2201	2352	3021	2838	2905	2901	1.6%	-0.2%	0.0%
Oil	3089	3487	3805	4670	5248	5173	1.0%	1.6%	-0.1%
Natural Gas	1679	2082	3160	3683	3954	3802	3.2%	1.1%	-0.2%
Biomass and wastes	940	1101	1227	1328	1482	2526	1.3%	0.9%	2.7%
Others	745	911	1062	1595	2585	6051	1.8%	4.6%	4.3%
Final Consumption (Mtoe)	**6267**	**6914**	**8181**	**9482**	**10696**	**12639**	1.3%	1.3%	0.8%
by source									
Coal, lignite	869	670	894	963	994	727	0.1%	0.5%	-1.5%
Oil	2553	2757	3262	4007	4570	4552	1.2%	1.7%	0.0%
Gas	985	1142	1363	1485	1598	1495	1.6%	0.8%	-0.3%
Electricity	826	1092	1517	1945	2463	3975	3.1%	2.5%	2.4%
Biomass and wastes	855	1004	891	804	726	800	0.2%	-1.0%	0.5%
Heat	179	249	250	252	253	257	1.7%	0.1%	0.1%
Hydrogen	0	0	5	27	93	833		16.3%	11.6%
by sector									
Industry	2416	2639	3160	3466	3720	3810	1.4%	0.8%	0.1%
Transport	1432	1529	1669	2028	2377	2908	0.8%	1.8%	1.0%
Household, Service, Agriculture	2418	2746	3352	3988	4599	5921	1.6%	1.6%	1.3%
Electricity Generation (TWh)	**11859**	**15468**	**21479**	**27633**	**35039**	**57377**	3.0%	2.5%	2.5%
Thermal, of which :	7609	10074	14923	17738	19335	21198	3.4%	1.3%	0.5%
Coal	4422	5848	8004	8084	8205	9371	3.0%	0.1%	0.7%
Gas	1705	2934	5698	8045	8851	8959	6.2%	2.2%	0.1%
Biomass and wastes	150	155	441	811	1644	2584	5.6%	6.8%	2.3%
Nuclear	2013	2653	3159	5083	8834	21426	2.3%	5.3%	4.5%
Hydro+Geothermal	2231	2703	3196	3761	4226	4998	1.8%	1.4%	0.8%
Solar	1	1	6	16	183	2058	11.6%	18.6%	12.8%
Wind	4	37	191	1030	2417	6799	21.5%	13.5%	5.3%
Hydrogen	0	0	2	5	44	898		16.0%	16.3%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**5**	**31**	**109**	**1047**		16.2%	12.0%
Coal	0	0	3	14	41	40		14.7%	-0.2%
Renewables	0	0	0	6	27	545		23.6%	16.2%
Nuclear	0	0	0	1	9	399		25.6%	20.6%
CO2 Emissions (MtCO2), *of which :*	**20161**	**23516**	**29389**	**31334**	**31838**	**27295**	1.9%	0.4%	-0.8%
Electricity generation	7433	8932	10872	9643	7559	4073	1.9%	-1.8%	-3.0%
Industry	4653	4812	5956	6366	6637	5307	1.2%	0.5%	-1.1%
Transport	3982	4487	4787	5741	6528	5660	0.9%	1.6%	-0.7%
Household, Service, Agriculture	3191	3196	4507	5829	6804	7698	1.7%	2.1%	0.6%
CO2 Sequestration (Mt CO2)	0	0	0	910	2874	6863			4.4%

NB : Oil consumption in international bunkers is accounted for in gross inland consumption at world level (but not at regional levels). The related emissions are included in the world total CO2 emissions (MtCO2).

Europe

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	564	588	599	605	606	586	0.3%	0.1%	-0.2%
GDP (G$95)	8373	10312	12660	15900	19079	25194	2.1%	2.1%	1.4%
Per capita GDP ($95/cap)	14849	17533	21124	26260	31496	43005	1.8%	2.0%	1.6%
Gross inland cons/GDP (toe/M$95)	212	186	160	132	114	103	-1.4%	-1.7%	-0.5%
Gross inland cons/capita (toe/cap)	3	3.3	3.4	3.5	3.6	4.4	0.4%	0.3%	1.1%
Electricity cons/capita (kWh/cap)	4206	4995	5812	6707	7765	11769	1.6%	1.5%	2.1%
Transport fuels per capita (toe/cap)	0.5	0.6	0.6	0.6	0.7	0.7	0.5%	0.5%	0.3%
CO2 emissions/capita (tCO2/cap)	7.7	7.4	7.5	6.9	6.0	4.8	-0.2%	-1.1%	-1.0%
% of renewables in gross inland cons	6	7.5	9.8	12.1	14.6	18.7	2.9%	2.0%	1.2%
% of renewables in electricity	18	20.4	21.0	24.8	29.2	28.6	0.7%	1.7%	-0.1%
Primary Production (Mtoe)	**1115**	**1196**	**1290**	**1087**	**1129**	**1697**	0.7%	-0.7%	2.1%
Coal, lignite	393	240	223	170	136	98	-2.8%	-2.5%	-1.6%
Oil	224	313	313	187	112	67	1.7%	-5.0%	-2.5%
Natural gas	190	244	307	226	204	196	2.4%	-2.0%	-0.2%
Nuclear	209	254	248	250	360	852	0.9%	1.9%	4.4%
Hydro, geothermal	44	54	55	58	60	64	1.1%	0.4%	0.3%
Biomass and wastes	53	87	131	164	201	273	4.6%	2.1%	1.6%
Wind, solar	0	3	12	30	56	147	29.2%	8.2%	4.9%
Gross Inland Consumption (Mtoe)	**1773**	**1921**	**2029**	**2091**	**2167**	**2589**	0.7%	0.3%	0.9%
Coal, lignite	481	359	366	281	230	167	-1.4%	-2.3%	-1.6%
Oil	681	734	685	714	712	616	0.0%	0.2%	-0.7%
Natural Gas	300	429	530	591	546	469	2.9%	0.2%	-0.8%
Biomass and wastes	53	87	131	164	201	273	4.6%	2.1%	1.6%
Others	258	313	316	340	478	1065	1.0%	2.1%	4.1%
Final Consumption (Mtoe)	**1263**	**1363**	**1414**	**1472**	**1500**	**1611**	0.6%	0.3%	0.4%
by source									
Coal, lignite	156	82	79	65	55	35	-3.3%	-1.8%	-2.2%
Oil	575	633	616	645	653	568	0.4%	0.3%	-0.7%
Gas	235	288	307	295	258	205	1.3%	-0.9%	-1.1%
Electricity	204	253	300	349	405	593	1.9%	1.5%	1.9%
Biomass and wastes	44	60	63	64	64	78	1.8%	0.1%	1.0%
Heat	50	47	48	49	50	53	-0.2%	0.3%	0.3%
Hydrogen	0	0	1	5	15	79		16.6%	8.5%
by sector									
Industry	493	472	486	475	458	433	-0.1%	-0.3%	-0.3%
Transport	308	366	365	389	404	413	0.9%	0.5%	0.1%
Household, Service, Agriculture	462	525	562	608	638	765	1.0%	0.6%	0.9%
Electricity Generation (TWh)	**2845**	**3489**	**4188**	**4864**	**5642**	**8845**	2.0%	1.5%	2.3%
Thermal, of which :	1540	1823	2395	2765	2698	2488	2.2%	0.6%	-0.4%
Coal	1070	1006	1102	959	794	633	0.2%	-1.6%	-1.1%
Gas	230	577	1077	1525	1540	1465	8.0%	1.8%	-0.2%
Biomass and wastes	15	51	108	186	311	360	10.4%	5.4%	0.7%
Nuclear	801	1006	1023	1081	1597	3942	1.2%	2.3%	4.6%
Hydro+Geothermal	503	633	643	677	702	743	1.2%	0.4%	0.3%
Solar	0	0	0	3	28	591	15.6%	27.1%	16.4%
Wind	1	27	126	338	604	838	29.0%	8.1%	1.7%
Hydrogen	0	0	0	1	12	243		24.1%	16.1%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**1**	**5**	**19**	**120**		17.0%	9.8%
Coal	0	0	0	1	6	4		18.9%	-1.9%
Renewables	0	0	0	2	5	47		20.2%	11.4%
Nuclear	0	0	0	0	4	64		26.1%	15.0%
CO2 Emissions (MtCO2), *of which :*	**4360**	**4367**	**4475**	**4170**	**3612**	**2841**	0.1%	-1.1%	-1.2%
Electricity generation	1608	1519	1617	1315	856	548	0.0%	-3.1%	-2.2%
Industry	961	765	738	654	580	428	-1.3%	-1.2%	-1.5%
Transport	826	1078	1065	1117	1122	914	1.3%	0.3%	-1.0%
Household, Service, Agriculture	828	800	821	852	826	755	0.0%	0.0%	-0.4%
CO2 Sequestration (Mt CO2)	0	0	0	177	412	498			0.9%

CIS

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	281	281	276	270	261	237	-0.1%	-0.3%	-0.5%
GDP (G$95)	2139	1463	2164	3041	3860	5488	0.1%	2.9%	1.8%
Per capita GDP ($95/cap)	7608	5204	7852	11263	14797	23174	0.2%	3.2%	2.3%
Gross inland cons/GDP (toe/M$95)	635	633	466	333	279	226	-1.5%	-2.5%	-1.0%
Gross inland cons/capita (toe/cap)	5	3.3	3.7	3.7	4.1	5.2	-1.4%	0.6%	1.2%
Electricity cons/capita (kWh/cap)	4438	3084	4178	5570	7352	11825	-0.3%	2.9%	2.4%
Transport fuels per capita (toe/cap)	0.5	0.2	0.2	0.2	0.3	0.3	-4.6%	1.2%	1.2%
CO2 emissions/capita (tCO2/cap)	11.9	8.3	9.0	8.3	7.7	6.8	-1.4%	-0.8%	-0.6%
% of renewables in gross inland cons	3	3.3	4.8	5.5	8.2	16.5	2.6%	2.7%	3.5%
% of renewables in electricity	15	19.1	18.2	16.6	21.1	28.1	1.1%	0.7%	1.4%
Primary Production (Mtoe)	**1637**	**1226**	**1637**	**1687**	**1954**	**2088**	0.0%	0.9%	0.3%
Coal, lignite	301	197	248	204	213	170	-1.0%	-0.8%	-1.1%
Oil	583	400	596	622	591	460	0.1%	0.0%	-1.2%
Natural gas	659	543	683	711	905	920	0.2%	1.4%	0.1%
Nuclear	55	54	62	94	157	332	0.6%	4.8%	3.8%
Hydro, geothermal	20	20	21	23	24	23	0.3%	0.5%	0.0%
Biomass and wastes	19	11	27	32	56	130	1.8%	3.7%	4.3%
Wind, solar	0	0	0	0	9	52		32.0%	9.2%
Gross Inland Consumption (Mtoe)	**1359**	**926**	**1008**	**1012**	**1079**	**1242**	-1.5%	0.3%	0.7%
Coal, lignite	289	176	198	158	166	133	-1.9%	-0.9%	-1.1%
Oil	416	183	161	195	192	171	-4.6%	0.9%	-0.6%
Natural Gas	562	482	539	511	475	402	-0.2%	-0.6%	-0.8%
Biomass and wastes	19	11	27	32	56	130	1.8%	3.7%	4.3%
Others	72	74	82	117	189	407	0.7%	4.2%	3.9%
Final Consumption (Mtoe)	**978**	**594**	**663**	**703**	**741**	**821**	-1.9%	0.6%	0.5%
by source									
Coal, lignite	139	58	53	43	41	27	-4.7%	-1.3%	-2.1%
Oil	322	109	146	162	166	147	-3.9%	0.6%	-0.6%
Gas	279	187	201	206	203	196	-1.6%	0.1%	-0.2%
Electricity	107	75	99	129	165	241	-0.4%	2.6%	1.9%
Biomass and wastes	19	9	7	6	7	35	-4.7%	-0.1%	8.4%
Heat	111	156	156	156	156	156	1.7%	0.0%	0.0%
Hydrogen	0	0	0	1	3	18		18.5%	9.9%
by sector									
Industry	492	257	276	263	254	235	-2.9%	-0.4%	-0.4%
Transport	147	50	56	62	67	77	-4.7%	0.9%	0.7%
Household, Service, Agriculture	339	287	331	378	420	509	-0.1%	1.2%	1.0%
Electricity Generation (TWh)	**1727**	**1252**	**1583**	**2015**	**2505**	**3573**	-0.4%	2.3%	1.8%
Thermal, of which :	1283	800	1080	1335	1425	1179	-0.9%	1.4%	-0.9%
Coal	431	252	329	382	442	377	-1.3%	1.5%	-0.8%
Gas	584	508	673	841	810	627	0.7%	0.9%	-1.3%
Biomass and wastes	21	3	39	60	149	169	3.1%	7.0%	0.6%
Nuclear	212	215	254	406	699	1538	0.9%	5.2%	4.0%
Hydro+Geothermal	233	237	249	270	275	273	0.3%	0.5%	0.0%
Solar	0	0	0	0	0	5		2.9%	13.4%
Wind	0	0	0	3	103	555		38.4%	8.8%
Hydrogen	0	0	0	0	2	22		10.2%	13.1%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**0**	**1**	**3**	**22**		17.0%	10.2%
Coal	0	0	0	0	1	1		22.0%	0.3%
Renewables	0	0	0	0	0	6			21.6%
Nuclear	0	0	0	0	0	11			27.3%
CO2 Emissions (MtCO2), *of which :*	**3343**	**2331**	**2482**	**2236**	**2011**	**1612**	-1.5%	-1.0%	-1.1%
Electricity generation	1330	763	801	594	392	202	-2.5%	-3.5%	-3.3%
Industry	866	444	481	419	365	194	-2.9%	-1.4%	-3.1%
Transport	398	135	152	168	176	157	-4.7%	0.7%	-0.6%
Household, Service, Agriculture	644	397	468	532	575	637	-1.6%	1.0%	0.5%
CO2 Sequestration (Mt CO2)	0	0	0	118	283	324			0.7%

North America

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	277	316	345	376	404	444	1.1%	0.8%	0.5%
GDP (G$95)	7146	10003	13225	16432	19843	26887	3.1%	2.0%	1.5%
Per capita GDP ($95/cap)	25778	31614	38341	43693	49146	60584	2.0%	1.2%	1.1%
Gross inland cons/GDP (toe/M$95)	299	252	222	181	151	111	-1.5%	-1.9%	-1.5%
Gross inland cons/capita (toe/cap)	8	8.0	8.5	7.9	7.4	6.7	0.5%	-0.7%	-0.5%
Electricity cons/capita (kWh/cap)	10999	12064	14366	14085	14330	17507	1.3%	0.0%	1.0%
Transport fuels per capita (toe/cap)	1.9	2.2	2.1	2.2	2.1	1.6	0.4%	0.2%	-1.6%
CO2 emissions/capita (tCO2/cap)	19.0	19.6	20.2	16.0	13.1	8.2	0.3%	-2.1%	-2.4%
% of renewables in gross inland cons	6	6.2	8.0	10.9	13.9	22.1	1.3%	2.8%	2.3%
% of renewables in electricity	19	14.6	13.8	20.0	29.6	36.2	-1.5%	3.9%	1.0%
Primary Production (Mtoe)	**1926**	**2040**	**2478**	**2301**	**2491**	**3232**	1.3%	0.0%	1.3%
Coal, lignite	582	611	687	500	526	488	0.8%	-1.3%	-0.4%
Oil	527	494	629	726	920	1225	0.9%	1.9%	1.4%
Natural gas	505	555	713	542	406	312	1.7%	-2.8%	-1.3%
Nuclear	178	224	214	208	221	546	0.9%	0.2%	4.6%
Hydro, geothermal	63	49	53	59	63	67	-0.9%	0.9%	0.3%
Biomass and wastes	70	105	178	234	287	392	4.8%	2.4%	1.6%
Wind, solar	0	2	5	32	69	202	14.4%	14.3%	5.5%
Gross Inland Consumption (Mtoe)	**2139**	**2525**	**2935**	**2970**	**3002**	**2986**	1.6%	0.1%	0.0%
Coal, lignite	488	576	579	393	401	387	0.9%	-1.8%	-0.2%
Oil	847	992	1030	1105	1106	730	1.0%	0.4%	-2.1%
Natural Gas	491	578	876	939	855	661	2.9%	-0.1%	-1.3%
Biomass and wastes	70	105	178	234	287	392	4.8%	2.4%	1.6%
Others	242	275	272	299	353	815	0.6%	1.3%	4.3%
Final Consumption (Mtoe)	**1450**	**1751**	**1889**	**1991**	**2031**	**1920**	1.3%	0.4%	-0.3%
by source									
Coal, lignite	62	44	43	26	17	12	-1.9%	-4.4%	-1.8%
Oil	768	941	945	1020	1043	702	1.0%	0.5%	-2.0%
Gas	324	366	390	382	358	282	0.9%	-0.4%	-1.2%
Electricity	262	328	426	456	498	668	2.5%	0.8%	1.5%
Biomass and wastes	30	60	70	84	79	73	4.3%	0.6%	-0.4%
Heat	3	12	12	13	13	13	7.2%	0.1%	0.1%
Hydrogen	0	0	3	11	24	170		11.5%	10.4%
by sector									
Industry	468	539	551	509	487	482	0.8%	-0.6%	0.0%
Transport	533	693	716	817	865	691	1.5%	1.0%	-1.1%
Household, Service, Agriculture	449	520	622	665	678	747	1.6%	0.4%	0.5%
Electricity Generation (TWh)	**3701**	**4474**	**5718**	**6121**	**6714**	**9233**	2.2%	0.8%	1.6%
Thermal, of which :	2411	3012	4182	4183	4215	3981	2.8%	0.0%	-0.3%
Coal	1782	2088	2112	1557	1491	1525	0.9%	-1.7%	0.1%
Gas	391	694	1801	2332	2186	1738	7.9%	1.0%	-1.1%
Biomass and wastes	90	78	133	184	474	685	2.0%	6.6%	1.9%
Nuclear	685	885	883	898	981	2474	1.3%	0.5%	4.7%
Hydro+Geothermal	602	571	615	680	730	782	0.1%	0.9%	0.3%
Solar	1	0	0	2	55	523	-10.0%	38.5%	12.0%
Wind	3	6	38	357	727	1352	13.5%	15.8%	3.2%
Hydrogen	0	0	0	1	7	120		28.0%	15.6%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**3**	**13**	**27**	**205**		11.7%	10.6%
Coal	0	0	2	8	20	14		12.8%	-1.8%
Renewables	0	0	0	1	2	82		16.5%	19.5%
Nuclear	0	0	0	0	1	104		22.2%	24.9%
CO2 Emissions (MtCO2), *of which :*	**5263**	**6198**	**6957**	**6034**	**5302**	**3620**	1.4%	-1.3%	-1.9%
Electricity generation	2128	2668	2923	1825	1067	723	1.6%	-4.9%	-1.9%
Industry	791	697	622	464	404	352	-1.2%	-2.1%	-0.7%
Transport	1499	2052	2094	2360	2448	1435	1.7%	0.8%	-2.6%
Household, Service, Agriculture	657	695	766	800	761	619	0.8%	0.0%	-1.0%
CO2 Sequestration (Mt CO2)	0	0	0	506	1074	1171			0.4%

Japan, Pacific

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	150	157	161	162	161	154	0.4%	0.0%	-0.2%
GDP (G$95)	3026	3583	4497	5474	6558	8731	2.0%	1.9%	1.4%
Per capita GDP ($95/cap)	20234	22775	27864	33713	40770	56786	1.6%	1.9%	1.7%
Gross inland cons/GDP (toe/M$95)	182	181	157	135	122	111	-0.7%	-1.3%	-0.5%
Gross inland cons/capita (toe/cap)	4	4.1	4.4	4.5	5.0	6.3	0.9%	0.6%	1.2%
Electricity cons/capita (kWh/cap)	6186	7496	8914	10524	12903	19442	1.8%	1.9%	2.1%
Transport fuels per capita (toe/cap)	0.7	0.7	0.7	0.7	0.8	0.9	-0.1%	0.6%	0.8%
CO2 emissions/capita (tCO2/cap)	8.5	10.1	9.9	8.0	7.0	6.0	0.8%	-1.7%	-0.8%
% of renewables in gross inland cons	5	3.8	5.0	7.1	9.4	13.7	0.2%	3.2%	1.9%
% of renewables in electricity	15	11.3	11.0	17.8	22.5	23.9	-1.5%	3.7%	0.3%
Primary Production (Mtoe)	**255**	**352**	**420**	**506**	**584**	**859**	2.5%	1.7%	1.9%
Coal, lignite	113	178	191	170	171	134	2.7%	-0.6%	-1.2%
Oil	38	40	34	37	40	30	-0.5%	0.8%	-1.4%
Natural gas	24	28	44	68	83	158	3.2%	3.2%	3.3%
Nuclear	53	81	114	178	216	404	3.9%	3.2%	3.2%
Hydro, geothermal	14	12	13	14	16	16	-0.7%	1.1%	0.1%
Biomass and wastes	12	12	21	25	37	62	2.7%	2.9%	2.6%
Wind, solar	0	1	2	13	22	55		13.9%	4.6%
Gross Inland Consumption (Mtoe)	**551**	**648**	**707**	**737**	**798**	**970**	1.3%	0.6%	1.0%
Coal, lignite	112	154	164	124	123	105	1.9%	-1.4%	-0.8%
Oil	294	296	268	260	242	212	-0.5%	-0.5%	-0.7%
Natural Gas	63	92	126	122	142	116	3.6%	0.6%	-1.0%
Biomass and wastes	12	12	21	25	37	62	2.7%	2.9%	2.6%
Others	69	94	128	206	254	475	3.2%	3.5%	3.2%
Final Consumption (Mtoe)	**382**	**453**	**460**	**478**	**507**	**579**	0.9%	0.5%	0.7%
by source									
Coal, lignite	45	46	42	31	25	21	-0.3%	-2.6%	-1.0%
Oil	222	255	242	243	235	209	0.4%	-0.1%	-0.6%
Gas	25	39	43	47	57	48	2.7%	1.4%	-0.9%
Electricity	80	101	124	147	178	257	2.2%	1.8%	1.8%
Biomass and wastes	8	9	7	5	4	10	-0.7%	-2.3%	4.0%
Heat	2	2	2	2	2	3	0.0%	1.1%	1.5%
Hydrogen	0	0	0	2	5	32		15.2%	10.2%
by sector									
Industry	173	200	200	197	205	222	0.7%	0.1%	0.4%
Transport	103	117	110	118	124	139	0.3%	0.6%	0.6%
Household, Service, Agriculture	106	136	150	162	177	218	1.8%	0.9%	1.0%
Electricity Generation (TWh)	**1047**	**1292**	**1651**	**1966**	**2394**	**3582**	2.3%	1.9%	2.0%
Thermal, of which :	705	831	1024	887	1001	863	1.9%	-0.1%	-0.7%
Coal	212	364	465	397	400	340	4.0%	-0.7%	-0.8%
Gas	216	341	458	415	477	392	3.8%	0.2%	-1.0%
Biomass and wastes	17	5	25	43	109	119	1.8%	7.6%	0.5%
Nuclear	202	320	471	770	956	1827	4.3%	3.6%	3.3%
Hydro+Geothermal	139	140	147	166	182	185	0.3%	1.1%	0.1%
Solar	0	1	0	2	51	275		35.7%	8.8%
Wind	0	1	9	140	196	275		16.5%	1.7%
Hydrogen	0	0	0	1	8	156		24.8%	16.0%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**0**	**2**	**6**	**57**		16.1%	11.7%
Coal	0	0	0	1	3	2		13.2%	-2.0%
Renewables	0	0	0	0	1	15		17.5%	13.7%
Nuclear	0	0	0	0	2	40		27.4%	16.2%
CO2 Emissions (MtCO2), *of which :*	**1277**	**1591**	**1606**	**1299**	**1131**	**926**	1.2%	-1.7%	-1.0%
Electricity generation	487	582	682	418	268	181	1.7%	-4.6%	-1.9%
Industry	318	357	329	288	269	236	0.2%	-1.0%	-0.6%
Transport	280	345	324	342	349	297	0.7%	0.4%	-0.8%
Household, Service, Agriculture	162	217	207	195	176	139	1.3%	-0.8%	-1.2%
CO2 Sequestration (Mt CO2)	0	0	0	108	254	238			-0.3%

Africa, Middle-East

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	755	983	1190	1439	1692	2177	2.3%	1.8%	1.3%
GDP (G$95)	1754	2643	3598	5087	7019	14703	3.7%	3.4%	3.8%
Per capita GDP ($95/cap)	2.3	2.7	3.0	3.5	4.1	6.8	1.3%	1.6%	2.5%
Gross inland cons/GDP (toe/M$95)	0.4	0.3	0.3	0.3	0.2	0.2	-0.9%	-1.3%	-1.0%
Gross inland cons/capita (toe/cap)	0.8	0.9	0.9	0.9	0.9	1.3	0.4%	0.3%	1.4%
Electricity cons/capita (kWh/cap)	577	781	965	1211	1483	2703	2.6%	2.2%	3.0%
Transport fuels per capita (toe/cap)	0.12	0.03	0.03	0.04	0.04	0.07	-6.5%	1.1%	2.9%
CO2 emissions/capita (tCO2/cap)	1.6	1.9	2.0	2.2	2.1	1.9	1.2%	0.3%	-0.5%
% of renewables in gross inland cons	31	26	18	12	10	19	-2.5%	-3.0%	3.3%
% of renewables in electricity	13	10	10	8	11	28	-1.6%	0.9%	4.6%
Primary Production (Mtoe)	**1616**	**2051**	**2171**	**3425**	**4485**	**5187**	1.5%	3.7%	0.7%
Coal, lignite	104	132	182	205	224	218	2.8%	1.0%	-0.1%
Oil	1171	1417	1192	1853	2340	2293	0.1%	3.4%	-0.1%
tural gas	149	281	597	1177	1634	1772	7.2%	5.2%	0.4%
Nuclear	2	3	4	31	126	379	3.0%	18.9%	5.7%
Hydro, geothermal	6	8	11	13	15	21	2.8%	1.7%	1.5%
Biomass and wastes	183	209	184	144	135	375	0.0%	-1.5%	5.2%
Wind, solar	0	1	1	2	10	129		12.5%	13.8%
Gross Inland Consumption (Mtoe)	**620**	**857**	**1062**	**1303**	**1606**	**2739**	2.7%	2.1%	2.7%
Coal, lignite	76	114	143	173	204	222	3.2%	1.8%	0.4%
Oil	237	305	284	393	506	705	0.9%	2.9%	1.7%
tural Gas	115	217	435	548	609	908	6.9%	1.7%	2.0%
Biomass and wastes	183	209	184	144	135	375	0.0%	-1.5%	5.2%
Others	9	12	16	46	151	529	3.1%	11.8%	6.5%
Final Consumption (Mtoe)	**469**	**575**	**663**	**800**	**965**	**1575**	1.7%	1.9%	2.5%
by source									
Coal, lignite	19	17	28	35	42	26	1.8%	2.1%	-2.4%
Oil	189	158	229	328	430	622	0.9%	3.2%	1.9%
Gas	46	124	138	150	162	216	5.7%	0.8%	1.4%
Electricity	37	66	99	150	216	506	5.0%	4.0%	4.4%
Biomass and wastes	177	209	169	135	109	134	-0.2%	-2.2%	1.0%
Heat	0	1	1	1	1	1	2.6%	0.0%	0.0%
Hydrogen	0	0	0	1	5	70		22.8%	13.8%
by sector									
Industry	135	233	252	286	324	456	3.2%	1.3%	1.7%
Transport	93	34	38	51	68	155	-4.3%	2.9%	4.2%
Household, Service, Agriculture	242	308	373	464	573	963	2.2%	2.2%	2.6%
Electricity Generation (TWh)	**552**	**953**	**1372**	**2079**	**2994**	**6924**	4.7%	4.0%	4.3%
Thermal, of which :	472	845	1225	1778	2148	3456	4.9%	2.8%	2.4%
Coal	174	248	395	546	673	833	4.2%	2.7%	1.1%
Gas	145	335	611	942	1140	2172	7.4%	3.2%	3.3%
Biomass and wastes	0	0	0	3	60	376		39.2%	9.6%
Nuclear	8	11	16	133	561	1759	3.3%	19.4%	5.9%
Hydro+Geothermal	72	97	128	152	178	240	2.9%	1.7%	1.5%
Solar	0	0	1	2	37	463		20.5%	13.4%
Wind	0	0	1	13	65	836		20.8%	13.6%
Hydrogen	0	0	1	1	5	170		10.4%	19.1%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**0**	**1**	**7**	**101**		19.1%	14.6%
Coal	0	0	0	0	0	1		5.5%	6.8%
Renewables	0	0	0	0	1	68		23.7%	23.5%
Nuclear	0	0	0	0	0	7			29.0%
CO2 Emissions (MtCO2), *of which :*	**1209**	**1855**	**2399**	**3095**	**3585**	**4190**	3.5%	2.0%	0.8%
Electricity generation	442	620	798	1027	1048	675	3.0%	1.4%	-2.2%
Industry	268	500	554	636	717	673	3.7%	1.3%	-0.3%
Transport	268	101	114	148	186	252	-4.2%	2.5%	1.5%
Household, Service, Agriculture	118	222	439	679	919	1532	6.8%	3.8%	2.6%
CO2 Sequestration (Mt CO2)	0	0	0	0	112	830			10.5%

Latin America

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	435	520	585	649	700	756	1.5%	0.9%	0.4%
GDP (G$95)	2393	3410	4474	6210	8145	12658	3.2%	3.0%	2.2%
Per capita GDP ($95/cap)	5502	6557	7645	9569	11636	16754	1.7%	2.1%	1.8%
Gross inland cons/GDP (toe/M$95)	198	180	155	145	133	111	-1.2%	-0.8%	-0.9%
Gross inland cons/capita (toe/cap)	1	1.2	1.2	1.4	1.6	1.9	0.4%	1.3%	0.9%
Electricity cons/capita (kWh/cap)	1147	1489	1823	2333	2866	4238	2.3%	2.3%	2.0%
Transport fuels per capita (toe/cap)	0.3	0.2	0.2	0.2	0.3	0.4	-1.2%	1.9%	1.6%
CO2 emissions/capita (tCO2/cap)	2.1	2.4	2.2	2.6	2.7	2.2	0.2%	1.1%	-1.1%
% of renewables in gross inland cons	28	24.2	29.7	26.6	26.2	39.1	0.3%	-0.6%	2.0%
% of renewables in electricity	65	58.6	54.5	48.2	51.0	57.1	-0.9%	-0.3%	0.6%
Primary Production (Mtoe)	**626**	**835**	**1232**	**1645**	**1823**	**1928**	3.4%	2.0%	0.3%
Coal, lignite	22	41	19	23	37	30	-0.7%	3.4%	-1.1%
Oil	394	523	687	921	1000	942	2.8%	1.9%	-0.3%
Natural gas	75	114	313	445	451	273	7.4%	1.8%	-2.5%
Nuclear	3	8	6	17	50	134	3.2%	11.1%	5.0%
Hydro, geothermal	38	48	56	67	77	96	1.9%	1.6%	1.1%
Biomass and wastes	94	101	149	171	189	365	2.3%	1.2%	3.3%
Wind, solar	0	0	0	2	18	89		22.7%	8.4%
Gross Inland Consumption (Mtoe)	**474**	**614**	**694**	**901**	**1085**	**1405**	1.9%	2.3%	1.3%
Coal, lignite	20	28	37	54	91	84	3.0%	4.7%	-0.4%
Oil	244	314	253	320	381	380	0.2%	2.1%	0.0%
Natural Gas	75	116	192	271	278	258	4.8%	1.9%	-0.4%
Biomass and wastes	94	101	149	171	189	365	2.3%	1.2%	3.3%
Others	42	55	63	86	145	318	2.1%	4.3%	4.0%
Final Consumption (Mtoe)	**359**	**413**	**484**	**614**	**737**	**919**	1.5%	2.1%	1.1%
by source									
Coal, lignite	12	15	17	19	20	7	1.7%	0.8%	-5.4%
Oil	187	186	197	257	315	318	0.3%	2.4%	0.0%
Gas	38	59	85	112	129	107	4.1%	2.1%	-1.0%
Electricity	43	67	92	130	173	275	3.9%	3.2%	2.4%
Biomass and wastes	80	87	93	94	91	118	0.8%	-0.1%	1.3%
Heat	0	0	0	0	0	0		0.0%	0.0%
Hydrogen	0	0	0	3	10	94		18.2%	12.0%
by sector									
Industry	151	196	217	261	289	273	1.8%	1.4%	-0.3%
Transport	109	96	114	153	198	296	0.2%	2.8%	2.0%
Household, Service, Agriculture	99	121	153	200	250	350	2.2%	2.5%	1.7%
Electricity Generation (TWh)	**612**	**959**	**1298**	**1841**	**2434**	**3882**	3.8%	3.2%	2.4%
Thermal, of which :	206	376	614	964	1113	1351	5.6%	3.0%	1.0%
Coal	21	42	80	159	332	359	7.0%	7.4%	0.4%
Gas	60	153	398	632	567	654	9.9%	1.8%	0.7%
Biomass and wastes	6	9	49	83	144	308	10.9%	5.5%	3.9%
Nuclear	12	30	25	73	222	591	3.6%	11.5%	5.0%
Hydro+Geothermal	393	553	656	784	895	1111	2.6%	1.6%	1.1%
Solar	0	0	0	0	1	35		8.3%	17.1%
Wind	0	0	2	19	200	764		26.2%	6.9%
Hydrogen	0	0	0	0	2	30		10.8%	15.8%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**0**	**3**	**11**	**109**		17.9%	12.1%
Coal	0	0	0	1	3	5		16.8%	1.6%
Renewables	0	0	0	1	4	73		27.9%	16.2%
Nuclear	0	0	0	0	0	24			23.5%
CO2 Emissions (MtCO2), *of which :*	**918**	**1268**	**1285**	**1712**	**1925**	**1659**	1.7%	2.0%	-0.7%
Electricity generation	242	276	309	442	411	233	1.2%	1.4%	-2.8%
Industry	226	307	330	389	424	249	1.9%	1.3%	-2.6%
Transport	301	255	272	369	476	480	-0.5%	2.8%	0.0%
Household, Service, Agriculture	108	142	195	275	349	438	3.0%	3.0%	1.1%
CO2 Sequestration (Mt CO2)	0	0	0	0	121	325			5.1%

Asia

	1990	2001	2010	2020	2030	2050	Annual % change 1990/10	2010/30	2030/50
Key Indicators									
Population (Millions)	2783	3267	3635	3995	4258	4511	1.3%	0.8%	0.3%
GDP (G$95)	5048	10810	18906	29416	41426	70429	6.8%	4.0%	2.7%
Per capita GDP ($95/cap)	1814	3309	5201	7363	9728	15612	5.4%	3.2%	2.4%
Gross inland cons/GDP (toe/M$95)	344	227	195	167	151	118	-2.8%	-1.3%	-1.2%
Gross inland cons/capita (toe/cap)	1	0.8	1.0	1.2	1.5	1.8	2.5%	1.8%	1.2%
Electricity cons/capita (kWh/cap)	388	721	1209	1700	2264	3697	5.8%	3.2%	2.5%
Transport fuels per capita (toe/cap)	0.0	0.1	0.1	0.1	0.2	0.3	2.0%	3.7%	2.5%
CO2 emissions/capita (tCO2/cap)	1.4	1.8	2.7	3.1	3.2	2.6	3.4%	0.9%	-1.0%
% of renewables in gross inland cons	31	25.1	16.3	13.4	11.7	16.0	-3.1%	-1.6%	1.6%
% of renewables in electricity	21	15.9	15.2	16.6	17.8	21.4	-1.6%	0.8%	0.9%
Primary Production (Mtoe)	**1657**	**2136**	**3047**	**3462**	**3707**	**5461**	3.1%	1.0%	2.0%
Coal, lignite	693	1009	1470	1565	1599	1761	3.8%	0.4%	0.5%
Oil	297	299	353	324	244	156	0.9%	-1.8%	-2.2%
Natural gas	107	164	503	514	273	171	8.0%	-3.0%	-2.3%
Nuclear	24	47	118	399	860	2041	8.3%	10.4%	4.4%
Hydro, geothermal	30	41	65	89	109	143	4.0%	2.6%	1.4%
Biomass and wastes	507	577	536	557	576	929	0.3%	0.4%	2.4%
Wind, solar	0	0	2	15	47	260		18.2%	9.0%
Gross Inland Consumption (Mtoe)	**1738**	**2459**	**3693**	**4919**	**6235**	**8321**	3.8%	2.7%	1.5%
Coal, lignite	735	947	1534	1656	1689	1802	3.8%	0.5%	0.3%
Oil	369	680	977	1504	1907	2159	5.0%	3.4%	0.6%
Natural Gas	73	169	462	701	1048	989	9.7%	4.2%	-0.3%
Biomass and wastes	507	577	536	557	576	929	0.3%	0.4%	2.4%
Others	54	87	184	501	1015	2443	6.3%	8.9%	4.5%
Final Consumption (Mtoe)	**1365**	**1765**	**2608**	**3425**	**4216**	**5215**	3.3%	2.4%	1.1%
by source									
Coal, lignite	435	409	632	744	794	601	1.9%	1.1%	-1.4%
Oil	290	474	887	1352	1729	1985	5.7%	3.4%	0.7%
Gas	37	79	199	293	431	441	8.7%	3.9%	0.1%
Electricity	93	203	378	584	829	1434	7.3%	4.0%	2.8%
Biomass and wastes	497	569	481	416	371	352	-0.2%	-1.3%	-0.3%
Heat	13	31	31	31	31	31	4.4%	0.0%	0.0%
Hydrogen	0	0	0	5	32	370		24.7%	13.1%
by sector									
Industry	504	742	1178	1476	1704	1708	4.3%	1.9%	0.0%
Transport	139	173	269	437	650	1136	3.4%	4.5%	2.8%
Household, Service, Agriculture	723	850	1161	1512	1862	2370	2.4%	2.4%	1.2%
Electricity Generation (TWh)	**1374**	**3049**	**5668**	**8747**	**12357**	**21340**	7.3%	4.0%	2.8%
Thermal, of which :	994	2387	4405	5825	6734	7882	7.7%	2.1%	0.8%
Coal	732	1847	3521	4084	4073	5304	8.2%	0.7%	1.3%
Gas	78	326	680	1358	2131	1911	11.5%	5.9%	-0.5%
Biomass and wastes	0	9	87	251	398	568		7.9%	1.8%
Nuclear	92	187	487	1723	3818	9295	8.7%	10.9%	4.5%
Hydro+Geothermal	288	473	758	1032	1264	1664	5.0%	2.6%	1.4%
Solar	0	0	4	7	10	165		4.5%	15.0%
Wind	0	2	14	159	523	2178	35.4%	20.0%	7.4%
Hydrogen	0	0	1	1	8	157		12.8%	15.7%
Hydrogen Production (Mtoe), *of which :*	**0**	**0**	**1**	**6**	**36**	**432**		23.4%	13.2%
Coal	0	0	0	2	8	13		20.1%	2.4%
Renewables	0	0	0	2	13	254		31.5%	15.8%
Nuclear	0	0	0	0	2	149		28.1%	24.6%
CO2 Emissions (MtCO2), *of which :*	**3791**	**5956**	**9746**	**12247**	**13666**	**11850**	4.8%	1.7%	-0.7%
Electricity generation	1197	2504	3742	4023	3516	1511	5.9%	-0.3%	-4.1%
Industry	1224	1742	2903	3516	3879	3176	4.4%	1.5%	-1.0%
Transport	411	519	768	1236	1771	2124	3.2%	4.3%	0.9%
Household, Service, Agriculture	675	724	1612	2495	3199	3578	4.4%	3.5%	0.6%
CO2 Sequestration (Mt CO2)	0	0	0	0	618	3478			9.0%

SPECIAL CONTRIBUTION – A MEAN-VARIANCE PORTFOLIO OPTIMISATION OF THE POLES REFERENCE SCENARIO

POLES and portfolio optimisation[52]

This chapter describes how the results of the POLES simulation can be extended to include the management of risk by using the finance technique of mean-variance portfolio theory. Estimating the cost of any future generating mix involves assessing long-term cost *expectations* for uncertain fossil fuel and other outlays. POLES simulates 2050 outcomes using a variety of technical, economic and policy relationships that determine successive investment decisions. Investment decisions can be evaluated using mean-variance portfolio techniques to manage risk and improve performance under a variety of unpredictable economic outcomes. Compared to traditional least-cost approaches that rely on the *stand-alone* generating costs of individual technologies, portfolio optimisation evaluates generating alternatives based on their cost and risk contributions to the generating asset mix.

The results presented here suggest that there are generating mixes that cost no more than the Reference case, yet have lower expected risk and other desirable properties including larger renewables shares and lower CO_2 emissions. These portfolios can be interpreted as providing greater diversity and security.

Like any dynamic simulation, POLES is *descriptive* and *path dependent*. It uses economic, policy and technical coefficients to describe the energy system and the behaviour of the actors. It is *path-dependent* in the sense that incremental policy and investment decisions successively produce new endpoints until the final 2050 horizon.

Portfolio optimisation, by contrast, is *normative* or *prescriptive*— it locates optimal outcomes subject to a set of constraints, which in a different way represent technical limits and policy priorities. Portfolio analysis locates all feasible and optimal endpoints, but some may not be practical given the technical and market constraints specified in POLES. Fully specifying a portfolio optimisation would require that the technical relationships of POLES be converted to a set of optimisation constraints.[53] Such an effort is not feasible or practical in this project.

The challenge of this research therefore is to merge the descriptive power of POLES with the ability of portfolio optimisation to rapidly locate many optimal endpoints. One important option is to use the POLES simulation to identify the technical and policy changes required to attain the optimal results identified by the portfolio analysis. The portfolio optimisation can locate all generating mixes with renewables shares that exceed a specified target, e.g. all mixes with total CO_2 emissions less than some target. The driving parameters of the POLES model could then be altered to identify the policy and technical changes needed to produce such optimised outcomes. The portfolio optimisation can in turn estimate the true cost[54] of such policy and resource changes. Such approaches could be complex and difficult to implement.

Operating within these limitations, the team successfully developed a practical demonstration that merges the descriptive power of POLES with the ability of portfolio optimisation to locate efficient, desirable outcomes. The approach identifies combinations of technologies for generating electricity that are close to the POLES Reference results, but may have lower risk and/or lower cost. This is a useful demonstration of how portfolio analysis can provide new interpretations and add value to the POLES results.

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52 This portfolio analysis is not intended to assess the risk associated with a given energy system in relation to security of supply. At this stage, this research provides only partial results illustrating the approach.

53 For, example POLES relates resource demand and availability to price. Modelling these relationships and the investment decisions they produce as an optimisation is not feasible in this project.

54 I.e. the *shadow cost*

"Least-Cost" versus portfolio-based approaches in generation planning

The planning of power system expansion traditionally seeks to determine a least cost solution, assuming that the generating alternatives are described by their *stand-alone* costs. This may have been satisfactory in the past when costs were relatively certain, rates of technological progress were low, generating alternatives were technically homogeneous and energy prices were stable [Awerbuch, 1995a]. The WETO-H_2 project evaluates a broad and diverse range of resource options in a dynamic, complex, and uncertain future. In this case, it is helpful to incorporate portfolio risk into the analysis [Awerbuch, 1996].

Portfolio analysis reflects the market risk of projected cost streams from alternative generating portfolios. Fossil fuel is an important constituent of electricity supply systems in many countries, but the future cost of supplies is uncertain. Exposure to this uncertainty constitutes a major risk and a loss of energy security that the use of renewable energy, among other measures, can mitigate.

Mean-variance portfolio (MVP) theory provides a technique to evaluate the mix of electricity generating technologies in the POLES Reference case against uncertainties in the future cost and performance of technology. A major influence on portfolio risk is the extent to which the costs of different technologies are independent. The cost streams of wind, solar and other non-fossil options are largely uncorrelated with other portfolio costs. If the risk of the portfolio is otherwise dominated by uncertainties in fossil fuel, then inclusion of the non-fossil options will diversify the portfolio and reduce portfolio risk.

This chapter evaluates the POLES outcomes using an MVP framework to identify a set of optimised 2050 generating mixes. Optimised, diversified generating mixes represent minimum cost options at every level of portfolio risk. Consequently, energy diversity and security concerns are simultaneously met.

Portfolio-based planning for electricity generation

Portfolio optimisation locates generating mixes with the lowest expected cost at every level of expected market risk. Risk is generally measured as the year-to-year variability (standard deviation) of technology generating cost components.[55] The 2050 POLES Reference or target generating mix serves as a benchmark or starting point. The optimised results indicate that it is possible to improve on the cost-risk properties of the POLES Reference mix, i.e. there exist feasible mixes that have lower cost and risk and have lower CO_2 emissions.

Portfolio analysis focuses on market risk— the expected variability of generating costs. Future costs of fossil fuel and other outlays are random statistical variables. Their historic averages and standard deviations are known, but they move unpredictably over time.[56] No one is sure what the price of gas will be next year, just as nobody knows what the stock markets will do. Estimating the generating cost of a particular portfolio presents the same problems as estimating the expected return to a financial portfolio. It involves estimating cost from the perspective of its market risk.

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55 Although in the analysis we apply a *semi-variance* approach to risk estimation as subsequently discussed.

56 The evidence suggests, however, that these movements are correlated with economic activity and with the returns to other assets (Awerbuch and Sauter, 2005, Awerbuch, 1995, 1993, Bolinger, Wiser and Golove, 2004).

Operating costs for wind, solar, nuclear and other capital-intensive non-fossil technologies are essentially fixed or *riskless* over time[57] and are uncorrelated to fossil prices.[58] These technologies diversify the generating mix and enhance its cost-risk performance. Given sufficient geographic dispersion in the wind resources, as would be expected in the WETO- H_2 study, the operating cost of a generating system with 30% wind will fluctuate less from year-to-year than a system with no wind.[59]

Basics of portfolio optimisation

MVP is an established part of modern finance theory, based on the pioneering work of Nobel Laureate Harry Markowitz from 50 years ago (Fabozzi, Gupta and Markowitz [2002] and Varian [1993]). MVP is widely used to optimise financial portfolios and has been applied to many other problems. Other applications include: capital budgeting and project valuation [Seitz and Ellison, 1995]; valuing offshore oil leases [Helfat, 1988]; energy planning [Krey and Zweifel, 2005, Awerbuch, 2005, Awerbuch and Berger 2003; Berger 2003; Awerbuch 2000a, Humphreys and McLain 1998, Awerbuch 1995, Bar-Lev and Katz 1976]; quantifying climate change mitigation risks [Springer, 2003]; optimizing real (physical) and derivative electricity trading options [Kleindorfer and Li, 2005], and evaluating energy security issues [Lesbirel (2004)].

Portfolio theory was developed for financial analysis, in which application it relates *expected* portfolio return to *expected* portfolio risk. Applied to electricity generation, portfolio optimisation focuses on generating cost as opposed to return, and locates minimum-cost generating portfolios at every level of portfolio risk.

The expected generating cost of a portfolio is the weighted average of the individual technology costs. The expected portfolio risk is a weighted average of the variances of the costs of the individual technologies as tempered by their correlations or co-variances (Box 6). Portfolio risk is measured as the standard deviation of year-to-year changes in generating costs, estimated based on *holding period returns* (HPRs)[60] as further discussed in Box 6.

How portfolio theory improves decision-making

Portfolio optimisation exploits the interrelationships (i.e. correlations) among the various technology generating costs (Box 6, Equation 2). For example, because fossil price are correlated with each other, a fossil-dominated portfolio is undiversified and exposed to fuel price risk. Conversely, renewables, nuclear and other non-fossil options diversify the mix and reduce its expected risk because their costs are not correlated with fossil prices.

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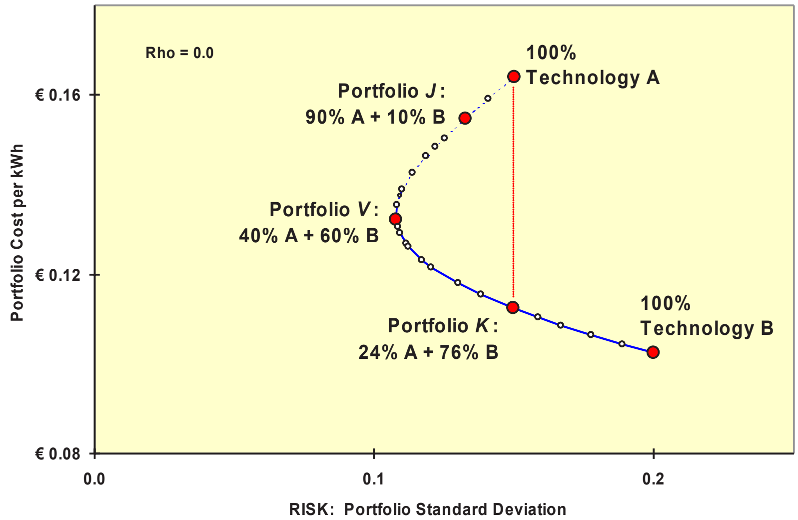
57 The finance theory aspects of this idea are developed in Awerbuch (2000).

58 Strictly speaking, in the case of capital costs, this statement holds only *ex-post* . However, given the short lead times of renewables projects and the large proportion of manufactured components, construction period risks for these technologies is low even *ex-ante*. The WETO-H2 analysis adopts costs based on long-run assumed progress ratios for capital outlays, and it may be reasonable to argue that deviations from these expectations, which may be non-negligible, represent an aspect of long-term risk. Nonetheless, it is reasonable to assume that deviations from expected capital costs of fossil and renewables technologies are uncorrelated.

59 For a recent discussion of how geographic dispersion serves to diversify wind variability, see Sinden, (2005) and Grubb, Butler and Sinden, (2005).

60 The HPR is the annual rate of change in the fuel price or other cost input.

Figure 69: Cost-risk- for illustrative two-technology portfolio



Box 6: Portfolio optimisation basics

This discussion of portfolio theory is based on a simple, two-asset generating portfolio. For a two-technology mix, expected portfolio cost is the weighted average of the individual expected costs of the two technologies:

Expected Portfolio Cost = E(Cp) = X1•*E*(C1) + X2•*E*(C2) (Eq. 1)

Where: X1, X2 are the fractional shares of the two technologies in the mix and E(C1) *and* E(C2) *are their expected generating costs, expressed as total levelised cost per MWh or other unit of output.*

Expected Portfolio risk, E(σ_p), is also a weighted average of the individual technology cost variances, as tempered by their co-variances:

Expected Portfolio risk = E(σ_p) = $\sqrt{X_1{}^2\sigma_1{}^2 + X_2{}^2\sigma_2{}^2 + 2X_1X_2\rho_{12}\sigma_1\sigma_2}$ (Eq. 2)

Where:
– X_1 and X_2 are the fractional shares of the two technologies in the mix
– σ_1 and σ_2 are the standard deviations of the *holding period returns* of the annual costs of technologies *1* and *2* as further discussed below.
–ρ_{12} is their correlation coefficient

Portfolio risk, the year-to-year variation in generating cost, is estimated based on the standard deviations of the holding period returns *(HPRs) of future generating cost streams, defined as:*

HPR = (EV – BV) / BV

where EV *is the ending value and* BV *the beginning value (e.g. Seitz and Ellison, 1995, Brealey and Myers, 2004 or any finance text). For cost streams with annual reported values,* EV *can be taken as the cost in Year* t+1 *and* BV *as the year t cost. HPR measures the rate of change in the cost stream from one year to the next. A detailed discussion of its relevance to portfolios is given in Berger (2003).*

Each individual technology actually consists of a portfolio of cost streams (initial and operating costs plus CO_2 costs). Total risk for an individual technology is σ_p or the portfolio risk for those cost streams. In this case the weights, X_1, X_2, etc. are the fractional share of total levelised cost represented by each individual cost stream. For example, total levelised generating costs for a coal plant might consist of ¼ capital, ¼ fuel ¼ operating costs and ¼ CO_2 costs, in which case each weight X_j = 0.25.

This so-called *portfolio effect* is evident in Figure 68, which shows the costs and risks for various possible two-technology portfolios. Technology *A* is an option with high costs and low risk (e.g. photovoltaics); the expected cost in this illustration is just over €0.16/kWh with an expected risk or cost variability of 0.15. Technology *B* is an option with lower cost and higher risk, such as gas-based generation; its expected cost is €0.10/kWh with an expected risk of 0.2. The correlation factor between the total cost streams of the two technologies is assumed to be zero.[61]

Because of the portfolio effect, total portfolio risk *decreases* when the riskier Technology *B* is added to a portfolio consisting of 100% *A*. For example, Portfolio *J*, which comprises 90% of Technology *A* plus 10% *B*, exhibits a lower expected risk than a portfolio comprising 100% *A*. Investors, in fact, would not hold any mix above Portfolio *V,* the minimum variance portfolio, since a mix with the same risk can be obtained at lower cost on the solid portion of the blue line. Portfolio *K* is therefore superior to 100% *A*. It has the same risk, but lower expected cost. Investors would hold Portfolio *K* in preference to 100%A. Most investors would also consider Portfolio *K* to be superior to a portfolio of 100% Technology *B.* It reduces risk by some 25% while increasing cost by only 10% (€0.01/kWh), which gives it a favourable Sharpe Ratio.[62]

Portfolio analysis: A note on systematic risk

Finance theory divides total market risk into two components: random or diversifiable risk[63] and systematic or undiversifiable risk. Random risk factors that may affect an individual asset are diversified in a portfolio and hence are usually irrelevant. Systematic risk is non-diversifiable and hence cannot be eliminated from the portfolio.

Portfolio optimisation locates generating mixes with minimum expected cost and year-to-year (HPR) risk. For each technology, risk is the HPR standard deviation for five generating cost inputs: construction period risk, fuel, fixed and variable O&M and CO_2 costs. While the portfolio analysis reflects all relevant risk, this does not mean that every risk possibility is measured and accounted for. In a generating portfolio, random (unsystematic) risk is diversified away and does not contribute to total portfolio risk.

For example, year-to-year fluctuations in electricity output of a wind farm— an unsystematic risk— is not relevant for portfolio purposes since it is uncorrelated to the risk of other portfolio cost streams.[64] Annual wind resource variability is random and uncorrelated to fossil prices or other portfolio generating costs. It therefore does not contribute to portfolio risk (Box 6, Equation 2). In finance terms, year-to-year wind variability is an unsystematic (uncorrelated) risk, even for single wind site.[65]

The same idea holds for annual variations in attained fuel conversion efficiency for a particular gas plant. In spite of the fact that such yearly changes might change the accountant's estimate of kWh generating costs at a given site hence representing a risk to the owners, that risk is uncorrelated and diversified and therefore does not affect overall portfolio risk.

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61 This is a simplification since in reality the capital and operating cost risks of PV may exhibit at least some correlation to the capital and operating costs of fossil technologies.

62 The Sharpe Ratio, developed by Nobel Laureate William F. Sharpe, relates changes in risk to changes in reward.

63 Sometimes called specific risk.

64 On an accounting basis, kWh generating cost is calculated by dividing annual capital charges plus operating costs by the year's kWh output. Given a fixed capital charge and relatively fixed maintenance costs, annual wind output variability would therefore cause year-to-year kWh costs to vary.

65 Capital markets will not compensate investors (through market rates of return) for such random risks. Investors can readily eliminate the variability by holding portfolios of geographically dispersed wind farms.

Approximating risk using the TECHPOL Database

This section describes the procedure used to estimate HPR risks for the five generating cost components: construction period outlays, fuel, CO_2-emission costs, and fixed and variable operating and maintenance (O&M) costs. These risks are estimated directly from data in the POLES model.

The TECHPOL database of the POLES Model includes a set of costs for technologies in the future. For each technology, there are *mean*, *favourable* and *unfavourable* cost projections to the year 2050. These cost outlooks were not intended for estimating risk, but they do provide upper and lower bounds that can be interpreted as a range of possible cost outcomes with an assumed distribution.

Portfolio analysis generally relies on risk estimates based on past performance. Although there is no theoretical requirement for this, (Fabozzi, Gupta and Markowitz 2002), such estimates implicitly presume that the historic risk for fuel and other costs is the best indicator of future risk. Given the distant time horizons in POLES, traditional historic estimates, though based on observed behaviour, are open to the criticism that they may not hold over the multi-decade period of this study.

The POLES *favourable* and *unfavourable* cost outlooks are not symmetric about the mean. This implies that the standard deviation, the traditional finance risk measure, is not a correct measure of distribution. The appropriate measure is the *semi*-standard deviation for the desired half of the distribution (e.g. Seitz and Ellison, p. 181-183). In this analysis, we focus on the so-called “downside” risk for each cost element, the portion of the cost distribution that lies above the mean (Box 7).

Box 7: Estimating HPR risk using the TECHPOL database

The procedure for estimating HPR risk for fuel, O&M and CO_2 cost streams is as follows:

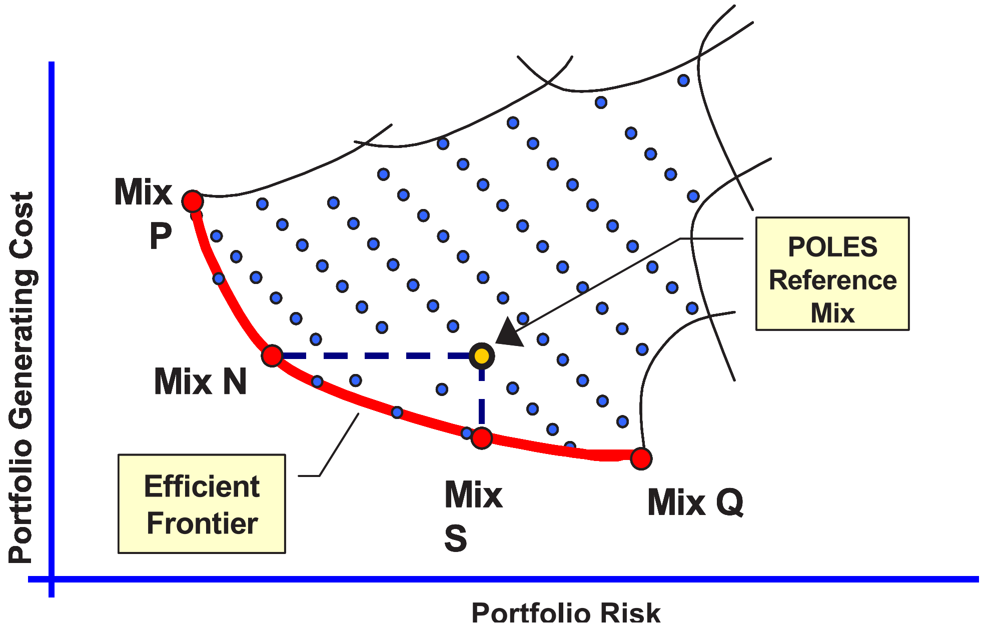
- *We make the reasonable, though arbitrary assumption that the POLES **unfavourable** cost outlook represents a 2-sigma deviation from the mean.*
- *We next estimate the ‘downside’ semi-standard deviation for each cost stream of each POLES technology.*
- *The semi-standard deviations are used to produce a Monte-Carlo set of **simulated** annual fuel, O&M and CO_2 costs. Approximately 10 sets of simulated annual costs (240 years total) were created for each technology cost component.*
- *We computed the HPRs for these simulated annual technology cost streams.*
- *Finally, we computed the average semi-standard deviation for each HPR stream.*
- *Construction period costs are taken as one-period outlays, with the estimated semi-standard deviation applied directly.*

Interpreting the POLES *mean* and *unfavourable* cost outlooks in this fashion is appropriate for the costs of fossil fuel and CO_2, and to a lesser extent for O&M, where the mean and unfavourable projections may reflect differences arising out of assumptions on technological development and geographic location. In reality, neither of these considerations would convert directly to year-to-year cost variability risk for a given project. In spite of these limitations, the approach provides a methodologically sound means for estimating portfolio risk components using a set of *forward-looking* cost outlooks that are consistent with other POLES assumptions.

The approach may be least appropriate for risks arising from construction period outlays. Here the difference between the *mean* and *unfavourable* cost streams is largely due to geographic location and rates of technological progress. Consequently, investment cost risks derived from the POLES projections were adjusted in several cases involving modular capital-intensive technologies, notably photovoltaics, wind and small hydro, where they overstate the risks relative to values that are known from interviews with developers.

Reference case portfolio optimisation

Figure 70: Illustrative feasible region, efficiency frontier and typical mixes



This section describes the application of portfolio optimisation to the results of the POLES Reference case. The POLES model assumes a comprehensive set of technical coefficients and it is not feasible to convert this entire set of relationships into a set of optimisation constraints. The optimisation is therefore constrained to locate optimal mixes in a region surrounding the POLES Reference outcomes. This region has been defined to include all mixes whose individual technology shares lie within +/-20% of the technology shares in the POLES Reference. It is believed that these solutions are 'close enough' to the POLES results so as not to significantly violate the POLES technical coefficients. The optimisation therefore ignores solutions involving, for example, significantly higher or lower fossil shares because for such solutions, Reference fuel prices and other relationships will likely not hold.

Portfolio optimisation: Interpreting results

Portfolio optimisation focuses on cost and risk. The *Efficient Frontier* (EF) is the location of all optimal mixes (Figure 69). Mixes lying above the *EF* are inefficient (sub-optimal) since expected cost *and* risk can both be improved. Along the EF, cost reductions can be achieved only by accepting greater risk. Radically different mixes can have nearly identical cost-risk, [66] i.e. they could be virtually co-located in risk-cost space. There exist no feasible solutions below the EF. Any mix that lies below or to the left

[66] The intuition for this is straightforward: there are many ways to combine ingredients in order to produce a given quantity of salad at a given price.

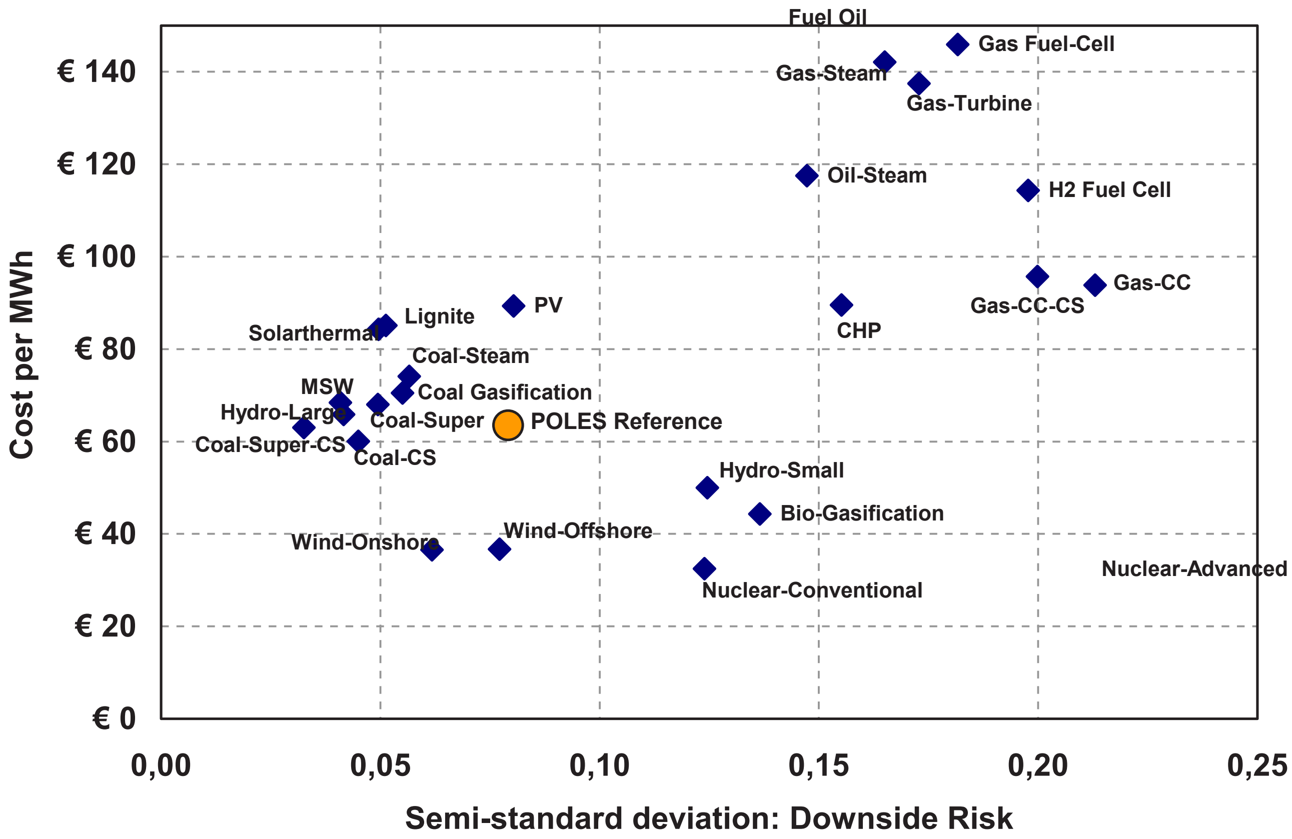
of the portfolio from the POLES Reference case is an improvement, because it has either lower cost or lower risk, or both. Such mixes may have other desirable properties related to the technology share or CO_2 emissions. The portfolio optimisation can locate desirable non-optimal generating mixes with specific properties.

There are infinite generating mixes, although we locate and show only a small set of *typical* optimal mixes as follows:

- **Mix *P* - High-cost Mix**: This is the feasible optimal generating mix with the highest cost and lowest risk. It is usually the most diverse (e.g. see: Stirling, 1996, Awerbuch, Stirling, Jansen and Beurskens, 2006).
- **Mix *N* - Equal-cost Mix:** This is the mix with *minimum-risk* that has a cost equal to that of the POLES 2050 Reference.
- **Mix *S* - Equal-risk Mix:** This is the mix with *minimum-cost* that has a risk equal to that of the POLES Target 2050 mix.
- **Mix *Q*: Low-cost Mix:** This is the lowest-cost, highest-risk feasible mix. It is usually the least diverse.

The portfolio analysis does not advocate a particular generating mix, but rather displays the trade-off among many mixes whose technology shares do not exceed +/-20% of the POLES Reference shares.

Figure 71: Technology cost and downside risk estimates based on TECHPOL cost outlooks



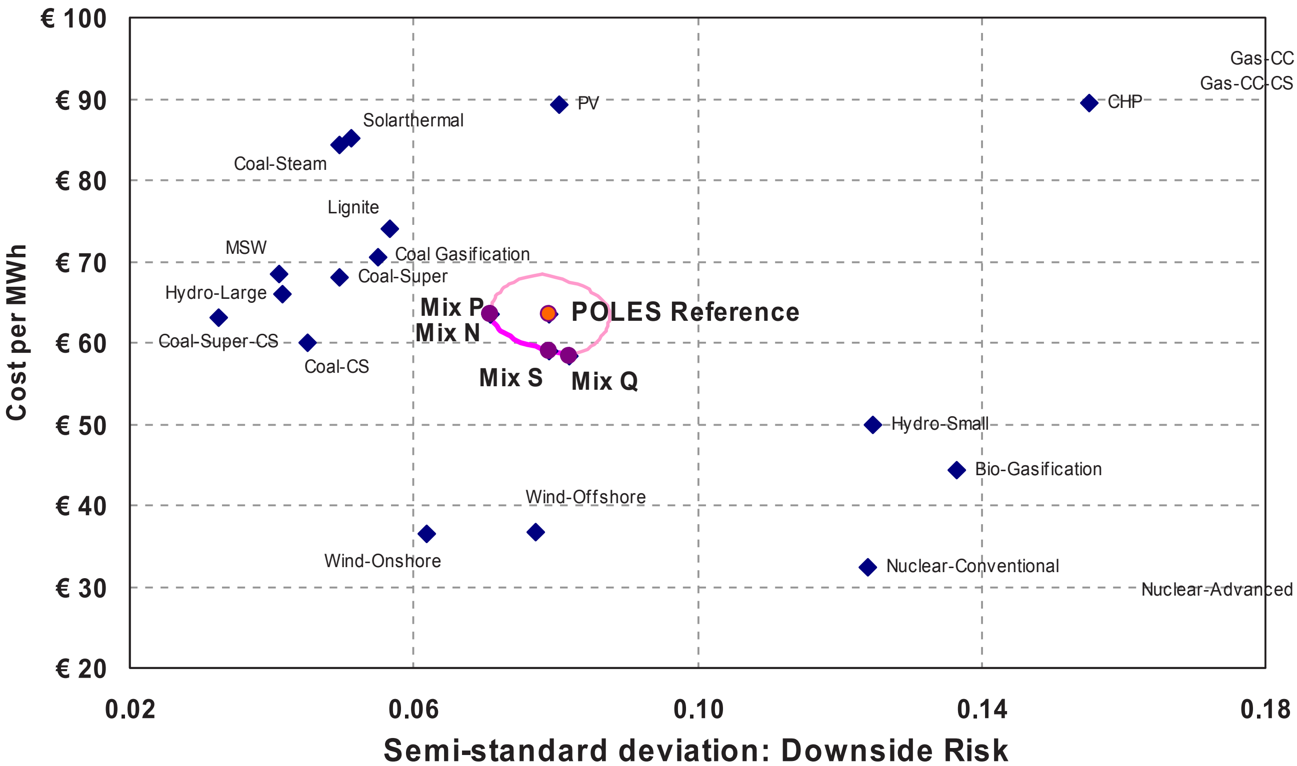
POLES 2050 forward-looking technology cost-risk

Figure 71 shows the POLES expected (mean) cost in 2050 for each of the generating technologies with its downside risk as estimated from the TECHPOL *mean* and *unfavourable* cost outlooks.[67] The gas and oil based technologies are generally clustered towards the upper right (Figure 69) suggesting moderate risk and high cost. The coal-based technologies fall into the lower left hand side where risk and cost are lower. Renewables are also generally located in this quadrant. Advanced nuclear power shows the largest risk.

Reference case optimisation

The assumptions in the MVP optimisation and the POLES Reference case differ in some important respects. The MVP optimisation of the Reference case uses only the cost inputs from 2050, but the portfolio in the Reference case is the result of a series of investment decisions made over time. In addition, POLES treats technology categories in detail, for example, POLES considers five wind categories representing sites with various mean wind speeds. The MVP cost estimates for the Reference case may therefore not be entirely consistent with the cost computations in the POLES Reference. Other factors could cause this difference, including exogenous learning curves in POLES and the fact that the Reference attempts to match the load-duration curve.

Figure 72: Feasible region and efficient frontier estimated using TECHPOL cost outlook



67 Risk for a given technology is determined through Equation 2 (Box 6) where the weights (X_1, X_2, etc.) are given by the proportional values of the levelised cost components, capital, fuel, O&M and CO_2.

Figure 71 locates the POLES 2050 Reference Mix in cost-risk space and shows the feasible region for mixes whose individual technology shares vary by +/-20% from the Reference. Mix N, the equal-cost mix, is virtually co-located with Mix P, the minimum risk mix. Technology shares and other parameters for these two mixes are virtually identical. We therefore treat them as a single solution, which we label Mix *P/N*.

Solutions on the solid portion of the *EF*, between Mix *P/N* and Mix Q, are efficient, although any solution that lies below and to the left of the POLES Reference portfolio has lower cost and lower risk. Figure 72 shows the EF and the typical mixes in more detail.

Table 11 provides relative generating cost, downside risk (i.e. semi-standard deviation), technology shares and CO_2 emissions for the Reference and the typical Mixes, *P/N, S and Q*. This information is summarised graphically in Figure 72. The Reference mix has an expected downside (semi-standard deviation) HPR risk of 7.9% (Table 7).

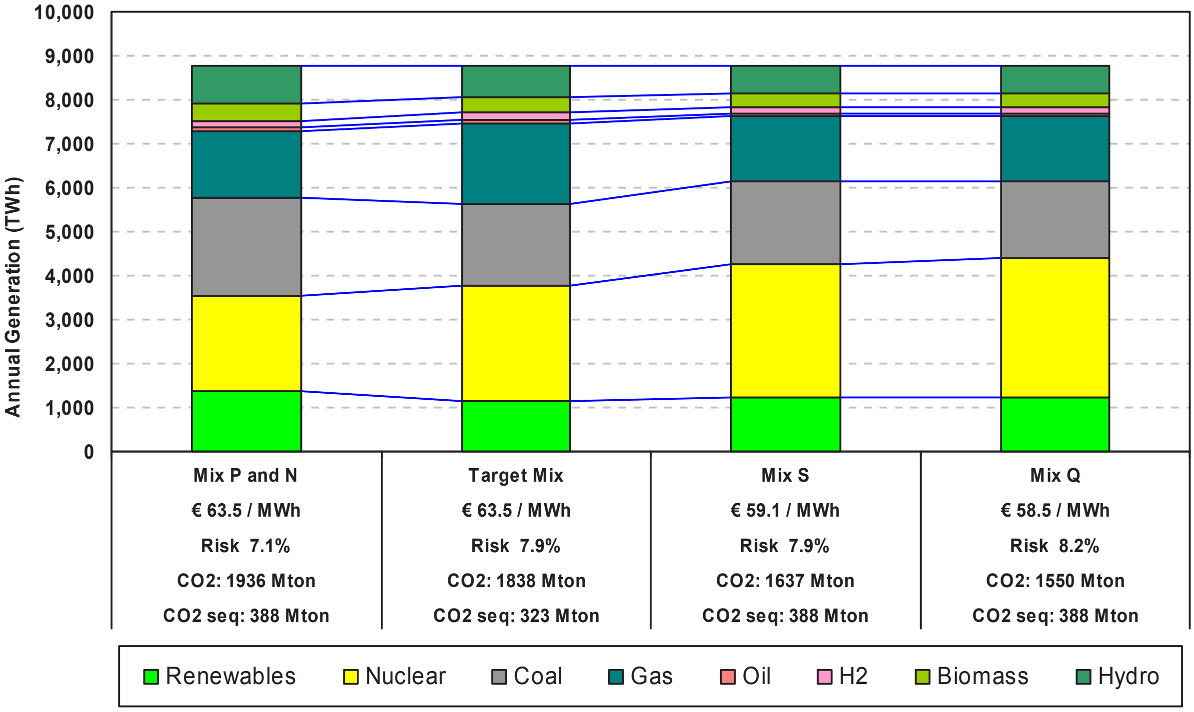
By comparison, Mix *P/N*, has the same expected cost as the Reference, but exhibits a lower risk. Mix *P/N* however does not perform as well in terms of CO_2 emissions, which are 5% higher than the Reference although sequestration shows a 20% improvement. The higher CO_2 emissions of Mix *P/N* are most likely due to the 20% higher shares of coal (and oil) relative to the Reference, an outcome that is largely driven by the estimated low risk of coal. Given our forward-looking estimates, coal technologies look attractive in risk-cost space (Figure 70). Gas is 19% lower in Mix *P/N* relative to the Reference, Nuclear 17% lower while hydrogen is 20% lower. Renewables share in Mix *P/N* is 20% greater than the POLES Reference (Table 11).

Table 11: Portfolio details for reference and typical optimised mixes: cost, risk, CO_2 and technology shares

	Mix *P/N*	POLES Reference Mix	Mix *S*	Mix *Q*
Portfolio Cost per MWh	—	**—**	-6.9%	-7.9%
Portfolio Downside Risk (Semi-Standard Deviation)	7.1%	**7.9%**	7.9%	8.2%
Emissions and TWh Generation: Percent Changes from Target Mix				
CO_2-emission	+5%	**1838 Mton**	-11%	-16%
CO_2-sequestration	+20%	**323 Mton**	+20%	+20%
Renewables	+20%	**1132 TWh**	+9%	+9%
Nuclear	-17%	**2634 TWh**	+15%	+20%
Coal	+20%	**1857 TWh**	+2%	-5%
Gas	-18%	**1848 TWh**	-20%	-20%
Oil	+20%	**71 TWh**	-20%	-20%
H_2	-20%	**182 TWh**	-20%	-20%
Biomass	+20%	**323 TWh**	-5%	-5%
Hydro	+20%	**732 TWh**	-12%	-13%
Total		**8778 TWh**		

Mix *S* has the same risk as the Reference, but the cost is 6.9% lower mainly because its share of nuclear is greater by 15%. Nuclear is relatively inexpensive (Figure 71) and though risky, does not contribute proportionately to overall portfolio risk because its risks are little correlated to those of other technologies. The share of renewables in Mix *S* is 9% higher than the Reference case; although still lower than Mix *P/N*. With the exception of coal, which increases its share by 2%, Mix *S* exhibits lower fossil shares compared to the Reference, along with lower shares of hydrogen, biomass and hydro. These reductions offset the higher nuclear and renewables shares. With its lower cost and lower CO_2 emissions, Mix S might be preferred to the Reference.

Figure 73: Portfolio cost-risk and technology shares: Reference and typical optimised mixes



Mix *Q* has the lowest expected cost of generation of all portfolios at € 58.5 per MWh. The cost is improved by only 1% over S, but the risk rises by almost 4 percentage points (from 7.9% to 8.2%). This is an unattractive risk-reward ratio[68] suggesting that a move from *S* to *Q* may not be desirable. However, in return for what is a relatively small absolute increase in risk, Mix *Q* improves CO_2 emissions by nearly one-half over Mix *S* (from –11% to –16%, Table 7). It achieves this with smaller shares of coal and larger shares of nuclear.

Figure 72 summarises the optimisation results compared to the Reference. It shows the differentials in cost and risk and technology shares as we move along the efficient frontier from Mix *P/N* on the left to Mix *Q* on the right. Over this range, the cost decreases while the risk increases, as nuclear displaces fossil fuel — notably gas and coal. The shares of renewables, biomass and hydro also fall.

This account shows how portfolio analysis can examine a variety of optimised mixes and identify those that meet particular policy priorities, e.g. mixes with minimum CO_2 emissions. In this manner, the shadow cost of attaining CO_2 reductions can be estimated.

68 Sometimes called the Sharpe Ratio.

Conclusions

- Mean-variance portfolio (MVP) theory can help provide new insights to energy investment strategies[69]

- MVP optimisation does not represent or advocate a particular 2050 technology mix. Rather, it demonstrates the range of possible mixes with technology shares that are +/-20% from the POLES Reference. This enables policy makers to compare alternative 2050 outcomes, which may present more desirable CO_2, energy diversity and other characteristics.

- Portfolio optimisation can locate all generating mixes with renewables shares that exceed a specified target, or all mixes with total CO_2 emissions less than some target. The optimisation can estimate the cost of such policy and resource changes. MPT can provide insights to possible trade-offs and can help set RES-E targets that integrate the three pillars of energy policy in a balanced manner [Jansen, 2003].

- Assuming that the POLES cost relationships as applied in the MVP hold over the +/-20% region studied, the optimisation results discussed here suggest that it may be possible to improve on POLES Reference. The relevant optimised mixes we show (Mixes *P/N* and SS) have lower expected cost or risk, along with lower CO_2 emissions.

- The challenge of this research has been to merge the technically rich descriptive powers of POLES with the ability of portfolio analysis to trade-off risk and reward. To the extent that the assumptions of the POLES model can be expected to hold over the permitted excursions of +/-20%, the optimisation identifies portfolios with better balances of cost and risk and other improved characteristics.

- The POLES 2050 Reference is the cumulative result of a series of annual investment decisions, each reflecting contemporary policies and resource costs. The electricity generating system has high inertia and this has many consequences including the rate at which old technologies and practices are abandoned and new technologies adopted. Mix *P/N* (Table 4.1) contains 20% more renewables than the reference - about 15% of total generation as compared to about 13% in the Reference. The world may not be able to reach this level by 2050, but that is a policy, rather than a technology issue.

- The optimised mixes show improvements that may be attainable and which lie within close to the Reference. The remaining challenge is to identify policy changes that produce such optimised outcomes, a task to which the POLES simulation is ideally suited.

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[69] Other techniques have been applied, e.g. A.C. Stirling [1996, 1994] develops maximum-diversity portfolios based on a broader uncertainty spectrum. Though radically different in its approach, his model yields qualitatively similar results. In addition, Awerbuch, Stirling, Jansen and Beurskens (2006) use mean-variance optimisation along with diversity analysis to develop efficient and maximum diversity portfolios.

LIST OF ACRONYMS AND ABBREVIATIONS

€	Euro at 1999 prices (=US$ at 1995 price)
AAU	Assigned Amount Units
AFC	Alkaline Fuel Cell
bl	Barrel
boe	barrel of oil equivalent
CCC	Carbon Constraint case
CCS	Carbon capture and storage
CDM	Clean Development Mechanisms
CEPII	Centre d'Etudes Prospectives et d'Informations Internationales
CER	Certified Emission Reduction
CGH_2	Compressed Gaseous Hydrogen
CHP	Combined heat and power
CIS	Community of Independant States
CNG	Compressed Natural Gas
CO_2eq	Emissions in CO_2-equivalent
EF	Efficient Frontier
EU, EU25, EU27	European Union, 25 EU countries, 25 + 2 accession countries
FC	Fuell Cell
g	Gram
Gbl	Billion barrels
GDP	Gross Domestic Product
GHGs	Greenhouse Gases
GIC	Gross Inland Consumption (=primary energy consumption or Total Primary Energy
GJ	Billion Joules
Gm3	Billion Normal cubic meters
Gt	Billion tons
Gtoe	Billions of tons oil equivalent
GWP	Global Warming Potential
h	Hour
HPR	Holding Period Returns
ICE	Internal Combustion Engine
ICTs	Information and Communication Technologies
IEA	International Energy Agency
IFP	Institut Français du Pétrole
IGCC	Integrated coal gasification combined cycle
IPCC	International Panel on Climatic Change
JI	Joint Implementation
LH_2	Liquefied Hydrogen
LNG	Liquefied Natural Gas
Mbd	Million barrels per day
MCFC	Molten Carbonate Fuel Cell
MEA	Membrane-electrode Assembly
MJ	Million Joules
MPa	Million Pascals
Mt	Million tons

MVP	Mean-variance portfolio
Nm3	Normal m^3 (m^3 at 0°C and 1 bar)
O&M	Operation and Maintenance
OECD	Organisation for Economic Cooperation and Development
OPEC	Organisation of Petroleum Exporting Countries
PAFC	Phosphoric Acid Fuel Cell
PEM	Proton Exchange Membrane
PEMFC	Proton Exchange Membrane Fuel Cell
PJ/a	PetaJoules (10^{15} Joules) per annum
POLES	Prospective Outlook on Long-term Energy Systems
POP	Population
ppmv	parts per million by volume
ppp	purchasing power parities
R&D	Research and Development
R/P	Reserve on Production ratio
SOFC	Solid Oxide Fuel Cell
TWh	Billion kWh
UAE	United Arab Emirates
UN	United Nations
UNFCCC	United Nations Framework Conference on Climate Change
URR	Ultimate Recoverable Resources
USGS	United States Geological Survey
VLEEM	Very Long Term Energy Environment Model

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