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# **AN ENERGY-ECONOMIC SCENARIO ANALYSIS OF ALTERNATIVE FUELS FOR TRANSPORT**

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## Abstract

Climate change and energy security are two key challenges that policy-makers are confronted with today. Specifically, a central policy concern is ensuring the provision of adequate, reliable and affordable access to energy services for meeting basic human needs and maintaining economic growth on the one hand, while on the other hand reducing greenhouse gas emissions from the consumption of fossil energy carriers in energy supply. The transport sector plays a pivotal role in this quest due to its heavy reliance on petroleum products and an expected growth in transport demand in the decades to come. Thereby, transport is a constant liability with regard to greenhouse gas emissions from the combustion of petroleum fuels, and its high vulnerability to volatile oil markets and resource scarcity.

Alternative fuels, and in particular hydrogen and biofuels, are potential substitutes to petroleum fuels that may help to overcome the dependency of transport on petroleum fuels and to reduce greenhouse gas emissions. These fuels possess numerous attributes that make them suitable for responding to the above challenges, but they still require substantial research and development efforts to become commercially viable. Moreover, the potential and competitiveness of these fuels for meeting climate change mitigation and energy security policy objectives is yet unclear, due to a lack of understanding key drivers and key bottlenecks to their deployment.

This dissertation seeks to improve this understanding by assessing the competitiveness of alternative fuels in transport with a particular focus on hydrogen and biofuels. The assessment is delineated into three key analyses that aim to provide a comprehensive overview on the competitiveness of these fuels in meeting climate change and energy security objectives. Firstly, a static analysis of the costs of individual parts of the fuel chain provides insights into key cost components of hydrogen and biofuels production and distribution. This is followed by two modelling analyses on a European and on a global level, using the European Hydrogen MARKAL model (EHM) and the Global Multi-regional MARKAL model (GMM), designed to understand technology dynamics, interactions with the broader energy system and bottlenecks.

The analysis of policies targeting climate change mitigation and energy security finds that biofuels are used in transport across all scenarios investigated. However, there are two central determinants affecting the extent of their utilization. Firstly, this is the regional availability of cheap biomass: areas with low potential and high costs are found to apply other options for decarbonisation of transport, in particular the utilization of hybrid-electric vehicles that allow for quick reduction of petroleum fuel consumption. Secondly, the degree of biofuels utilization is driven by the stringency of the climate policy target pursued. Biofuels are competitive mostly for mild climate policy targets. The more stringent the target, however, the more biomass is cost-effectively used in other sectors.

Hydrogen can become an important and competitive alternative fuel for transport, as it can be produced from zero- to near zero carbon emitting production facilities. This makes hydrogen an attractive energy carrier for pursuing climate change mitigation targets. However, there are two key obstacles for hydrogen. That is firstly the future costs of the fuel cell, which is required to achieve costs in the order of US\$ 40 to 50 per kW to assure market competitiveness. The sooner such costs can be achieved, the earlier hydrogen fuel cells can become competitive. Secondly, the development of a hydrogen distribution infrastructure is a key bottleneck. The analysis with GMM, which includes a high level of detail for hydrogen distribution infrastructure as a result of this dissertation, shows that central hydrogen production, delivered by pipelines, is likely to dominate hydrogen synthesis in the long-run. Early hydrogen deployment takes place most cost-effectively through central hydrogen routes as well, i.e. is initiated in pilot regions. However, mobilising the required investments for such projects is an important policy challenge. An analysis of minimum deployment levels for hydrogen delivery infrastructure conducted here reveals that these investments are only mobilised if stringent climate policy targets are pursued to achieve an atmospheric CO<sub>2</sub> concentration of 450 ppmv by the end of the 21<sup>st</sup> century. Thus, utilising hydrogen for transport is on the one hand motivated by climate policy targets, but on the other hand limited to stringent climate policy regimes.

Policy-makers, thus, need to bring forward clear, consistent and early climate policy targets in order to mobilise required investments for achieving them. The present analysis shows that particularly stringent climate policy requires the deployment of a broad portfolio of technologies and significant structural changes in the energy

system. Under a flexible carbon policy regime, the bulk of investment in the deployment of new energy technologies, in particular for hydrogen, takes place in the second half of the century. However, it takes policy incentives today to facilitate critical R&D and early experience to ensure that the necessary technology development takes place so that hydrogen and biofuels can become a commercially viable option for achieving climate policy targets later.

*Keywords: Climate change, Energy security, Hydrogen, Biofuels, Transport, MARKAL*

## Kurzfassung

Klimawandel und Energieversorgungssicherheit sind zwei zentrale globale Herausforderungen. Insbesondere stellt sich die Frage, wie der Zugang zu geeigneten, verlässlichen und erschwinglichen Energiedienstleistungen sichergestellt werden kann, um grundlegende menschliche Bedürfnisse zu decken und Wirtschaftswachstum zu fördern, während gleichzeitig die Treibhausgasemissionen aus dem Verbrauch fossiler Energieträger in der Energiebereitstellung gesenkt werden müssen. Der Transportsektor spielt in diesem Zusammenhang eine zentrale Rolle durch seine hohe Abhängigkeit von Erdöl. Aufgrund des zu erwartenden Anstiegs des Mobilitätsbedarfs in den nächsten Jahrzehnten ist abzusehen, dass die Bedeutung des Transportsektors hinsichtlich Treibhausgasemissionen und Versorgungssicherheit weiter zunehmen wird, letzteres gerade auch vor dem Hintergrund steigender Ölpreise und Ressourcenknappheit.

Alternative Treibstoffe und insbesondere Wasserstoff und Biotreibstoffe bieten sich als potenzielle Substitute an, um die Abhängigkeit des Transportsektors vom Erdöl und die resultierenden Treibhausgasemissionen zu verringern. Beide Treibstoffe erscheinen am ehesten geeignet für die Herausforderungen Klimawandel und Versorgungssicherheit, doch benötigen sie zum Teil noch bedeutenden Forschungs- und Entwicklungsaufwand, bevor sie kommerziell eingesetzt werden können. Ihr tatsächliches Potenzial und ihre Wettbewerbsfähigkeit hinsichtlich des Erreichens von Klimaschutz- und Versorgungssicherheitszielen sind noch unklar, da zu wenig über Einflussfaktoren auf ihre Nutzung bekannt ist.

Die vorliegende Doktorarbeit hat zum Ziel, zu einem verbesserten Verständnis ebendieser Faktoren beizutragen. Zu diesem Zweck wurden drei Arten von Untersuchungen durchgeführt, die einen möglichst umfassenden Gesamtüberblick über das Themenfeld bieten sollen. Zum einen wurde eine statische Kostenanalyse der einzelnen Teile der Treibstoffbereitstellungskette durchgeführt, mittels derer Einblicke in die bedeutendsten Kostenfaktoren gewonnen werden konnten. Anschließend wurden zwei modellgestützte Analysen durchgeführt, davon eine auf europäischer Ebene mit Hilfe des European Hydrogen MARKAL Modells (EHM), und eine auf globaler Ebene mit dem Global Multi-regional MARKAL Modell (GMM).

Mittels dieser Energiesystemmodelle konnten Einblicke in die Dynamik von technologischem Wandel sowie in Interaktionen des gesamten Energiesystems gewonnen werden.

Die Analyse von Rahmenbedingungen zur Erreichung von Klimaschutz- und Energieversorgungssicherheitszielen zeigt, dass Biotreibstoffe eine bedeutende Rolle im Transportsektor spielen können. Es zeigt sich jedoch, dass es zwei zentrale Einschränkungen gibt, die das Ausmaß der Nutzung von Biotreibstoffen bestimmen. Dies ist zum einen die regionale Verfügbarkeit von kostengünstiger Biomasse: je weniger davon vorhanden ist, desto wichtiger werden andere Möglichkeiten zur Minderung von Treibhausgasemissionen, insbesondere Hybridfahrzeuge. Zum anderen ist es das zu erreichende Klimaschutzziel. Biotreibstoffe sind besonders wettbewerbsfähig bei moderaten Emissionsminderungszielen, doch je höher das gesteckte Ziel, desto mehr wird die knappe Ressource Biomasse in anderen Sektoren des Energiesystems benötigt.

Wasserstoff kann in der Zukunft ein bedeutender und wettbewerbsfähiger Energieträger werden, da er emissionsarm hergestellt werden kann. Dadurch ist Wasserstoff gerade für die Erreichung von Klimaschutzzielen interessant. Doch auch für die Nutzung von Wasserstoff im Transportsektor gibt es zwei zentrale Hürden. Dies sind zum einen die Kosten der Brennstoffzelle, die möglichst schnell auf gut 40 bis 50 US\$/kW gesenkt werden müssen, um ihre Wettbewerbsfähigkeit sicherzustellen. Zum anderen ist dies die Infrastruktur zur Verteilung von Wasserstoff. Die Analysen mit GMM, das als Ergebnis der vorliegenden Arbeit über eine detaillierte Abbildung der Erzeugung und Verteilung von Wasserstoff verfügt, zeigen, dass Wasserstoff langfristig in Großanlagen hergestellt und mittels Pipeline verteilt wird. Auch in frühen Phasen der Wasserstoffnutzung ist dies der kostenoptimale Weg und beginnt mit Pilotprojekten. Es ist jedoch eine bedeutende Herausforderung, die dafür notwendigen Investitionen zu mobilisieren. Die Analysen in vorliegender Arbeit zeigen, dass nur ambitionierte Klimaschutzziele zur Stabilisierung der atmosphärischen CO<sub>2</sub> Konzentration auf 450 ppmv dafür ausreichend Anreiz bieten. Dadurch ist das Erreichen von Klimaschutzzielen zwar eine zentrale Motivation für die Verwendung von Wasserstoff, doch bleibt sie auf ambitionierte Ziele beschränkt.

Aufgabe der Politik ist daher, rechtzeitig transparente und konsistente Rahmenbedingungen zu schaffen, damit die erforderlichen Investitionen mobilisiert werden können. Die vorliegende Arbeit zeigt, dass besonders ambitionierte Klimaschutzziele einen hohen Bedarf an neuen Energietechnologien und einen hohen Umstrukturierungsaufwand im Energiesektor nach sich ziehen. Auch wenn durch flexible Ausgestaltung der Klimaschutzpolitik der Grossteil des Investitionsbedarfs erst in der zweiten Hälfte des 21. Jahrhunderts zu erwarten ist, so braucht es dennoch schon heute politische Rahmenbedingungen, die Forschung und Entwicklung neuer Energietechnologien fördern und somit sicherstellen, dass diese Technologien, und insbesondere Wasserstoff, rechtzeitig zur Verfügung stehen, um Klimaschutzziele erreicht zu können.

*Stichwörter: Klimawandel, Energieversorgungssicherheit, Wasserstoff, Biotreibstoffe, Transportsektor, MARKAL*



## Nomenclature / abbreviations

ATR-FC	Autothermal reforming – fuel cell
AW	Alkaline water (electrolysis)
CCS	Carbon capture and sequestration
CNG	Compressed natural gas
CO	Carbon monoxide
CO <sub>2</sub>	Carbon dioxide
DME	Dimethyl ether
EAW	Alkaline water electrolysis
EHM	European Hydrogen MARKAL model
EHP	High-pressure electrolysis
EHT	High-temperature electrolysis
EIA	Energy Information Administration
EJ	Exajoules
EU	European Union
FAME	Fatty acid methyl esters
FAO	Food and Agricultural Organisation of the United Nations
FCV	Fuel cell vehicle
FT	Fischer-Tropsch
GHG	Greenhouse gas
GJ	Gigajoules
GMM	Global Multi-Regional MARKAL model
GSF	Gasifier
Gt	Gigatons
Gtoe	Gigatons of oil equivalents
GTU	Gas turbine
H <sub>2</sub>	Hydrogen
H <sub>2</sub> A	Hydrogen analysis
HEV	Hybrid ICE-electric vehicle
HP	High pressure
HT	High temperature
ICE	Internal combustion engine

ICEV	Internal combustion engine vehicle
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
kW	kilowatt
kWh	kilowatt hour
LHV	Lower Heating Value
MARKAL	MARKet ALlocation
Mtoe	Million tons of oil equivalents
MW <sub>th</sub>	Megawatt thermal
NNU	Advanced nuclear power plant
OECD	Organisation for Economic Co-operation and Development
PEMFC	Proton exchange membrane fuel cell
ppm	parts per million
ppmv	parts per million by volume
PV	Photovoltaic
R&D	Research & Development
RD&D	Research, Demonstration & Development
RES	Reference energy system
RoW	Rest of the world
SFC	Stationary fuel cell
SI	Sulphur Iodine
SIC	Sulphur-iodine cycle
SNG	Synthetic natural gas
SPV	Solar photovoltaic
SRR	Stationary methane reformer
STH	Solar thermal heliostat field
Syngas	Synthetic gas
US DoE	US Department of Energy
WND	Wind turbine
Zn	Zinc
ZnO	Zinc-oxide

## 1 Introduction

The use of energy has been an important driver of global development during the past century. Today, access to adequate and reliable energy services is an essential prerequisite for economic growth and enhanced social welfare. However, global energy supply today is largely based on fossil fuels, namely coal, oil and natural gas, which has two important undesired implications. Firstly, the heavy reliance on fossil fuels makes the global energy system vulnerable to events that may affect the availability and price of fossil resources; that is, fossil fuel dependence raises challenges with regard to energy security. Secondly, the use of fossil energy carriers is inevitably linked to the production of CO<sub>2</sub> emissions at all steps of the fuel chain, i.e. from extraction of resources to conversion of primary energy carriers to the use of final energy carriers, and is thus an imminent threat to global climate.

Energy security and climate change are issues that remain very high on the agenda of policy-makers, and one key policy challenge today is to ensure provision of adequate and reliable access to energy services to everyone, while at the same time reducing energy-related CO<sub>2</sub> emissions, and without jeopardizing economic growth. While this quest is already challenging, the situation is likely to become even more complex in light of increasing energy demand in countries experiencing substantial economic growth such as China and India, as is widely anticipated by most analysts today (see for example IEA 2007).

The transportation sector plays a pivotal role in this challenge due to its heavy reliance on petroleum fuels and the projected increasing demand for mobility, especially in developing countries (WBCSD 2004). If such trends continue, alternative technologies – whether fuels or vehicle technologies or both – will be required to meet this increasing demand in a sustainable way. Such alternative technologies need to meet an array of complex requirements, such as the need to be affordable to purchase and use; clean in their utilization; and easily accessible to everyone.

In transport, numerous technologies have been identified as promising alternatives, including alternative fuels as well as alternative vehicle technologies. With regard to

fuels, hydrogen and biofuels have attracted particular attention in recent years, as both have the potential to meet the requirements described above. Recent research has for example discussed the emergence of a “hydrogen economy”, i.e. a global energy system attributing a key role to hydrogen (see for example Wokaun *et al.* 2004 or Barreto *et al.* 2003). Moreover, some governments have increased R&D efforts (IEA 2004a), and the US government has even announced a roadmap towards a hydrogen economy (US DoE 2002).

At the same time much of public and policy attention has been on the use of biofuels in transportation, as they seem similarly suitable to meet the above-mentioned challenges and probably even at lower costs. Brazil today is at the forefront of biofuels production and accounts for more than 50% of global fuel ethanol production (IEA 2005a); and the European Commission has proposed a biofuels target of 10% of transportation fuels by the year 2020 for the EU-27 member states (EC 2008).

Understanding the potential of these technology options, however, is a complex task. On the one hand, there is a high level of uncertainty about the actual potential of the different technology options and the conditions that may or may not necessitate their application in transportation. On the other hand, such technology changes are affected by a variety of obstacles and barriers. By way of example, a transition to hydrogen in transport may require the development of a hydrogen delivery infrastructure in the long-run, which could be a bottleneck to the deployment of hydrogen due to the need for large upfront investments in infrastructure prior to the emergence of significant demand for hydrogen.

## **1.1 Scope of the Analysis**

Driven by the crucial role of personal transport in the climate and energy security debate, there is a need to assess alternative technology options that would be best suited to meeting those challenges in a cost-effective manner and to understand the long-term energy system-wide impacts of policies addressing climate change and energy security. This dissertation aims at assessing the role of alternative fuels in personal transport, in particular hydrogen and biofuels, by pursuing three main approaches:

1. an analysis of the costs of technologies for the production and delivery of hydrogen and biofuels and vehicle technologies for their utilization in personal transport
2. an assessment of the cost-competitiveness of the different fuel and vehicle choices in personal transport under different policy regimes targeting climate change and energy security in an energy system-wide context
3. an assessment of key drivers as well as key bottlenecks for the implementation of hydrogen and biofuels in personal transport

## **1.2 Methodology**

A comprehensive analysis assessing the competitiveness of technology options in personal transport and conditions for their market penetration comprises firstly a review of available literature, allowing for a *static* analysis of costs and prospects of relevant technologies along the entire fuel chain, i.e. the production of alternative fuels for transport and the different technologies available in personal transport. Secondly, this *static* assessment is coupled with a modelling analysis on an energy-system level to understand the *dynamics* of energy-system transformations that are induced by technology change, policy and other driving forces that can impact the deployment of technologies.

The specific methodological approach employed in this dissertation to undertake the *static* analysis of technology costs, covering both fuel chains (i.e. the production and delivery of alternative fuels) and personal transport technologies (i.e. current and future vehicles), started with a data collection based on a review of available literature. It further benefited from discussions with technology experts during a research visit to the US National Renewable Energy Laboratory (NREL); and with researchers and industrial partners in the context of a joint project with the Sloan Automotive Laboratory of the Massachusetts Institute of Technology (MIT) under the umbrella of the Alliance for Global Sustainability (AGS): “Reducing greenhouse gas emissions from transport – before a transition to hydrogen”. The fuel chain technology review pays particular attention to hydrogen and biofuels given their high degree of uncertainty in costs and prospects. For the *static* analysis, collected data was then compared in a comprehensive spreadsheet assessment of available data

for fuel chain and transport technology costs and efficiencies, focusing on current technology specifications as well as technology improvements that are likely to be achieved within a foreseeable timeframe.

For the *dynamic* analysis of potential energy system transformations as a result of climate and energy security policy and the contribution of alternative fuels and drivetrains in personal transport, two MARKAL-type of models were applied. MARKAL (MARKet ALlocation) models belong to the family of technology-oriented “bottom-up” energy-system models, which identify least-cost solutions for the energy-system under certain sets of assumptions and constraints (see e.g. Fishbone and Abilock 1981, Fishbone *et al.* 1983 and Loulou *et al.* 2004). The models applied in this dissertation consider the entire energy system, thus allowing for an assessment of the cost-optimal allocation of resources and cost-optimal reduction of CO<sub>2</sub> emissions across all sectors of the energy system. Both models applied possess a great level of technology detail, and the representation of fuel chain and personal transport technologies is based on the static technology assessment described above. The modelling time horizon of both models is 100 years (2000-2100), allowing for due consideration of the inertia of the energy system and the long-term nature of technology change. Moreover, it allows for the assessment of the long-term implications of investment decisions taken today and provides an understanding of the long-term impacts of technology improvements anticipated today. Finally, different CO<sub>2</sub> mitigation regimes can be analysed and the impact of different scenarios on climate change.

Given the focus of this dissertation described above and the applied tools, the emphasis of the work is on an assessment of the *cost-competitiveness* of the different technologies considered under different policy regimes in the context of the entire energy system. Particular attention is paid to the said competitiveness under different CO<sub>2</sub> *mitigation regimes*, since CO<sub>2</sub> is the most important greenhouse gas.

### **1.3 Thesis Structure**

The general structure of the dissertation follows the stepwise approach of static and dynamic analyses described above. It starts, however, by further elaborating on the

motivation of this analysis – the two main energy system challenges climate change and energy security – in **chapter 2**.

**Chapter 3** introduces the static techno-economic assessment of fuel chains and personal vehicles. For fuel chains, special attention is paid to hydrogen and biofuels as potential key fuels for future transport. Each fuel chain is introduced by a description of relevant technologies for fuel production and delivery, followed by a summary of costs for each individual step of the fuel chain. The latter draws on the review of various studies, and aims to evaluate the robustness of available data.

Personal vehicles are introduced with a description of technology options, followed by a detailed assessment of costs. The chapter finishes with a discussion of fuel chains, providing a first-order comparison of costs and prospects of different technology options.

**Chapter 4** aims to provide insights into the cost-competitiveness of technology choices in personal transport under different scenarios in a dynamic cost-optimization framework. The objective of this chapter is to provide an advanced assessment of the cost-competitiveness of the various technology options under different policy regimes and to identify key drivers for their market penetration.

The assessment is conducted on a European level, i.e. for EU-29 (EU-27 plus Norway and Switzerland). For the purpose of this analysis, the European Hydrogen MARKAL model (EHM) has been developed, which is a cost-optimization model that considers the entire energy system of EU-29. The modelling analysis in this chapter makes use of the results of the static cost analysis in chapter 3 for specifying all fuel chain costs in EHM. The results of the analyses strive to expand upon the static analysis of chapter 3 dynamically, by identifying both the conditions and the time horizon needed for technologies in personal transport to achieve competitiveness in the market-place. Chapter 4 concludes by discussing implications for policy-makers.

In **chapter 5** expands upon the *dynamic* analysis of chapter 4 by considering a global perspective. The added global dimension is intended to further advance the study of technology dynamics in order to assess the role of technology change on the competitiveness and the potential of alternative fuels and drivetrains to deal with energy system challenges such as climate change and energy security. Again, a

MARKAL-type model is used. The Global Multi-regional MARKAL model (GMM), coupled to the climate model MAGICC (Wigley and Raper 1997; Wigley 2003), allows for a more detailed analysis of climate mitigation targets. Within this modelling framework, numerous scenarios are explored, including a range of different climate change mitigation targets that provide insights into the competitiveness of alternative fuels and drivetrains in stabilizing global climate. Using the multi-regional feature of GMM, an analysis of the potential influence of additional energy security targets on the market penetration of technologies in personal transport is conducted. Finally, the chapter investigates the production and delivery of hydrogen in great detail in order to provide an answer to the question “where will the hydrogen come from?” should a transition to hydrogen in the transport sector take place, and analyses the hydrogen delivery infrastructure as a potential barrier to the deployment of hydrogen.

Finally, **chapter 6** provides a summary of the analyses conducted in this dissertation, and derives conclusions with regard to the potential of the different technologies investigated in addressing energy system challenges. It concludes by outlining implications for policy-makers that can be derived from the analyses.



## 2 Energy System Trends and the Role of Transport

Global primary energy supply in the year 2005 was 11.4 Gtoe (478.5 EJ), up from 10 Gtoe (420 EJ) in the year 2000 (IEA 2007). It relies heavily on fossil fuels, namely coal, oil and natural gas, which are responsible for approximately 81% of total primary energy supply. Figure 1 depicts global energy trends since 1971 and shows that primary energy supply has almost doubled since the 1970s. Fossil fuels have dominated global primary energy supply ever since, despite some growth in nuclear and renewables.

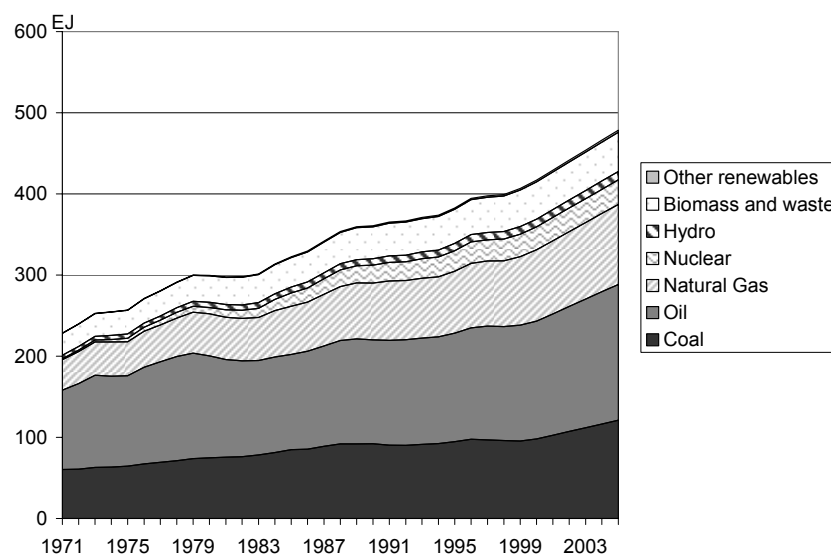


Figure 1. Global primary energy supply 1971-2005 (IEA 2002a, b; IEA 2007).

According to the International Energy Agency IEA (IEA 2007) as well as the US Energy Information Administration EIA (EIA 2007a), a continuation of current trends is likely to increase global primary energy demand to 17.7 Gtoe (742 EJ) by the year 2030, driven by strong growth in China and India and despite a number of policy measures that are taken in OECD countries.<sup>1</sup> The reference scenario of the IEA's World Energy Outlook 2007 suggests that "new" renewable energies (i.e. solar, wind, geothermal) are expected to experience the highest growth, increasing by 6.7% per year until 2030, albeit from a low base. Among the other energy carriers, coal is anticipated to experience the strongest growth in demand, increasing on average by

<sup>1</sup> OECD = Organisation for Economic Co-operation and Development; Paris-based international organization with currently 30 mainly industrialized member countries.

2.2% per year until the year 2030. However, oil is currently the dominant fossil fuel in global primary energy supply, and the IEA analysis suggests that it is likely to remain so until 2030, contributing 5.6 Gtoe (234 EJ) to total primary energy demand. The share in total demand, however, is expected to decrease to 31.5% by 2030, down from 35% in 2005, due to the stronger growth of other energy carriers (IEA 2007).

The transport sector – and in particular personal transport – plays a pivotal role in current energy system debates, mainly as a result of two key issues. First and foremost, it relies almost entirely on one fossil resource alone, i.e. petroleum and its products. Petroleum supplies 95% of the total energy used by world transport (IPCC 2007), and this high reliance on petroleum fuels translates into high CO<sub>2</sub> emissions as a result of the combustion process. The transport sector produced about 6.3 GtCO<sub>2</sub> emissions in 2005, or 23% of global energy-related CO<sub>2</sub> emissions (IEA 2008). Figure 2 shows that while its share of total CO<sub>2</sub> emissions has increased only modestly since 1971 (20%), the total amount has more than doubled during the same period (2.8 GtCO<sub>2</sub> in 1971).

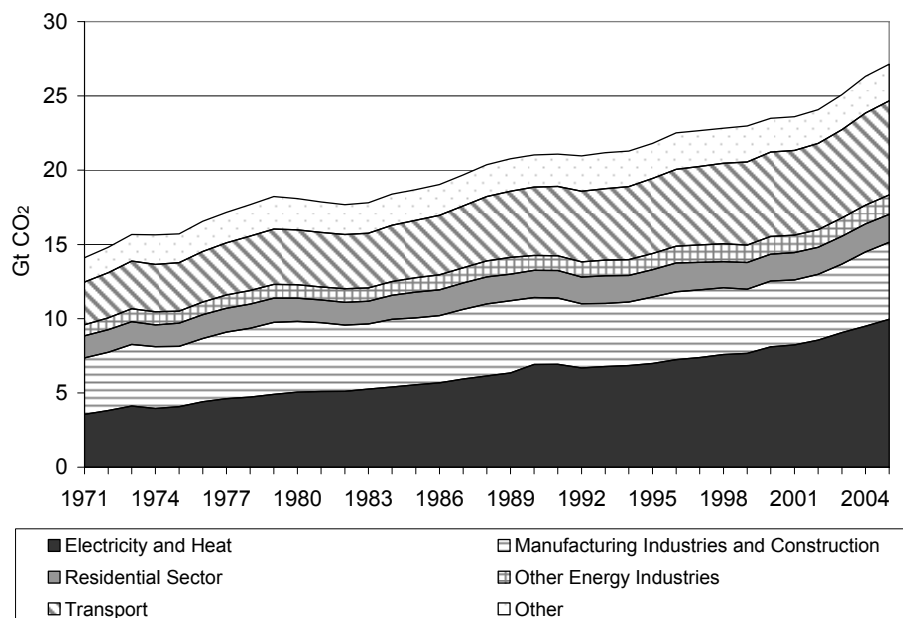


Figure 2. Global CO<sub>2</sub> emissions by sector 1971-2005 (IEA 2008).

Moreover, a high reliance on petroleum fuels is a constant liability with regard to energy security, threatened by increasing oil prices and vulnerability of oil markets;

geographical distribution of oil resources and the problem of geopolitical instabilities; and generally fossil fuel scarcity.

Energy security concerns as well as the problem of CO<sub>2</sub> emissions from transport are likely to increase in the future as a result of the second key problem in transportation: the global demand for transport is projected to increase strongly in the decades to come (WBCSD 2004; EIA 2007a). This is largely a result of economic development and growth, which is e.g. likely to increase the need for freight transport. Moreover, increasing welfare is an important driver in increasing demand for mobility, through higher vehicle ownership rates, or higher value attributed to time in wealthier societies leading to a preference for faster transport modes (Schafer and Victor 2000; WBCSD 2004). The choice of faster transport modes is likely to increase the utilization of more and faster vehicles in personal transport, and also to facilitate an increased use of aviation.

Consequently, global final energy demand in transport is expected to grow quickest in comparison to other end-use sectors at 2.1% per year until the year 2030 according to IEA (2004b). Much of the growth is anticipated to take place in the developing world, notably in growing economies such as China, India or Brazil. Goldman Sachs (2004) expects China and India to emerge as the world's leading car markets, overtaking the United States in 20 (China) to 30 (India) years; whereas the IEA projects that China will overtake the United States as the largest car market in the world even sooner, by 2015 (IEA 2007).

While it is generally possible that future generations may choose to commute by public transport rather than using their own car, most studies suggest the opposite and anticipate an increasing role for individualised personal transport (e.g. Schafer and Victor 2000; WBCSD 2004). The European Commission states in its white paper on transport policy that personal mobility in Europe is more or less perceived as an "acquired right" (EC 2001). There is no reason to believe that people in developing countries will not perceive personal mobility in a similar way.

It is apparent that the described developments do not comply with the ideal of a sustainable energy system, where everyone has equal access to affordable modern

energy services and the needs of current generations are met without compromising the ability of future generations to cover their own needs, following the definition of the term “sustainability” by the Brundtland Commission in 1987 (Brundtland 1987).

As a consequence of the described developments, responding to the challenge of satisfying increased demand for energy and mobility, while at the same time combating climate change and maintaining and improving current levels of energy security, is high on the agenda of policy-makers. The following sections take a closer look at this challenge and the role of the transport sector through a discussion on climate change and energy security against the backdrop of transport sector trends. Thereafter, technology change is introduced as a means of dealing with these challenges.

## **2.1 Climate Change**

In the context of sustainability, public attention has focused lately on climate change, highlighted by the awarding of the Noble Peace Prize to the Intergovernmental Panel on Climate Change (IPCC) and Al Gore for their work on assessing climate change and raising public awareness. The fourth IPCC assessment report has, indeed, been essential in alerting the global community to alarming developments; this is illustrated by a few key messages:

- “The years 1995 to 2006 rank among the twelve warmest years in the instrumental record of global surface temperature (since 1850)”.
- “The global atmospheric concentration of CO<sub>2</sub> increased from a pre-industrial value of about 280 ppm to 379 ppm in 2005”.<sup>2</sup>
- “Most of the observed increase in global average temperatures since the mid-20th century is very likely due to the observed increase in anthropogenic GHG [*greenhouse gas*] concentrations” (all quotes from IPCC 2007b).

The report provides strong evidence that climate change is induced by human activities, and suggests that immediate action is required to mitigate climate change, in particular reducing CO<sub>2</sub> emissions. As a result of human activities, however,

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<sup>2</sup> ppm = parts per million

greenhouse gas (GHG) emissions and, in particular, CO<sub>2</sub> emissions have been steadily rising during the last decades, as illustrated in Figure 3.

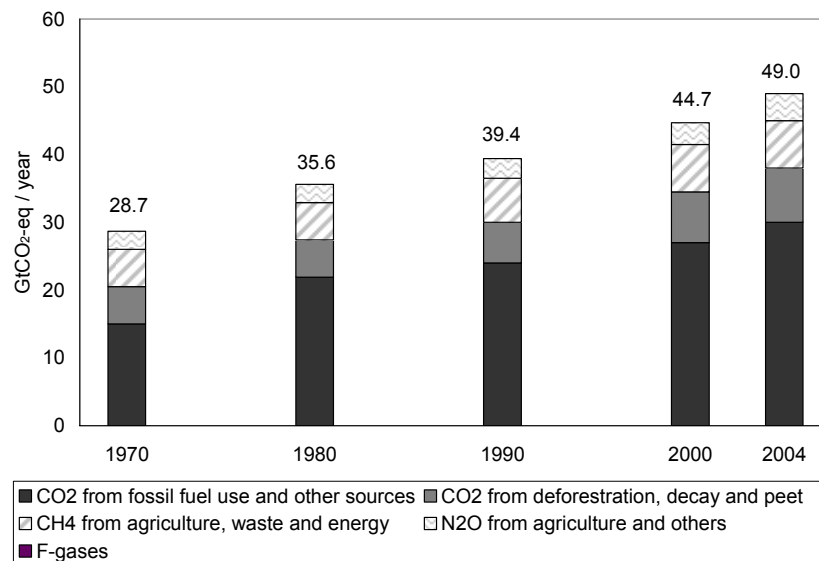


Figure 3. Global annual anthropogenic GHG emissions from 1970 to 2004 (IPCC 2007b).

This development has consequences with regard to the world's climate. In the latest edition of the IPCC report, the best estimates of global mean temperature increases over the 21<sup>st</sup> century range from 1.8° to 4.0° Celsius, depending on the GHG trajectories of the various scenarios analysed (IPCC 2007b). This may result in severe and irreversible changes to the global ecosystems, upon which humankind depends.

Most global GHG emissions arise from the combustion of fossil fuels for energy purposes. Figure 4 distinguishes the contribution of different sectors to global anthropogenic GHG emissions, i.e. emissions that are induced by human activities, and most of them are from energy-related activities.

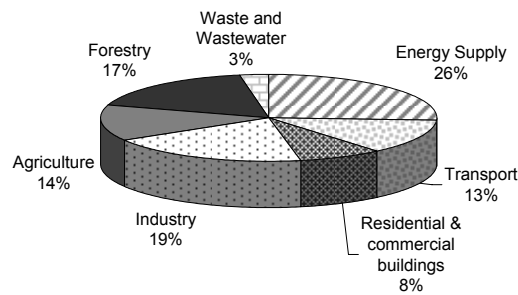


Figure 4. Share of different sectors in total anthropogenic GHG emissions in 2004 in terms of CO<sub>2</sub>-equivalents (IPCC 2007b). Forestry includes deforestation.

The breakdown of anthropogenic GHG emissions in Figure 4 further emphasizes the crucial importance of transport in global GHG emissions, responsible for approximately 13% of all anthropogenic GHG emissions in 2004. As was discussed above, the increasing demand for mobility suggests that if current trends continue, transport is likely to remain a key contributor to global GHG emissions and, thus, climate change.

Moreover, Figure 4 suggests that any analysis of how to reduce CO<sub>2</sub> emissions in order to mitigate climate change should consider the energy system as a whole rather than focus on individual sectors only. Reducing CO<sub>2</sub> emissions is an energy-system effort, and focusing on individual sectors may fall short of addressing the complexity of the problem. The modelling analyses in this thesis take due consideration of this by assessing the role of transport in reducing total CO<sub>2</sub> emissions in optimization models, which represent the entire energy system.

## 2.2 Energy Security

Energy security is another central issue in the sustainability debate, all the more so because it is multi-faceted and embodies different characteristics. The International Energy Agency (IEA) broadly defines energy security as “adequate, affordable and reliable supplies of energy” (IEA 2007).

However, at its most rudimentary level, energy security is an issue of resource and resource availability, and the possible depletion of fossil resources has been

discussed for decades. While analysts commonly agree that sufficient coal reserves are available to cover increasing demand throughout the entire 21<sup>st</sup> century, this is not the case for oil and gas. Projections of the availability of oil and gas reserves, however, have usually underestimated reality, mainly due to their failure to account for new oil and gas field discoveries and increasingly sophisticated exploration technologies. As a result, the static reach, i.e. the availability of oil and gas resources as a function of proved reserves and annual consumption, has remained fairly constant over the past decades, as shown in Figure 5.<sup>3</sup> This is despite increases in global oil and gas consumption.

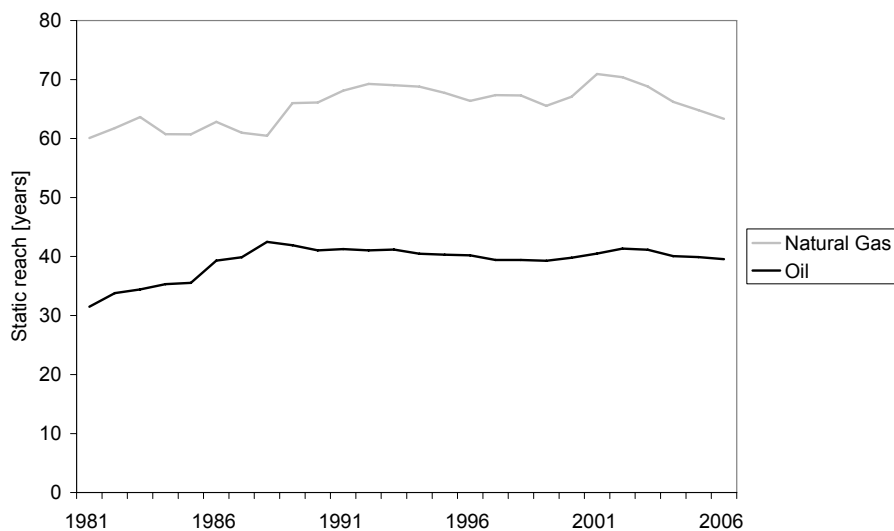


Figure 5. Static reach of oil and gas reserves (calculated from BP 2007).

Nevertheless, it is unlikely that the situation will persist forever; fossil resources are finite by their very nature. However, while fossil resource depletion can be expected to become a bottleneck for energy security over the next decades, geopolitical frictions are perceived to impose even more urgent threats from today's perspective. Figure 6 and Figure 7 show the 10 countries with largest shares of global proved oil and natural gas reserves according to BP (2007). Most oil and natural gas reserves are located in areas with significant political instability, adding a geopolitical dimension to the overarching topic of energy security. This implies that even if sufficient fossil resources were available, the reliability of supply – one of the three key dimensions of energy security in the above definition of the IEA – may not be

<sup>3</sup> Static reach = proved reserves / annual consumption.

guaranteed and may be determined more by political relationships rather than well-functioning markets. However, whether or not reliable access to energy sources is threatened by resource depletion or geopolitical frictions, they both imply a need for policy action in order to maintain reliable access to energy and consequently to ensure economic growth.

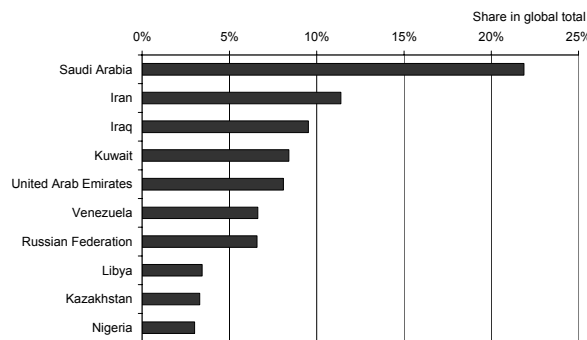


Figure 6. Share of global proved oil reserves of top 10 countries.<sup>4</sup>

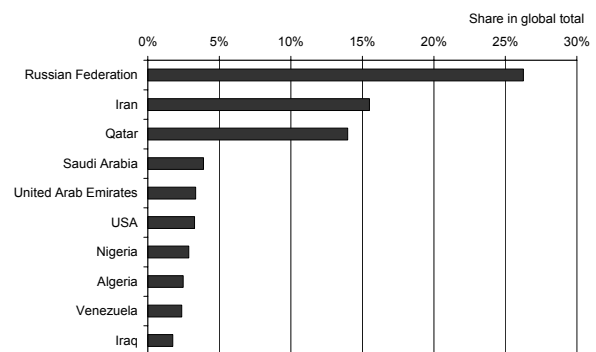


Figure 7. Share of global proved natural gas reserves of top 10 countries.

Finally, the availability of resources does not end at the sheer amount of resources available, i.e. the adequacy of resources. Low-cost resources are also required, allowing energy demand to be met in a cost-efficient manner, i.e. what the IEA refers to as “affordable” supply. While the actual costs associated with exploiting oil and natural gas reserves have probably not increased much in recent years, the market price has amplified significantly as illustrated for the case of oil in Figure 8 and Figure 9.

<sup>4</sup> Note that this figure does not consider the recent oil field discovery in Brazil.



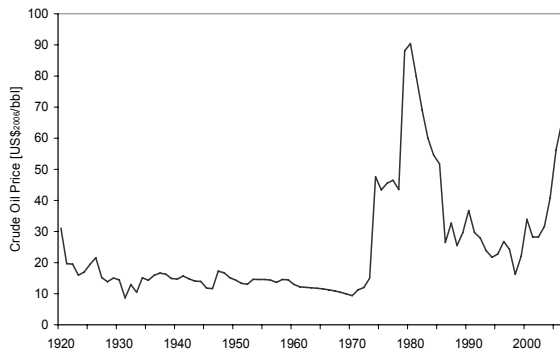


Figure 8. Historical crude oil prices (BP 2007).

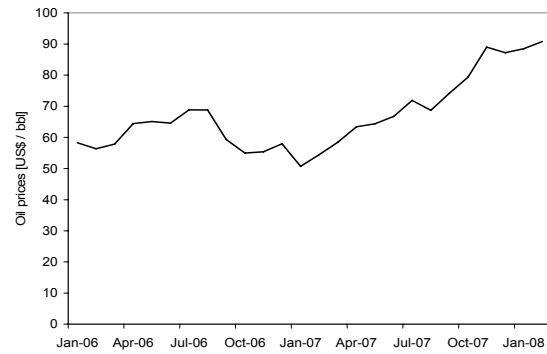


Figure 9. Recent oil price developments (MWV 2008).

There is much debate on the reasons for recent oil price peaks and the volatility of energy markets (see for example Wirl 2008; IEA 2007);<sup>5</sup> nevertheless, there is growing consensus that the time of cheap oil supply could be over. Consequently, the International Energy Agency currently projects in their reference case oil prices of US\$<sub>2006</sub> 62 per barrel of oil in the year 2030 (IEA 2007), up from US\$<sub>2000</sub> 29 per barrel in previous projections (IEA 2004b).

## 2.3 Technology Change

Technology constitutes one of the main driving forces of economic growth (Arrow 1962). The last 200 years have seen major technological breakthroughs, e.g. the development of internal combustion engines, aeroplanes, computers, mobile phones and many more. The widespread adoption of these technology examples today shows clearly how technology has become a pervasive factor in shaping our lives, and is likely to remain so in the future.

Technology change will be essential if energy system challenges are to be met. Energy systems and in particular the transport sector will need to change their

<sup>5</sup> While it is not aimed here to participate in this debate, it is interesting to note that global oil refining capacities have roughly doubled between 1965 and 1975 from about 35 to 70 million bbl/day according to BP (2007). Thereafter, significantly less investment has taken place, resulting in 87 million bbl/day of refining capacity in 2006. This indicates that increasing oil prices could also be a result of shortage of refining capacities. Total oil consumption exceeded 90% of available refining capacity in 1992, and reached 96% in 2006 consuming 83.7 million bbl/day. However, global oil consumption from 1975 onwards, i.e. after the first wave of investment, barely exceeded 80% of available refining capacity, reaching 85% in 1987 only. Still, oil prices saw its highest spikes in the early 1980s. Lack of refinery capacity may, thus, be part of the explanation. However, other market forces (monopolistic behavior, geopolitical frictions, or speculations) seem at least equally important.

structure. In theory, the process of technology development and change involves a series of interrelated steps from technology invention to innovation, niche market diffusion, large-scale diffusion, eventual saturation and finally decline if “better” competitors appear in the marketplace (Schumpeter 1934; Grübler *et al.* 1999).

Technology change, however, does not take place without effort. Each step of the described innovation chain involves overcoming hurdles, and most innovations do not succeed in the marketplace. The reason for a technology’s success or failure in the marketplace is not always easy to grasp, and there are a variety of mechanisms that can hinder the market penetration of an innovation. One example that is highly relevant for the energy system in general and the transport sector in particular is the creation of “lock-in” effects. This means that certain historical choices, in the case of transport this refers to the choice of petroleum fuels and internal combustion engines, can lead to situations that are difficult to reverse, i.e. “lock-in” situations (Arthur 1989). When certain technologies or groups of technologies become dominant in the market, they retain and improve their competitive advantage through technology improvements, with regard to performance or cost, or through the constitution of technological regimes, i.e. through the implementation of infrastructures, which are difficult to challenge and displace (Kemp 1997). Such technology lock-in situations create significant inertia in the energy system, making transitions in the energy and transport sector (e.g. a shift to hydrogen- or biofuels-based transportation) a long-term and challenging process.

Another important hurdle to overcome in ensuring success in the marketplace includes the perception of consumers to the new product. The success of any technology stands and falls with the acceptance of consumers, and from gaining acceptance to the widespread adoption of a technology is a time-consuming process. The process by which innovative technologies become what is called “social norm”, i.e. a “standard” social behaviour, may take decades. This has been illustrated for the case of the automobile industry by Ulli-Beer *et al.* (2008), who use the average lifespan of vehicles as a reference point for how long it takes to replace an old technology within certain adopter categories. They conclude that if the social norm building process is the only social policy in place (i.e. no climate change or other

policy), then it may take three times the average lifetime of the vehicle until the new technology is adopted by half of the car drivers, as depicted in Figure 10.

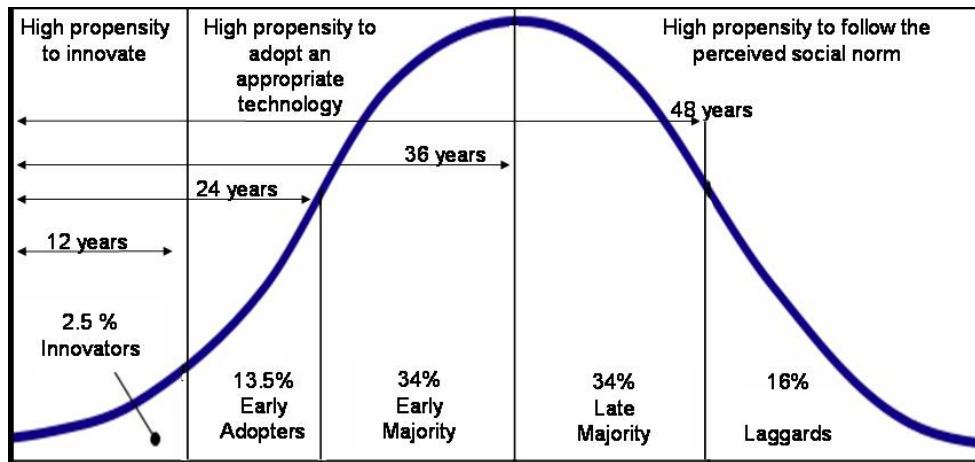


Figure 10. Adopting new transport vehicles due to social norm-building processes (Ulli-Beer et al. 2008).

While this thesis does not intend to address the impact of consumer choices on technology adoption processes due to social norms, it is important to keep both this and the phenomenon of lock-in in mind. Both are examples of obstacles to technology change and illustrate the challenge new technologies face when entering the market. Inevitably, technologies first need to evolve out of niche markets, where initial commercialization commonly takes place, to finally reach large-scale deployment. Many technologies fail to do so, that is if they enter the stage of niche market deployment at all.

Technologies that enter this stage, however, may benefit significantly from technological learning, i.e. learning from experience and effort. In this stage, technology development involves learning at two levels, the first being more at a fundamental level, where the adoption of a technology may influence, for example, technology design. Deployment at this stage may also involve learning at the production level, where upscaling of production sizes, optimization of repetitive production steps or employing mass production techniques can lead to reductions in technology costs and, thus, better positioning in the marketplace (Grübler 1998).

This discussion shows that it is imperative to address the role of technology change in the analysis of the prospects of alternative technologies in personal transport.

Technology transitions can take a long time, and decisions made today with regard to the deployment of future technologies are likely to determine the technology options available to future generations for a long time to come – they have done so in the past, as described in the case of transport above in the context of historical fuel and engine choices. Today's society has the tools and experiences for understanding the long-term consequences of technology choices, and should make use of it in order to provide future generations with the best possible technologies for covering future demand for energy. This thesis is thought of as being in line with such “sustainability” considerations, as it aims to not only analyse technology options for transport, but also to assess their long-term competitiveness and prospects in addressing global energy system challenges that were described before.

## **2.4    *Summary and Outlook***

This section has described the challenges that the global energy system faces and the role of transportation and technology change therein. It should be understood that dealing with these challenges is a holistic task, which is likely to change the current energy system substantially, in particular if climate change is taken a serious threat and is to be tackled seriously.

Hydrogen and biofuels are two promising options in the broad portfolio of technologies, but making use of them in transport requires technology changes along all parts of the fuel chain. The following section aims at providing a first static analysis of hydrogen and biofuels by discussing all parts of the fuel chains in detail.

### 3 Techno-Economic Analysis of Fuel Chains

This chapter summarizes the results of a comprehensive static techno-economic assessment of fuel chains and personal vehicles, which was conducted in the course of this PhD thesis and forms the backbone of all modelling analyses conducted in the remainder of this dissertation. Two fuel chains are analysed in more detail: hydrogen and biofuels, which are deemed as potential key fuels for future transport. Each fuel chain is introduced with a description of relevant technologies for fuel production and delivery, followed by a state-of-the-art review of costs of the individual steps of the fuel chain. The latter draws on the review of available literature and an analysis with the H2A spreadsheet models;<sup>6</sup> it aims at understanding the robustness of available data throughout available literature.

Personal vehicles are introduced with a description of technology options as well, followed by a detailed assessment of costs. The chapter finishes with a discussion of fuel chains, providing for a first-order comparison of costs and prospects of technology options.

The intention of this chapter is to introduce the reader to the technological detail applied in this dissertation and to outline key uncertainties with regard to fuel chain costs.

All cost data presented in the following sections is based on the following relation:

$$Cost = INVCOST \times \frac{CRF}{AF} + \frac{FIXOM}{AF} + VAROM + \frac{FuelCost}{\eta}$$

where

INVCOST = Specific investment cost [US\$/kW]

CRF = Capital recovery factor [-]

AF = Availability factor [-]

FIXOM = Fixed operation and maintenance cost [US\$/kW/yr]

VAROM = Variable operation and maintenance cost [US\$/GJ]

$\eta$  = Process efficiency

---

<sup>6</sup> The H2A spreadsheet models are developed under the umbrella of the US Department of Energy (US DoE) and were established in 2003. These models provide for a consistent and transparent analysis of hydrogen production alternatives (H2A production models) as well as hydrogen delivery options (H2A components model). Further details may be found on the US DoE website at [http://www.hydrogen.energy.gov/h2a\\_analysis.html](http://www.hydrogen.energy.gov/h2a_analysis.html).

The capital recovery factor CRF is computed using

$$CRF = dr \times \frac{(1 + dr)^n}{(1 + dr)^n - 1}$$

where

dr = Discount rate [%], assumed 5% for all technologies in this analysis

n = Plant life time [years].

Moreover, all cost data presented in this chapter have been assessed using the same fuel cost assumptions. They will be introduced where appropriate.

### **3.1 The Hydrogen Fuel Chain**

Hydrogen is not a “new” energy carrier in the energy system. Globally, around 5 EJ (about 100 Mtoe) of hydrogen are produced each year, of which about 40% are used in chemical processes, 40% in refineries and 20% for other purposes (IEA 2006). However, its use in transport has so far not gone beyond experimental tries.

This section discusses the entire hydrogen fuel chain, i.e. production as well as delivery to the fueling station. Firstly, an overview on technologies is presented. This is followed by a review of relevant studies on the costs of technologies.

#### **3.1.1 Technologies for Central Hydrogen Production**

Even though hydrogen is the most abundant element on earth, it is not easily accessible and needs to be produced by technical means. There is a wide variety of technological options for its production: in 2001, world’s hydrogen production was mainly based on fossil fuels with 48% originating from natural gas, 30% from heavy oils and naphtha, 18% from coal and only 4% from electrolysis as a by-product of chlorine production (Penner 2006).

There is a high number of potential future technologies for hydrogen production. However, some of these processes are highly speculative from today’s perspective, and may be applicable for niche markets only. This thesis considers those technologies only, which are promising for hydrogen production on a global scale.

Technologies which from today's perspective seem suitable for niche markets only, such as biological hydrogen production routes making use of algae or microbacteriae for producing hydrogen from biomass or waste, were neglected. For such technologies, the interested reader is referred to IEA (2005b) or Vijayaraghavan and Soom (2004).

### **Natural Gas Reforming**

Steam Reforming of Methane (SMR) is the most proven process and commercially available. The common SMR process involves basically three steps: a steam reformer, a shift reactor and a hydrogen purification unit.

The steam reformer produces a synthetic gas ("syngas") composed of Carbon monoxide and hydrogen, which is then sent to one or two shift reactors in order to increase the yield of hydrogen via water-gas shift reaction. After this step, the resulting gas contains 70—80% of hydrogen, the rest of the gas is made up mainly by  $\text{CO}_2$  and  $\text{CH}_4$  with small quantities of  $\text{H}_2\text{O}$  and  $\text{CO}$ . With an additional purification step, pure hydrogen is obtained.

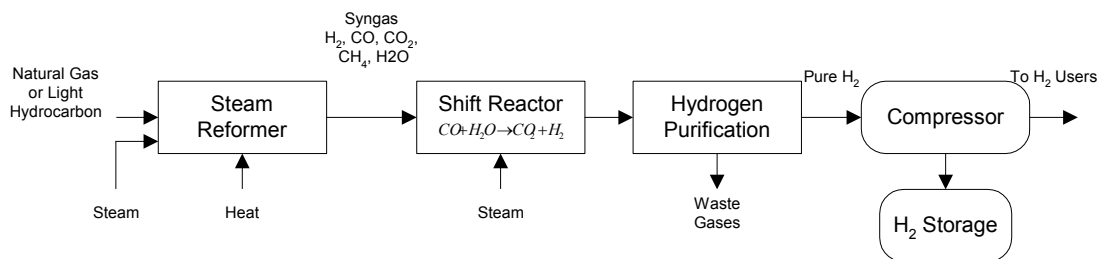


Figure 11. Steam reforming of methane for hydrogen production (Ogden 1999a).

### **Gasification of Coal and Biomass**

Gasification of coal, biomass, petroleum residuals or coke converts a solid feedstock to syngas using steam and an oxidant Basye and Swaminathan (1997). The process temperature depends on the individual gasification technologies, but needs to be high and is in general in the range of 800°C to 1800°C.

Gasification appears as a very flexible technology with regard to the fuel: in principle, gasification processes can handle different carbon-based energy carriers and are, thus, applicable also for fuel mixes, i.e. coal together with biomass. Gasification

systems for biomass only though are similar, but not fully equivalent to those applying coal: they operate at slightly lower temperatures and have different clean-up requirements (Ogden 1999a).

There are different possibilities to use the resulting syngas, as will be further discussed in the section on biofuels below. Relevant here is the separation of hydrogen through a gas-shifting process with subsequent purification of the hydrogen-syngas, using Pressure Swing Adsorption (PSA) or a Hydrogen Separation Membrane Reactor (Ogden 1999a).<sup>7</sup> Figure 12 depicts the process scheme.

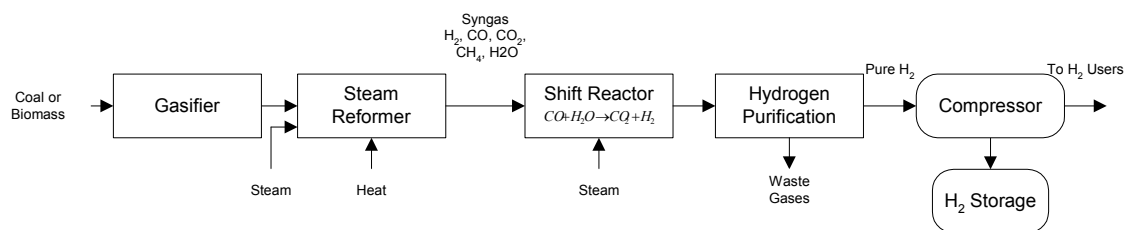


Figure 12. Gasification process for hydrogen production (Ogden 1999a).

Coal gasification is the most commercialized technology today mainly as part of Integrated Gasification Combined Cycles (IGCC), where the syngas is used as an input to a combined cycle turbine for combustion and, thus, the production of electricity. These facilities have been suggested to later move to a co-production mode for the combined production of i.e. hydrogen and electricity (Yamashita and Barreto 2003).

One example for future co-production of hydrogen and electricity is FutureGen, a technological concept of the US Department of Energy (US DoE) that is intended to produce hydrogen from coal gasification. FutureGen is intended to couple numerous advanced energy technologies for co-producing hydrogen and electricity (compare e.g. Williams *et al.* 2005). For this purpose, a syngas consisting mainly of hydrogen and carbon monoxides is produced from coal gasification. The obtained hydrogen is used for electric power generation either in turbines, fuel cells - here Solid Oxide Fuel Cells (SOFC) – or in combinations of these technologies.

<sup>7</sup> Other ways to use the syngas include the direct use as town gas or for the production of electricity. Fuels such as methanol or Fischer-Tropsch liquids can be obtained by similar gas-cleaning processes as the one described for hydrogen. We will return to this issue at a later stage.



At this stage, a 275MW plant is intended to be designed, constructed and then operated for demonstrational purposes, sequestering at least 90% of its CO<sub>2</sub> emissions (US DoE 2003).

### Electrolysis

The concept of producing hydrogen from water via electrolysis is, in principle, rather simple: electricity is used to split water into its two components hydrogen and oxygen; depending on how electricity is generated, electrolysis is a potentially CO<sub>2</sub>-free option for hydrogen production.

Typically, an electrolysis cell consists of two electronic conductors, i.e. anode and cathode, which are in contact with an ionic conductor, i.e. the electrolyte. Connected to an electric direct current, a cell containing water will split the water molecules into hydrogen and oxygen. Figure 13 shows the principle of an electrolysis cell for the example of an alkaline electrolyte.

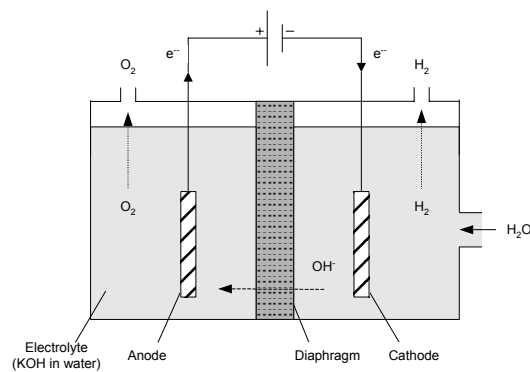


Figure 13. Principle of alkaline water electrolysis (Prince-Richard 2004).

Although large-scale electrolysis currently only makes use of alkaline water electrolysis (AWE), there are numerous other promising concepts available, of which high-pressure (HP) electrolysis and high-temperature (HT) electrolysis are explicitly considered in this thesis. HP electrolysis operates at higher pressures than AWE, thereby reducing the need for compression energy for compressing hydrogen for delivery. This technology, however, is still at R&D stage: the German research centre Forschungszentrum Jülich developed a 5 kW prototype, able to produce hydrogen at 120 bar with efficiency levels similar to that of a low-pressure model (Janssen *et al.* 2001).

HT electrolysis applies ceramic materials as electrolytes and, thus, can operate at higher temperatures typically in the range of 900-1000°C (Prince-Richard 2004). Operating at such high temperatures allows reducing the need for electricity, as the required energy input can be partially provided from heat.

### ***Solar Thermal Hydrogen Production***

Two promising solar thermal hydrogen production technologies are solar zinc (Zn)/zinc-oxide (ZnO) water splitting and solar coke gasification. These thermochemical cycles make use of hydrolysis, i.e. the conversion of water into hydrogen and oxygen, by a series of chemical reactions using zinc as a catalyst. Zinc is produced from zinc-oxide at temperatures above 2000K, and the required heat is provided by solar thermal devices. The highly reactive zinc is then cooled down to some 300K by quenching, and then after reheating used for water splitting at 700K.

In order to decrease operating temperatures of the reactor and for a more simple chemistry, however, the solar split of ZnO can be catalysed by a carbon-containing material such as coke, which acts as a reducing agent. This process is here referred to as solar coke gasification.

Both process are at a stage of R&D and not yet commercialized. Detailed discussions of these processes as well as further information on solar hydrogen can e.g. be found in Steinfeld (2002), Steinfeld (2005) and Felder (2007).

### ***Sulphur-Iodine Cycle***

The sulphur/iodine cycle makes use of sulphur (S) and iodine (I) for water splitting and requires high-temperature heat to thermally produce hydrogen. While in principle, both solar thermal and nuclear energy could be used for heat provision, this thesis only considers nuclear SI cycles. The principles of this process are outlined in Figure 14; note that both sulphur and iodine are recycled.

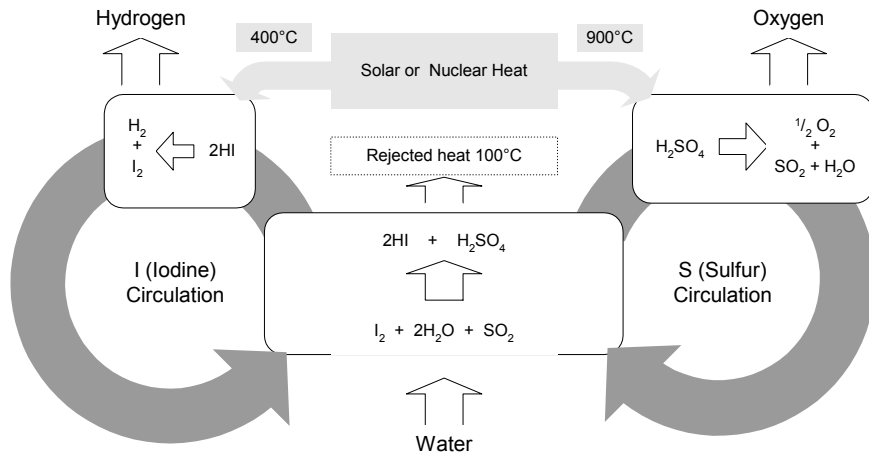


Figure 14. Principles of a sulphur/iodine thermochemical process (IEA 2006b).

Research and development needs for the S/I cycle include the capture of thermally split hydrogen, to avoid side reactions and to handle corrosion problems, which are likely to be extremely serious (IEA 2006b).

### 3.1.2 Costs of Central Hydrogen Production

This section compares the cost of major hydrogen production routes found in various studies. Data have been harmonized with regard to fuel cost assumptions and applied discount rates (5%); the fuel costs assumed in this section are reported in Table 1.

Table 1. Fuel cost assumptions – hydrogen production.<sup>8</sup>

Fuel	Cost [US\$/GJ]
Natural Gas	4.6
Coal	1.6
Biomass	5.1
Electricity	12
Coke	0.3
Petroleum residuals	2.0

<sup>8</sup> All hydrogen related data are on LHV basis. Note that fuel and electricity costs and prices as presented here do not necessarily reflect the outcome of the modelling assessments conducted in the remainder of this dissertation; there, fuel and electricity prices are either endogenous to the model and, thus, subject to change over time; or, exogenously applied according to a particular scenario or for sensitivity analyses.

An overview of current and potential future costs of hydrogen production is presented in Table 2, drawing on several studies reviewed for the purpose of this comparison (see appendix 1 for the full dataset). Note that in this table, future costs refer to the cost of technologies potentially available from between 2020 and 2030 (e.g. nuclear and solar hydrogen production) as well as to improvements to existing technologies in the future (e.g. coal gasification, natural gas reforming, AW electrolysis). Note also that costs in this table exclude the costs of carbon storage for those technologies with carbon capture.

As Table 2 shows, there is some agreement between studies on the general trends in terms of which technologies are able to produce hydrogen in a cost-effective manner. Current technologies, in this regard, include coal gasification and natural gas reforming. They appear able to produce hydrogen cost-effectively and with low CO<sub>2</sub> emissions if applying carbon capture. Observed differences in cost and efficiency figures in particular for coal gasification are explained mostly through differences in assumed production scales, as scale-economies can be significant for coal gasification. Moreover and similarly important, some of the studies reviewed interpret coal gasification as a coupled-production technology, where both hydrogen and electricity are produced. Such flexible technologies are potentially able to produce hydrogen at least cost, if a credit is earned for electricity co-production.

In the future, nuclear hydrogen can play an important role. Even though the number of studies reviewed here is low compared e.g. to coal gasification, hydrogen production could be a future market for advanced nuclear reactors. It is, however, obvious that a solid assessment of the prospects of future nuclear hydrogen production will depend on whether technology and cost development targets for future nuclear reactors can be met, and on the public acceptability of these technologies.

Table 2. Range of hydrogen production costs in literature.<sup>9</sup>

Technology	Status	Production Costs [US\$/GJ]		Conversion Efficiency [%]		No. of data sources
		Min	Max	Min	Max	
Coal gasification	current	5.9	10.1	52%	71%	8
	future	3.2	4.6	60%	79%	2
Coal gasification with carbon capture	current	6.6	10.8	48%	69%	7
	future	4.2	8.0	59%	77%	7
Natural gas reforming	current	7.5	9.0	69%	83%	10
	future	6.8	8.1	73%	79%	3
Natural gas reforming with carbon capture	current	8.2	10.3	63%	82%	7
	future	7.5	9.2	71%	76%	4
Biomass gasification	current	16.1	28.6	44%	57%	4
	future	13.2	16.3	54%	66%	2
Coke gasification	current	8.2	8.2	62%	62%	1
Petroleum residuals gasification	current	8.3	8.3	67%	67%	1
Alkaline water electrolysis	current	24.0	30.7	34%	39%	3
	future	18.0	18.1	39%	43%	2
Wind + AW electrolysis	current	24.0	24.0	100%	100%	1
	future	13.1	13.1	100%	100%	1
High-pressure electrolysis	future	20.1	20.1	70%	70%	1
Nuclear high-pressure electrolysis	future	12.0	12.0	n.a.	n.a.	1
Nuclear high-temperature electrolysis	future	9.1	10.0	n.a.	n.a.	2
Nuclear sulphur-iodine cycle	future	8.5	9.4	n.a.	n.a.	2
Solar Zn/ZnO cycle	future	44.3	44.3	100%	100%	1
Solar coke gasification	future	33.2	33.2	87%	87%	1

Data sources: Yamashita and Barreto (2003), Simbeck and Chang (2002), H2A (2006a), NRC (2004), Felder (2007), Simbeck (2004a), Schultz (2003)

<sup>9</sup> All cost data is on LHV basis for the entire thesis, all cost reported are in US\$ of the year 2000 unless indicated otherwise, using the U.S. Department of Labor's inflation calculator at <http://data.bls.gov/cgi-bin/cpicalc.pl> for conversion. Where studies did not indicate the year that costs are expressed in, then the year of publication was used. Discount rate = 5%. Where efficiencies are reported as not applicable (n.a.), values were not explicitly reported in the respective studies or fuel use is considered in operation and maintenance costs (nuclear hydrogen, see appendix). Efficiencies for renewable energy technologies assumed 100%.

Particular disagreement was found for the cost of biomass gasification. Three key studies were reviewed in more detail for understanding these differences: Simbeck and Chang (2002), NRC (2004) and H2A (2006a). All look not only at biomass gasification, but at various central hydrogen production technologies at a time. Key to understanding cost differences are again scale-economies: H2A (2006a) assumes a daily hydrogen output of about 155 tons of hydrogen; NRC (2004) uses 24 tons per day only in what is called “midsize” technology, but “no midsize gasification facility exists to date that converts biomass to hydrogen, and no empirical data are available on the operation, performance and economics of a midsize biomass-to-hydrogen plant, as assumed in the economic model” NRC (2004:233). Simbeck and Chang (2002) use 150 tons of hydrogen per day. Scale-economies obviously influence cost assumptions of these studies at all levels and not only with regard to the gasifier itself. By way of an example, the capital costs of pure oxygen provision from an air separation unit have been assumed almost twice as costly in NRC (2004) as compared to Simbeck and Chang (2002), with unit costs at assumed sizes of US\$ 47 per kg of oxygen per day in NRC (2004), compared to US\$ 24 per kg of oxygen per day in Simbeck and Chang (2002).

More details that explain differences observed in cost of hydrogen production in the three key studies Simbeck and Chang (2002), NRC (2004) and H2A (2006a) can be found in appendix 1.

***Hydrogen from Dedicated Wind & Electrolysis – A Special Case?***

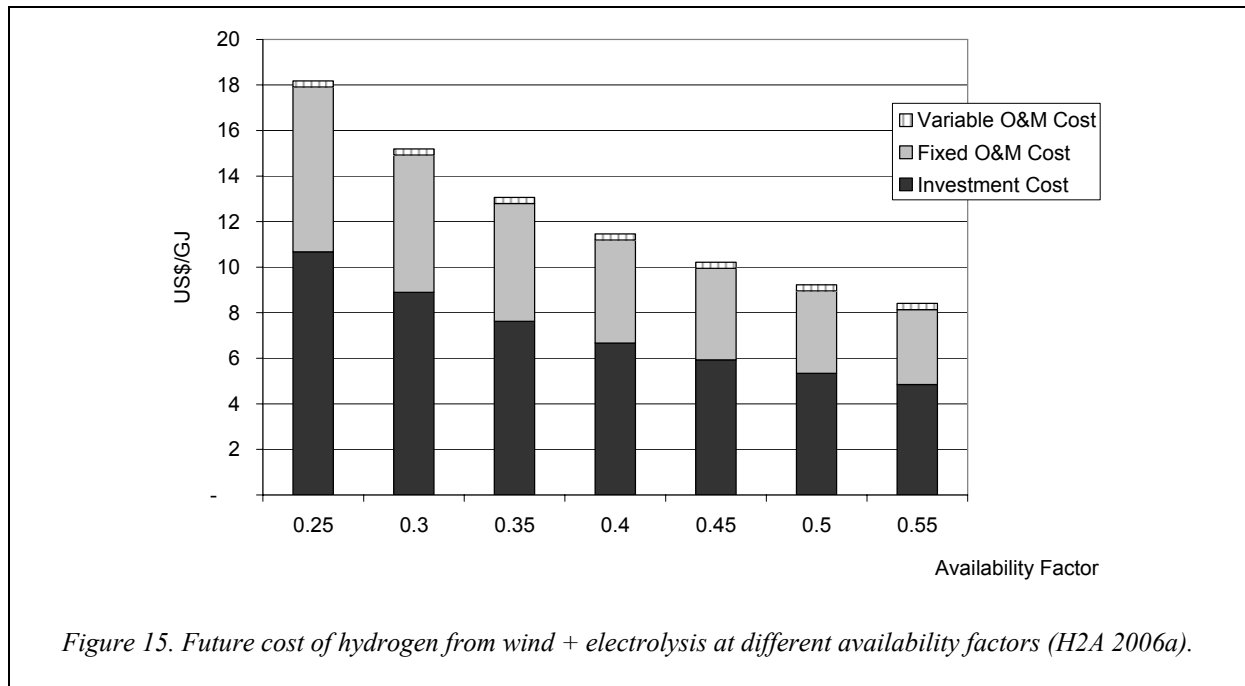
An interesting carbon-free option for hydrogen production is the coupling of wind power plants with electrolyzers. Considering the large-scale utilization of wind power in certain electricity markets such as Northern Germany or Denmark, the question of storage of excess wind power in times of low demand has attracted significant attention; storage of wind power as hydrogen, converted through electrolysis, is one of the options that could become promising in the future in tackling questions such as intermittency of some renewables. For a detailed analysis of intermittency related issues, see e.g. IEA (2005) and Gül and Stenzel (2006).

In aggregated models such as those used in this dissertation, it is not feasible to assess the interplay of wind power utilization and hydrogen production from excess wind generation satisfactorily. However, wind power plants and electrolyzers dedicated to produce hydrogen have been considered in this analysis.

In the studies reviewed here for the purpose of a hydrogen cost comparison, only H2A (2006a) considers large-scale central wind power parks dedicated to hydrogen production from electrolysis. This option is assessed to be highly promising and potentially cost-competitive given it comprises two components which still have somewhat significant potential to reduce their costs: the wind turbine and the electrolyser. However, key to success of this technology is the location of the wind park. The availability factor that underlies the analysis in H2A (2006a) is 54% for the case of future hydrogen production costs. Such an availability factor is to be expected in very few locations only, such as along coastlines e.g. at the Northern Sea in Europe.

In any case, it is clear that the costs of hydrogen from dedicated wind + electrolysis technologies will differ substantially depending on the wind availability at different sites. This is illustrated in Figure 15, where the costs of future hydrogen production from wind + electrolysis as assessed in the H2A dataset are varied with different availability factors.

For the aggregated models such as they are used in the analyses in the remainder of this dissertation, and in absence of a distinct wind speed distribution profile, an availability factor of 35% has been assumed for this technology.



### 3.1.3 Technologies for Hydrogen Distribution

Centrally produced hydrogen needs to be delivered to hydrogen fueling stations, i.e. to the point of hydrogen demand. The analysis in this thesis has been conducted with the H2A components model H2A (2006b), which is an excel-based spreadsheet model for the analysis and design of hydrogen delivery infrastructures. For the analysis, a demand for hydrogen of 250'000 kg of hydrogen per day has been assumed as a representative market size for hydrogen. A load centre of this size could be for example a city with about around 1 million inhabitants, if all hydrogen demand was from personal vehicles, and all personal vehicles were hydrogen fuelled vehicles.<sup>10</sup>

Moreover, a total delivery distance (one-way) of 80 km has been depicted. This number may naturally differ in reality; for the modelling analyses conducted in this thesis, it seems sufficient though to assess this distance as an average number given the aggregate nature of the applied models.

<sup>10</sup> In reality, load centre size could naturally have other sizes. The approach chosen here implies that if the load centre was "x times" larger, then "x times" the infrastructure needs to be constructed. Given the highly aggregate nature of applied models in this dissertation, this seems sufficient. However, an analysis on a more regional geographical level would need a more detailed assessment of infrastructure sizes on a case-by-case basis.



Five different possibilities for hydrogen delivery from central production facilities are considered:

1. delivery by *truck* in *gaseous* form with a *terminal onsite* of the hydrogen production facility for the handling of hydrogen (option 1);
2. delivery by *truck* in *liquid* form, with a *terminal onsite* of the hydrogen production facility for the handling of hydrogen (option 2);
3. delivery by *pipeline* using a system of transmission, trunk and delivery pipelines (option 3);
4. *combined systems* with *pipeline* delivery to a terminal at load centre's boundaries, and delivery by *truck* from the terminal in *gaseous* state to the fueling stations (option 4); and
5. *combined systems* with *pipeline* delivery to a terminal at load centre's boundaries, and delivery by *truck* from the terminal in *liquid* state to the fueling stations (option 5).

The general setup is depicted in Figure 16.

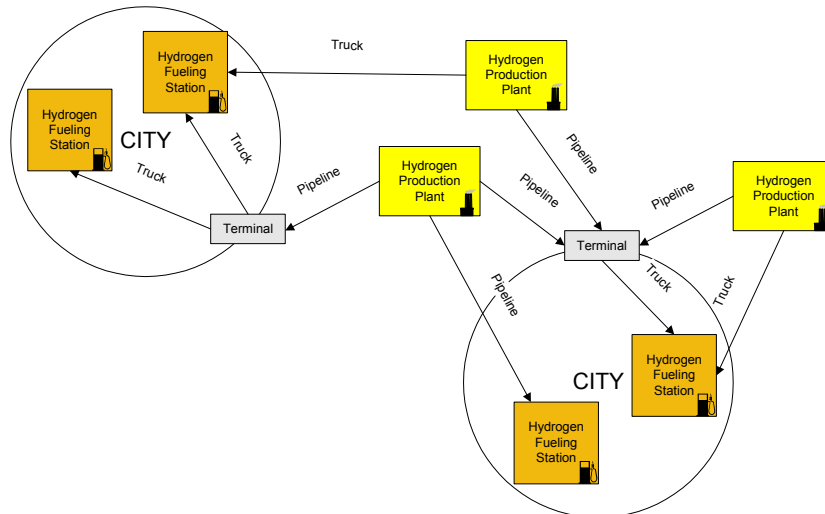


Figure 16. Hydrogen delivery infrastructures.

For a more convenient reading of this dissertation, the five different options will only be summarized briefly in the following. The interested reader is referred to appendix 2 for a more detailed analysis of technologies and costs for hydrogen delivery infrastructures.

### **Hydrogen Delivery by Truck (options 1 and 2)**

Hydrogen can be delivered by truck in either gaseous or liquid manner. The setup is as such that there is a terminal located onsite of the hydrogen production facility where hydrogen is compressed or liquefied for the distribution by truck to the fueling stations. Liquefiers, compressors and terminals are designed according to the individual output of the plants, and the round-trip travel distance of each individual truck corresponds to 160 km. Figure 17 gives an overview on the considered pathways.

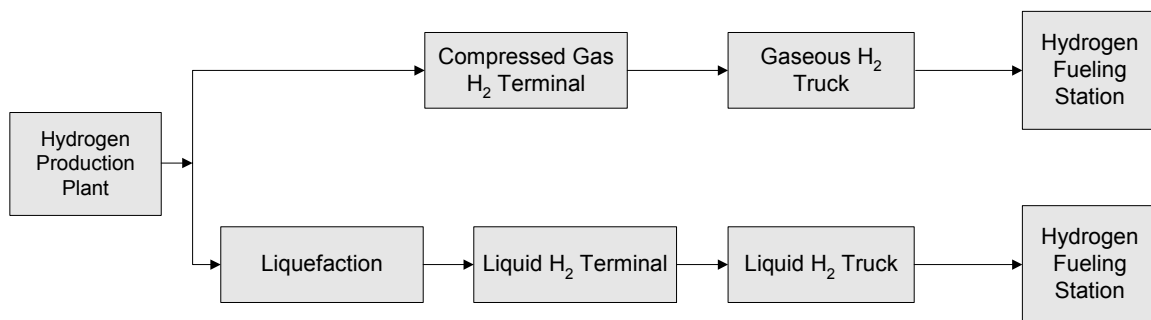


Figure 17. Hydrogen delivery by truck.

Truck delivery is the most flexible among all options presented here: hydrogen can be delivered to almost any place where there is demand, and is, thus, not restricted to one aggregated demand centre such as a larger city. With this delivery option it is therefore for example possible to deliver hydrogen to several smaller demand centres at a time, or to simply extend the number of trucks in operation in cases where demand is growing.

### **Hydrogen Delivery by Pipeline (option 3)**

Hydrogen can be compressed and delivered to demand centres by a system of transmission, trunk and delivery pipelines. Transmission pipelines serve for the bulk delivery of hydrogen from the production facility to the load centre's boundaries, i.e. the city gates. According to H2A (2006b), it is then expected to distribute hydrogen with two rings of trunk pipelines along ring roads. From the trunk pipelines, delivery pipelines branch off to distribute hydrogen to the fueling stations. Figure 18 presents a schematic sketch of the pipeline delivery pathway.

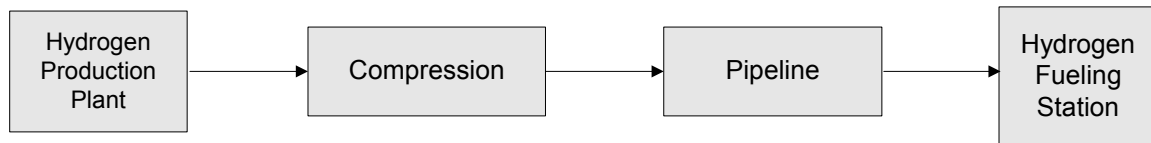


Figure 18. Hydrogen delivery by pipeline.

### Hydrogen Delivery by Combined Pipeline and Truck (options 4 and 5)

Besides direct delivery of hydrogen by truck or pipeline, there is the possibility of combining the two options. This means that hydrogen could be delivered by pipeline to a terminal located at the outer boundary of a load centre, from where hydrogen is distributed to the fueling stations by truck in either liquid or gaseous state (compare Figure 16). One main advantage is the possibility to take advantage of economical competitive pipelines in combination with the higher flexibility of truck delivery.

For the analysis conducted here, a hydrogen demand of 250'000 kg per day was depicted again. On this ground, a delivery network was developed to accommodate this demand. The total delivery distance of 80 km is broken up into 60 km pipeline delivery, and 40 km round-trip distance for truck delivery. Figure 19 displays the entire system.

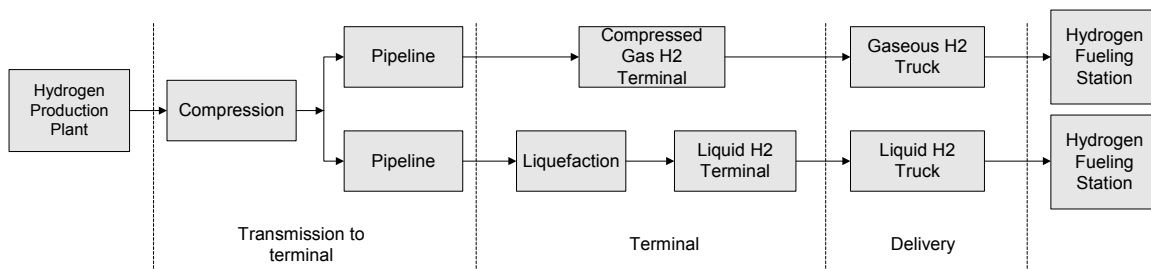


Figure 19. Flowchart of combined pipeline and truck delivery.

### Hydrogen Fueling Stations

Two sizes of fueling stations are considered in this analysis based on the H2A components model (H2A 2006b), distinguished by their peak design capacities of 100 kg H<sub>2</sub>/day and 1'500 kg H<sub>2</sub>/day respectively.

In addition to the size, fueling stations can be distinguished according to the physical condition of the delivered hydrogen, i.e. liquid or gaseous. Table 3 gives an overview

on which fueling stations are considered for which hydrogen delivery infrastructures. It shows that for option 1, i.e. gaseous truck delivery, only small fueling stations are used as one truck in H2A can carry only 9 tubes of hydrogen with a capacity of 31.15 kg/day each. The total amount of hydrogen delivered by one truck is, thus, not enough to satisfy the need of a fueling station. Consequently, the H2A model only allows combining gaseous truck delivery with small-scale fueling stations.

For option 2, i.e. liquid truck delivery, both fueling station sizes were considered as one liquid hydrogen truck delivers net 3'650 kg of hydrogen per trip. However, H2A (2006b) provides the possibility of serving up to 3 stations per trip only, which means in turn that if liquid truck delivery to small-size fueling stations is desired, then the number of trips per year per truck becomes very low, resulting in high cost per unit of hydrogen delivered to small fueling stations. This will be further elaborated in the cost section 3.1.4.

For options 3 to 5, i.e. pipeline networks and combined pipeline + truck delivery infrastructures with truck delivery in gaseous or liquid state, only large fueling stations were considered. This is due to the fact that these elaborated systems will require significant hydrogen demand within one load centre for their implementation. With significant demand, however, investments in large fueling stations become economically viable, thus justifying the choice of modelling delivery infrastructure options 3 to 5 with large fueling stations only.

*Table 3. Fueling stations considered for hydrogen delivery pathways.*

	Large fueling station 1500 kg / day		Small fueling station 100 kg / day	
	Liquid	Gaseous	Liquid	Gaseous
Truck delivery (Options 1 & 2)	X		X	X
Pipeline delivery (Option 3)		X		
Combined systems (Options 4 & 5)	X	X		

More details on the choice of hydrogen fueling stations can be found in appendix 2. Note that Baker (2005) suggests that in 2005, about 100 hydrogen fueling stations were in operation worldwide.

### 3.1.4 Cost of Hydrogen Distribution

As a general remark, there is a wide range of literature available on the delivery of hydrogen, and a lot of different viewpoints. This may be partly due to a lack of data, given the absence of significant real-world hydrogen delivery projects at the scale required for large-scale hydrogen deployment. In particular, there is some disagreement on the cost of delivering hydrogen by pipeline (see the discussion below). Moreover, the cost of delivering hydrogen in a liquid state by truck is widely debated, and generally, approaches to calculating hydrogen delivery costs differ.

Again it is emphasized that all modelling analyses of hydrogen delivery infrastructure conducted in this thesis are based on data from the H2A components model (H2A 2006b). Two key assumptions were chosen:

- the design demand of the load centre is 250'000 kg of hydrogen per day;
- a total delivery distance of 80 km (one-way) has been used; for combined pipeline + truck delivery, this distance has been split into 60 km pipeline and 20 km (one way) truck delivery.

For the modelling analyses, a detailed delivery network has been designed; the complete dataset for all hydrogen fuel chains, i.e. for each individual production facility is reported in appendix 3. Table 4 shows the total cost of hydrogen delivery infrastructures as designed for the case of coal gasification, distinguishing each option and the size of fueling stations considered (small fueling stations with a peak demand of 100 kg/day, and large fueling stations with a peak demand of 1'500 kg/day).

Note that for hydrogen delivery infrastructures, no explicit cost reductions were assumed in any modelling analysis of this thesis.

Table 4. Discounted cost of hydrogen delivery infrastructures for current coal gasification (H2A 2006b).<sup>11</sup>

Infrastructure Option	Efficiency	Investment Cost	Fixed O&M	Variable O&M	Electricity & Fuel Cost	Hydrogen Delivery Cost
	[%]	[US\$/GJ]				[US\$/GJ]
Truck gaseous, small fueling station	98.9	16.86	16.43	5.50	1.23	40.03
Truck liquid, small fueling station	82.2	24.16	15.25	2.97	3.00	45.38
Truck liquid, large fueling station	85.7	6.33	4.22	1.11	3.00	14.66
Pipeline, large fueling station	98.5	5.27	3.23	0.40	0.96	9.86
Pipeline + truck gaseous, large fueling station	97.9	8.34	7.14	1.27	0.70	17.46
Pipeline + truck liquid, large fueling station	84.8	6.80	4.78	1.02	3.15	15.76

The data shows a cost advantage for the delivery of hydrogen by pipeline ring systems to large hydrogen fueling stations. However, this delivery option will not be available without a significant hydrogen demand; therefore, truck delivery has its merits. Moreover, it needs to be noted that direct truck delivery as well as combined pipeline and truck delivery systems are comparatively easier to implement and extend with increasing demand than is direct pipeline delivery.

In terms of efficiency of hydrogen delivery, liquid hydrogen delivery is significantly less efficient than all compressed hydrogen gas delivery options. This is mainly related to significant tank unloading losses at the fueling station (assumed 6% of tank volume in H2A). Further details may be found in appendix 2.

In order to better understand the reasons for the observed cost differences, a more detailed look at the different components of each fuel chain is provided in Figure 20, which displays the costs of hydrogen delivery for the example of current coal gasification. In doing so, it further separates the costs of delivering hydrogen into its different components, i.e. handling (compression, liquefaction, terminal), delivery (truck, pipeline) and fueling stations (large, small). The detailed cost analysis can be found in appendix 2 of this thesis.

<sup>11</sup> Discount rate used: 5%. All costs reported are expressed in US\$ of the year 2000 using the U.S. Department of Labor's inflation calculator at <http://data.bls.gov/cgi-bin/cpicalc.pl> for conversion.

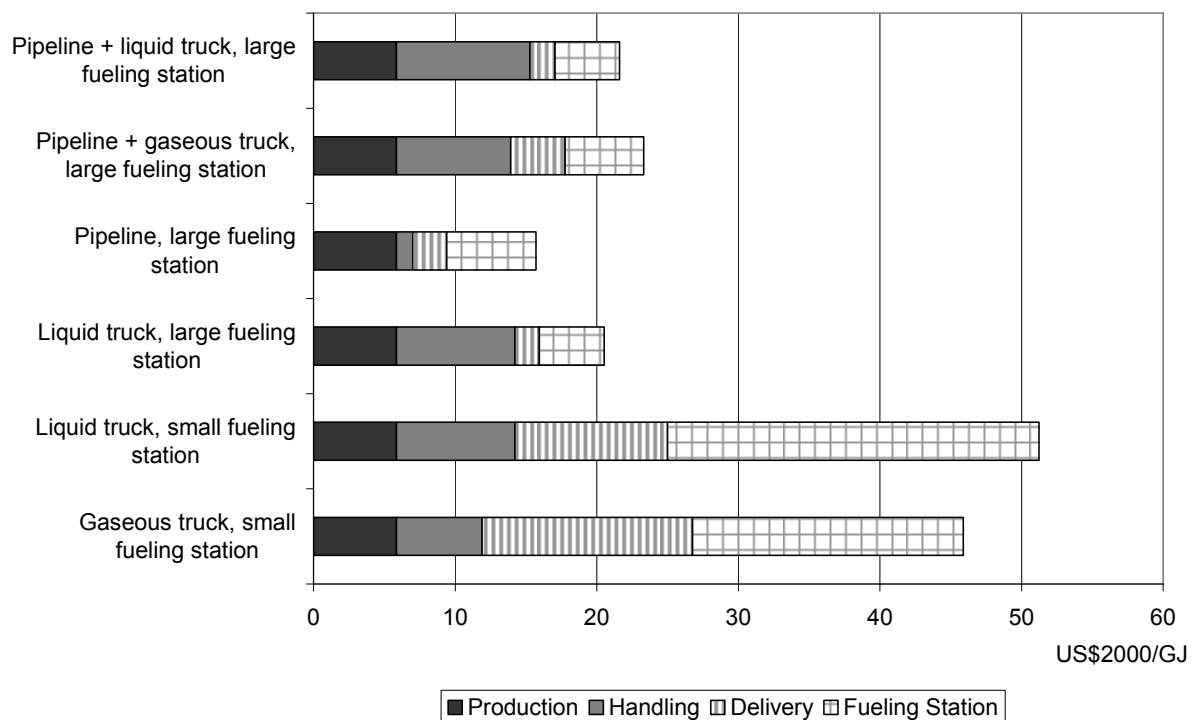


Figure 20. Comparison of hydrogen cost chains for current coal gasification (H2A 2006b).<sup>12</sup>

Before comparing the different fuel chains with each other, it is useful to remember that if the average cost of gasoline at fueling stations in the year 2005 was at about US\$ 0.5 /litre before taxes, this would convert to US\$ 14.8 /GJ. As Figure 20 shows, the analysis with the H2A components model suggests that if hydrogen can be produced at low cost, then the cost of hydrogen at the fueling station could be competitive with such gasoline cost if delivery takes place by pipeline. Nevertheless, the analysis also suggests that for hydrogen produced at such low cost, the delivery infrastructure at least doubles the cost of hydrogen at the fueling station, i.e. for low-cost hydrogen production, the delivery infrastructure is a very important cost factor.<sup>13</sup>

The comparison of individual hydrogen cost chains, then, reveals firstly a general cost advantage for large fueling stations. Fueling stations experience significant economies-of-scale, an observation that has been confirmed in other studies as well,

<sup>12</sup> All cost reported are expressed in US\$ of the year 2000 using the U.S. Department of Labor's inflation calculator at <http://data.bls.gov/cgi-bin/cpicalc.pl> for conversion. Cost of current coal gasification are based on H2A (2006), see appendix 1 for details.

<sup>13</sup> For understanding the magnitude of required investment, it is useful to know that total undiscounted investment cost for pipelines are in the order of US\$ 175 million. Additional investment for required 167 fueling stations is in the order of US\$ 255 million.

e.g. IEA (2005b). For gaseous hydrogen fueling stations, the analysis of H2A (2006b) showed considerable scale economies for the cost of hydrogen compressors, which are likely to be relatively cheaper if designed for larger flowrate. Similar observations were made for the case of liquid hydrogen fueling stations, where scale-economies do exist for hydrogen storage and pumps, and liquefaction gets cheaper the more hydrogen is liquefied (see also Syed et al. 1998). As O&M costs in the H2A components model are calculated in percent of capital investment, the impact of these scale economies is further pronounced. In addition, the size of fueling stations has an impact on the cost of delivering hydrogen by truck, as it is directly linked to the degree at which trucks are utilized.

Other than fueling stations, the cost of handling hydrogen is an important contributor to total fuel chain costs except in the case of pipeline delivery. There are two key reasons for this observation: on the one hand, all infrastructure options except for pipeline delivery networks require a terminal for loading and unloading of trucks that deliver hydrogen, which is an important cost factor. On the other hand, compression / liquefaction are more cost-intensive for truck delivery. Liquefaction requires significant electricity input, which is a key cost factor; and compressed gas delivery by truck takes place at higher pressure than pipeline delivery, thus also requiring higher electricity input for compression.

A comparison of the costs obtained from the H2A components model with other studies is difficult. The studies conducted by NRC (2004) and Simbeck and Chang (2002) also consider hydrogen delivery infrastructures, but neither in the same level of detail as applied in H2A (2006b), nor with assumptions that are comparable with those made in the H2A components model (e.g. assumed scale and distance of hydrogen delivery as well as assumed fueling station sizes). Nevertheless, one key difference between the studies is worth mentioning here, which is the cost of hydrogen delivery by pipeline. Pipelines are the cheapest option for hydrogen distribution both in NRC (2004) with US\$ 1.9 /GJ and H2A (2006b) with US\$ 2.4 /GJ, while they are not in Simbeck and Chang (2002), where they are as high as US\$ 13.5 /GJ. This is a difference by a factor of 7 between Simbeck and Chang (2002) and NRC (2004), even though both studies assume similar costs per km pipeline



(about US\$ 620'000 per km in Simbeck and Chang (2002), and US\$ 600'000 per km in NRC (2004)) and the same delivery distance (150 km).<sup>14</sup>

The key to understanding this difference is the throughput of pipelines: NRC (2004) apply pipelines for 1'200 t/day throughput, while Simbeck and Chang (2002) have designed the system for 150 t/day, and this difference by a factor of 8 is then partially reflected in hydrogen delivery costs per unit of energy given the fact that both studies calculate pipeline delivery costs on a per-km basis with similar relative costs, i.e. they assume the same cost per km for different capacity pipelines. However, Mintz *et al.* (2002) suggest that a doubling of pipeline diameter results roughly in a doubling of investment costs: thus, increasing throughput by a factor of 8 would result in a cost reduction by about a factor of 3 on a per-unit of energy basis, which should also be reflected in the cost differences between the two studies.

As this short discussion of data shows, there is considerable difference in how the cost of delivering hydrogen is assessed in literature. Further research will be required to get a clearer picture of the costs of delivering hydrogen. From the perspective of the author of this dissertation, the H2A components model is a very good starting point due to the transparency and consistency in applied assumptions as well as its flexibility, and it was thus chosen as the basis for modelling hydrogen infrastructure for the analyses in the remainder of this dissertation.

### 3.1.5 Forecourt Hydrogen Production

As an alternative to central hydrogen production facilities, forecourt hydrogen production could be important in particular in early phases of hydrogen penetration when demand for hydrogen is still low. Forecourt hydrogen refers to the production of hydrogen onsite at the demand centre, which could be a point of industrial hydrogen use, but in the context of this analysis is a fueling station.

Some of the technologies described in section 3.1.1 are particularly suitable for forecourt hydrogen production. In this thesis, four technologies have been considered as forecourt hydrogen production facilities, namely reforming of natural gas, gasoline and methanol, and alkaline water electrolysis. There is no fundamental technical

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<sup>14</sup> H2A (2006) uses a detailed analysis of pipeline costs in Parker (2005) who assessed hydrogen pipeline cost based on natural gas pipelines. The results of Parker (2005) are then additionally multiplied with a factor of 1.1.

difference between small decentralized production technologies and large-scale central production technologies among those considered here. Thus, no further technological description is provided here, and the interested reader is referred to section 3.1.1 for further details.

In terms of hydrogen production costs, however, differences between small- and large-scale production exist, particularly for natural gas reforming and electrolysis scale-economies can be significant (IEA 2005b). As an example, IEA (2005b) suggests that “high-capacity centralised electrolysis at high production volumes can result in a cost reduction factor of 2 to 5”.

Table 5 gives an overview on forecourt hydrogen production costs found in literature drawing on three key studies reviewed for this purpose.

Table 5. Range of forecourt hydrogen production costs in literature<sup>15</sup>

Technology	Status	Production Costs [US\$/GJ]		Conversion Efficiency [%]		No. of data sources
		Min	Max	Min	Max	
Natural gas reforming	current	20.5	37.0	58%	67%	4
	future	16.0	31.5	68%	78%	3
AW electrolysis	current	32.6	56.9	60%	61%	4
	future	19.9	37.2	71%	72%	3
Gasoline reforming	current	26.1	26.1	62%	62%	1
Methanol reforming	current	23.7	23.7	71%	71%	1

Data sources: H2A (2006a), NRC (2004), Simbeck and Chang (2002)

The observed differences for the cases of natural gas reforming as well as alkaline water electrolysis are explained mainly through the different scales applied: NRC (2004) applies a capacity of 480 kg of hydrogen per day, similar to Simbeck and

<sup>15</sup> All cost reported are expressed in US\$ of the year 2000 using the U.S. Department of Labor’s inflation calculator at <http://data.bls.gov/cgi-bin/cpicalc.pl> for conversion. Prices assumed for forecourt applications in this table only: natural gas 7.29 US\$/GJ (higher for forecourt applications), gasoline 6.01 US\$/GJ, methanol 6.51 US\$/GJ. These prices do not necessarily reflect modeling outcomes or recent price developments. Discount rate: 5%.

Chang (2002) who apply 470 kg. H<sub>2</sub>A (2006a), however, distinguishes two capacities of 100 kg and 1'500 kg of hydrogen per day.

Note that again and as for central hydrogen, current and future technology costs are considered where available. Future costs are understood as the technology potential, i.e. the cost that hydrogen production of the respective technologies can be reduced to in the future by around 2020 / 2030. The detailed cost data are available in appendix 1.

### **3.2 Biofuels Fuel Chains**

Among the new transportation fuels, biofuels are generally considered a highly promising alternative to oil products. Consequently, many states world-wide have adopted policies to support the market introduction of biofuels.

This section aims at assessing the cost of biofuels production and delivery to the fueling station. In doing so, it draws widely on a comprehensive literature review conducted by Martin Ragettli in the course of his Master thesis (Ragettli 2007). This work was pursued at the Energy Economics Group at Paul Scherrer Institute and was supervised by the author of this PhD thesis.

#### **3.2.1 Biofuels Production Technologies**

A variety of biofuels is currently being discussed for the use in transportation. They generally differ by the applied feedstock, the type of conversion process and the type of biofuels produced. Moreover, first as well as second generation biofuels are distinguished, with first generation biofuels currently available to the market, and second generation biofuels potentially available until the year 2020.

Given the high public attention that biofuels have received lately and the indeed pressing need for assessing the prospects of alternative transportation fuels, it does not come as a surprise that there is a considerable amount of literature available on this matter. A detailed description and analysis of biofuels production processes, however, is beyond the scope of this dissertation. The interested reader is, thus, referred to Ragettli (2007), who reviewed as many as 50 different biomass-to-biofuels

conversion process and analyzed technologies and costs in much detail. In this dissertation, only a brief summary of available and considered biofuels is provided in the following.

### **Biodiesel**

Biodiesel is after ethanol the most important biofuel globally today: in 2002, 1'503 million litres were produced, mostly in Europe (IEA 2005a). The term "biodiesel" commonly refers to fatty acid methyl esters (FAME), which can be produced from oil crops such as rapeseed or sunflowers through transesterification<sup>16</sup>. Biodiesel production through transesterification is a mature technology, such as that major improvements are not likely to be anticipated (IEA 2005a). The key advantage of biodiesel is the fact that it possesses similar fuel properties as diesel, and can, thus, be utilized in diesel engines without major adjustments to the engine. Moreover, biodiesel is basically free of sulphur, thus reducing the need for exhaust treatment. Blending of biodiesel with conventional diesel in any proportion is technically possible (Barnwal and Sharma 2005) as is flex-fuel use, i.e. alternate use of either conventional diesel or biodiesel (Kaltschmitt and Hartmann 2001), which has been demonstrated in Brazil.

While the use of biodiesel is highly attractive, the production has been criticized for example in the case of biodiesel derived from rapeseed, a process which is e.g. be used widely in Germany. Rapeseed requires a comparatively significant amount of nitrogen as fertilizer and is, thus, seen as critical from an ecological perspective (Kaltschmitt and Hartmann 2001).

An alternative to the production of biodiesel through transesterification is the pyrolysis of wood. In this process, thermal energy is used to split biomass and produce pyrolysis oil, which is generally applicable to the use in diesel engines (Ringer *et al.* 2006). However, as the heating value is lower than for conventional diesel, the volumetric use of biodiesel from pyrolysis is significantly higher, thus favouring its application in stationary diesel engines (Kaltschmitt and Hartmann 2001).

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<sup>16</sup> Transesterification is the decomposition of high-molecular Triglyceride to three lower-molecular compounds using excess alcohol such as methanol, as well as a catalyst.

**FT-Diesel**

FT-diesel is an acronym for Fischer-Tropsch diesel and was discovered by Fischer and Tropsch in 1923 already (Spath and Dayton 2003). The production of bio-FT-diesel involves a pre-treatment of biomass, gasification of biomass, gas-cleanup, the FT synthesis and finally a product upgrading step (Hamelinck *et al.* 2004). It is, thus, one way of using the synthetic gas (syngas) that is produced in biomass gasification, i.e. a process, which has been described already in section 3.1.1 for the production of hydrogen. In the synthesis step, the syngas is converted into a liquid fuel in presence of a catalyst, and the choice of catalyst and reactor type determines which fuel fraction (gasoline or diesel) is maximized (Spath and Dayton 2003).

FT-diesel can be blended into conventional diesel fuel even better than biodiesel from transesterification, as FT-diesel is slightly closer in composition to conventional diesel fuels (IEA 2005a). Naturally, it is also possible to use FT-diesel alone.

**Ethanol**

Ethanol is by far the most widely applied biofuel world-wide, mainly due to high production volumes in the United States and Brazil: in 2002, 21'841 million litre were produced and almost entirely in these two countries (IEA 2005a).

Key process to ethanol production today is the fermentation of sugar by enzymes and alcohol distillation. Accordingly, biological feedstocks applied to producing ethanol contain significant amounts of sugar or materials, which can be converted into sugar such as starch or cellulose. The type of feedstock used determines the type and extent of feedstock pre-treatment required (IEA 2005a), and the most simple way of producing ethanol is the direct fermentation of sugar-containing materials such as sugar cane or sugar beet. Sugar cane is especially used in Brazil and in most tropical countries, where it is abundantly available. The United States and Europe focus more on converting the starch component of grain crops such as corn or wheat to sugars (IEA 2005a).

Current research aims at utilizing cellulosic materials to create fermentable sugars. This has several advantages, among others the fact that ethanol production of grain crops can be achieved more efficiently by not only using the small starchy products of the plant, but also the remaining cellulosic materials. Moreover, it allows access to a wider range of possible feedstock, thus allowing for higher ethanol production

levels (IEA 2005a), and could additionally lower potential conflicts with food production by utilizing the entire feedstock.

One key advantage of ethanol as a transportation fuel is that it can be used in blends in existing gasoline vehicles; for this reason, efforts to newly introduce ethanol into fuel markets have focused on low-percentage blends such as E10, which is a 10% ethanol and 90% gasoline blend (IEA 2006a).

### ***Methanol and Dimethyl Ether (DME)***

While most of global methanol production today makes use of a syngas produced from natural gas reforming (Spath and Dayton 2003), the syngas can also be provided from the gasification of biomass – yet another application of the gasification process described in section 3.1.1. Key to the production, then, is a methanol conversion step, where methanol is produced from syngas in presence of a catalyst (Spath and Dayton 2003).

While methanol today is mostly used in the chemical industry, it can also be used as an alternative transportation fuel in spark-ignition engines directly. However, since methanol is not miscible with hydrocarbons, blending with gasoline is not possible (IEA 2006a).

Another possibility of using methanol is dehydrating to dimethyl ether (DME), which is suitable for the use in slightly-adjusted diesel engines due to its excellent combustion properties and good energy density; nevertheless, production volumes are still low (IEA 2006a). Alternatively, DME can also be produced directly out of the syngas derived from the gasification stage, and the synthesis process is very similar to methanol synthesis (Edwards *et al.* 2007a).

### ***Bio-Synthetic Natural Gas (Bio-SNG)***

Bio-synthetic natural gas (bio-SNG) is a synthetic natural gas produced from biomass. Two main production routes can be distinguished: firstly, bio-SNG can be derived through anaerobic fermentation of organic matter, mostly manure or waste. This bio-SNG is often referred to as “biogas” and is today mostly used for heat and power production. Nevertheless, developments towards larger plant concepts with the perspective of producing a synthetic natural gas as transportation fuel exist, e.g. in Scandinavia (Edwards *et al.* 2007a).

Secondly, producing bio-SNG from wood through gasification is investigated at Paul Scherrer Institute in Switzerland and has been proven to significantly reduce overall ecological impacts and external costs when substituting oil-based fuels in transportation (Felder and Dones 2007).

### 3.2.2 Biofuels Production Costs

Given the high number of studies available on the production of biofuels, it does not come as a surprise that a wide range of cost has been identified. A detailed breakdown of cost estimates in the various studies is beyond the scope of this thesis, and can be found in (Ragettli 2007). For the purpose of cost comparison in this chapter, assumptions with regard to discount rate (5%) and biomass feedstock cost were harmonized. For the latter, two different cost categories for six types of biomass are distinguished here, as depicted in Table 6. Reported costs are based on the study of (Ragettli 2007) and are weighted averages for the years 2000-2003 from the Food and Agricultural Organization (FAO) of the United Nations (FAO 2006), including the costs of truck transport to the plant gate.<sup>17</sup>

*Table 6. Low and high costs for various biomass types (FAO 2006; Ragettli 2007).*

<b>Biomass Type</b>	<b>Low cost biomass [US\$ / GJ]</b>	<b>High cost biomass [US\$ / GJ]</b>
Rapeseed / sunflower	7.90	8.44
Wood	1.67	3.10
Waste / manure	1.79	3.22
Corn grains	6.54	6.71
Sugar beet / sugar cane	1.92	10.32
Stover	1.72	3.15

Table 7 provides an overview of biomass-to-biofuels conversion processes and the range of costs and efficiencies identified using the low and high biomass costs introduced above.

<sup>17</sup> Assumed truck delivery distance 50 km. Low cost biomass corresponds to the weighted average of costs in Latin America, Africa and the Middle East as calculated in Ragettli (2007); high cost biomass correspond to the weighted average cost in Western Europe (EU-25 plus Norway and Switzerland).

Table 7. Range of biofuels production costs in literature (adjusted and extended from Ragettli 2007).<sup>18</sup>

Biofuel	Generation	Feedstock	Conversion process	Conversion efficiency [%]		Production cost with low-cost biomass [US\$/GJ]		Production cost with high cost biomass [US\$/GJ]		No. of data sources
				Min	Max	Min	Max	Min	Max	
Biodiesel	1 <sup>st</sup>	Rapeseed / sunflower	Trans-esterification	54.4%	59.7%	10.6	11.7	11.4	12.6	6
	2 <sup>nd</sup>	Wood	Pyrolysis	56.0%	56.0%	8.7	8.7	11.2	11.2	1
FT-Diesel	2 <sup>nd</sup>	Wood	Gasification	43.0%	53.7%	5.9	14.6	10.5	17.6	7
Ethanol	1 <sup>st</sup>	Corn grains	Fermentation	34.3%	44.2%	14.6	20.5	14.9	20.9	9
	1 <sup>st</sup>	Sugar beet / sugar cane	Fermentation	44.4%	65.1%	5.2	15.0	20.7	30.5	3
	2 <sup>nd</sup>	Wood / stover	Pre-hydrolysis & fermentation	32.6%	58.1% <sup>19</sup>	4.7	13.7	7.3	18.4	9
Methanol	2 <sup>nd</sup>	Wood	Gasification	48.9%	65.4%	2.3	9.9	7.1	12.8	9
DME <sup>20</sup>	2 <sup>nd</sup>	Wood	Gasification	48.8%	67.0%	5.1	10.6	7.2	13.4	3
Bio SNG	1 <sup>st</sup>	Manure / waste	Anaerobic digestion	61.4%	61.4%	12.6	14.8	15.4	19.1	2
	2 <sup>nd</sup>	Wood	Gasification	54.3%	54.3%	8.9	8.9	11.5	11.5	1

As evident from the literature review, there is a high level of uncertainty involved with cost and efficiencies especially of second generation biofuels. While this is somewhat self-explanatory given their early stage of commercialization, there are two key reasons behind the observed differences: scale-economies and by-product credits.

- As in the case of hydrogen, the question of scale economies is a key difference. Ragettli (2007) found capacities varying across all biofuels from 3 MW<sub>th</sub> up to 2000 MW<sub>th</sub>.
- Along with the installed capacity goes the question of by-products. Some studies tend to design processes more as biomass-to-electricity conversion processes, where biofuels are actually the by-product rather the main output of the plant. This clearly brings along competitive advantages in early stages of biofuels deployment with insufficient demand for biofuels. Nevertheless, if

<sup>18</sup> All costs reported are expressed in US\$ of the year 2000 using the U.S. Department of Labor's inflation calculator at <http://data.bls.gov/cgi-bin/cpicalc.pl> for conversion. This table uses a discount rate of 5%, electricity costs = US\$12/GJ, natural gas price = US\$4.6/GJ. All other details can be found in Ragettli (2007).

<sup>19</sup> The analysis of Ragettli (2007) suggests that higher maximum overall efficiencies are possible for 2<sup>nd</sup> generation ethanol. As the obtained value was deemed very high, it was, however, excluded here.

<sup>20</sup> DME = dimethyl ether



biofuels were to become a major replacement for petroleum fuels, the limited availability of biomass would favour the use of dedicated biofuels production plants. Other by-products commonly considered in such studies include for example heat or animal feed.

The differences in economies of scale as well as by-product generation make up for most of the observed uncertainty: the more by-products produced, the more efficient is the use of biomass in the conversion process.

Finally, the distinction between low and high cost biomass in Table 7 clearly emphasizes how the costs of biofuels are directly related to the availability of low cost biomass. This is particularly evident for the case of ethanol from sugar beet / sugar cane, where significant differences in biomass costs result in significantly different ethanol production costs. Whether or not biofuels can be cost-competitive as a fuel for transport is, thus, inevitably linked to regional conditions, i.e. how much biomass is available for energy purpose, and at which costs.

### 3.2.3 Biofuels Delivery Costs

Just as with hydrogen, biofuels need to be delivered from the production facility to fueling stations. However, as opposed to the in-depth analysis of delivery infrastructure for hydrogen above, no attempt has been made to conduct a similar analysis of infrastructure for biofuels due to a lack of literature on this topic. Instead, distribution costs for biofuels were derived from IEA (1999) and are depicted in Table 8.

*Table 8. Biofuels distribution costs.*

Biofuel	Distribution costs [US\$/GJ]
Biodiesel	3.49
Dimethyesther	8.40
Ethanol	5.27
Methanol	6.06
Bio-SNG <sup>21</sup>	8.40

<sup>21</sup> Costs are assumed the same as for DME.

### **3.3 Personal Transport**

The following sections present an overview of the various alternatives, followed by an assessment of costs and efficiencies.

#### **3.3.1 Technologies in Personal Transport**

There is a wide variety of technology options, and not all of them can be considered in this analysis. This dissertation considers technologies, which are technically proven, i.e. are either in operation already, close to market introduction, or are technically proven but still facing a number of challenges to become commercially viable. In doing so, some more speculative innovations in engine technologies (such as large flywheels or compressed air) were neglected.

##### ***Internal Combustion Engine Vehicles (ICEVs)***

Internal combustion engines (ICEs) are the dominant engine technology in personal transport today and power almost all vehicles on the global market. Developed for transportation in the course of the 19<sup>th</sup> century, they have ever since undergone massive improvements with regard to performance (efficiency, weight), and due to continuous R&D efforts can be expected to sustain an important role in transport during the decades to come.

ICEs induce fuel combustion either through spark or through compression, but the usually gasoline-fuelled spark ignition engines today are globally more widely applied than diesel-fuelled compression engines. This is mainly a result of lower cost as well as smaller, lighter and quieter engines (Turton 2006), even though fuel efficiencies are commonly somewhat lower. Only in some European countries such as Germany, diesel-fuelled compression engines make up for significant shares in personal transport. The application of diesel engines is, thus, more common in freight transport or in ship engines.

However, recent developments in Europe indicate an increasing role for diesel engines in personal transport, mainly as a result of tax exemptions, but also because of better fuel economies, which offset higher purchase cost for diesel ICEVs over their lifetime if fuel prices get high enough (Pock 2007).

ICE vehicles are also available in non-petroleum fuel configurations, i.e. they run on alternative fuels such as compressed natural gas (CNG) or biofuels. While CNG contributed 3.2% to final consumption in transport in OECD-countries (IEA 2006a), the use of biofuels – particularly ethanol – on a larger scale has so far been restricted to Brazil and is developing strongly in the United States. In Europe, countries such as Germany have been supporting biodiesel from rapeseed (compare section 3.2).

### ***Electric vehicles***

Electric vehicles are powered by an electric motor rather than by combustion engines. Rechargeable batteries deliver power to a controller, which then directs power to the electric motor (IEA 2006a).

Battery vehicles can achieve high levels of efficiency and produce no tailpipe emissions. However, emissions may occur on a well-to-wheel basis depending on the source of electricity. A number of battery technologies is available or under development, but key concern to the application of battery vehicles is the driving range of electric cars built to date. Current generation battery vehicles are applicable for urban use only (IEA 2006a). Other key challenges in battery research include operating temperature and high purchasing costs. Significant improvements have been made with regard to lifetime of batteries, but it remains a key challenge as well (Chalk and Miller 2006).

Using electric cars on a large scale and in a similar way as today's oil products ICEVs, however, is challenging. Today's battery technology does not allow for quick recharging at recharging stations. Unless quick-loading batteries are available, travelling distances longer than the battery's driving range will be challenging and requires different ways of "fueling". The solution for this, however, may not be so "new": much as horses were formerly changed at post-houses, batteries could be replaced at service stations along highways with charged ones, treating the battery as a kind of energy tank and recharging the replaced battery for the next customer. For the moment, however, this concept is limited by high battery costs, battery lifetime and heavy weight (IEA 2006a).

**Hybrid ICE-electric vehicles (HEVs)**

The term “hybrid” in general refers to any vehicle that can use various different sources of energy in combination (IEA 2006a). It is, however, common practice to refer to hybrids when meaning the combination of internal combustion engine and battery in one drivetrain, i.e. hybrid ICE-electric vehicles (HEVs).

Hybrid ICE-electric drivetrains can be distinguished according to how they deliver energy to the transmission. In *series* hybrids, an electric motor drives the wheels and derives its energy from a battery or an engine (ICE), which is used as a power generator. The ICE supplies the average power required to operate the vehicle, while the battery stores the excess energy and provides it when necessary; regenerative breaking can be used to improve efficiency. Such series hybrids are best suited for vehicles where driving cycles do not vary much, e.g. in urban buses (IEA 2006a).

Common technology in personal transport is the *parallel* hybrid, where both ICE and an electric motor can deliver energy for motion. In “mild” parallel hybrids, an electric motor acts as a starter and can serve as an alternator during breaking (regenerative breaking), while an ICE powers the motion. There are cars on the market that incorporate this starter-alternator technology without being advertised as hybrid vehicles such as the Citroen C3 Stop and Start. Fuel economy benefits occur mainly in urban drive cycles (IEA 2006a).

“Full” hybrids are those that are commonly advertised as hybrid ICE-electric vehicles. They can operate in internal-combustion mode, in hybrid mode or in all-electric mode for as long as enough battery energy is available. Batteries are recharged during periods of ICE driving or through regenerative breaking (IEA 2006a). The extent to which fuel economy gains occur relies largely on how the vehicle is utilized: in rural and highway driving, the vehicle will almost entirely operate in ICE mode, while in urban driving the electric motor will take over; in any case, efficiency gains can be very significant. Nevertheless, hybrid driving is also very sensitive to the operator’s driving style, and smoothly-driven full hybrids can reduce fuel consumption considerably (IEA 2006a).

One of the most successful manufacturers of hybrid ICE-electric vehicles is Toyota. In May 2007, Toyota announced that global cumulative sales passed 1 million vehicles.<sup>22</sup> Main vehicle sold is the Toyota Prius, which was launched in 1997.

Even though today, only gasoline-fuelled HEVs are available to the market, there is nothing that speaks against the use of other fuels or the diesel compression engine in hybrid electric-ICE operation. Diesel-, natural-gas-, biofuels- or hydrogen-fuelled HEVs are as possible as are gasoline-fuelled HEVs.

### ***Plug-in Hybrids***

Plug-in hybrids are hybrid ICE-electric vehicles with the ability to recharge the battery from the grid rather than from operating the ICE. Plug-in hybrids would be endowed with modest electric driving range for short distance driving, mainly due to cost considerations (Kromer and Heywood 2007). The share of fuel and electricity use will depend on the driving range required and on the battery's storage capacity; however, as most of the drivers use their vehicles mainly for short distances, the share of electricity could potentially become very high (IEA 2006a).

Plug-in hybrids are attractive technologies in a variety of ways beyond the reduction of fuel economies. In particular, the fact that they could potentially act as storage medium for electricity grids when parked and during battery recharge is highly promising. Storage of electricity is still a problem in today's electricity grids, and could be even more so with higher utilization of renewable energies. Nevertheless, there are bottlenecks to a widespread utilization of this technology as well other than cost, which will be discussed in the following section. These bottlenecks include e.g. the need for widespread recharge stations. In order to fully exploit the benefit of plug-in hybrids with regard to fuel economy, any parking lot would ideally be equipped with plugs. While this will take efforts, it is not totally infeasible: in northern Scandinavia, for example, many parking lots are equipped as such in order to deal with vehicle starting during extreme coldness.

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<sup>22</sup> Compare [http://www.hybrid-zukunft.at/hybrid\\_news.php](http://www.hybrid-zukunft.at/hybrid_news.php). Accessed March 15, 2008.

### Fuel Cell Vehicles

Hydrogen-powered fuel cell vehicles (FCVs) have received a great deal of attention over the past 10 to 15 years. Main car manufacturers such as Daimler-Benz moved into this market in the 1990's by implementing ambitious R&D programmes. Public perception of hydrogen FCVs has been facing ups and downs during this time: around the time that Daimler announced its R&D efforts, there was a considerable hype for hydrogen FCVs and hydrogen was deemed *the* solution for future transportation. In recent years, however, public opinion has somewhat reversed and attention focused more on biofuels. Key reasons include the cost of the fuel cell, questions of hydrogen (on-board) storage and hydrogen safety.

Fuel cells are electrochemical devices that convert hydrogen and oxygen into water and produce electricity. The most investigated fuel cell for this purpose is the Proton Exchange Membrane Fuel Cell (PEMFC). Its key advantage is that it delivers high power density at low weight and volume, operates at low temperatures of around 80°C and reaches high electrical efficiencies (Abhari 2005). It applies a mixture of hydrogen and oxygen/air as input. Table 9 provides an overview on some of the main properties of PEMFCs and their consequences for their application.

Table 9. Properties of PEMFCs and consequences (Sources: Abhari 2005; Krewitt and Schmid 2004)

Properties	Consequences
Low-temperature operation	<p>Fast-start capability for application in vehicles</p> <p>Sensitive to CO production, which binds strongly to Platinum at temperatures below 150°C<sup>23</sup></p>
Delivers high power density	<p>Fast-start capability for application in vehicles</p> <p>Compact and lightweight cell</p>
Works in any orientation	Suitable for vehicles and mobile applications
Anode-electrolyte-cathode assembly is very thin	Compact stack
Catalyst Platinum required to promote reaction	High capital costs
No corrosive fluid hazard	Environmental benign, good durability

<sup>23</sup> CO = carbon monoxide

PEMFCs consist of two porous carbon electrodes with a platinum catalyst and a solid proton conducting membrane pressed between them, acting as the electrolyte. RD&D efforts nowadays concentrate on developing new, high-temperature membrane materials in order to decrease sensitivity to poisoning and to enable on-board reforming. Additionally, the need for large cooling systems to avoid overheating of the fuel cell could be eliminated.

For the application of fuel cells in cars, a number of different settings is potentially feasible. Firstly, hybridization with batteries similar to hybrid ICE-electric vehicles offers an attractive opportunity to increase the vehicle's on-road efficiency by making use of regenerative braking and operating the fuel cell at high-efficiency points on its operating curve (Kromer and Heywood 2007). The degree of hybridization, however, is ultimately a question of costs, and the choice will depend on whether batteries or fuel cells get cheaper on a per kilowatt basis.

Secondly, fuel cell vehicles can be thought of as "pure" hydrogen fuel cell vehicles with hydrogen being stored on-board of the vehicle; or, alternatively, fuel cell vehicles could be fuelled by hydrogen-rich fuels, which are then reformed on-board of the vehicle. For the latter option, the attractiveness lies in that it avoids the large upfront need for hydrogen fuel infrastructures. FCVs making use for example of on-board gasoline reforming could easily be integrated into today's fueling station infrastructure. With the high-efficiency of fuel cells, there is the potential to reduce CO<sub>2</sub> emissions from transport despite the fact that on-board reforming decreases overall system efficiency compared to the "pure" hydrogen option (Turton 2006).

Despite this advantage, there is a sense that on-board reforming does not make much sense due to the described efficiency losses, considerable higher complexity, the associated costs and because fuel impurities tend to poison the fuel cell catalyst (Kromer and Heywood 2007). Thus, the focus in recent years has been more on the utilization of "pure" hydrogen FCVs, which, ultimately, needs to be the way to go if a transition to a "hydrogen economy" is the desired way of transforming the energy system.

Key to the utilization of the "pure" hydrogen option is on-board storage. Hydrogen has a high energy density per unit of weight, but a very low one per unit of volume, thus requiring significantly larger storage tanks to produce the same amount of

energy as for example gasoline. On-board storage, in principal, can take place in three different ways: as compressed gaseous hydrogen, as liquefied hydrogen or as hydrogen absorbed in solid materials such as hydrides or high-surface materials (von Helmholtz and Eberle 2007). For the latter, there is still considerable need for R&D (IEA 2006b). Liquefied hydrogen storage suffers from significant energy input requirement for liquefaction and problems with boil-off, making the compression of gaseous hydrogen the technology of choice for the moment, despite the fact that this will require large storage tanks. Gaseous storage in a 700 bar tank of 150 litre size can be expected to meet the required travel distance of 450 to 600 km (Kromer and Heywood 2007).

### 3.3.2 Vehicle Specifications

Improving vehicle efficiency is one of the keys to reducing CO<sub>2</sub> emissions in personal transport in the short-term. It is, thus, important to assess the potential of different technologies to realize efficiency improvements in the years to come, and to then understand the impact of such efficiency improvements on the competitiveness of different drivetrains and fuels under various policy regimes in meeting the needs of the 21<sup>st</sup> century.

Tank-to-wheel efficiencies and efficiency improvements of new vehicles in this dissertation were derived from Edwards *et al.* (2007), Kromer and Heywood (2007), Kasseris and Heywood (2007) and Turton (2006) and are complemented by own assumptions, as depicted in Table 10. In this dissertation it is tried to make use of efficiency improvements only that are somewhat “expected” to take place from today’s perspective. This means that no additional assumptions beyond anticipated efficiency targets in above literature were applied. It is, thus, assumed that most significant efficiency improvements take place until 2030; thereafter, all efficiencies have been kept constant.

Most vehicle efficiencies found in above literature are driving-cycle efficiencies. In order to adjust them to road traffic conditions, a simple approach was used suggested by Smokers *et al.* (2006), who propose a factor of 1.195 for the adjustment.



Table 10. Efficiency improvements of personal vehicles [MJ/vehicle-km].

Vehicles <sup>24</sup>	Fuel Input	2010	2020	2030
Gasoline ICEV advanced	Gasoline	2.27	2.14	2.01
Diesel ICEV advanced	Diesel	2.11	1.92	1.72
Natural gas ICEV	Natural gas	2.24	2.12	2.01
Biodiesel ICEV	Biodiesel	2.11	1.96	1.72
Bio-SNG ICEV	Bio-SNG	2.24	2.12	2.01
Methanol ICEV	Methanol	2.27	2.14	2.01
Ethanol ICEV	Ethanol	2.27	2.14	2.01
Oil products ICE-electric hybrid	Oil products	1.84	1.47	1.10
Natural gas ICE-electric hybrid	Natural gas	1.67	1.37	1.08
Biofuels ICE-electric hybrid	Biofuels	1.84	1.47	1.10
Hydrogen ICE-electric hybrid	Hydrogen	1.77	1.43	1.09
H2 fuel cell & battery hybrid	Hydrogen	1.00	0.94	0.88
Gasoline ATR-FC & battery hybrid	Gasoline	1.94	1.79	1.63
Plug-in hybrid	Electricity	0.25	0.24	0.23
	Gasoline	0.98	0.78	0.59
Battery electric vehicle	Electricity	0.71	0.68	0.65

Table 10 shows the impact of efficiency improvements for advanced ICEVs that can be expected in the coming 20 years due to improved engine efficiency, reduced vehicle weight or rolling resistance. Even more efficiency improvements are anticipated for hybrid vehicles.

As Table 10 also indicates, it was assumed that all new vehicles are available to the market as of the year 2010, independent of their current degree of maturity.<sup>25</sup> For the use of alternative fuels in vehicles, it was assumed that vehicle efficiencies of alternative fuel vehicles in the long-run are similar to those using conventional petroleum products.

### 3.3.3 Costs of Personal Transport

Personal transportation in this dissertation is treated using “generic” vehicles, i.e. no distinction is made between different vehicle sizes, and average annual mileages are assumed for all vehicles. The reason is that the intention of this analysis is to get a better sense of the competitiveness of alternative fuels and advanced engine

<sup>24</sup> ICEV = Internal Combustion Engine Vehicle; Bio-SNG = Bio Synthetic Natural Gas; ATR-FC = Autothermal Reforming – Fuel Cell.

<sup>25</sup> Obviously, the maximum cumulative number of new vehicles available as of 2010 has been varied in the modelling analyses. This idea will be introduced in the introduction to the model results in chapters 4 and 5.

technologies under different policy regimes only rather than to identify market segments for fuels or engine concepts.

For personal vehicles, it is possible to distinguish between learning and non-learning components. Learning components are those which are expected to undergo significant cost reductions after their initial commercialization, whereas any possible cost reductions of non-learning components are deemed less pronounced. Non-learning components, thus, comprise mature components such as engine / transmission, electric motor / controller, fuel tank, exhaust system, wiring and charger for battery vehicles. Learning components include batteries, fuel cells and the on-board reformer for fuel processing for the use in gasoline-based fuel cell vehicles with on-board reforming.

Most of cost data are based on Kromer and Heywood (2007) and Kasseris and Heywood (2007) and were obtained in the context of a project of the Alliance for Global Sustainability (AGS) with the Massachusetts Institute of Technology (MIT). The data was complemented by Turton (2006) and by own assumptions where appropriate. Table 11 summarizes the cost of non-learning components and the cost for the balance of the vehicle, which is assumed to be US\$ 15'000.

Table 11. Cost of non-learning components of personal vehicles [US\$ / vehicle].

Vehicles	Year	Drive Train			Storage Fuel Tank System	Miscellaneous				Rest of Car	Total
		Base Cost: Engine / Transmission	Motor / Controller	Engine / Transmission additional		Exhaust	Wiring etc.	Charger	Fuel Cell additional	Processor additional	
Gasoline Advanced ICEV	2010	3000			100						18100
	2030	3700			100						18800
Diesel Advanced ICEV	2010	3000		1400	100	500					20000
	2030	3700		700	100	500					20000
Natural Gas ICEV	2010	3000			1000						19000
	2030	3700			500						19200
Biodiesel ICEV	2010	3000		1400	100	100					19600
	2030	3700		700	100	100					19600
Bio-SNG ICEV	2010	3000			1000						19000
	2030	3700			500						19200
Methanol ICEV	2010	3000			100						18100
	2030	3700			100						18800
Ethanol ICEV	2010	3000			100						18100
	2030	3700			100						18800
Oil Products & Syntfuels HEV	2010	3700	600	200	100		200				19800
	2010	3700	600	200	400		200				20100
Natural Gas HEV	2010	3700	600	200	100		200				19800
	2010	3700	600	200	2200		200				21900
Hydrogen HEV	2010	0	1400	200	1700	-300	200				18200
	2010	0	1400	200	100	-100	200		1000	800	18600
Petroleum ATR-FC HEV	2010	3700	800	100	100		200	400			20300
	2010	0	1400	200	100		200				16900
Plug-In Hybrid Vehicle	2010	3700	800	100	100		200	400			20300
Battery Electric Vehicle	2010	0	1400	200	0	-300	200	400			16900

In Table 12, initial costs of learning components at market introduction, as well as anticipated floor costs are presented, i.e. the lowest cost each technology is assumed to be able to achieve. Initial and floor costs assumptions were derived within the same AGS project mentioned above and are, thus, based on Kromer and Heywood (2007).

Table 12. Cost of learning components for personal vehicles.

Technology	Size	Initial Cost	Floor Cost	
Fuel Cell	40 kW	250	50	US\$/kW
Reformer	40 kW	90	25	US\$/kW
Hybrid Battery System	28 kW	2'500	800	US\$/vehicle
Fuel Cell Battery System	42 kW	3'250	1'200	US\$/vehicle
Battery Electric	48 kWh	16'250	12'000	US\$/vehicle
Plug-in Hybrid	8.2 kWh	6'500	2'800	US\$/vehicle

While there is some consensus on current and future cost of hybrid battery systems – the figures here are roughly in line with various literature sources such as Ogden *et al.* (2004) or Bitsche and Gutmann (2004) – this is not the case for fuel cells. Firstly, there is quite some debate in literature on what are the *current* costs of the fuel cell, and the key to understanding the enormous differences in current costs of the fuel cell is the issue of mass production. At the extremes, there is on the one hand e.g. a study by Tsuchiya and Kobayashi (2004), which assesses current costs of manually manufactured Proton Exchange Membrane (PEM) fuel cells to be in the order of US\$ 1'800 /kW. A breakdown of these costs is depicted in Figure 21.

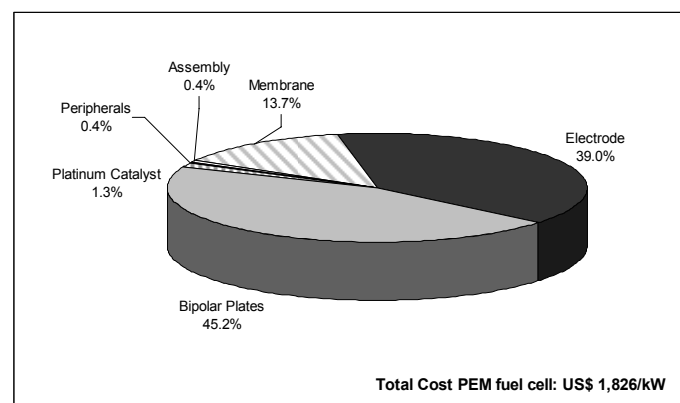


Figure 21. Current cost of a manually produced PEM fuel cell (Tsuchiya and Kobayashi 2004).

This cost assessment can be thought of as in line with current production volumes of hydrogen fuel cells: the International Energy Agency reports recent production volumes of hydrogen fuel cell vehicles to be in the order of 200 vehicles per year only (IEA 2005b). Experts suggest that currently around 300 to 400 hydrogen fuel cell vehicles are in operation (Büchi 2008). Neither of these figures falls into the category “mass production”.

On the other hand, i.e. on the other side of extremes, there is a study by Carlson *et al.* (2005), which suggests that the cost for a fuel cell system using year 2005 technology is in the order of US\$ 108 / kW assuming mass production of 500'000 fuel cell vehicles per year. With this order-of-magnitude cost difference in mind, it is evident that there is no one answer to the question “what is the current cost of the fuel cell?”

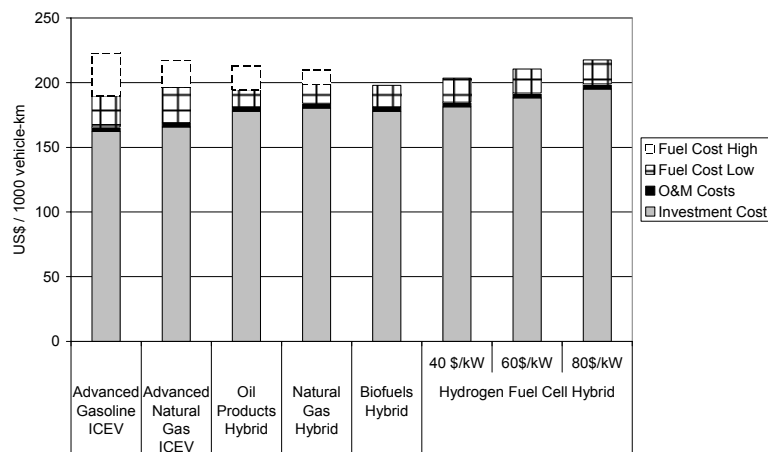
In this thesis, an optimistic choice has been made for current fuel cell cost. It is assumed that mass production could potentially take place within the next years through significantly ramping up current production volumes. Such a development, so is assumed, could facilitate initial cost of the fuel cell of US\$ 250 per kW by 2010, thus making possible fuel cell costs as reported by Carlson *et al.* (2005) as a result of mass production and technology learning within the decade thereafter.

Concerning the potential *future* costs of the hydrogen fuel cell, there is similarly no clear consensus on the levels that can be reached after commercialization. Kromer and Heywood (2007) suggest that fuel cell stack costs have decreased by 50% within the last 5 years largely as a side-effect of reducing stack size and weight, and the US Department of Energy short-term commercialization target for the fuel cell is US\$ 30/kW. Achieving this target, however, requires dramatic breakthroughs in membrane technology and an order of magnitude reduction in platinum loading (Kromer and Heywood 2007). The ultimately achievable long-term future cost of US\$ 50 per kW chosen here are, thus, are deemed optimistic, but not unrealistic in the long-run, and will be subject to a sensitivity analysis in section 4.4.4.

### ***Understanding the competitiveness of hydrogen fuel cell vehicles***

For understanding the competitiveness of hydrogen fuel cell vehicles, it is a useful exercise to compare the costs per vehicle-kilometre driven under various floor cost assumptions for the fuel cell with those of hydrogen's competitors. Such a comparison is presented in the following graph that compares hydrogen fuel cell vehicles with hybrid electric vehicles as well as advanced conventional ICE vehicles, using for the different vehicles the data presented in this chapter, with the learning components at their floor costs.

For the oil price, US\$ 50 /bbl is assumed for the sake of this comparison, the natural gas price is set to US\$ 0.195 /m<sup>3</sup> (scenario "fuel cost low"); for illustrating the influence of increased oil and gas prices, these prices are tripled in an additional scenario "fuel cost high". The costs of hydrogen production are assumed as US\$ 6 /GJ, roughly in line with the costs of coal gasification. For this exercise, the distribution costs for oil products are set to US\$ 3.73 /GJ and US\$ 8.4 /GJ for natural gas following (IEA 1999); for hydrogen, US\$ 15 /GJ is assumed similar to the case of liquid truck delivery in H2A. The results are depicted in Figure 22.



*Figure 22. Comparison of costs per vehicle-km driven for different transport options.*

The simple analysis presented here shows firstly that the bulk of costs for all vehicle types over the assumed lifetime of 10 years originates from the discounted investment costs. Thus, it is an essential requirement for the fuel cell to reach low cost levels, if no other policy is in place, e.g. a target for CO<sub>2</sub> reduction.

Nevertheless, it also shows that the range of costs is narrow for future vehicles and that increasing fuel prices favour hydrogen fuel cells if hydrogen can be produced and delivered in a cost-efficient manner. The fact that not all hydrogen can be produced at the suggested level; that significant technology learning is necessary to achieve the costs assumed in Figure 22, requiring major investments; and the fact that certain policy targets do exist, implies the need for a modelling analysis.

### **3.4 Discussion**

In this chapter, an overview on the considered technologies, the criteria for their selection, basic specifications and assumptions as well as cost data and their robustness was given. This static analysis provided a first-order comparison of relevant technology options available for personal transport in order to tackle the energy- and transport-related challenges motivating this dissertation. Despite the discussed uncertainties in available data, there are some important aspects worth mentioning, i.e. some “lessons learned”.

With regard to hydrogen, the lesson learned in this chapter is that there is a large number of potential technology options available or under development to produce this fuel. While hydrogen is currently produced mostly from fossil fuels, particularly natural gas and leading to CO<sub>2</sub> emissions, this could change in the future. With carbon capture and sequestration, hydrogen production from coal gasification and natural gas reforming could potentially become viable at low cost and with low CO<sub>2</sub> emissions. Electrolysis, in particular if powered by CO<sub>2</sub>-free electricity from renewable or nuclear power, is also anticipated to become a more important hydrogen production technology in the future. Biomass gasification could play a role, but this technology was found to have the highest level of uncertainty in terms of current and future costs. In any case, the question as to whether or not biomass gasification is a practical option for hydrogen production will probably be ultimately linked to the availability of biomass and its price, i.e. the availability of low-cost biomass for energy purposes. We will return to this issue in the course of the modelling analyses in the following chapters.

Centrally produced hydrogen needs to be delivered to the customers. A number of technology options has been identified and analysed, and it was found that pipeline

delivery is the least-cost option. However, delivery by truck in liquid state could potentially become feasible given the fact that pipelines will only be implemented if sufficient hydrogen demand is available. Truck delivery is somewhat more flexible in meeting hydrogen demand, as it can supply hydrogen to several small load centres at a time and can be extended more easily in response to demand increases. As a further remark, the analysis of hydrogen fuel chains revealed that the cost of delivering hydrogen is a key cost factor, which at least doubles the total cost of the fuel chain if hydrogen is produced at low cost (e.g. from coal gasification).

Concerning biofuels, both first and second generation biofuels have been assessed based on a significant number of available studies that analyse the production of various types of biofuel in detail. A considerable level of uncertainty was identified in particular with regard to second generation biofuels; nevertheless, if technology development targets can be met, biofuels have the potential to become a competitive option in the future, especially in geographical areas where low-cost biomass is available in high quantities.

Various technology options are considered for personal transport in this dissertation, ranging from advanced internal combustion engine vehicles to hybrid ICE-electric drivetrains, fuel cells vehicles, battery vehicles and plug-in hybrids. It was shown that significant efficiency improvements can be expected from conventional ICE vehicles as well as from hybrid-electric vehicles in the coming decades. If these efficiency improvements are realized, then these technologies are promising options for reducing CO<sub>2</sub> emissions from personal transport even if used with oil products.

The same, however, holds true for other options in personal transport such as hydrogen fuel cells, but the cost for the fuel cell must be reduced substantially. The answer as to whether any of the considered transport options is competitive, however, cannot be derived by simple spreadsheet analysis only. There are numerous competitors for hydrogen and biofuels, including most importantly liquid fuel derived from coal and natural gas, which are both already applied in some markets today. Moreover, the deployment of technologies is influenced by many driving forces such as policy targets, energy prices and energy system inertia, making such technology change towards alternative personal vehicles and alternative fuels likely to be a long-term process. Understanding this process requires



analytical tools that are capable of reflecting such driving forces and inertia, and the dynamics of the system. The modelling analyses in the following chapters seek to respond to this need.

### **3.5 Final Comments – Treatment of Costs in the Modelling Analyses**

The static analysis in this chapter provided some insights into the costs of fuel chains and drivetrains. However, in order to understand their potential to contribute to efforts to deal with the challenges to which personal transport is linked, there is a need for an assessment in a dynamic modelling framework. This will help to understand key drivers as well as key bottlenecks for the deployment of the different technologies.

For the modelling analysis conducted in the following chapters, there is clearly a need to harmonize assumptions, not only for fuel production, but also between technologies considered in fuel and electricity production. A stepwise approach is taken in this dissertation: in the first modelling analyses on a European level in chapter 4, current and future fuel production costs are defined on the basis of the static analysis in the above chapter. Hydrogen production costs are based on the H2A dataset. For biofuels, a set of technologies is chosen based on the above literature review and expert judgement. Each dataset is introduced at the beginning of chapter 4.

On these grounds, some first modelling exercises are undertaken in order to achieve a better understanding of the competitiveness of alternative fuels and drivetrains in personal transport and identify key bottlenecks for their deployment. In doing so, the analysis intends to shed light on whether and when alternative fuels can become cost-competitive in the personal transport sector of Europe. The analysis is conducted in a dynamic cost-optimization framework and looks into different policy targets.

In a second step and in the modelling analyses on a global level in chapter 5, a more sophisticated approach is taken, i.e. technology clusters are constructed in electricity and fuel production as well as personal transport. This means that key technologies

are identified, and cost reductions achieved for one technology influence the competitiveness of other technologies. In specifying technology clusters, the static review in the above chapter is used as a benchmark for the lowest cost achievable for each technology. This approach is described in section 5.2 in more detail.

For the delivery of hydrogen and biofuels, no cost reduction mechanisms were applied. The reason is that cost reductions that are anticipated for this part of the fuel chain are deemed to be somewhat too low to warrant explicit treatment. Note that the models applied in the remainder of this dissertation treat hydrogen distribution infrastructure using average cost data per GJ of hydrogen delivered based on the assumptions made in the above static cost analysis. This is a simplification given the fact that the cost analysis here is based on certain production scales, and a variation of these scales will reveal different average cost per GJ of hydrogen delivered. However, an analysis in chapter 5.5.6 using “lumpy” investment levels, i.e. minimum capacities for the installation of hydrogen distribution infrastructures, will take due consideration of this fact, making the analysis conducted here more unique and realistic.

## 4 Modelling Cost-effective Technology Choices in Europe

This chapter aims to provide insights into the cost-competitiveness of technology choices in personal transport under different scenarios in a dynamic cost-optimization framework. The objective of this chapter is to provide an advanced assessment of the cost-competitiveness of the various technology options under different policy regimes and to identify first key drivers and bottlenecks for their market penetration.

The assessment is conducted on a European level, i.e. for EU-29 (EU-27 plus Norway and Switzerland). With the choice of Europe, the assessment framework is located in a high-cost and low-availability region with regard to biomass potential.

For the purpose of this analysis, the European Hydrogen MARKAL model (EHM) has been developed. The model considers the entire energy system of EU-29 and is a cost-optimization model, which identifies least-cost solutions for energy system developments under given sets of assumptions and constraints. The modelling analysis in this chapter makes use of the results of the above static cost analysis for determining all fuel chain costs in EHM, including hydrogen and biofuels production and delivery as well as technologies in personal transport.

The results of the analyses strive at understanding under which circumstances and within which time horizon technologies in personal transport can achieve competitiveness in the market-place. This extends the static analysis of chapter 3 by a dynamic dimension. The chapter will conclude by discussing implications for policy-makers.

### 4.1 *The European Context*

The personal transport sector of Europe today is facing the challenges of increasing demand for individual mobility on the one hand, which has tripled over the last 30 years, and is likely to continue increasing especially in the new member states of the European Union (EC 2001). On the other hand, increasing fossil fuel prices and the question of long-term availability of fossil fuels pose a severe threat to the possibility to satisfy demand for mobility in a cost-efficient manner. In addition, the transport

sector with its high reliance on oil products is one of the major sources of greenhouse gas emissions in Europe, accounting for 28% of CO<sub>2</sub> emissions in the European Union in 1998, and expected to increase by around 50% by 2010 compared to 1990 levels (EC 2001). In light of the latest report of the Intergovernmental Panel on Climate Change (IPCC 2007b), the European Union intends to reduce its greenhouse gas emissions by at least 20% by the year 2020 (EC 2008). An extension to the year 2050 is debated on a commission level.

Aside from a major modal switch to public transport, there are generally two key ways in transport of tackling this challenging task. The first comprises changes to vehicle technologies, including the adoption of improved efficiency, reduced vehicle weight or rolling resistance and hybridization of internal combustion engines with electric drives and batteries, which may be seen as relatively easy to implement “low hanging fruit”. Such options are readily available and could help reduce quickly and cheaply fuel needs and CO<sub>2</sub> emissions in personal transport, unless these gains lead to substantial rebound effects such as a shift to larger and more powerful vehicles.

The second way of tackling the challenge described above involves the deployment of alternative fuels such as biofuels and hydrogen, but also natural gas. Particularly biofuels have received a great deal of attention lately, and the European Commission’s new target requires sustainable biofuels to constitute a share of 10% of overall petrol and diesel consumption by the year 2020 (EC 2008). Visions of a sustainable energy system for Europe such as in Uytterlinde *et al.*, (2007) suggest that biofuels and hydrogen could gain significant market shares in the decades to come.

In light of this wide array of technology options, there is a need for a better understanding of their economic and environmental sustainability and of conditions that could accelerate the utilization of any of these options. This chapter aims at contributing to a better understanding of the competitiveness of the available options in personal transport under different market conditions, in particular in trying to reduce CO<sub>2</sub> emissions from personal transport in a cost-efficient manner. In doing so, this chapter further elaborates on key drivers and bottlenecks for alternative fuel deployment in personal transport. Thus, it presents a “thinking exercise” on the future

of personal transport in Europe, and on the contribution alternative fuels could make towards a more sustainable transport system.

The “thinking framework” of this analysis is the European Hydrogen MARKAL model EHM, a partial-equilibrium, technology-oriented “bottom-up” model with a detailed representation of energy technologies. Using this model, a set of scenarios has been generated that strive at a better understanding of the competitiveness of technological choices and at deriving policy recommendations. The model and its components are further described in section 4.2. Section 4.3 describes the baseline scenario analysis, while Section 4.4 presents and discusses the scenarios investigated. Section 4.5 summarizes results obtained; in Section 4.6, results are discussed and conclusions are derived.

## **4.2 The European Hydrogen MARKAL Model EHM**

The European Hydrogen MARKAL model EHM is a perfect foresight, partial-equilibrium, technology-oriented “bottom-up” model of the MARKAL family of models<sup>26</sup> with a detailed representation of energy technologies on a European scale (EU-27 plus Norway and Switzerland, modelled as a single region). MARKAL-type of models identify least-cost solutions for the energy system under given sets of assumptions and constraints.

The so-called Reference Energy System (RES) is the basis of every MARKAL-model and represents current and potential future technologies in the different sectors of the energy system with their technology-specific details such as investment costs, operation and maintenance costs, availability factors and efficiencies. Figure 23 shows a sketch of the RES as applied in EHM separating resource extraction, conversion of primary energy carriers and the use of final energy carriers in end-use technologies of various demand sectors.

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<sup>26</sup> See i.e. Loulou et al. (2004), Fishbone et al. (1983) and Fishbone and Abilock (1981) for details on MARKAL-type of models.

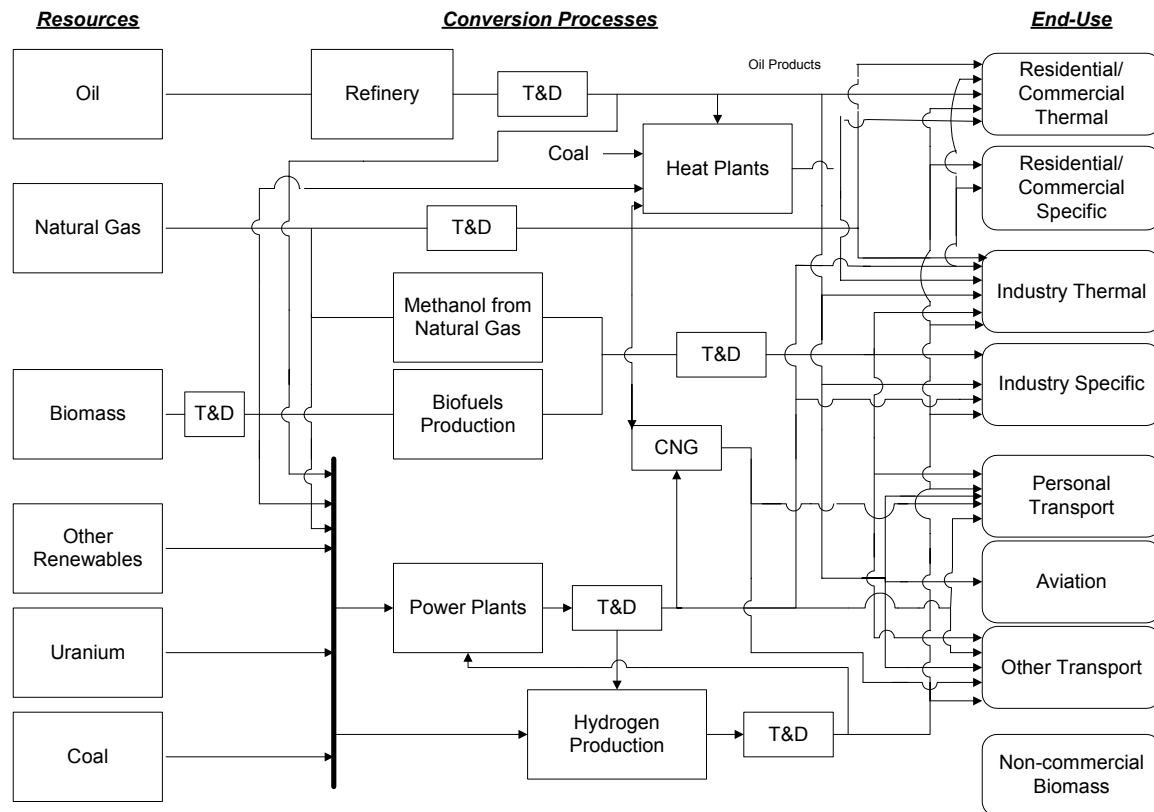


Figure 23. Simplified Reference Energy System (RES) as applied in EHM.

As can be seen in Figure 23, EHM distinguishes three main end-use energy demand sectors, which are further separated into several sub-categories of end-use demand:

- residential / commercial demand: residential / commercial thermal and residential / commercial specific
- industrial demand: industrial thermal and industrial specific
- transportation demand: personal transport, aviation and other transport merging public transport and freight transport

A set of generic standard and advanced end-use devices is defined for each of the demand sectors except for personal transport, which is modelled in more detail based on the techno-economic assessment performed in section 3.3 of this dissertation. For these generic end-use devices specified in the model, no explicit investment or fixed operation and maintenance costs are considered. Rather, “inconvenience costs” are introduced that reflect the fact that as historical trends of shifting towards more flexible and cleaner energy carriers continues at the level of final energy carriers, some technologies may be more difficult or much less attractive to introduce. Substitution of technologies at this level is, thus, mainly driven by

efficiencies and fuel costs. The penetration of end-use technologies here as in all sectors of EHM is controlled by exogenous annual growth and declination rates and by the exogenous enforcement of absolute upper bounds on specific technologies to allow competition in the end-use markets. For all end-use sectors other than personal transport, upper market penetration bounds were defined using a Weibull distribution with  $n = 4$ , following a suggestion of Kypreos (2006).

An overview on end-use technologies as applied in EHM is presented in Table 13. Given the focus of this chapter on the prospects of personal transport, detailed results for these other sectors will only be reported where appropriate.

Table 13. End-use technologies applied in EHM.

End-Use Demand Sectors						
Residential / Commercial		Industry		Transportation		
Thermal	Specific	Thermal	Specific	Personal	Aviation	Other
Coal heating	Electric	Coal thermal	Electric	ICEVs Hybrids	Current	Coal-based
Oil heating	appliances	Oil thermal	specific	Plug-in hybrids	aircraft	transport
Gas heating	Hydrogen fuel	Gas thermal	Diesel specific	Electric vehicles	Adv. aircraft	Oil-based
Electric	cell	Electric	Hydrogen	Fuel cell		transport
heating		thermal	replacement	vehicles		Gas-based
Biomass		Biomass	for diesel			transport
heating		thermal	Methanol			Electricity-
District heating		Process heat	replacement			based
Methanol		Methanol	for diesel			transport
heating		thermal	Hydrogen fuel			Alcohol-based
Hydrogen		Hydrogen	cell			transport
heating		thermal				Alcohol fuel
Electric heat		Electric heat				cell
pump		pump				Hydrogen fuel
Gas heat		Gas heat				cell
pump		pump				
Hydrogen fuel		Hydrogen fuel				
cell		cell				
Solar thermal		Solar thermal				

The model is calibrated to year 2000 statistics from the IEA (2002a). The timeframe of EHM is from the years 2000 to 2100, divided into 10 years time steps, and the model applies exogenous cost reduction assumptions that will be introduced later. A discount rate of 5% per annum in all calculations and for all technologies is assumed.

The biomass potential of Western Europe was derived from Mattson *et al.* (2004) and IEA (2005b), and amounts to 7.2 EJ per year in total. A breakdown of available biomass types is provided in Table 14.

Table 14. Biomass potential in Europe (Mattson et al. 2004; IEA 2005).

Biomass type	Potential [EJ / yr]
Wood residues	2.3
Rapeseed / soybeans	0.1
Corn grains	0.6
Sugar beet	0.0
Stover	3.2
Waste / manure	1.0

For the analyses in this chapter, biomass feedstock costs for Europe were derived from the Food and Agriculture Organization (FAO) as weighted averages for the years 2000-2003 (FAO 2006), using producer prices including biomass production, harvesting, pre-treatment, transport and storage, as well as the farmer's margin.<sup>27</sup> Resulting biomass costs are reported in Table 6.

Table 15. Cost of different biomass types in Europe (FAO 2006; Ragettli 2007).

Biomass type	Biomass cost [US\$ / GJ]
Wood residues	3.10
Rapeseed / soybeans	8.44
Corn grains	6.71
Sugar beet	10.32
Stover	3.15
Waste / manure	3.22

No restriction has been made on the availability of oil and natural gas resources. Oil and gas prices, however, have been varied in sensitivity analyses in order to assess their impact on technology choices, thereby reflecting the dimension "affordability" of energy security as outlined in chapter 2. Uranium and coal are abundantly available in EHM as well, and coal reserves and resources are based on Rogner (1997).

EHM possesses a great level of detail in three key modules, which have been designed to assess the competitiveness of alternative fuels in the transportation sector:

- a hydrogen module with a detailed representation of hydrogen production technologies and delivery infrastructure including fueling stations;
- a biofuels module comprising promising biofuels production pathways and their delivery to fueling stations; and
- a transportation sector module reflecting existing and future technology option in personal transport.

<sup>27</sup> Transport of biomass is assumed to take place by truck over a distance of 50 km, which is assumed to cost US\$ 10 /t in addition to the producer prices of biomass. For details, see Ragettli (2007).



The hydrogen and biofuels modules have been developed on the basis of the techno-economic assessment in chapter 3 of this thesis. The hydrogen module will be described in the following section. Thereafter, a description of the biofuels and personal transport modules of EHM is presented.

#### 4.2.1 The Hydrogen Module

The hydrogen module of EHM is composed of central hydrogen production facilities, a hydrogen delivery infrastructure and forecourt hydrogen production based on the techno-economic assessment in chapter 3. For the purpose of this analysis, technology data for central hydrogen production was mostly derived from the US H2A spreadsheet models (H2A 2006a) with the exception of the solar-based technologies, where more recent data was available from experimental work at the Paul Scherrer Institut in Switzerland (Felder 2007). The applied dataset is depicted in Figure 24; details are available in appendix 1.

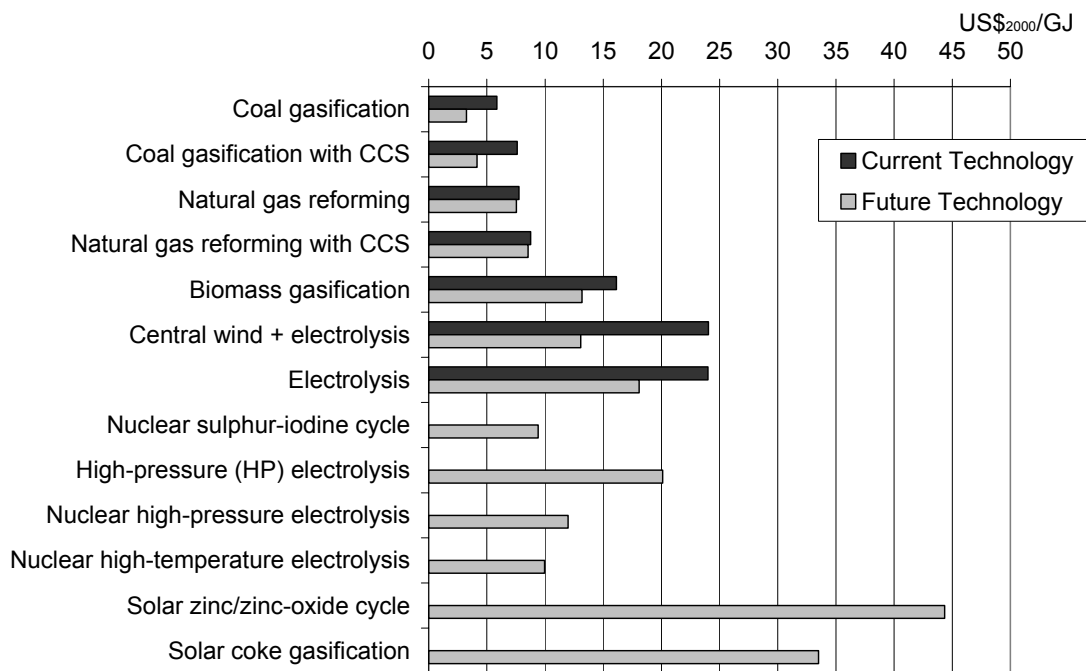


Figure 24. Cost of central hydrogen production<sup>28</sup>; adapted from: H2A (2006); Felder (2007).

<sup>28</sup> All calculations herein are based on a discount rate of 5% and individual technology lifetimes. US\$ are understood as US\$2000. All hydrogen related data are presented on LHV basis. Fuel input cost assumptions for this graph only (subject to change over time in the modeling analysis in later sections): Natural Gas = US\$ 4.6 /GJ; Coal = US\$ 1.6 /GJ; Biomass = US\$ 5.1 /GJ; Electricity = US\$ 12 /GJ; Coke = US\$ 4.6 /GJ. CCS is carbon capture and storage; cost of CO<sub>2</sub> storage, however, is not included in the cost in this graph, but is assumed to be US\$10 per ton of CO<sub>2</sub> stored in the modeling framework of EHM.

Note that the H2A models use high availability factors for dedicated hydrogen production from wind turbines electricity generation with electrolysis (up to 54%). However, this has been reduced for this analysis to 35%, which is deemed to be more realistic in an aggregate model like EHM. Also note that fuel cost used for the hydrogen cost analysis in Figure 24 does not necessarily reflect modelling outcomes, as fuel cost are endogenously generated within the model (coal, electricity), change over time (oil, gas) as further discussed in section 4.3.1, or are different per individual biomass type (see model description above).

Figure 24 also distinguishes cost estimates of current and future technologies, where current technology refers to today's technologies, and future technologies to the years 2020 to 2030. In the modelling analysis, costs were interpolated between current and future for the period 2000-2030. Future costs, then, mark the "floor costs" of each technology as of 2030 and beyond, i.e. the costs each individual technology can at most be reduced to in this analysis.

In addition to production technologies, this analysis also accounts for the cost for distribution infrastructure to deliver hydrogen to fueling stations by pipeline or truck. Costs were derived from an analysis of the H2A components model (H2A 2006a) for a demand centre size of 250 tons of hydrogen per day. As discussed in section 3.1.4, the lowest costs of the different hydrogen delivery options vary between US\$ 9.9 /GJ to US\$ 17.5 /GJ and are additive to the cost of hydrogen production. Again, for comparison of these costs it is worth mentioning that if the cost of gasoline at fueling stations was US\$ 0.5/litre, this converts to US\$ 14.8 /GJ.

As an alternative to central hydrogen production facilities, forecourt hydrogen production could be important in particular in early phases of hydrogen penetration when demand for hydrogen is still low. Forecourt hydrogen production facilities have been modelled with the H2A forecourt hydrogen production models (electrolysis and natural gas reforming, H2A 2006), extended with data from Simbeck and Chang (2002) for methanol and gasoline reforming. Electrolysis and natural gas reforming are, thus, available at two production capacities related to the available fueling stations in H2A, i.e. 100 kg/day or 1'500 kg/day. Steam reforming of methanol and gasoline are designed for an output of 470 kg/day of hydrogen. Figure 25 gives an

overview on forecourt hydrogen costs, which represent the cost of hydrogen at the fueling station to the final consumer assuming no taxes or margins. Again and as for central hydrogen, future costs have been modelled as cost reductions for existing technologies, with the future technology costs as “floor costs”. All details for the cost of forecourt hydrogen are reported in appendix 1.

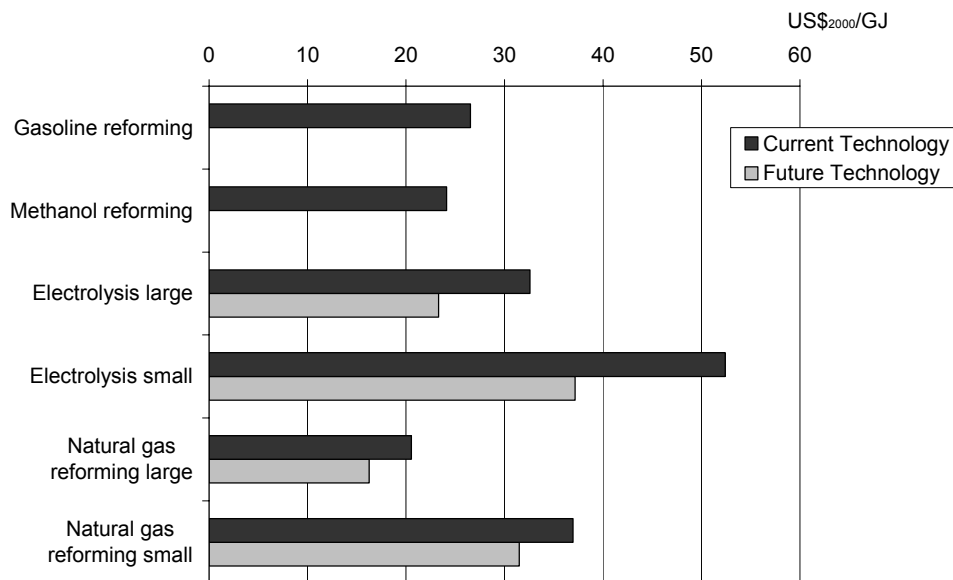


Figure 25. Cost of forecourt hydrogen production<sup>29</sup>; sources: H2A (2006); Simbeck and Chang (2002).

#### 4.2.2 The Biofuels Module

The European Commission intends to replace 10% of liquid fossil fuels with biofuels by 2020. Several countries in Europe have, thus, already adopted different incentives to promote the use of biofuels.

The economics and prospects of biofuels production have been assessed with a literature review in Ragettli (2007). The analysis covers “first generation” biofuels as well as “second generation biofuels”. Some 50 biofuel production processes were reviewed for the purpose of setting up this biofuels module, and the results of this analysis have been reported in section 3.2. For the dynamic analysis of prospects of alternative fuels in Europe, a number of processes were selected based on expert judgement.

<sup>29</sup> Prices assumed for forecourt applications in this table only: Natural gas US\$ 7.29 /GJ, Gasoline US\$ 6.01 /GJ, Methanol US\$ 6.51 /GJ. Again, these prices do not necessarily reflect modeling outcomes. Discount rate: 5%.

Figure 26 provides an overview on the biofuels costs at the fueling station as applied in the analyses with EHM. It shows the costs of producing individual biofuels from different feedstocks, divided into “production cost” (composed of capital costs and O&M costs), “biomass costs” (cost of feedstock), “energy costs” (net cost of other energy input such as electricity or heat) and “T&D costs” (costs of transmission and distribution of fuels). T&D cost of delivery to the fueling stations vary according to the individual biofuels based on (IEA 1999), and are in the range of US\$ 3.49 to 8.4 per GJ as reported in section 3.2.3.

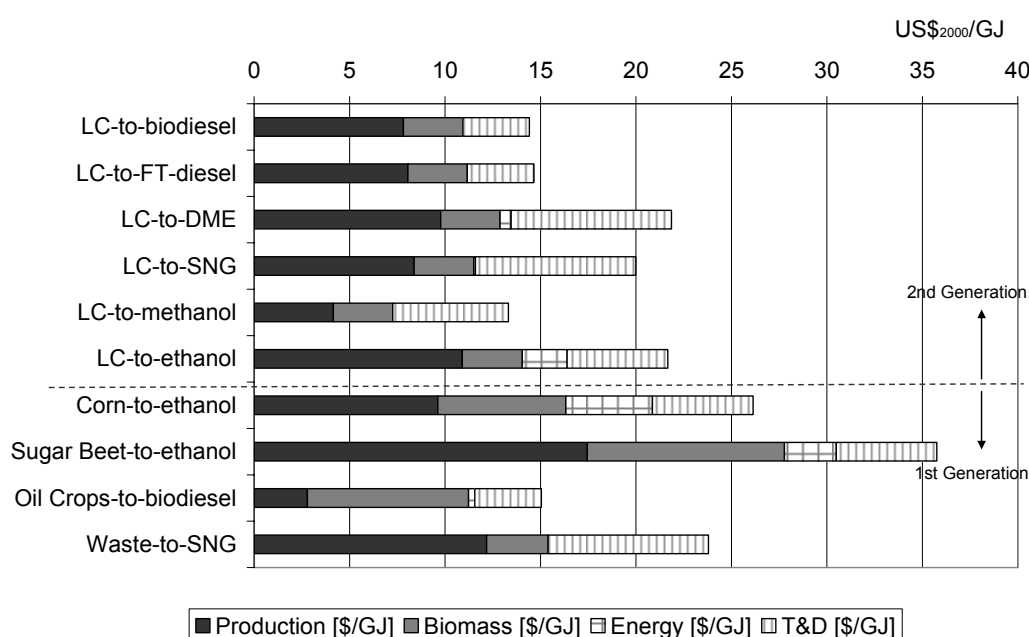


Figure 26. Cost of biofuels fuel chains (various sources as reported in Ragetli 2007).<sup>30</sup>

#### 4.2.3 Personal Transportation Module

Personal transportation in EHM is treated using “generic” vehicles, i.e. no distinction is made between different vehicle sizes, and an average annual mileage of 15'000 km is assumed for all vehicles. The reason is that the intention of this analysis is to get a better understanding of the competitiveness of alternative fuels and advanced engine technologies under different policy regimes only rather than to identify market segments for fuels or engine technologies.

<sup>30</sup> LC = lignocellulosic biomass; DME = dimethyl ether; SNG = synthetic natural gas. Discount rate: 5%.

The costs of vehicles are again based on the previous techno-economic assessment in section 3.3 and have been reported in much detail already there. Assumed efficiencies and costs of non-learning components are not repeated here; the interested reader is referred to section 3.3 for more details. Nevertheless, Table 16 presents again initial costs of learning components as well as anticipated floor costs, i.e. the costs technologies can at best be reduced to in the analysis in this chapter. These cost assumptions are exogenous to the model, and costs are assumed to decline linearly from initial to floor costs within 50 years after market launch of the vehicle, which is assumed to take place in the year 2010 for all new vehicles considered. Initial and floor costs assumptions were derived from Kromer and Heywood (2007).

*Table 16. Cost of learning components for personal vehicles in EHM (Kromer and Heywood 2007).*

Technology	Size	Initial Cost	Floor Cost	
Fuel Cell	40 kW	250	50	US\$/kW
Reformer	40 kW	90	25	US\$/kW
Hybrid Battery System	28 kW	2'500	800	US\$/vehicle
Fuel Cell Battery System	42 kW	3'250	1'200	US\$/vehicle
Battery Electric	48 kWh	16'250	12'000	US\$/vehicle
Plug-in Hybrid	8.2 kWh	6'500	2'800	US\$/vehicle

The existing fleet was calibrated using TREMOVE (2007) and IEA statistics IEA (2002a) for the year 2000. The efficiency of currently available conventional ICEVs is assumed to improve by 2% per decade until 2030. Thereafter, the efficiency is kept constant.

### **4.3 Baseline Scenario**

This chapter presents baseline scenario assumptions and the results of the baseline case.

#### **4.3.1 Key Modelling Assumptions**

The baseline scenario is based on the IPCC-SRES B2 scenario available at IIASA (2007), and can, thus, be interpreted as a „dynamics-as-usual” development of the

European energy system. However, it was not aimed to reproduce the B2 scenario, but just to use key input parameters to define a set of scenarios for analyzing the prospects of different technologies in personal transport. The demand for personal transport was derived and adjusted using IEA/WBCSD (2004) until 2050 and extrapolated to 2100 assuming a further growth of 0.1% per year given large uncertainty about future developments. Table 17 presents an accompanying scenario of population and GDP developments.

*Table 17. Population, GDP and travel demand scenario in EHM.<sup>31</sup>*

		2000	2050	2100
Population	[million US\$]	514	466	460
GDP per capita	[1000 US\$ / capita]	19	45	74
Travel demand	[1000 billion vehicle-km]	2.7	3.6	3.7

For the analysis, it has been assumed that oil prices increase linearly from US\$ 35/bbl in the year 2000 to US\$ 77.5/bbl in 2050 and US\$ 120/bbl in 2100. The price for natural gas is proportionally coupled to the oil price with a factor of 0.625 and increases accordingly. No restriction has been made on the availability of either fuel to the European energy system, which is a simplification given the problem of resource scarcity that may occur in the course of this century, or geopolitical threats, as discussed in section 2.2.

In personal transport, it was assumed that all new vehicle technologies that are today available to the market as commercialized technologies (advanced gasoline and diesel ICEVs, oil product hybrids and biofuels ICEVs) can obtain a market share of up to 5% by the year 2010. All other new vehicles were restricted to an optimistic maximum of 70'000 vehicles in 2010, and can get up to 1% of the entire market by 2020, i.e. some 2 million cars. This setup is combined with moderate growth assumptions, trying to reflect the inertia of the transportation system until new technologies are deployed in significant shares. It is assured, however, that any vehicle can make a significant contribution within few decades, and take over the entire market by the end of the time horizon.

<sup>31</sup> Based on IEA/WBCSD (2004) and complemented by own assumptions.

For biomass, it is again emphasized that this analysis uses European biomass potential only, i.e. no imports of biomass or biofuels are allowed. The potentials were derived from Mattson *et al.* (2004) and IEA (2005b) and amount to 7.2 EJ in total per year, as reported above. The costs of biomass were assumed constant over time.

For the calibration of the model, renewable energy potentials were derived from WEC (2001), Hoogwijk *et al.* (2004) and IEA (2003a). It was assumed that intermittent renewable power sources such as wind power or solar photovoltaic would not contribute to more than a total of 25% of electricity production due to intermittency reasons.

#### 4.3.2 Baseline Results

Figure 27 illustrates the development of primary energy consumption for Europe in the base case. Primary energy consumption increases from 80 EJ in 2000 to 116 EJ in 2050 and 137 EJ in 2100. In this analysis, coal increases its share in primary energy consumption to 38% in 2100, up from about 18% in the year 2000. Renewables considerably extend their share, primarily due to increased utilization in the power sector as well as residential and commercial thermal uses. Total electricity production in EU-29 grows by a factor of more than 3 until 2100 in the baseline case.

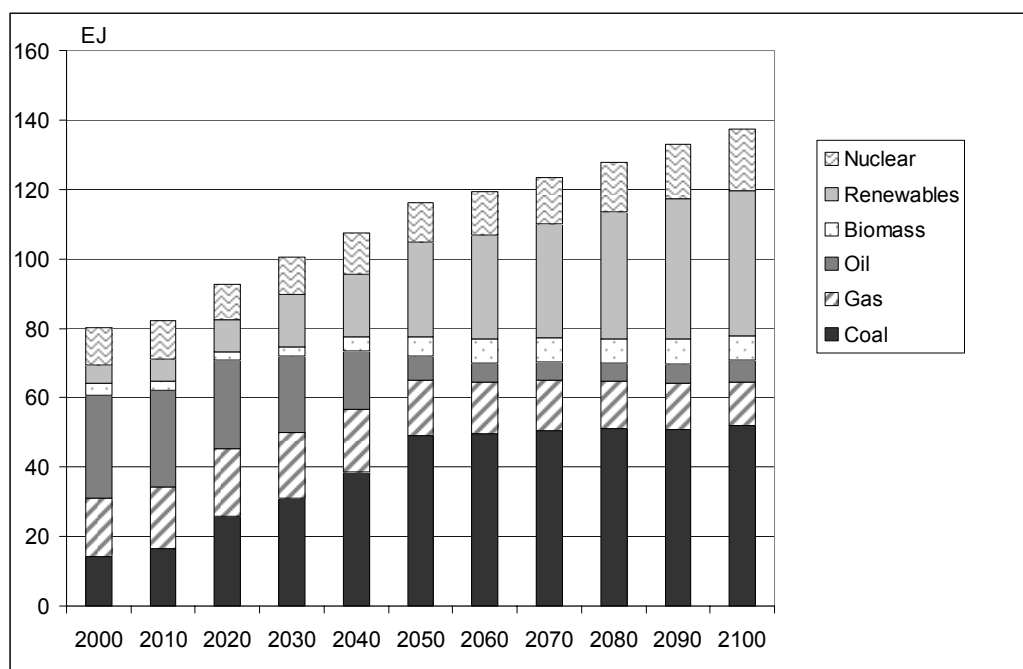


Figure 27. Primary energy consumption in EU-29 in the base case.

The use of oil is reduced in the long-run. One key reason apart from the increasing oil price is the gradual replacement of inefficient current technology with highly efficient alternatives, for example in the transport sector. This reflects the fact that new vehicles are important contributors even in the baseline scenarios (see Figure 28).

The results of the baseline analysis of personal transport are presented in Figure 28. The analysis suggests a trend towards more efficient engine technologies in the long-run in absence of transport sector policies and with the given oil price increase. As a result of the latter, oil product hybrids dominate the transportation sector of Western Europe by the end of the century, contributing to some 90% of total personal transport demand. By that time, biofuels vehicles contribute to personal transport, but only in a marginal fashion. A sensitivity analysis of assumptions on oil and gas prices, which is not shown here, revealed that at higher prices the penetration of gasoline hybrids is likely to be spurred even further, whereas at lower prices, advanced gasoline and diesel ICEVs would dominate personal transport.

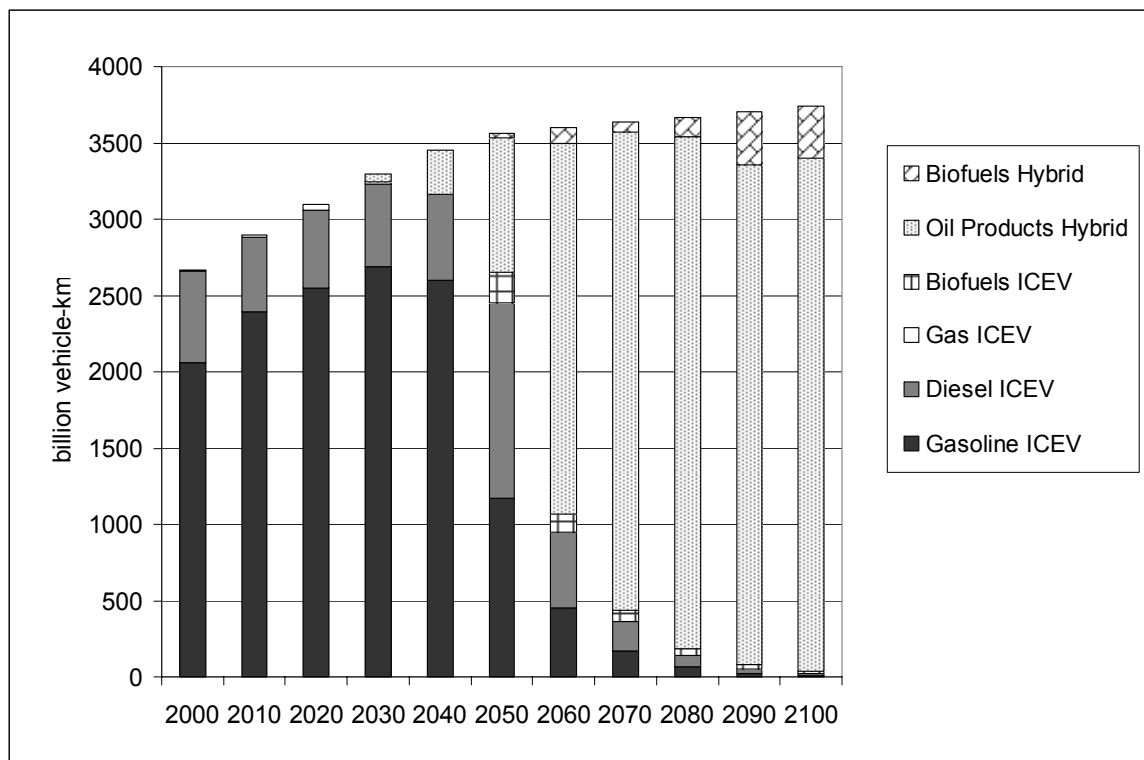


Figure 28. Share of vehicles in EU-29 personal transport baseline scenario.<sup>32</sup>

<sup>32</sup> ICEV = Internal Combustion Engine Vehicle.



It needs to be noted, though, that this model does not account for recent developments in personal transport such as the trend towards a higher market share for diesel-fuelled cars in Europe. One reason is that the model assumes a generic personal vehicle sector rather than distinguishing different vehicle sizes and, thus, a common mileage to all vehicles. Diesel ICE vehicles (ICEVs) stand to benefit from their higher annual utilization despite their higher capital costs. This aspect has been neglected in this analysis, and the share of diesel cars was bounded to at least 20% of gasoline use in order to avoid an artificial early phase out.

#### **4.4 Scenario Analyses**

The scenario analyses presented here are intended to help derive a better understanding of driving forces in personal transport from the perspective of a cost-optimizing social planner. For this purpose, a set of different scenarios has been computed that were deemed most relevant for such an analysis on a European level.

The analyses conducted here intend to answer the following questions:

- What is the role of a stringent CO<sub>2</sub> reduction target for Western Europe on the deployment of alternative fuels in transport?
- What is the impact of the level of CO<sub>2</sub> reduction targets on the market penetration of alternative fuels in transport?
- What is the impact of increasing oil prices under a CO<sub>2</sub> mitigation regime?
- Can hydrogen fuel cells make a significant contribution in the first half of the century? How important are the ultimately achievable floor costs and the timing at which they are reached?

With these scenarios, the analysis in this chapter is linked to the climate change (CO<sub>2</sub> target scenarios) and energy security debate (variation of oil and gas price assumptions) outlined in chapter 2 of this dissertation. By looking at these driving forces, the scenarios will provide first insights into the dynamics of technology change in personal transport on a European level. In addition, the analysis of hydrogen fuel cells aims at understanding its role as a potential key bottleneck.

#### 4.4.1 The Role of a 50% CO<sub>2</sub> Reduction Target

In this scenario, it was intended to assess the role of a stringent CO<sub>2</sub> reduction target on the penetration of alternative fuels in personal transport. Therefore, an illustrative CO<sub>2</sub> target of a 50% reduction by 2050 in comparison to 1990 levels was imposed on the entire energy system, similar to current policy discussions at the European Commission level. The CO<sub>2</sub> target is extended to 2100 by assuming a further reduction of 5% per decade after 2050, resulting in a CO<sub>2</sub> reduction of 38.7% by the end of the century compared to 1990 levels.

The result of this analysis is presented in Figure 29. The analysis generally reveals that if Europe wants to reduce CO<sub>2</sub> emissions to the extent assumed here, personal transport will need to be transformed substantially. Among the available technology options, hybrid drivetrains are a key option to reduce CO<sub>2</sub> emissions from personal transport and account for about 86% of all vehicles by the year 2050. Under this scenario, hybrids fuelled with oil products constitute 67% of all hybrids by 2050, natural gas hybrids for 27% and increasing even further thereafter, the remainders are biofuels (about 6%).

These figures already provide an indication that alternative fuels are playing a major role in decarbonising personal transport, and in particular natural gas. By 2050, total natural gas consumption in personal transport is 931 PJ, biofuels consumption 223 PJ and hydrogen 25 PJ in this scenario, the latter resulting from the use of hydrogen fuel cells. Taken together, alternative fuels, i.e. non-petroleum fuels, are responsible for about 25% of total fuel consumption in personal transport in 2050.

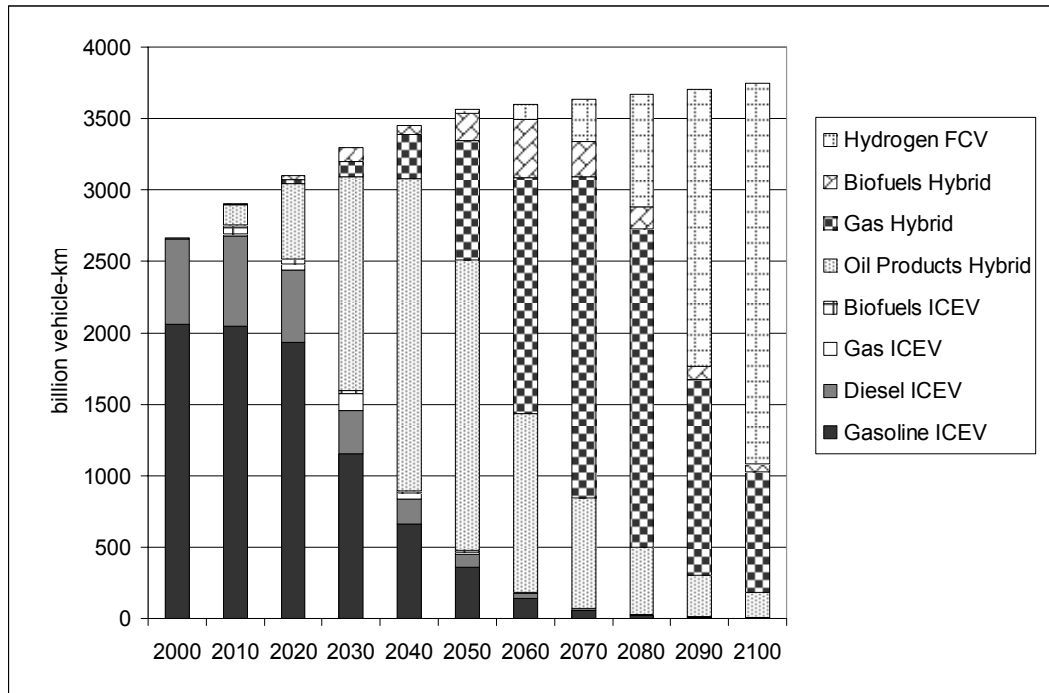


Figure 29. Contribution of different vehicles to personal transport in EU-29 under a 50% CO<sub>2</sub> reduction target for 2050.

Hydrogen fuel cell vehicles (FCVs) gain significant market share only in the very long run, i.e. towards the end of the century, when they become the dominating vehicle technology, accounting for 71% of all vehicles on the market in 2100. The key reason for the late penetration of hydrogen FCVs is the assumption that floor costs of all learning components, including the fuel cell, are reached 50 years after their market launch in 2010, meaning that fuel cells achieve their lowest costs in 2060 only.

Note that for the market success of hydrogen fuel cells in a CO<sub>2</sub> mitigation regime, large-scale hydrogen production with little or no CO<sub>2</sub> emissions is a prerequisite. While it is not intended to discuss technologies for hydrogen production at this point already (an in-depth analysis can be found in section 5.5.5 of this dissertation), it is worth noting that in the scenario investigated here, 54% of all hydrogen is from CO<sub>2</sub>-free nuclear and combined wind+electrolysis technologies in 2050; the remainder is produced from natural gas reforming and coal gasification with carbon capture and sequestration (CCS), i.e. technologies with only little CO<sub>2</sub> emissions. In the long-run, i.e. towards the end of the century, coal gasification with CCS becomes the dominating option and provides for some 89% of total hydrogen production.

#### 4.4.2 The Impact of the Choice of CO<sub>2</sub> Targets

In order to understand the sensitivity of the obtained results to the CO<sub>2</sub> reduction target of 50% by 2050 applied so far, two cases were run in addition: one with 40% CO<sub>2</sub> reduction, another one with 60% CO<sub>2</sub> reduction by 2050 compared to 1990 levels, further extended by assuming additional 5% reduction per decade thereafter in both cases. The result is presented in Figure 30 and shows that the penetration of hydrogen and biofuels over the medium-term (2050) critically depends on the choice of CO<sub>2</sub> targets. The results suggest for hydrogen that more stringent CO<sub>2</sub> reduction targets always increase the competitiveness and, thus, the deployment of hydrogen fuel cells in personal transport. However, Figure 30 shows that only with the most stringent target explored here, hydrogen fuel cell vehicles make a larger contribution to personal transport by 2050 already, when it makes up for 23% of total demand. Over the long-term (2100), hydrogen fuel cells are competitive under all three CO<sub>2</sub> targets investigated here.

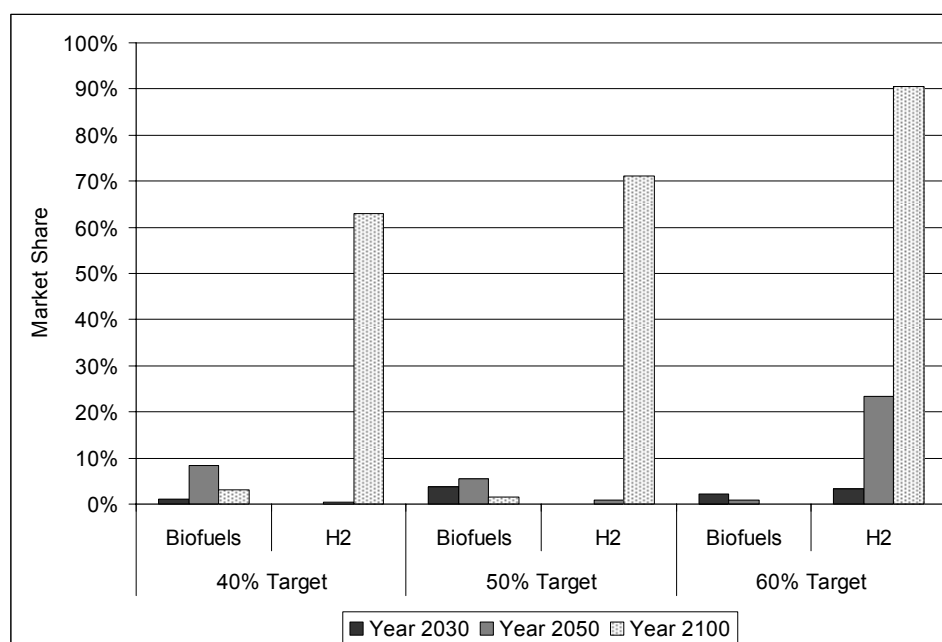


Figure 30. Market share of hydrogen fuel cells and biofuels vehicles in personal transport under different CO<sub>2</sub> reduction targets.

For biofuels, the reverse trend is observed. The more stringent is the CO<sub>2</sub> reduction target, the less biofuels are being deployed. Stronger CO<sub>2</sub> reduction targets result in increasing CO<sub>2</sub> prices in the model, thus making the utilization of the limited and costly biomass potential in other sectors more attractive. This results in even lower

market shares for biofuels in personal transport than observed before, and increases the share of hydrogen fuel cells.

#### 4.4.3 The Role of Oil Prices under a 50% CO<sub>2</sub> Reduction Target

The analyses conducted so far focused on the changes in personal transport as a result of different CO<sub>2</sub> reduction targets. In a next step, another potential influence on the deployment of alternative fuels and drivetrains is investigated: the price of conventional fuels, an intrinsic concern with regard to energy security. The analysis is pursued by varying oil and gas prices under the 50% CO<sub>2</sub> reduction target in order to understand the sensitivity of the penetration of alternative fuels in transport to oil and gas price assumptions.

The results presented here focus on the role of hydrogen fuel cell vehicles and biofuels vehicles (ICEVs and hybrids) until 2050, aiming at answering whether and to which degree higher oil and gas prices increase the competitiveness of either technology in the first half of the century. Note that in this analysis, all learning components in personal transport reach their floor costs still by the year 2060 only.

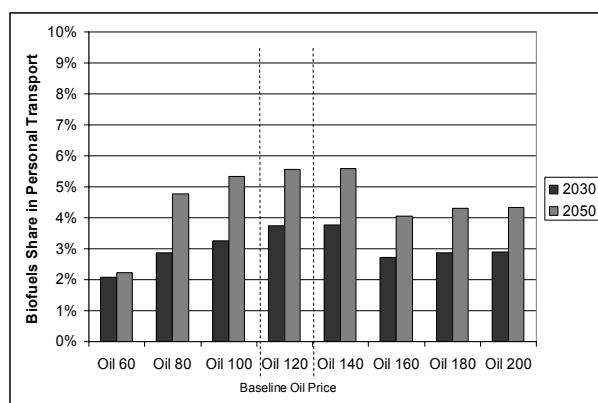


Figure 31. Transport market share of biofuels vehicles at various oil prices.

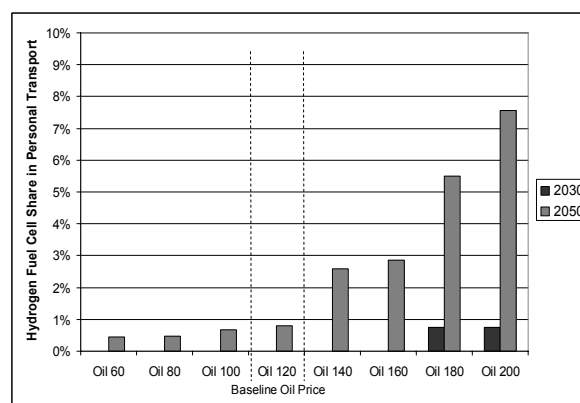


Figure 32. Transport market share of hydrogen fuel cell vehicles at various oil prices.

Figure 31 and Figure 32 show that high oil and gas prices support the market penetration of hydrogen fuel cells and increase their competitiveness already in the first half of the century. For the most extreme oil price investigated here, hydrogen fuel cells make up for more than 7% of total personal transport by 2050. Note that across all scenarios, hydrogen fuel cells were again the dominant engine technology

in the second half of the century and made up for at least 64% of demand in personal transport by the end of the time horizon.

For biofuels, the impact of oil prices on the competitiveness in the first half of the century is low. Limited to European biomass potential only, biomass is more cost-effectively used to decarbonize other sectors than personal transport, in particular the residential sector and electricity and heat production under the assumptions used here. In total, 5.2 EJ of biomass are used in these sectors by the year 2050 under the US\$ 120 /bbl oil price scenario, or 72% of the total biomass available for energy purposes in Europe. Note again that with the choice of Europe as a modelling framework, this first analysis of the prospects of alternative fuels in transport is geographically located in a high-cost area with regard to available biomass.

In the scenarios investigated here, the increased competitiveness of hydrogen FCVs is clearly a result of increasing oil and gas prices. However, the observed increasing market shares for hydrogen translate into reduced market shares for oil products vehicles only. With increasing oil and gas prices, natural gas hybrid vehicles obtain increasing market shares of up to 24% in the year 2050 due to their cost-effective and highly efficient performance and the use of a fuel with lower carbon content than in the case of oil products. Oil product vehicles market shares, however, are gradually decreasing from 97% in 2050 in the scenario with a maximum oil price of US\$ 60 per barrel, down to 64% in the scenario with highest oil prices.

As a final remark, it is clear that the restricted availability of biomass in this modelling analysis, which uses European biomass potential only, imposes a severe constraint on the extent of their utilization. Increasing the availability of biomass or biofuels, e.g. through allowing for imports from other world regions, can potentially alter the results obtained here in favour of higher utilization of biofuels depending on the price of imports. Without imports and in absence of policy support, however, EHM decides to make use of biomass where it is most cost-efficient. In personal transport, biofuels are competing with a high number of cost-effective other options for reducing CO<sub>2</sub> emissions, of which hydrogen is potentially carbon-free if appropriately produced. Besides, the use of hybrid vehicles or, more generally speaking, advanced and more efficient drivetrains reduces fuel consumption from personal transport significantly

until the year 2050, thus creating a lower need for CO<sub>2</sub> reduction of the entire energy system.

An interesting discussion of the question “where is biomass most cost-effectively utilized” can be found in Grahn *et al.* (2007). The paper derives similar conclusions by comparing the results of two different cost-optimization models, of which one has the option of CO<sub>2</sub>-free hydrogen in personal transport, the other has not. It is concluded that if no hydrogen is available in personal transport, then biofuels will be utilized if carbon prices are high enough. If, however, CO<sub>2</sub>-free hydrogen is available at affordable prices, then biomass is rather used elsewhere. This is consistent with the observations made here.

#### 4.4.4 The Role of Fuel Cell Costs under a 50% CO<sub>2</sub> Reduction Target

The analysis conducted in section 4.4.1 indicated that the cost of the fuel cell plays a crucial role in determining the competitiveness of hydrogen against other fuels. In section 4.4.1, the results suggested that hydrogen fuel cell vehicles obtained significant market shares around the year 2060, i.e. when the assumed floor costs of US\$ 50 /kW were reached.

It is therefore important to understand the significance of this assumption – both in terms of timing (“when are the floor costs reached?”) and of the level of floor costs eventually reached. A respective sensitivity analysis is presented in this section in order to understand the dynamics of such technology change, which will also help to answer the question: can hydrogen fuel cells contribute to decreasing CO<sub>2</sub> emissions from personal transport already in the first half of this century?

Two sets of scenarios were analyzed. In the first set, it is assumed that floor costs of all learning components for all vehicles, i.e. fuel cell, battery and reformer, are already reached in 2020: 10 years after the assumed market introduction. Within this set, the level of floor costs of the fuel cell is then varied and the impact on the market penetration of the hydrogen fuel cell is assessed.

In the second set of scenarios, it is assumed that the floor costs of all learning components are reached by 2060 only, i.e. 50 years after market introduction as in

the previous analyses. Again, within this set the level of floor costs reached by 2060 is then varied for all technologies.

Note that in both sets of scenarios, a CO<sub>2</sub> reduction target of 50% by 2050 compared to 1990 levels and further reduction thereafter as described in section 4.4.1 is imposed on the entire energy system.

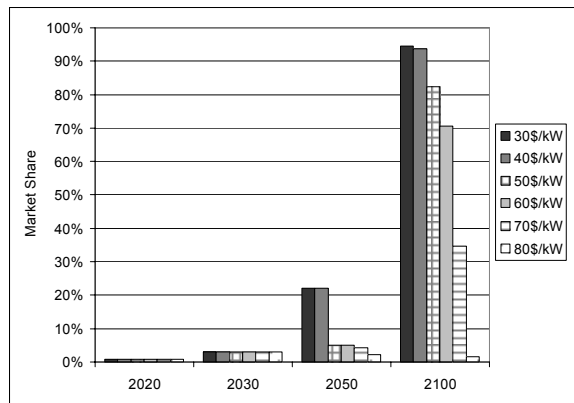


Figure 33. Fuel cell market share with different levels of floor costs reached in 2020.

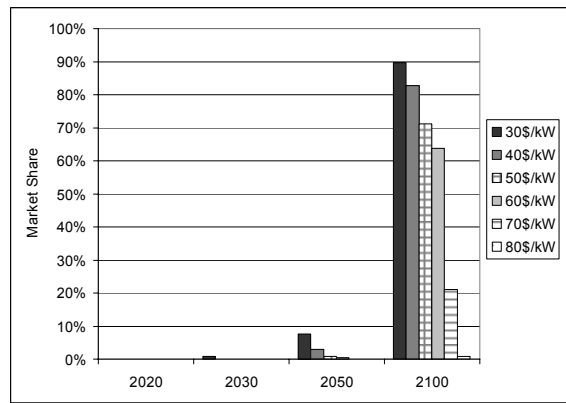


Figure 34. Fuel cell market share with different levels of floor costs reached in 2060.

Figure 33 presents the results of the sensitivity analysis assuming floor costs reached by 2020; Figure 34 presents the results for floor costs in 2060. First and foremost, results indicate that whether floor costs are achieved in 2060 or 2020, the key variable is the cost at the floor, with US\$ 70 /kW needed to achieve significant market penetration towards the end of the century.

The results also suggest that in order to gain significant market shares in the first half of the century already, hydrogen fuel cell cost need to be reduced to at least US\$ 40 /kW soon. The analysis show that a market share of over 20% is possible by the year 2050 at such fuel cell cost levels under the assumptions of this analysis<sup>33</sup>, but timing in terms of “when are fuel cell cost reductions achieved” is important. This means that reaching the floor cost early is important to gain a comparatively larger market share later. If cost reductions materialize in the long-run only, hydrogen fuel cells can contribute to CO<sub>2</sub> reduction targets in the long-run only as well.

In additional scenarios, which are not presented here, the impact of the choice of CO<sub>2</sub> reduction targets on the results obtained was assessed. It was found that with

<sup>33</sup> Moderate growth rate assumptions were taken in this analysis to reflect the inertia of the transportation sector; adopting new vehicle technologies is a time-consuming process.



more stringent CO<sub>2</sub> reduction targets, the choice of fuel cell floor costs becomes less important, i.e. the fuel cell is competitive at higher floor costs. The reason for this observation is that more stringent CO<sub>2</sub> reduction targets require more costly CO<sub>2</sub> abatement activities to reach the target; thus, even more expensive fuel cell systems become cost-competitive sooner.

### ***Understanding fuel cell cost reductions***

Technology cost reductions do not take place without efforts; rather, they are a result of R&D expenditures, experience gained during production and commercialization, and economies of scale. For assessing the rate at which such so-called “technological learning” takes place, one can define a learning curve using cumulative installed capacity as a proxy for accumulated experience (Barreto 2001; Barreto and Kypreos 2004). In such a one-factor learning formulation, specific investment cost (SC) of a learning technology *te* at the time period *t* are represented as

$$SC_{te,t}(CC) = a \times CC_{te,t}^{-b}$$

where *CC* is the cumulative capacity, *b* the learning index and *a* the specific cost at unit cumulative capacity.

Instead of the learning index *b*, the learning rate (*LR*) is commonly specified, i.e. the rate of cost decline per doubling of cumulative capacity. The learning rate is expressed as

$$LR = 1 - 2^{-b}$$

In literature, one can commonly find learning rates for energy technologies from -11% to +35% McDonald and Schrattenholzer (2001). The highest rates were found for solar photovoltaic and for early deployment stages of new technologies.

In this chapter, exogenous cost reductions have been applied to new vehicles in personal transport. This means that these cost reductions will take place, independent of whether the technology is deployed and without paying for it. It is, thus, important to understand what kind of learning rates are required to reach the postulated floor costs in time.

**Key assumptions:** initial capacity at market introduction 70'000 vehicles at cost of US\$ 250/kW; maximum capacity by 2020 is 1% of the market (2.1 million vehicles); 10% growth per year is possible thereafter, allowing for cumulative installations of about 230.9 million fuel cell cars by 2060. The following table provides an overview on the corresponding learning rates for all scenarios investigated.

Table 18. Learning rates for different fuel cell cost scenarios.

		Floor Costs reached in				
		2020	2030	2040	2050	2060
Level of floor costs	US\$ 30/kW	34.6%	25.7%	21.4%	18.6%	16.5%
	US\$ 40/kW	30.1%	22.7%	18.8%	16.3%	14.4%
	US\$ 50/kW	27.6%	20.2%	16.7%	14.4%	12.8%
	US\$ 60/kW	24.9%	18.2%	23.4%	12.9%	11.4%
	US\$ 70/kW	22.5%	16.4%	13.5%	11.6%	10.3%
	US\$ 80/kW	20.4%	14.8%	12.1%	10.5%	9.2%
Max. no. of vehicles [million]		2.1	7.2	20.6	55.4	145.5
Max. cumulative installations [million]		2.1	9.4	30.0	85.4	230.9

As this analysis shows, learning rates for all scenarios are in the range of what has been observed before. Nevertheless, the most optimistic cases for the fuel cell are close to the highest historical learning rates assuming maximum possible deployment. However, if maximum deployment was not achieved as was assumed for this simple analysis, the learning rates would be even higher. Moreover, sustaining such high growth rates is rare, which implies that “reality” may reveal lower hydrogen fuel cell shares than observed here in the optimistic case.

## 4.5 Summary of Results

This chapter has looked into the dynamics of technology change in personal transport and at the impact of various driving forces on the adoption of different engine technologies and alternative fuels in European transport; particular attention was paid to the role of CO<sub>2</sub> emission targets.

The analysis revealed firstly that hybrid engine technologies are a key option to address stringent CO<sub>2</sub> targets, providing 86% of total demand in personal transport by the year 2050 under a 50% CO<sub>2</sub> target by that year. Among hybrid vehicles, mostly oil product hybrids were adopted, but all alternative fuels taken together made up for 33% of all hybrid vehicles on the market by the middle of the century with this mitigation target, with natural gas at the forefront. In the long-run, hydrogen fuel cell

vehicles gained importance in this analysis and covered almost the entire personal transport demand by 2100.

A variation of the level of CO<sub>2</sub> reduction targets showed that the higher is the target, the more important is the role the fuel cell can play already in the year 2050, since biomass is required to decarbonize other sectors of the energy system in the cost-optimization framework of EHM and low-carbon sources of hydrogen are adopted at low cost. However, as this analysis considered European biomass potential only, the full technological potential of vehicles fuelled with biofuels could not be exploited. The situation, therefore, may look different when assessing prospects of biofuels on a global scale. As an example, Turton (2006b) conducted an analysis of global car transport under a climate change target with the integrated assessment modelling framework ECLIPSE. On the one hand he also found that hybrids play a key role in the middle of the century, and hydrogen fuel cells become important in the second half of the century, which is similar to the results of the analysis with EHM. On the other hand, however, the scenario results suggest a much more important role for biofuels hybrids than in the analysis here, driven by higher availability of low cost biomass on a global scale. This implies for Europe that if a larger role for biomass and biofuels is desired, imports from other world regions would be required. Otherwise, one may lose out on more cost-effective CO<sub>2</sub> reduction measures using biomass in other sectors than personal transport. We will return to the issue of biofuels utilization with the modelling analyses in chapter 5, which are conducted on a global scale.

For the hydrogen fuel cell, the analysis in this chapter showed that this technology can play an important role in future personal transport in Europe in the second half of the century. The sensitivity of the results to several assumptions was investigated and it was found that the penetration of hydrogen fuel cells critically depends on oil and gas price developments. The higher oil and gas prices become in the long-run, the more competitive becomes this option. In fact, the results obtained even suggest that unless there is a really stringent CO<sub>2</sub> target (here 60% reduction by 2050), hydrogen market shares may respond stronger to increasing oil and gas prices than to CO<sub>2</sub> abatement targets.

Another key to the market success of hydrogen fuel cell vehicles is the future level of the fuel cell cost, which was assumed to reach US\$ 50 /kW by the year 2060, i.e. 50 years after the assumed market introduction. A sensitivity analysis showed that the earlier fuel cell floor costs are reached, the more significant is the contribution that hydrogen FCVs can make, already in the first half of the century. However, it was also shown that the most critical factor is the actual level of the floor cost reached: under a 50% CO<sub>2</sub> reduction target, fuel cell cost levels of US\$ 40 /kW were needed in order to make these vehicles competitive by the year 2050. The earlier these costs are reached, the higher can be the market share by 2050. With more stringent CO<sub>2</sub> target for the year 2050, however, fuel cells are competitive at even higher cost. Throughout all scenarios, hydrogen was produced from technologies with little to zero CO<sub>2</sub> emissions such as wind+electrolysis, nuclear hydrogen and natural gas reforming and coal gasification with carbon capture and sequestration. This made hydrogen an attractive energy carrier for the use in transportation.

#### **4.6 Discussion and Conclusions**

The analysis conducted here sheds light on conditions under which different fuels and different technologies could play a role in European personal transport from a cost-optimization point of view. It shows that if Europe wants to fulfil its ambitious targets by the year 2050, then personal transport will need to contribute, and advanced engine concepts and alternative fuels will be key elements in this contribution.

As regards engine technologies, hybrid drivetrains have been found to be a cost-efficient solution for reducing CO<sub>2</sub> emissions from European personal transport. The choice of alternative fuels, however, is not straightforward, as key limitations have been found for all alternative fuels considered. For biofuels, the availability of biomass is the limiting factor and restricts the deployment of biofuels under the scenarios analyzed here. For hydrogen, the ultimately achievable fuel cell production cost has been identified as the key factor for the timing of market introduction and for hydrogen's ability to become a cost-competitive fuel in a foreseeable timeframe. The sooner fuel cell costs can be reduced e.g. through mass production, the earlier they can become competitive and contribute to reducing CO<sub>2</sub> emissions from personal transport. In this light, manufacturing cheap fuel cells is both a driver for the

deployment of hydrogen fuel cell vehicles as well as an obstacle: if cost reduction targets for the fuel cell cannot be achieved, then this is an important barrier for hydrogen market success.

Sensitivity analyses of fuel cell floor costs conducted by Azar *et al.* (2003) on a global level also suggest that with aggressive fuel cell cost targets, high market shares can be obtained already in the first half of the century. Their analysis of sensitivities went as far as to assume US\$ 20 /kW fuel cell costs by the year 2020, resulting in a hydrogen fuel cell global market share of 50% by the year 2040. Reaching these costs in such a short timeframe is somewhat unlikely from the point of view of required learning rates and current levels of fuel cell production, as discussed earlier in this thesis. However, it is consistent with the analyses here and shows the potential that hydrogen fuel cell could have in personal transport if cost reductions are achieved.

#### 4.6.1 Policy Implications

The analyses show that fundamental changes are required in order to meet demand for future personal transport in a cost-efficient, but environmentally benign way. However, such fundamental changes do not unfold without efforts, and the results obtained within this section should not be understood as to whether CO<sub>2</sub> targets (or, alternatively, CO<sub>2</sub> taxes) alone are a sufficient measure for the market success of hybrid vehicles in the medium- and hydrogen fuel cells in the long-run. They are required, but in order to achieve technological change and the required cost-reductions that were assumed in this analysis, policy-makers need to set suitable incentives and give appropriate signals to industry and consumers. By way of example, efficiency standards on personal vehicles may facilitate a better market position for hybrid vehicles; and tax exemptions on alternative fuels would provide incentives to switch fuels (see e.g. Steenberghen and López (2008) for a comprehensive discussion on policy measures).

One key uncertainty of the analyses in this section is – obviously – whether floor costs assumed for all technologies will eventually be reached. However, it is probably most important for the fuel cell to do so in order to make hydrogen become a viable option for personal transport. Hydrogen holds a great promise for fuelling future

transport; this observation is not new and has been shown elsewhere (see for example Ramesohl and Merten (2006), who suggest on the example of Germany that efficiency improvements in ICEVs will be sufficient for the decades to come, and a transformation towards hydrogen-based transportation is required for the second half of the century). It is evident, however, that a transformation of the transportation sector takes time. The results in this chapter suggest that it takes fuel cell cost reductions today to make hydrogen viable in the future, and the earlier low cost fuel cells can be manufactured, the earlier and more important hydrogen fuel cells can be. Achieving this may take more than CO<sub>2</sub> targets alone: additional support for R&D efforts in academia and industry would help facilitate the adoption of hydrogen as a means to realize policy targets related to achieving a sustainable transport sector in Europe.

#### 4.6.2 Final Comments

The analyses in this chapter have been limited in various ways. First and foremost, many energy security aspects have not been considered in this analysis, including the desire of Europe to gradually become more independent from oil and gas imports; moreover, the restricted natural availability of fossil resources may cause shifts towards other fuels or other modes of transportation in the course of the century. The analysis of energy security has been limited to increasing oil prices - one important, but not the only aspect of energy security. The other two aspects, i.e. the availability of natural resources as well as the desire for import independency for geopolitical reasons will be dealt with in chapter 5.

Moreover, the deployment of alternative fuels in transport requires considerable infrastructure investments, which is particularly the case for hydrogen. Industry is reluctant to make such upfront large-scale investments where there is high uncertainty about future demand, unless forced by policy. Large-scale hydrogen fuel cell market penetration, as was obtained under various policy regimes in this chapter, therefore, inevitably entails the question how large-scale deployment of hydrogen is going to take place in practical terms. All analyses in this chapter were conducted with hydrogen production and delivery costs based on units of hydrogen delivered,

i.e. the question of scales of hydrogen delivery from central production facilities was not considered explicitly. It will, thus, be further dealt with in chapter 5 as well.

Finally, the analyses in this chapter have been restricted to cost-optimization, and thus neglect the aspect of consumer preferences. Observations such as that biofuels are hardly competitive throughout all scenarios investigated here, because the limited biomass is rather utilized in other sectors, are, therefore, to be taken with caution. This observation is appropriate from the point of view of a least-cost optimization social planner. However, other driving forces do exist that could alter the picture, e.g. consumer preferences and, in the case of biofuels, policies supporting agricultural production. While least-cost planning reveals that hybrid drivetrains using oil products or natural gas and hydrogen fuel cells are competitive, consumers may choose differently, motivated for example by questions such as higher comfort, convenience or “fashion” on the one hand, or the desire to “do something for the environment” on the other hand. The analyses in this dissertation will not take due consideration of these aspects given the focus on cost-competitiveness, but is important to keep them in mind when reading.

## 5 Global Scenarios for Alternative Fuels

This chapter intends to broaden the scope of the analyses conducted so far by looking into the prospects of alternative fuels on a global level. In doing so, it seeks to provide answers to three overarching questions:

1. What is the role of energy security and moderate climate policy targets on the competitiveness of hydrogen and biofuels as alternative fuels in personal transport?
2. What are the implications of stringent climate policy on the market penetration of hydrogen and biofuels in personal transport?
3. What are further barriers to the implementation of hydrogen and biofuels?

With questions 1 and 2, the analysis returns to the discussion of energy system challenges, namely climate change and energy security as they were introduced in chapter 2 of this dissertation, and the potential roles of alternative fuels in dealing with these challenges. In addition to the above overarching questions, this chapter further advances the representation of technology dynamics in order to assess the role of technology change on the competitiveness and potential of alternative fuels. Moreover, it seeks to provide insights into the question “where will hydrogen come from?”, if a transition to hydrogen is taking place, and how it will be delivered.

Again, a MARKAL-type model is used, in this case the Global Multi-regional MARKAL model (GMM), which is coupled to the climate model MAGICC<sup>34</sup>, thus allowing for a more detailed analysis of climate mitigation targets. GMM is introduced in detail in section 5.1. Section 5.2 introduces endogenous technology learning and learning clusters as a means to account for technology change in GMM. Section 5.3 presents the baseline scenario. In section 5.4, the implications of pursuing energy security and moderate climate policy in isolation or in combination are analysed. This analysis is followed by a scenario assessment of more stringent climate policy targets in section 5.5, which aims at providing comprehensive insights into energy system structural changes in response to stringent climate policy and the role of alternative fuels therein. The analysis is complemented by a discussion of the sources of hydrogen production for selected scenarios, where hydrogen market

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<sup>34</sup> See Wigley (2003) and Wigley and Raper (1997) for details about MAGICC.



penetration takes place. Finally, section 5.6 derives conclusions and policy implications.

## **5.1 Introduction to the Global Multi-Regional MARKAL Model GMM**

An analysis of policy instruments targeting climate change and energy security is most adequately being pursued in a global modelling framework due to the global nature of climate change. The same holds true for energy security targets, where a global, but regionally disaggregated model that reflects the complex interdependencies of the energy systems of different world regions can help finding answers as to whether and how energy security targets can be achieved.

Furthermore, an effective assessment of energy-related policy instruments towards a more sustainable energy-system is most adequately pursued in a modelling framework that reflects the entire energy-system and is capable of simulating the required technological changes and the complex interactions between different sectors of the energy system.

As a tool that provides the framework for such policy assessment, the Global Multi-regional MARKAL model GMM has been developed and applied at the Energy Economics Group of the Paul Scherrer Institute. Originally developed by Barreto (2001), the model has ever since been enhanced and applied for numerous energy policy analyses (e.g. Barreto and Kypreos 2004; Rafaj and Kypreos 2005; Rafaj *et al.* 2005; Rafaj 2005; and Krzyzanowski 2006). Just like EHM, which was used for the analyses in chapter 4 of this dissertation, GMM belongs to the MARKAL (MARKet ALlocation) family of models, i.e. a group of bottom-up, perfect foresight cost-optimization models that identify least-cost solutions for the energy system under given sets of assumptions and constraints and for a given time horizon.<sup>35</sup>

The analyses in this chapter of the dissertation have been carried out starting with the latest version of GMM as described in Barreto and Kypreos (2006). However, a

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<sup>35</sup> See for example Fishbone and Abilock (1981) for the basic MARKAL model and Loulou *et al.* (2004) for the official documentation of the standard MARKAL model including the full set of model equations and variables.

number of model enhancements and some maintenance work have been carried out, namely

- the transfer of GMM from its original DOS-based formulation into the modelling interface ANSWER (Noble-Soft 2007), involving substantial efforts with regard to debugging as a result of differences in the formulation of the code between the original DOS-based GMM and the ANSWER interface;
- the extension of world regions in GMM from originally five to six regions (see below for further discussion);
- the re-formulation of the code of MARKAL-ANSWER for a more suitable representation of endogenized technological learning (ETL) as further described in section 5.2;
- the introduction of a more detailed representation of hydrogen and biofuels production and delivery technologies as well as an update of the existing personal transport sector for the assessment of prospects of and policies for alternative fuels in transport, which is the purpose of this dissertation.

As mentioned above, the original version of GMM was disaggregated to the level of five world regions; this has been extended to six regions in the course of this dissertation. These regions are depicted in Figure 35. The region Western Europe (WEUR), which represents EU-27 plus Norway and Switzerland, is new to GMM. Other regions include Asia (ASIA); Former Soviet Union and Eastern Europe<sup>36</sup> (EEFSU); Latin America, Africa and the Middle East (LAFM); North America (NAM) and other OECD (OOECD).

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<sup>36</sup> Eastern Europe, here, is a naming convention that originates from the “historic” development of GMM. The current version of GMM considers “Eastern Europe” as those countries in Europe which are not part of EU-29.

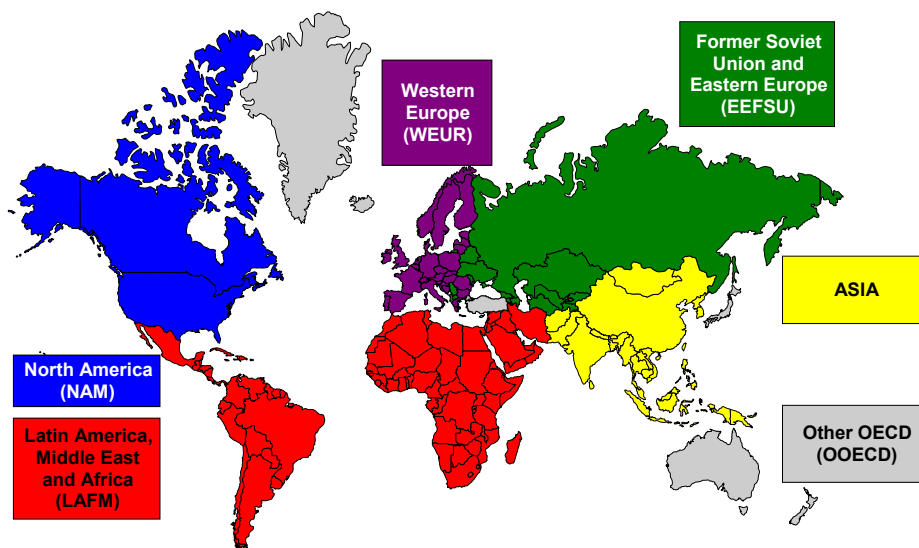


Figure 35. The six world regions in GMM.

The reference energy system (RES) of GMM is the same as in the European model EHM applied in the analyses in chapter 4, i.e. it covers the entire energy system from the extraction of resources, to conversion of primary energy carriers, to the use of final energy carriers in end-use technologies across different demand sectors. As for the latter, GMM distinguishes the same demand sectors and sub-categories, as well as technologies, as EHM. Moreover, a set of generic standard and advanced end-use devices is defined for each of the demand sectors other than personal transport, which is again modelled based on the techno-economic assessment in chapter 3.

While the RES of GMM is not being described any further here (the interested reader is referred to chapter 4 as well as Rafaj (2005) for this purpose), it is again important to mention that GMM possesses a high level of detail: firstly in electricity generation as a result of the work of Rafaj (2005); and secondly, as a result of the present dissertation, it considers hydrogen and biofuels fuel chains as well as personal transport in much detail, based on the techno-economic assessments in chapter 3 just as for EHM.

The multi-regional feature of GMM allows simulation of bi-lateral or global trade of energy or environmental commodities. Trade of any given commodity must balance at each period, i.e. the sum of trade variables over all regions is equal to zero. Energy commodities traded in GMM include hard coal, natural gas, liquefied natural

gas, oil, diesel and gasoline as well as biofuels (Bio-SNG, methanol, ethanol and biodiesel). One environmental commodity is traded in GMM, which are CO<sub>2</sub> emissions. Energy commodity trade comes at a cost, estimated based on the latest version of the MERGE model originally developed by Manne *et al.* (1995); CO<sub>2</sub> emissions can be traded freely.

While global trade of all fossil energy commodities is possible as of the base year 2000, the trade of both biofuels has been assumed to start as of the year 2010 in GMM throughout all scenarios.

The time horizon of GMM is 100 years divided into time steps of 10 years each with the base year 2000. GMM applies a discount rate of 5% per annum in all calculations and for all technologies, although the choice of discount rate is subject to sensitivity analysis in section 5.5.2.1.

### 5.1.1 GMM Calibration, Demand Projections and Assumptions

GMM is, just as EHM, calibrated to reproduce year 2000 statistics of the International Energy Agency (IEA 2002a; IEA 2002b) on both the production and demand side. Most of the future sectoral energy demands of GMM, with the exception of transport, are based on the B2 scenario of the IPCC in the Special Report on Emission Scenarios (SRES), described in detail in Riahi and Roehrl (2000). This scenario has undergone some adjustments since it was originally developed and these have been applied in GMM; all changes are reported in Grübler *et al.* (2006) and Riahi *et al.* (2007), and demands are available online at IIASA (2007). The B2 scenario can be interpreted as a „dynamics-as-usual” development of the global energy system with differences in economic growth across regions being gradually reduced and concerns for environmental and social sustainability rising with time. While demand projections have been taken directly from the B2 scenario, the objective of this analysis is not to reproduce the results of the SRES-B2 baseline scenario.

The scenario database of the B2 scenario as available at IIASA (2007) accounts for transport as one aggregated sector only, while GMM distinguishes personal transport, aviation and other transport. Details about how aviation and other transport

(mainly freight transport) are modelled have already been reported elsewhere (Barreto and Kypreos 2006); in summary, demands for the year 2000 were derived from IEA (2002a, 2002b), and future demand is assumed to grow at the same pace as the GDP growth rates of the SRES-B2 scenario.

Personal transport is again calibrated to reproduce year 2000 statistics derived from IEA (2002a, 2002b). Future demand growth is based on IEA/WBCSD (2004) until the year 2050. Thereafter, demand developments are based on the latest version of the ERIS model, originally developed at Paul Scherrer Institute and used for the dissertation of Turton (2006a). Figure 36 depicts demand developments in GMM; it shows that future growth in mobility is to a large extent assumed to take place in Asia (ASIA) and Latin America, Africa and the Middle East (LAFM) due to a gradual economic catch-up of these regions. Demand growth in developed regions such as Western Europe (WEUR), North America (NAM) and Other OECD (OOECD), in contrast, is anticipated to level off and begin to decline in the future.

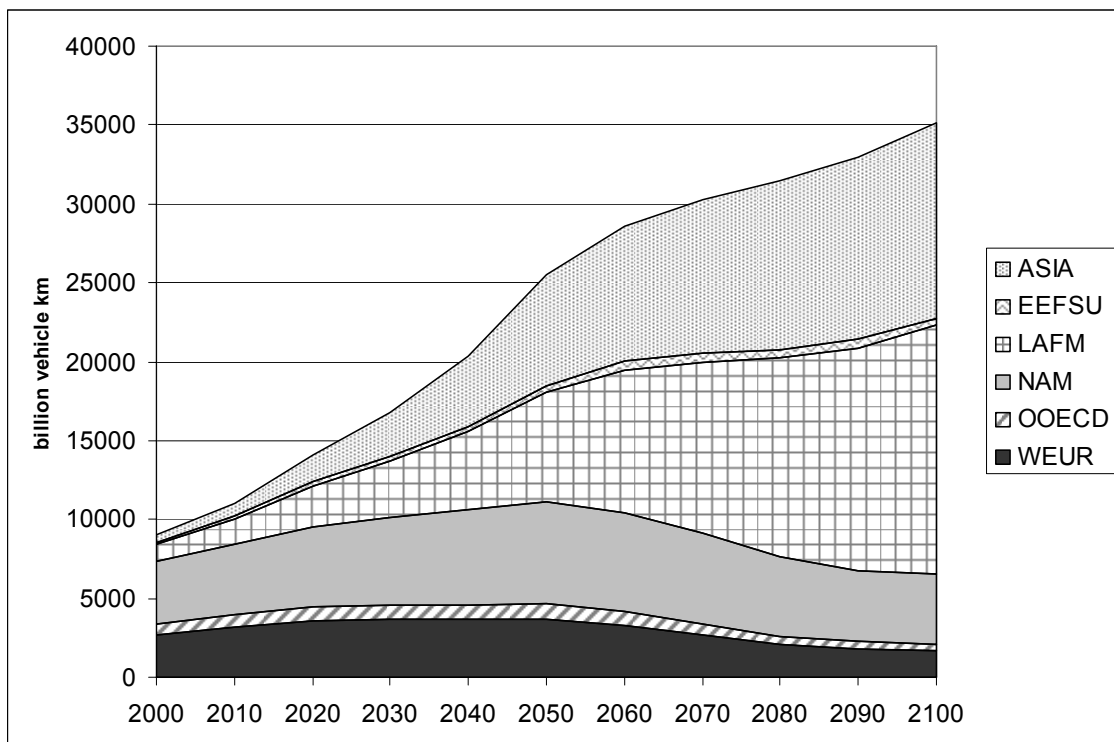


Figure 36. Global car travel demand in GMM

*ASIA = Asia; EEFSU = Eastern Europe and Former Soviet Union; LAFM = Latin America, Africa and the Middle East; NAM = North America; OOECD = Other OECD; WEUR = Western Europe (EU-29).*

Throughout all scenarios, it is assumed that new vehicles that are today available to the market as commercialised technologies (advanced gasoline and diesel ICEVs, oil product hybrids and biofuels ICEVs) can obtain a share of up to 5% of the total global personal transport market by the year 2010. All other new vehicles were restricted to a global maximum of 250'000 vehicles in total by the year 2010, and assumed to be able to achieve a market share of up to 1% in each region by the year 2020. Again, as in EHM, this setup is combined with moderate growth assumptions to reflect inertia in the transport sector. Nevertheless, the setup allows any technology to gain significant market shares within a few decades.

### 5.1.2 Reserves and Resources in GMM

A long-term analysis on a global level as conducted here brings along a number of issues beyond a simple comparison of technologies and their future prospects. In particular, the problem of resource availability is endogenous to GMM and influences modelling results, in line with energy security discussions of this dissertation. This section will introduce reserves and resources of the various energy carriers as applied in GMM.

#### ***Fossil Resources***

In GMM, total global oil reserves and resources amount to 20'042 EJ (or 479 Gtoe) and are separated into various categories based on Rogner (1997). For natural gas, 35'286 EJ (or 843 Gtoe) of reserves and resources are assumed available, also based on Rogner (1997). Figure 37 shows a breakdown of reserves and resources for the different world regions of GMM and according to categories defined by Rogner (1997); it shows, not surprisingly, that most of the oil reserves and resources are located in LAFM, i.e. Latin America, Africa and the Middle East. Gas reserves and resources are mainly concentrated in LAFM as well as EEFSU, i.e. Eastern Europe and Former Soviet Union.

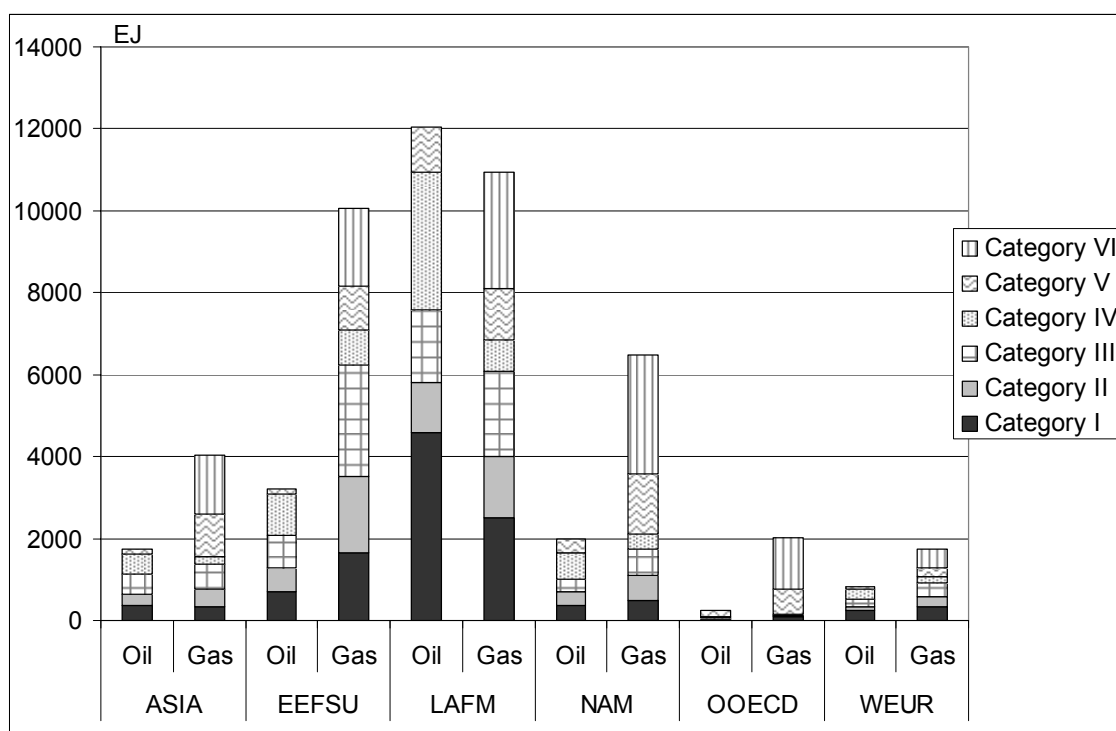


Figure 37. Oil and gas reserves and resources in GMM (based on Rogner 1997)<sup>37</sup>.

ASIA = Asia; EEFSU = Eastern Europe and Former Soviet Union; LAFM = Latin America, Africa & the Middle East; OOECD = Other OECD; WEUR = Western Europe (EU-29)

Other resources considered in GMM include uranium, coal and biomass. While uranium is assumed abundantly available, the availability of coal reserves and resources is based on Rogner (1997), just as for oil and gas. Further details are not reported here and can be found elsewhere (Barreto 2001). It is, however, important to note that coal availability does not impose a limitation over the next 100 years; nevertheless, prices are increasing with increasing utilisation.

Note that no limitation has been imposed on the availability of geological carbon storage reservoirs; rather, carbon storage was modelled assuming CO<sub>2</sub>-storage cost of US\$ 10 /ton of CO<sub>2</sub>, or US\$ 36.7 /ton of carbon that is captured.

### Biomass

Available biomass resources in GMM are based on IEA (2005b) and Mattson *et al.* (2004), distinguishing six different types of biomass. In total, global biomass resources amount to some 195 EJ (4.66 Gtoe) per year. Clearly, there is a lot of

<sup>37</sup> Categories I to III: conventional oil and gas (proved recoverable reserves; estimated additional reserves; additional speculative resources). Categories IV – VI: unconventional reserves and resources (enhanced recovery; recoverable reserves; resources). Category VI only considered for natural gas, categories VII and VIII (additional occurrences) are not considered in GMM.

uncertainty about this biomass potential, and Hoogwijk *et al.* (2003) suggest a possible range of (technical) primary biomass potentials of 33 to 1135 EJ per year for the year 2050. The potential assumed here is therefore rather at the conservative end of this range, and is depicted in Table 19.<sup>38</sup>

Table 19. Biomass resources in GMM (based on IEA 2005 and Mattson *et al.* 2004).

	ASIA [EJ/yr]	EEFSU [EJ/yr]	LAFM [EJ/yr]	NAM [EJ/yr]	OECD [EJ/yr]	WEUR [EJ/yr]
Wood residues	27.1	10.2	50.2	9.9	3.5	2.3
Rapeseed / soybeans	1.3	0.2	2.8	2.1	0.0	0.1
Corn grains	3.3	1.1	3.3	1.7	0.3	0.6
Sugar cane / sugar beet	10.6	0.0	11.8	0.2	0.5	0.0
Stover	8.5	9.6	14.0	9.4	2.3	3.2
Waste	0.8	0.4	0.5	2.0	0.2	1.0

Just as in the modelling analyses of chapter 4, biomass feedstock costs were derived from the FAO as weighted averages for the years 2000-2003 (FAO 2006), using producer prices including biomass production, harvesting, pre-treatment, transport and storage, as well as the farmer's margin. Resulting biomass costs are reported in Table 20.

Table 20. Biomass costs in GMM<sup>39</sup> (FAO 2006)

	ASIA [US\$/GJ]	EEFSU [US\$/GJ]	LAFM [US\$/GJ]	NAM [US\$/GJ]	OECD [US\$/GJ]	WEUR [US\$/GJ]
Wood residues	5.26	1.92	1.67	7.47	8.04	3.10
Rapeseed / soybeans	11.21	7.10	7.90	8.62	10.48	8.44
Corn grains	6.52	5.99	6.54	4.99	6.88	6.71
Sugar cane/ sugar beet	1.78	7.73	1.92	2.25	1.49	10.32
Stover	5.41	1.97	1.72	7.52	8.09	3.15
Waste	5.21	2.04	1.79	7.59	8.16	3.22

<sup>38</sup> There is a lot of controversy about potential conflicts in land-use regarding biomass for food production or energy purposes. Indeed, some feedstocks such as corn grains bear this inherent problem. Nevertheless, there is substantial cellulosic biomass considered here that allows to generate fuels without interference with food production.

<sup>39</sup> Includes costs of transport by truck over a distance of 50 km, which is assumed to cost 10 \$/t in addition to the producer prices of biomass. For details, see Ragetti (2007).



### Renewable Energies

Some explicit assumptions have been applied to reflect deployment potential of renewable energy technologies, which limit the market penetration of renewable energy technologies such as solar energy and wind and hydro power in GMM. Most of these assumptions have already been reported in Rafaj (2005); additional sources applied were IEA (2003a), WEC (2001) and Hoogwijk *et al.* (2004) and are modelled as maximum potentials by region. Furthermore, intermittent renewable electricity technologies such as solar photovoltaic or wind power were limited to a maximum penetration level of 25% of electricity generation by region, which has been assumed to be the upper limit due to the variable nature of electricity generation from these sources.

#### 5.1.3 The Climate Model MAGICC

GMM has been linked to the simplified climate model MAGICC (Wigley and Raper 1997; Wigley 2003). This allows the assessment of energy system changes on climate, and the impact of climate policy on the energy system, in particular on the introduction of alternative fuels in transport. Note, however, that GMM in its current formulation in ANSWER does not consider greenhouse gases other than CO<sub>2</sub>. This is due to the fact that the formulation of abatement curves in the original DOS-based GMM cannot be applied in ANSWER, and a re-formulation was beyond the scope of this thesis. Emissions of other greenhouse gases are instead based on the Greenhouse Gas Initiative (GGI) scenario database of the International Institute for Applied System Analysis IIASA (IIASA 2007) for the B2 scenario.

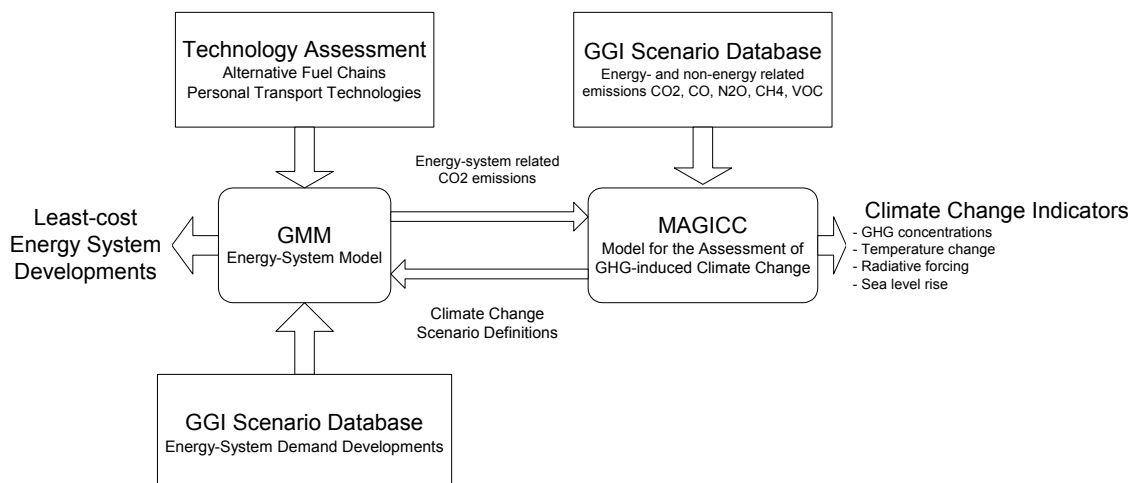


Figure 38. Link between the energy-system model GMM and the climate change model MAGICC.

## 5.2 Endogenous Technological Learning (ETL)

Endogenizing technological learning advances the representation of technological change in energy-optimization models by accounting for the need for early investments and experience for a technology to progress in the marketplace and achieve cost-competitiveness in the long-term Messner (1997). With this aspect of technology change represented, the model decides to invest in technologies that are deemed most promising in the long-run in terms of cost-competitiveness, including the costs of early of early technology development. Thus, the ETL mechanism reflects that society pays for technological progress and cost reductions do not happen without societal efforts. In addition, cost-reductions for technologies, which are not cost-competitive in the long-run, do not take place and technologies that are not cost-efficient are simply locked-out.

To represent ETL, the GMM model endogenizes learning (or experience) curves using cumulative installed capacity as a proxy for accumulated experience (Barreto 2001; Barreto and Kypreos 2004). In such a one-factor learning formulation, specific investment costs (SC) of a learning technology  $te$  at the time period  $t$  are computed as

$$SC_{te,t}(CC) = a \times CC_{te,t}^{-b}$$

where

CC: Cumulative capacity

b: Learning index

a: Specific cost at unit cumulative capacity

Instead of the learning index  $b$ , the learning rate ( $LR$ ) is commonly specified, i.e. the rate of cost decline per doubling of cumulative capacity. The learning rate is expressed as

$$LR = 1 - 2^{-b}$$

In order to avoid unrealistic reductions of investment costs below technology specific thresholds, earlier formulations of learning in GMM used to apply a “floor cost”, i.e. a lower bound for the specific investment costs of a learning component (Barreto and Kypreos 2006). However, and as mentioned above, GMM has been transferred from

the previously applied DOS-format to ANSWER for this thesis. In doing so, this thesis is the first that applies global technological learning in ANSWER beyond experimental tries, in particular as regards clustered technological learning that will be introduced in the following section.

In ANSWER, however, the formulation of the learning code does not allow the specification of a floor cost. Instead, the user specifies a maximum installed cumulative capacity that marks the floor costs of the technology, i.e. the installation of this cumulative capacity leads to cost reductions still deemed realistic and mark the end of the learning curve.

This approach has one significant shortcoming: once the maximum cumulative capacity is reached, no additional capacity of this technology can be installed. Thus, the technology is limited in its market penetration by the maximum cumulative capacity that marks the end of the learning curve and, thus, the floor costs of the technology. As the modelling timeframe of GMM is the year 2100, this is a significant weakness, since certain technologies with high cost reduction potentials may exploit this capacity in the long-run.

In order to overcome this weakness, the code of ANSWER was modified in the course of this PhD thesis to allow the user to specify floor costs. This involved a reformulation of the ETL-code for ANSWER based on the work of Barreto (2001) and Barreto and Kypreos (2006). With these changes, “floor costs” can be used to mark the end of the learning curve without jeopardizing the technology’s ability to penetrate the market further.

### 5.2.1 Learning clusters

Technological change does not evolve in isolation; rather, complex interactions exist, and there is a wide variety of literature available studying the complexity of this question (see for example Nakićenović 1997; Grübler, *et al.* 1999). These interactions lead to the creation of technology clusters (Sahal 1980), i.e. families of technologies evolving and diffusing together (Barreto and Kypreos 2006).

Investigating the role of spillover effects and technology clusters is important when it comes to an assessment of alternative fuels such as hydrogen and biofuels. Similar

technologies from the same technology family may benefit from experience gained through the deployment of other technologies in the family, leading to improvements in cost or performance for all the technologies in the same technology cluster.

In this thesis, the clusters approach has been applied to a number of technologies by identifying several “key components”, i.e. components that are common to several technologies.<sup>40</sup> Figure 39 illustrates this approach for the example of a gasifier as a key component to electricity, hydrogen and other fuel production. Despite some technical differences in such gasifiers, this approach to technological learning suggests that the utilization of one technology, e.g. coal-based IGCC, will ultimately lead to cost reductions for the other technologies as well.

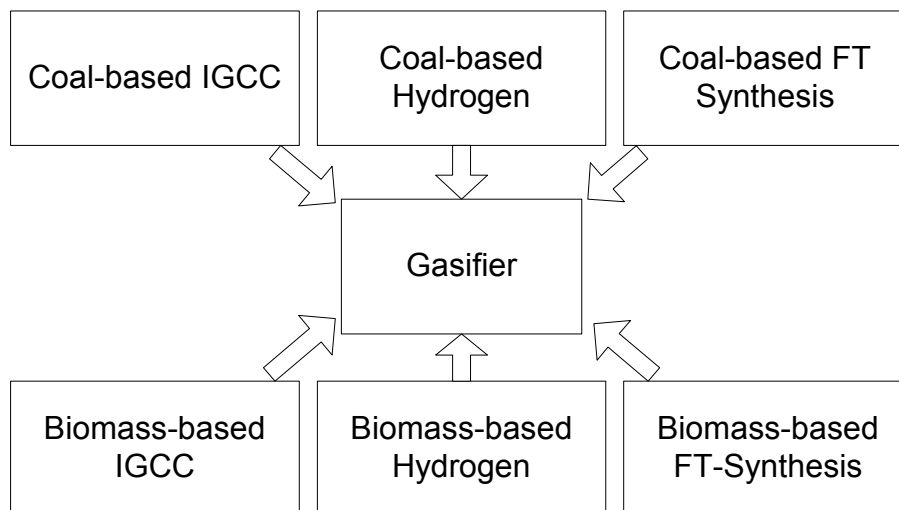


Figure 39. Learning clusters for gasifiers.

Clearly, some technologies may include several key components from different clusters. This is illustrated in Figure 40 for the case of the hydrogen fuel cell vehicle (FCV), which is here considered as a fuel-cell-battery hybrid car applying the two key technologies battery and fuel cell. The balance of system (BoS) is considered to be non-learning.

<sup>40</sup> A previous DOS-based version of GMM has already made use this mechanism, compare Barreto and Kypreos (2006).

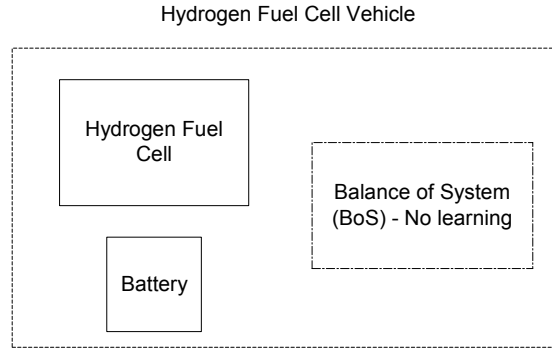


Figure 40. Hydrogen fuel cell vehicle as an example of a technology with several key components.

In the present approach to clustered learning, full spillovers between technologies of the same technology clusters are assumed, with technology learning assumed to take place on a global level. The relationship between cumulative capacity of a key component  $kc$  and the cumulative capacity of all technologies  $te$  that share the component in the time period  $t$  is thus understood as

$$CCAP_{kc,t} = \sum_{te \in kc} \sum_{reg} clust_{te,ke} \times CCAP_{te,t}$$

where:

$CCAP_{kc,t}$ : Cumulative capacity of key component  $kc$  in time  $t$

$CCAP_{te,t}$ : Cumulative capacity of technology  $te$  in time  $t$

$tetokc$ : Mapping set between key component  $kc$  and technologies  $te$  sharing it

$clust_{tetokc}$ : Clustering factor relating the fraction of cumulative capacity of technology  $te$  that contributes to cumulative capacity of the key component  $kc$

Other than the above described examples, numerous additional technologies are specified as key components in GMM including:

- Gasifier (GSF)
- Gas turbine (GTU)
- Stationary fuel cell (SFC)
- Solar photovoltaic (SPV)
- Wind turbine (WND)
- Advanced nuclear power plant (Generation III+, IV) (NNU)

- Solar thermal heliostat field (STH)
- Stationary steam methane reformer (SRR)
- CO<sub>2</sub> capture in conventional coal power plants (post-combustion) (CC1)
- CO<sub>2</sub> capture in natural gas combined-cycle power plants (post-combustion) (CC2)
- CO<sub>2</sub> capture in coal and biomass-based integrated gasification combined-cycle (IGCC) power plants (pre-combustion) (CC3)
- CO<sub>2</sub> capture in hydrogen production (natural gas steam reforming / coal gasification / biomass gasification) (CC4)
- Sulphur-iodine cycle for hydrogen production (SIC)
- Alkaline water electrolysis (EAW)
- High-temperature electrolysis (EHT)
- Battery (BAT)
- Mobile hydrogen fuel cell (HFC)
- Mobile auto-thermal reformer (REF)

The above key components are linked with a number of technologies in electricity and fuel production as well as in the transport sector. Table 21 gives an overview on the electricity production technologies.

Table 21. Technology clusters in electricity generation.

Technology	Key Components									
	GSF	SFC	GTU	SPV	STH	WND	NNU	CC1	CC2	CC3
NGCC			X							
Gas turbine			X							
NGCC w/CCS			X						X	
Coal conventional w/CCS								X		
Coal IGCC	X		X							
Coal IGCC w/CCS	X		X							X
Biomass IGCC	X		X							
Biomass IGCC w/CCS	X		X							X
Solar PV				X						
Solar thermal electric					X					
Onshore wind						X				
Offshore wind						X				
Advanced nuclear power							X			
Stationary hydrogen fuel cell		X								
Gas fuel cell		X								

In Table 22, an overview of technologies and their link to key technologies in hydrogen, biofuels and other synfuels production is given.

Table 22. Technology clusters in fuel production.

Technology	Key Components											
	GSF	SFC	GTU	STH	WND	NNU	CC4	SRR	SIC	EAW	EHP	EHT
Coal gasification	X		X									
Coal gasification w/ CCS	X						X					
Coal Gasification w/CCS electricity co-production	X	X					X					
Gas reforming								X				
Gas reforming w/ CCS							X	X				
Biomass gasification	X											
Nuclear SI cycle						X			X			
Nuclear high-pressure electrolysis						X					X	
Nuclear high-temperature electrolysis						X						X
Wind & electrolysis					X					X		
High-pressure electrolysis											X	
Electrolysis										X		
Solar Zn/ZnO cycle				X								
Solar coke gasification				X								
Methanol reforming								X				
Gasoline reforming								X				
Wood-to-FT-diesel	X											
Wood-to-DME	X											
Wood-to-SNG	X											
Wood-to-methanol	X											
Coal-to-FT-liquids	X											
Gas-to-methanol								X				

Finally, technology clusters have been applied in personal transport, and are depicted in Table 23 below.

Table 23. Technology clusters in personal transport.

Technology	Key Components		
	BAT	REF	HFC
Gasoline hybrid vehicle	X		
Natural gas hybrid vehicle	X		
Hydrogen hybrid vehicle	X		
Biofuels hybrid vehicle	X		
Hydrogen fuel cell vehicle	X		X
Gasoline fuel cell vehicle	X	X	X
Plug-in hybrid vehicle	X		
Battery electric vehicle	X		

### 5.2.2 Cost Assumptions for Key Learning Components

Applying technology clusters helps to assure that assumptions are consistent throughout sectors, i.e. assumptions on initial and floor costs of each key component

are the same no matter for which technology they are used; moreover, the year at which floor costs are reached is the same for these technologies and endogenous to the model as a result of the optimization process.

### ***Electricity and Fuel Production***

Table 24 presents the initial and floor cost assumptions along with the assumed learning rates used in electricity and fuel production in this analysis. Most of the data are based on Barreto and Kypreos (2006). The existing dataset was extended with additional key technologies for fuel production.

For future technologies that are expected to become available no earlier than around 2030 such as the sulphur-iodine cycle or high-pressure and high-temperature electrolysis for hydrogen production, initial costs were adjusted from the US H2A spreadsheet models (H2A 2006a); for the floor costs an additional cost reduction of 5% was then deemed possible due to technology learning.

Further details about the contribution of each learning component to total initial investment costs for the technologies that use these components are reported in appendix 4 of this dissertation.

*Table 24. Costs of key components in electricity and fuel production.*

		Key Components							
		GSF	GTU	SFC	SPV	WND	NNU	STH	SRR
Initial Cost	[US\$ / kW]	300	200	1250	5500	1200	2200	1500	180
Floor Cost		100	100	500	1000	700	1000	500	90
Learning rate	[%]	12%	10%	15%	18%	8%	6%	12%	10%
		CC1	CC2	CC3	CC4	SIC	EAW	EHP	EHT
Initial Cost	[US\$ / kW]	940	542	509	200	466	1200	631	359
Floor Cost		500	250	250	100	442	350	599	341
Learning rate	[%]	10%	10%	10%	10%	5%	8%	5%	5%

### ***Personal Transport***

Personal transportation in GMM is treated using “generic” vehicles, i.e. no distinction is made between different vehicle sizes. Vehicle costs are divided into costs for learning and non-learning components. Learning components are those which are expected to encounter significant cost reductions after their initial commercialization, whereas non-learning components are assumed to remain at a constant cost because potential reductions are deemed less pronounced. All cost data are based



on Kromer and Heywood (2007), Kasseris and Heywood (2007) and Turton (2006a) and have been presented in detail in section 3.3 already. Table 25 presents again the initial and floor cost assumptions along with the learning rates used in the personal transport sector in this analysis.

Table 25. Investment cost clusters in personal transport.

Technology	Size	Learning rate	Initial Cost	Floor Cost	
Fuel Cell	40 kW	15%	250	50	US\$/kW
Reformer	40 kW	15%	90	25	US\$/kW
Hybrid Battery System	28 kW	15%	2'500	800	US\$/vehicle
Fuel Cell Battery System	42 kW	15%	3'250	1'200	US\$/vehicle
Battery Electric	48 kWh	15%	16'250	12'000	US\$/vehicle
Plug-in Hybrid	8.2 kWh	15%	6'500	2'800	US\$/vehicle

### 5.2.3 Some Modelling Remarks

Including endogenous technological in a modelling framework such as GMM is a mixed blessing. On the one hand, it enhances the representation of cost reduction mechanisms and the ability of the model to make appropriate technology choices.

One substantial drawbacks of this approach, on the other hand, is computing time. GMM in its structure is a highly complex model consisting of some 2400 technologies and processes. While solving the baseline case in the linear programming version of GMM with exogenous cost reduction assumptions takes a few minutes only, including endogenous technological learning with some 20 learning technologies significantly increases computing time up to several hours and even days, depending on the scenario investigated. This fact has been drawback to several attempts in applying ETL in ANSWER-MARKAL based models. One example is the ETP-model of the International Energy Agency (IEA), which is a multi-regional global MARKAL model with significant technological detail. Gielen *et al.* (2003) highlight how implementing only three key learning technologies and increasing the time horizon raised computing time by a factor of 10.

At some point, thus, computing time becomes a limiting factor for such an analysis and one needs to decide on a case-by-case basis whether it is wise to include ETL in an analysis and at which level of detail. In this thesis, it was decided to choose a high

level of technology detail as outlined above given the strong technology-oriented focus of this dissertation.

### **5.3 Baseline Scenario**

As described earlier, the baseline scenario is based on the IPCC-SRES B2 scenario available at IIASA (2007), and can, thus, be interpreted as a „dynamics-as-usual” development of the global energy system with differences in economic growth across regions being gradually reduced and concerns for environmental and social sustainability rising with time. Again, however, it is emphasized that it is not intended to reproduce the B2 scenario; rather, key input parameter were used to define energy demand developments.

The baseline scenario of GMM does not consider any current policy efforts such as Kyoto- or post-Kyoto policies for reducing CO<sub>2</sub> emissions. Consequently, CO<sub>2</sub> emissions in the baseline continue increasing along current trends and reach 21 Gt of CO<sub>2</sub>/year in the year 2100, resulting in global CO<sub>2</sub> concentrations of 770 ppmv in the atmosphere by the end of the century. Figure 41 displays global CO<sub>2</sub> emissions by region, showing how anticipated economic growth in developing regions such as ASIA and LAFM results in these regions becoming the main contributors to global CO<sub>2</sub> emissions.

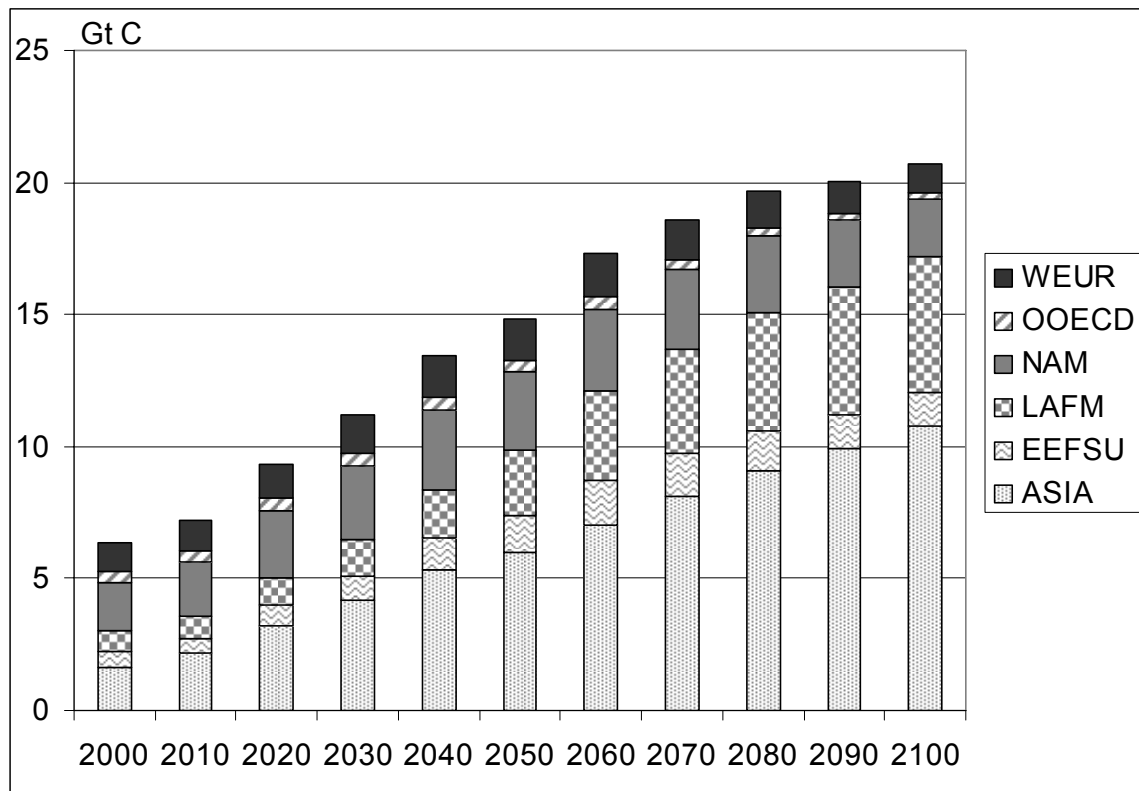


Figure 41. Global CO<sub>2</sub> emissions in the baseline scenario (in Gt C)

Under baseline scenario assumptions, primary energy consumption experiences significant growth, reaching almost 1'600 EJ / year by 2100. In absence of carbon mitigation policies or policies that internalize external costs, fossil fuels remain the predominant fuels, and coal makes up for 41% of total primary energy consumption in 2100. Even though the relative shares of oil and natural gas in total primary energy consumption are declining, their total consumption is increasing until the year 2050; thereafter, consumption declines driven by resource depletion and correspondingly increasing oil and gas prices. Oil and natural gas together make up for 19% of primary energy consumption by 2100, of which 158 EJ is from oil, and 139 EJ from natural gas. By the end of the century, oil is almost entirely consumed in aviation, which is a strongly growing sector and where no substitution fuels are considered in this modelling analysis.

Most of the growth in primary energy consumption takes place in ASIA as well as in LAFM, as shows Figure 42, in line with CO<sub>2</sub> emission developments described before.

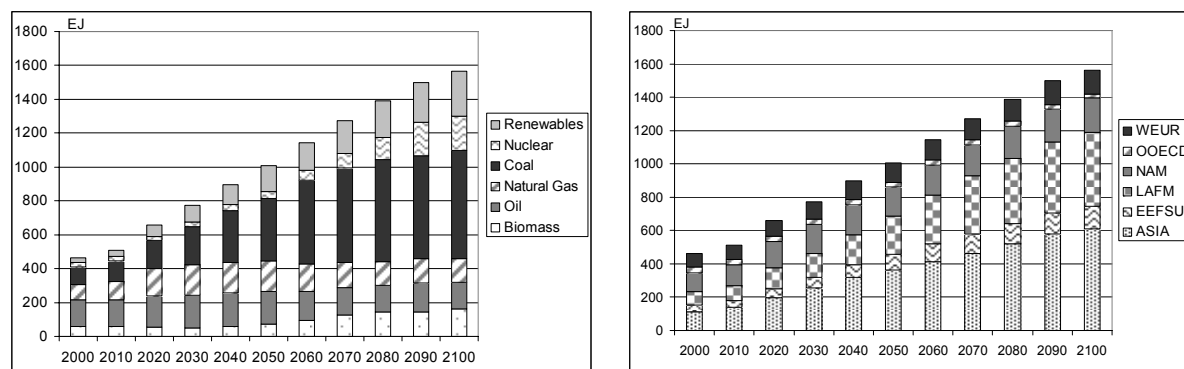


Figure 42. Primary energy consumption in the baseline scenario

Global electricity production in the baseline scenario grows by a factor of more than 7 under baseline scenario conditions, as depicted in Figure 43. In absence of climate policy, electricity production remains largely coal dominated, and the share of coal increases from 39% in the year 2000 to 57% in the year 2100. Electricity generation from natural gas almost doubles until the year 2040 and declines thereafter. New renewable energy technologies such as wind power or solar photovoltaic constitute a growing share in electricity production, making up for 10% of global electricity production in 2100. The same holds true for nuclear electricity production, which makes up for 16% of global electricity by 2100.

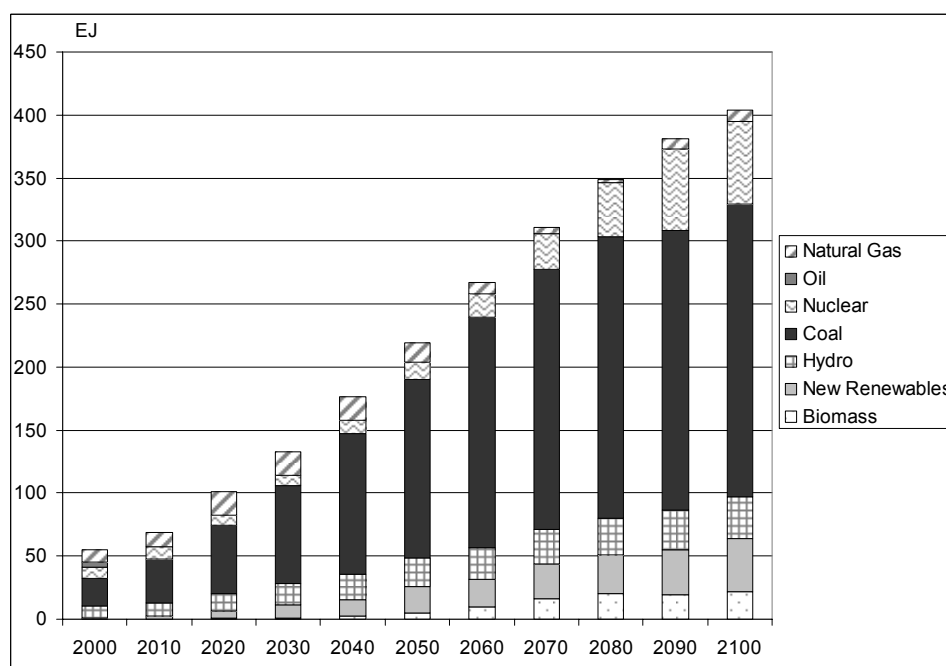


Figure 43. Global electricity production in the baseline scenario.

Personal transport undergoes considerable changes in the baseline scenario. In contrast to the baseline scenario of EHM, oil and gas resources are limited in GMM. With vigorously growing demand for mobility in developing countries, availability of oil reserves as well as their price becomes an important issue for the personal transport sector and requires adaptation. This is reflected in Figure 44, which shows how conventional ICEVs are gradually replaced by biofuels ICEVs and by hybrid vehicles, in particular oil product & synfuels hybrids. In the long-run, biofuels hybrids become an important technology in personal transport.

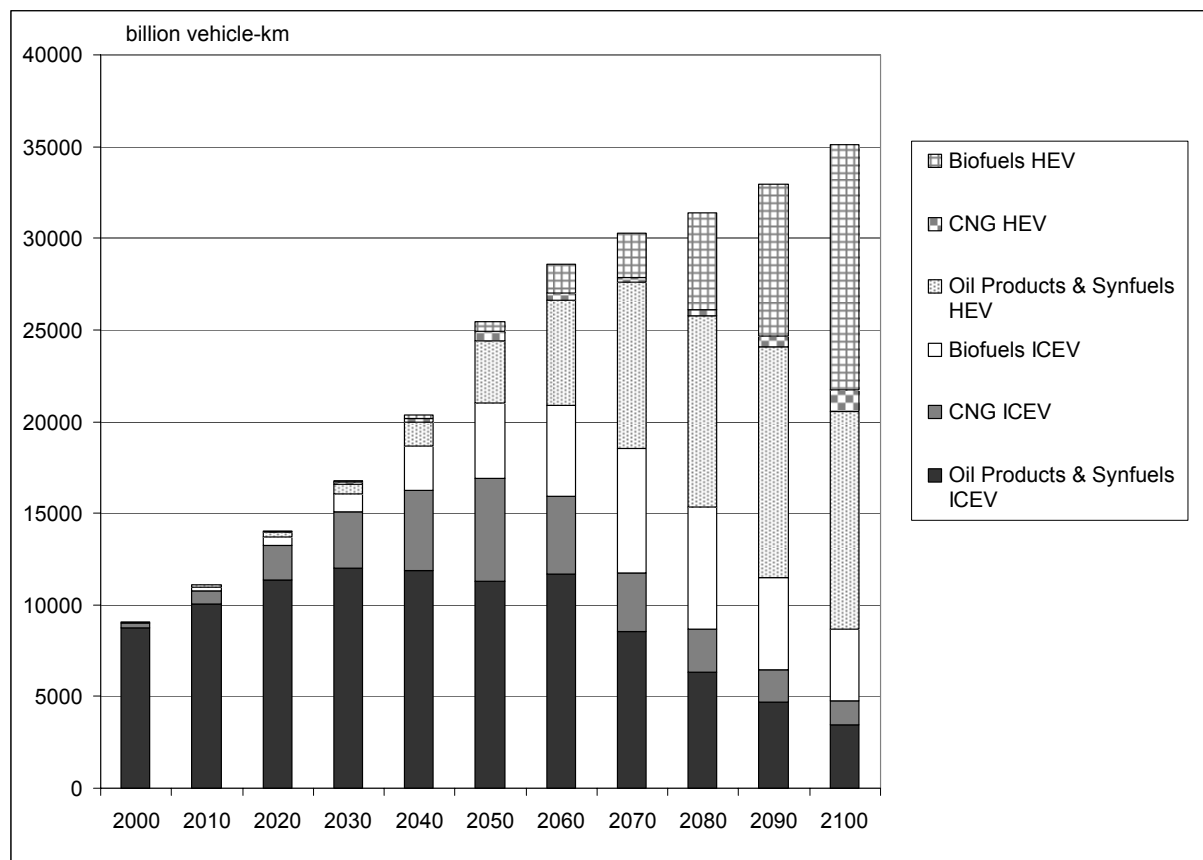


Figure 44. Personal transport development in the baseline scenario.

A closer look at where the growth of biofuels vehicles is taking place sheds light on the reasons for this development. Figure 45 shows that while early utilization of biofuels hybrids is predominately in North America (NAM), this region is overtaken by the developing regions LAFM and ASIA towards the middle of the century, i.e. by regions with high availability of low-cost biomass.

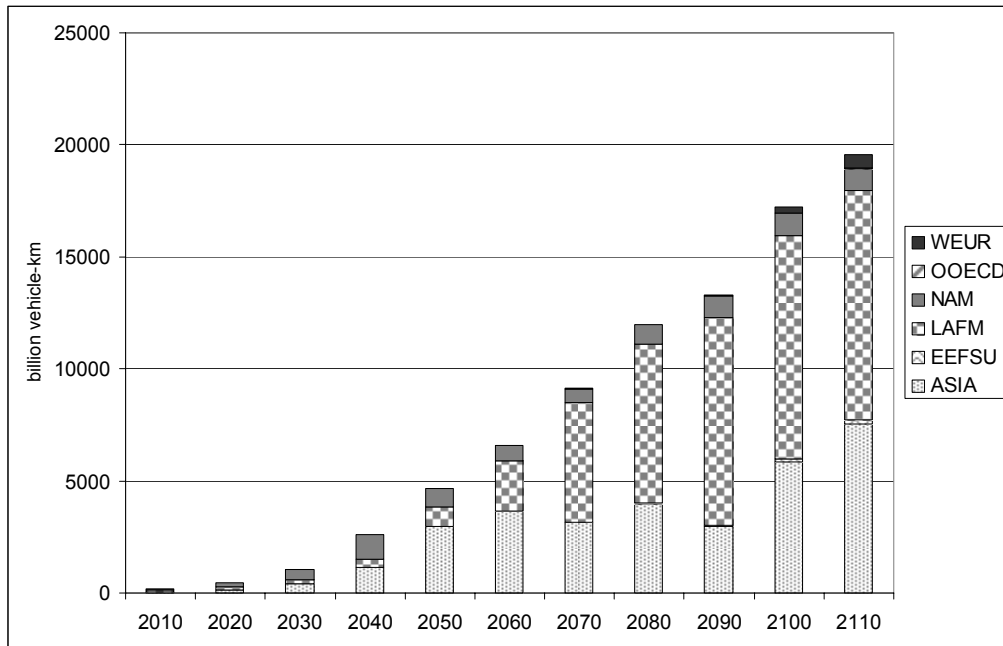


Figure 45. Biofuels vehicles across world regions in the baseline scenario.

The baseline scenario, thus, suggests that biofuels are a competitive option in personal transport in the long-run when petroleum becomes a limited and costly resource. Even though this scenario only considers biomass potential that is deemed as available for energy purposes, however, it is still important to keep in mind that biomass costs are assumed to stay at current levels, i.e. constant throughout the century. With developing biomass markets, however, the situation may alter and market prices of biomass may increase.

In any case, the baseline scenario confirms the trend observed in EHM that hybrid vehicles could become very important in future transport as a result of increasing fuel prices as well as fuel scarcity, in addition to technology learning making hybrids cheaper and, thus, more competitive even at comparatively lower fuel prices. Whether or not alternative fuels can play a role is largely observed as a result of their costs. Low-cost biomass is required in high quantities in order to make biofuels an important fuel in personal transport.

Global alternative fuel production increases significantly in the baseline scenario. Figure 46 shows that the main alternative fuels produced are liquid fuels derived from coal, constituting 80% of alternative fuel production in the year 2100 with 115 EJ of fuel produced.

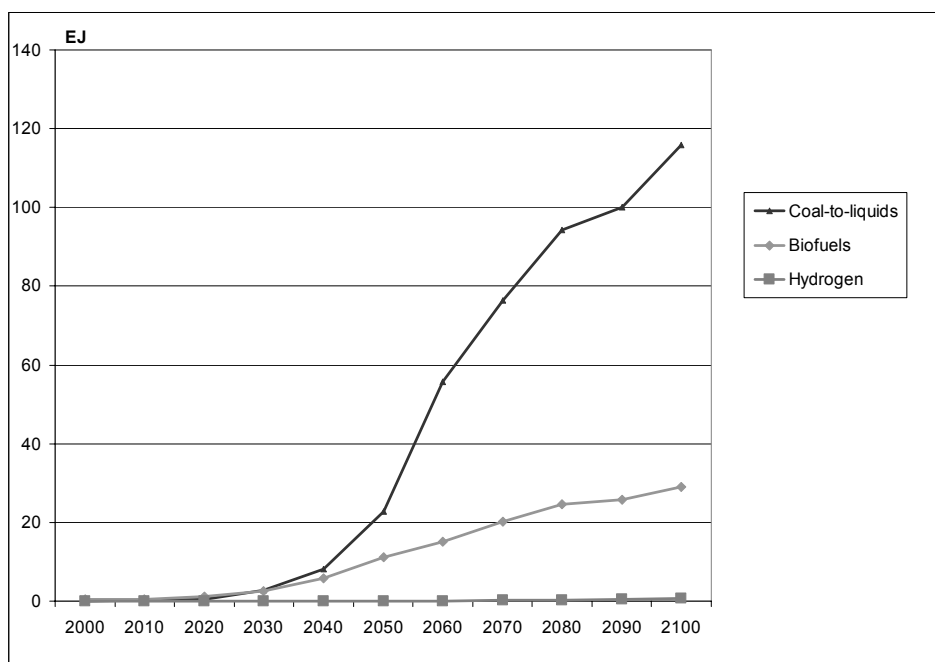


Figure 46. Alternative fuels production in the baseline scenario.

Total global biofuels production reaches 29 EJ in the year 2100, mainly taking place in LAFM as a result of high availability of low-cost biomass resources. In absence of policy support, hydrogen production remains marginal at about 0.6 EJ in the year 2100.

The following sections now aim to explore the impact of policies addressing the two key energy system challenges - energy security and climate change - on the market penetration of alternative fuels. The results will shed light on the competitiveness of alternative fuels to respond to energy system challenges.

The analysis is conducted in two steps. Firstly, the impact of energy security targets is assessed by looking at energy security targets alone as well as energy security targets in combination with a mild climate policy target. Secondly, the analysis is extended to more stringent climate policy targets.

#### 5.4 Energy Security and Climate Change

The scenario analysis conducted in this section follows up on the initial discussion of the relevance of energy security and climate change as energy system challenges by assessing the impact of energy security targets and climate policy on the market

penetration of alternative fuels. In a first step, energy security targets are analysed. This is followed by an analysis of a mild GHG mitigation scenario and an assessment of combined policy efforts.

#### 5.4.1 Energy Security Policy

The analyses in this section explore the impact of energy security policy alone. Two scenarios were designed for this purpose, each including an energy security target for every single world region for the year 2050 and beyond. Given the high dependency of many societies on oil and gas and the corresponding vulnerability to increasing prices as well as geopolitical instabilities, the scenarios explored here focus on reducing the dependency on imports of oil and gas for every single world region, implying a need to use local resources to satisfy demand for energy services at all levels of the energy system, or to shift away from oil and gas to other energy carriers. Two scenarios are analysed:

- a maximum share of oil, oil products and natural gas imports of 10% of domestic consumption of these energy carriers from the year 2050 onwards
- a maximum share of oil, oil products and natural gas imports of 30% of domestic consumption of these energy carriers from the year 2050 onwards

In order to allow for a smooth transition and accounting for energy system inertia, the targets have been applied along the trajectory displayed in Figure 47. Note that the import dependency target was not further tightened after 2050; rather, the 2050 target was kept constant for the decades thereafter.



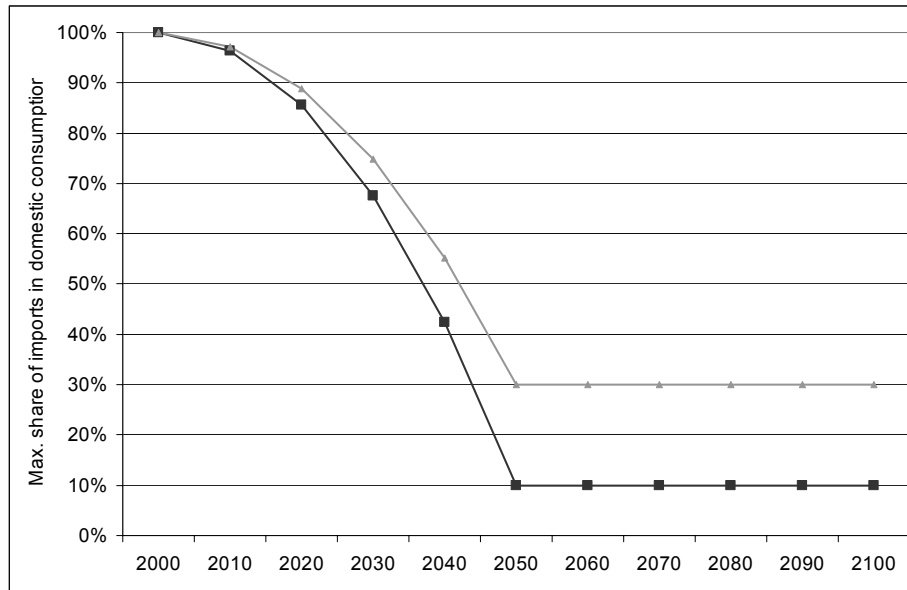


Figure 47. Maximum share of oil and gas imports in the energy security scenarios.

These scenarios can be interpreted as a global development towards more isolation, i.e. a development characterized by decreasing global mutual agreement and trust and an increasing level of geopolitical conflicts. Countries (or world regions in GMM) are forced to make use of their own oil and gas resources as much as possible to provide energy services. Alternatively, they may substitute oil and gas with other energy carriers and technologies.

Figure 48 depicts the impact of the chosen energy security targets on global hydrogen and biofuels production. It shows that achieving energy security targets for the year 2050 may require an accelerated deployment of biofuels. However, in absence of other policy measures, the impact on biofuels production for the year 2100 is relatively small in absolute terms, increasing from 29 EJ under baseline conditions to about 33 EJ under a 30% target and 41 EJ with a 10% security target. The production of hydrogen is also affected by energy security targets, but total production remains low; it increases from 0.6 EJ in the year 2100 in the baseline scenario to 1.2 EJ under a 30% target scenario and about 6 EJ in the most stringent energy security target.

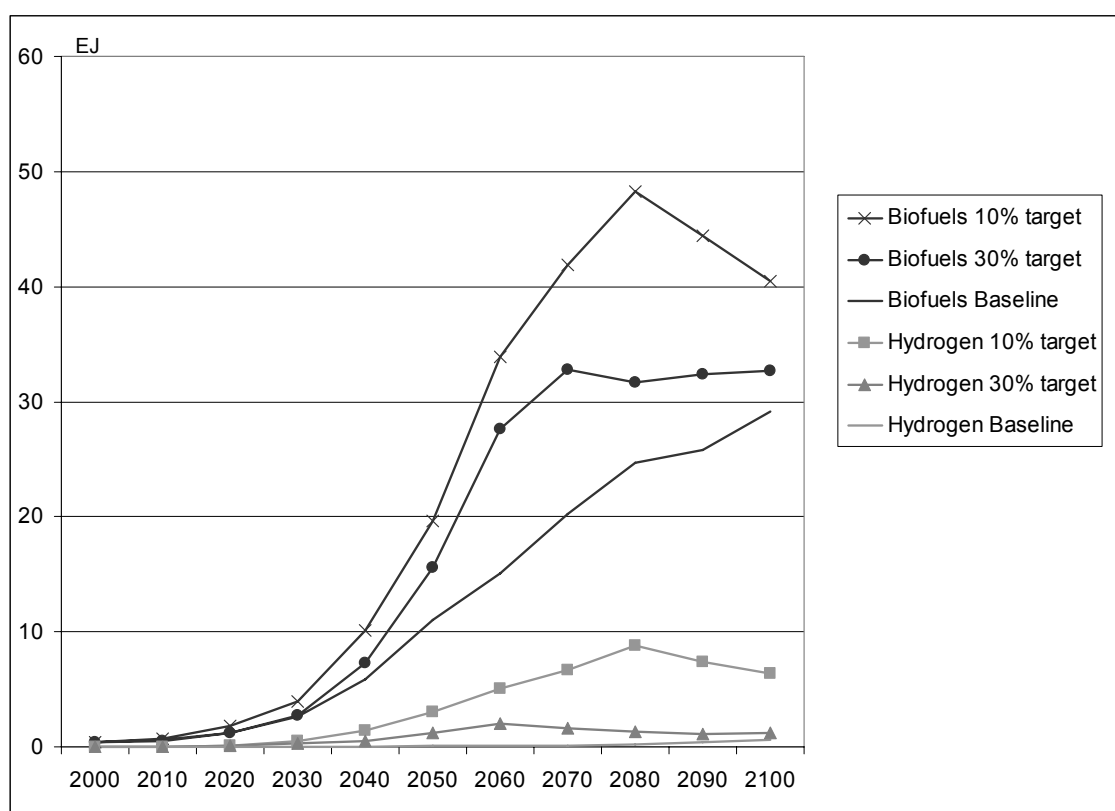


Figure 48. Impact of energy security targets on global biofuels and hydrogen production.

One key reason for the observed overall little impact on hydrogen and biofuels production is an increased utilization of liquid fuels derived from coal. Figure 49 depicts coal-to-liquids production throughout the scenarios investigated. The results suggest that energy security targets for the year 2050 facilitate an earlier and more significant deployment of coal-to-liquids. Towards the end of the time horizon, however, production levels are similar to those in the baseline. The reason for this observation is that more efficient fuel use in the various demand sectors reduces the consumption of oil and gas in the second half of the century, and consequently the import dependency of world regions, already in the baseline. This lowers the impact of the energy security targets imposed in the present analyses.

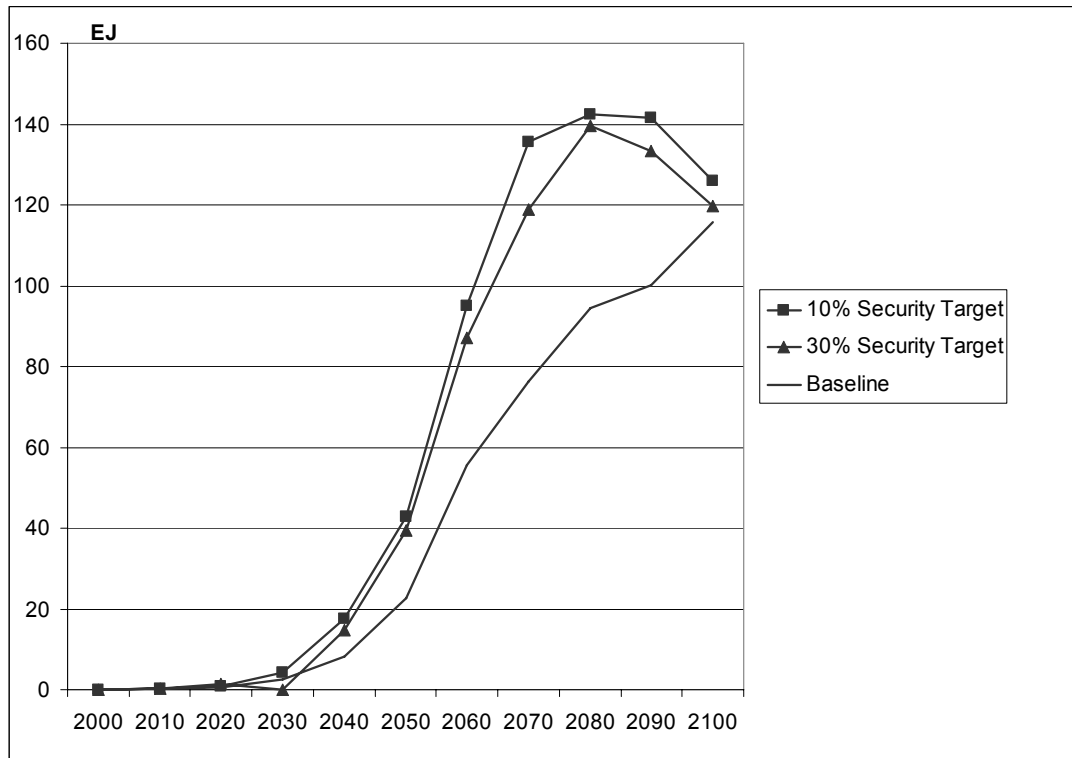


Figure 49. Coal-to-liquids fuel production under energy security scenarios.

Another reason is the structure of the applied model in combination with the way the security targets have been designed. The energy security targets have been designed for each individual region, meaning that every region is forced to use its own domestic oil and gas resources. Thus, only in regions where resources are scarce or expensive, the model will choose to use alternatives, e.g. biofuels.

In GMM, now, the bulk of oil and gas resources and reserves is located in LAFM, which is also one of the regions with demand for mobility increasing the fastest. Under baseline conditions, LAFM mostly exports its oil and gas resources and reserves and utilizes biofuels in personal transport, because cheap biomass is available to meet domestic demand. Under energy security targets as modelled here, however, there is less demand for oil and gas exports, meaning that LAFM has more low-cost oil and gas resources available, which implies a lower need to shift to alternative fuels in transport.

Due to these model-specific behaviours, a shift to biofuels rather takes place on a regional scale. While LAFM is reducing its biofuels consumption, particularly ASIA sees a significant increase. Figure 50 depicts this development by comparing the

change in domestic biofuels consumption under a 10% energy security constraint to the development under baseline conditions.

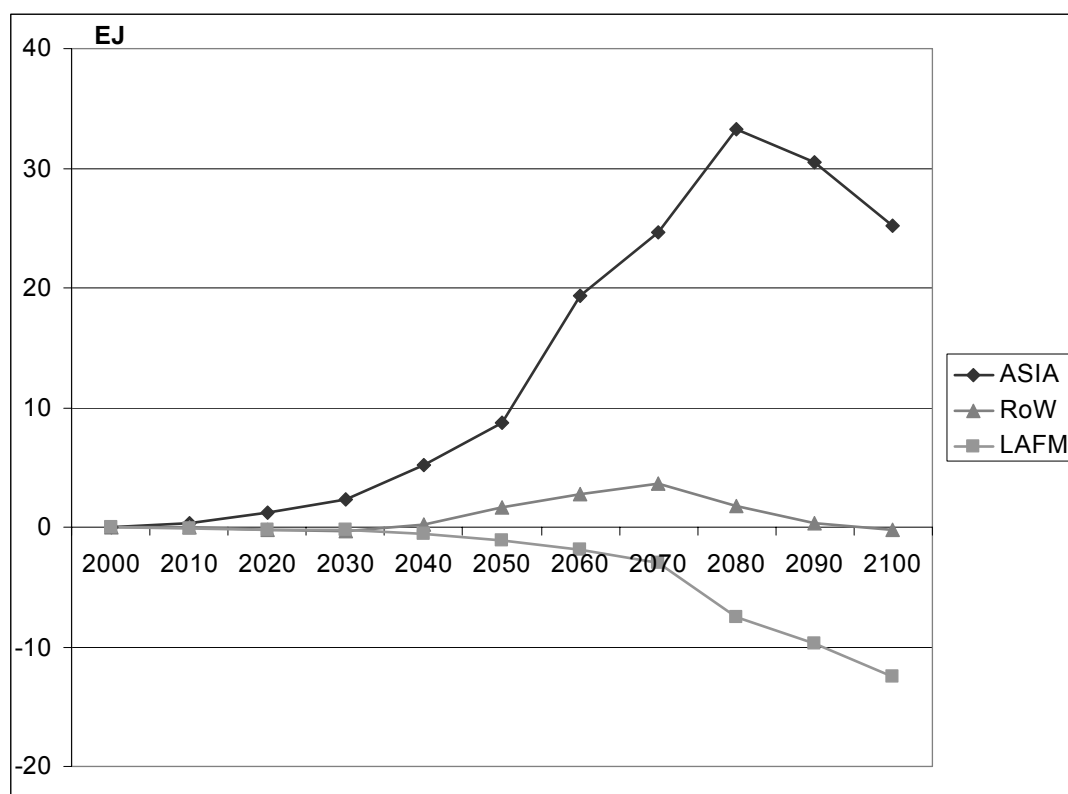


Figure 50. Absolute change of biofuels consumption under a strong energy security target compared to baseline.<sup>41</sup>

The result of these analyses suggest that energy security targets are likely to increase the utilization of biofuels in such parts of the world where there is an increasing demand for mobility, but where oil and gas resources are scarce in comparison to anticipated growth in demand. For hydrogen, energy security targets alone do not necessitate much additional utilization. Rather, it is the deployment of coal-to-liquids that is substantially increasing as a result of energy security targets due to its abundant availability and relatively low cost.

Clearly, the increased utilization of coal-to-liquids has a negative impact on climate change. Therefore, the implications of addressing energy security concerns, while at the same time pursuing mild CO<sub>2</sub> reduction targets to combat climate change are analysed in a next step.

<sup>41</sup> RoW = rest of the world.

### 5.4.2 Climate Policy and Energy Security

As discussed at various occasions throughout this thesis, energy security is only one of the challenges the energy system needs to deal with during the decades to come; addressing climate change is at least equally important. In order to assess the ability of the global energy system to respond both to climate change mitigation goals as well as energy security targets, a scenario combining a mild climate mitigation target and energy security policies was analysed. The climate targets analysed was selected to stabilize global CO<sub>2</sub> concentrations at 650 ppmv by the end of the century. The scenarios, therefore, will shed light on the role of alternative fuels, particularly in personal transport, in responding to such combined policy efforts, aiming at understanding the key drivers for the deployment of alternative fuels.

Figure 51 depicts the results obtained for global biofuels and hydrogen production under the different policy regimes, i.e. a climate policy target only, and combinations of climate policy with energy security targets.

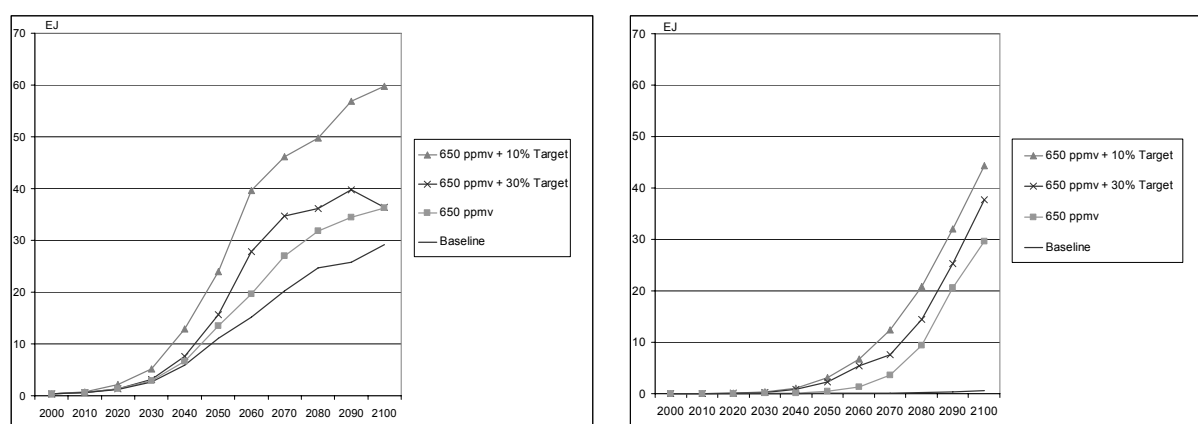


Figure 51. Production of biofuels (left) and hydrogen (right) under different policy regimes.

The results suggest that climate policy alone facilitates an increasing production of biofuels as well as hydrogen. The effect, however, is much more pronounced in the case of hydrogen, where production increases from 0.6 EJ in the baseline scenario to about 30 EJ in the climate-policy-only scenario by the year 2100. With additional energy security policy targets, the production of hydrogen is spurred even further, reaching 44 EJ under the most stringent security target by the year 2100. Main sector for hydrogen utilization is the other transport sector for buses as well as freight transport.

Biofuels production is influenced by the discussed policy regimes as well, albeit to a lower extent. Biofuels production increases from 29 EJ in 2100 under baseline conditions to 36 EJ under the climate-policy-only scenario. Additional energy security targets promote an earlier deployment of biofuels, similar to what has been found in the analysis of energy security targets only. However, it is only with the most stringent energy security target that biofuels production is considerably increasing by 2100, reaching 60 EJ under an additional 10% oil and gas import dependency target, i.e. slightly more than double the production compared to the baseline scenario.

Coal-to-liquids play a similar role as in the energy-security-target-only scenario during the first half of the century. In the second half of the century, however, production levels decline with additional climate policy. The results for coal-to-liquids production levels across scenarios are displayed in Figure 52.

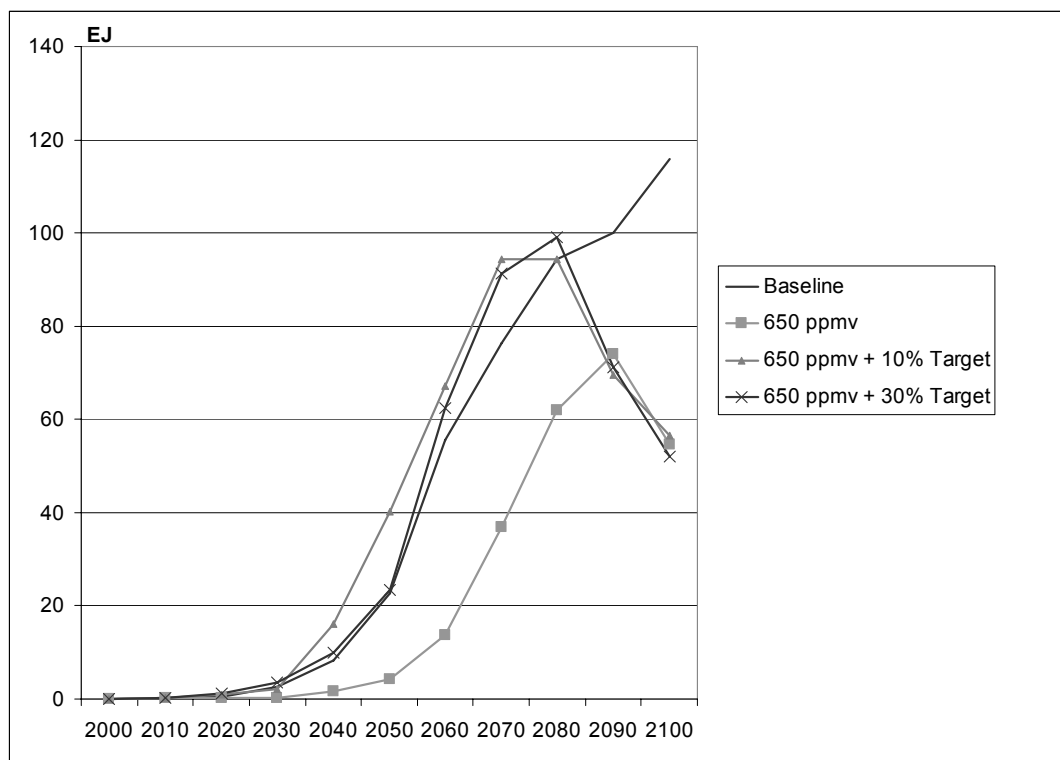


Figure 52. Production of liquid fuels from coal under different policy regimes.

Finally, it is important to note that climate policy only at the level considered in this analysis does not support pursuing energy security targets. As a matter of fact, the results obtained from the 650 ppmv climate policy scenario suggest that only marginal reductions of import dependency can be achieved by the year 2050.

### 5.4.3 Summary of Results

The analysis in this section targeted the implications of energy security and climate change mitigation targets on the production of alternative fuels. A number of findings were made:

- Coal-to-liquids were found to play a pivotal role in future fuel production not only in the baseline, but even more under energy security policy targets. The reason is that the resource coal is available in significant quantities and at low cost and liquid fuels from coal are potentially highly attractive substitutes for petroleum fuels. However, the analysis also suggests that coal-to-liquids are an option for the first half of the century only, promoted by energy security targets. Throughout all scenarios assessing combined policy efforts, the production of coal-to-liquids declined in the second half of the century in favour of hydrogen and biofuels in order to achieve climate policy targets.
- Biofuels were found an attractive option throughout all scenarios. Biofuels are competitive already in the baseline scenario, and any policy target investigated here ranging from different energy security targets for the year 2050 to a mild climate change mitigation target and combinations of these policies, revealed an increasing and earlier deployment of biofuels.
- Hydrogen is an option if reducing CO<sub>2</sub> emissions from the global energy system is desired. For energy security targets only, hydrogen is a less competitive option. With a combination of policy targets, however, the extent of hydrogen deployment is further enhanced in comparison to a mild climate mitigation target only.

In general, the results in this section suggest that a combination of policies is required to address the energy system challenges, climate change and energy security. Energy security targets only do not mitigate climate change, as greenhouse gas emissions are likely to increase as a result of enhanced deployment of liquid fuels derived from coal. Climate policy at the level considered in this section, in turn, does not enhance energy security in terms of import dependency. Clearly, climate policy reduces the use of fossil energy carriers and, thus, vulnerability to price fluctuations. However, import dependency was observed to decrease only modestly by 2050 for almost all world regions of GMM with the 650 ppmv climate policy target alone. The objective to decrease dependency is, thus, not achieved through mild

climate policy targets, requiring combined policy efforts for tackling both challenges at the same time. The combination of these policies, then, increases the need for hydrogen as well as biofuels, which suggests that both fuels can play an important role in dealing with current and future challenges.

While this section has focused on a mild climate policy target only and has varied energy security targets, the following section intends to explore the impact of increasingly stringent climate policy on the competitiveness of hydrogen and biofuels. In doing so, a more comprehensive analysis of energy system changes required to deal with climate policy targets will be conducted.

## **5.5 Climate Change Scenarios**

This section explores the prospects of alternative fuels in global transport under increasingly stringent climate policy targets. This analysis makes use of one important feature of GMM, which is the possibility to assess the impact of climate change policies with the climate model MAGICC. MAGICC was introduced in section 5.1.3 in some detail.

The relevance of this analysis is evident from the initially discussed need to combat climate change (see chapter 2 for details). The analyses conducted here focus on three key climate stabilisation scenarios:

- 650 ppmv CO<sub>2</sub> concentration in the atmosphere
- 550 ppmv CO<sub>2</sub> concentration in the atmosphere
- 450 ppmv CO<sub>2</sub> concentration in the atmosphere

Emission limits in GMM have been implemented as cumulative emission constraints. The analysis therefore considers “when” and “where” flexibility for CO<sub>2</sub> mitigation. Flexibility mechanisms such as “where” flexibility are mechanisms defined by the Kyoto protocol (UNFCCC 1999) and are greenhouse gas emission trading methods designed to allow mitigation targets to be achieved at lower cost. Applied to the modelling analyses with GMM, “when” and “where” flexibility mean that the scenario results presented here are cost-optimal with regard to timing and location of CO<sub>2</sub> mitigation measures. Previous analyses with GMM conducted by Rafaj (2005) found



that a combination of “when” and “where” flexibility results in lower energy system costs than pursuing only one of these flexibility mechanisms consistent with theory. In this light, the results presented here can be regarded as least cost-solutions not only from a perspective of optimal technology choices, but also from a perspective of optimal CO<sub>2</sub> abatement timing.

### 5.5.1 Structural Changes in the Energy System

Figure 53 compares primary energy consumption across the three scenarios investigated here with baseline developments. It shows firstly that the most significant changes in the energy system take place in the second half of the century, which is a result of the “when” flexibility mechanism for CO<sub>2</sub> reduction, combined with the cost reductions from technology learning and the discounting of future costs. Then, nuclear as well as renewable energy constitute a more significant share in global primary energy consumption with increasingly stringent climate stabilization targets, while the share of coal is decreasing substantially in the long-run in comparison to the baseline scenario. Under the most stringent CO<sub>2</sub> mitigation regime, renewables and nuclear energy together are responsible for 49% of primary energy consumption in 2100. Note, however, that the analysis here takes a conservative point of view by limiting the market share of renewable energy technologies to 25% of the total electricity market for intermittency reasons. Restructuring of electricity markets may support accommodating more renewable energy technologies above such a maximum share, see e.g. IEA (2005c) or Gül and Stenzel (2006) for details about required changes.

In contrast, no explicit assumptions were made in this analysis to limit the market penetration of nuclear. It must be recognized that the future role of nuclear energy is primarily a societal and political decision and will depend on several issues such as nuclear safety, waste disposal, questions of proliferation and consequently public acceptance. Constraints to the availability of uranium resources, moreover, have not been considered in the present analysis, and may impose an additional obstacle for nuclear energy in the future.<sup>42</sup>

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<sup>42</sup> The analysis in this dissertation considers current nuclear technologies as well as generation III+, IV. The latter is considered as one aggregate technology. No limitation has been imposed to the availability of uranium in the present analysis.

Given these limitations, this analysis is not intended to make a strong statement on the shares between renewables and nuclear energy in primary energy supply. Rather, it suggests that under stringent climate policy, a substantial share, perhaps half of primary energy supply will need to be from CO<sub>2</sub>-free energy supply technologies.

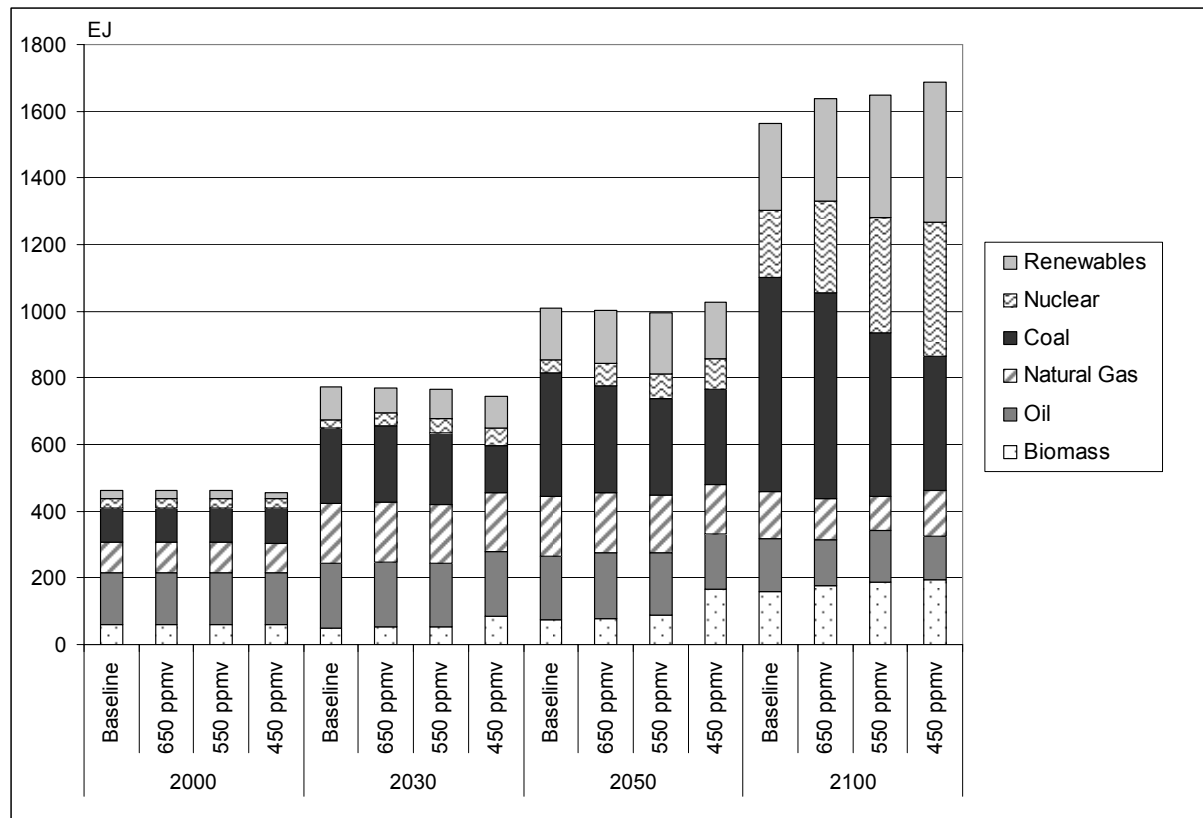


Figure 53. Primary energy consumption changes as a result of climate policy.

Natural gas shares increase throughout the climate policy scenarios towards the middle of the century, but then start declining as a result of increasing cost and resource limitations on the one hand, and the expansion of renewables and nuclear on the other hand. The use of oil is reduced in the long-run and with increasing climate change mitigation targets; however, as aviation in GMM does not consider substitutes for oil products, a certain amount of oil remains being used across all scenarios even in the year 2100.

Biomass becomes an increasingly important energy carrier with rising climate policy targets. This is further reflected in Figure 54, which shows that more stringent climate policy promotes an earlier as well as higher deployment of biomass resources. Under

the most stringent climate policy target, the entire biomass resource base is being used during the second half of the century.

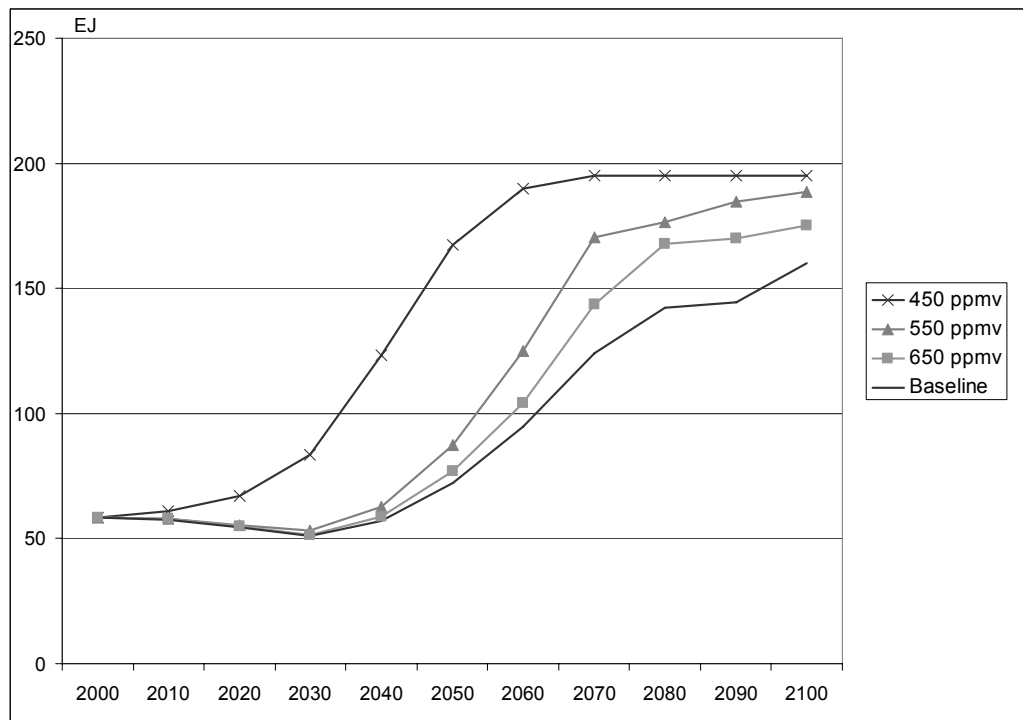


Figure 54. Use of biomass across scenarios.

Figure 55 depicts final energy consumption across the scenarios investigated here. Similar to primary energy consumption, the most significant structural changes take place in the second half of the century as a result of the “when” flexibility of abatement in response to the applied climate policy. Here, oil products are substituted by hydrogen and to some extent biofuels, and total final energy consumption is reduced as a result of more efficient technologies associated with the use of these energy carriers, in particular of hydrogen. Biofuels’ contribution to final energy consumption increases with moderate climate policy targets, but is then again reduced under the most stringent climate policy regime investigated here, despite the observed increased utilisation of biomass discussed above. This suggests that biofuels deployment may suffer from the limited biomass availability with stringent climate policy. In fact, most of the biomass resources are used for electricity and heat generation under the 450 ppmv climate policy regime.

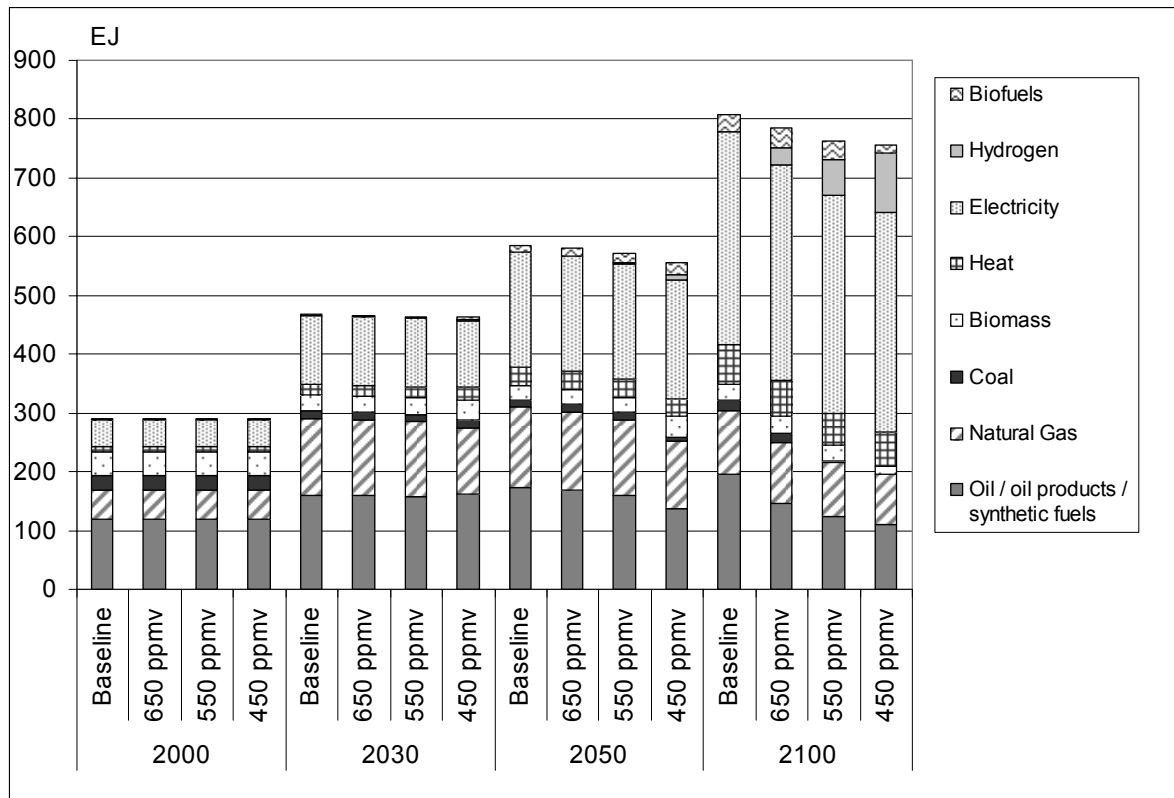


Figure 55. Final energy consumption changes as a result of climate policy.

Throughout all scenarios, electricity is the dominating energy carrier by the end of the century, with total contribution to final energy consumption in 2100 fairly constant across scenarios. These results indicate that competition between energy carriers is likely not taking place between hydrogen and electricity, but rather between hydrogen and liquid fuels, as hydrogen is mostly used as a transportation fuel, while electricity dominates other end-use sectors. Hydrogen and electricity should, therefore, not to be seen as competitors, but rather as complementary energy carriers.<sup>43</sup>

### 5.5.2 Personal Transport and Alternative Fuels

Personal transport contributes to increasingly stringent climate policy targets through the deployment of an increasing share of hydrogen fuel cells. While fuel cell vehicles do not enter the market in the 650 ppmv climate policy target scenario, they constitute a market share of 78% of the entire personal transport sector by the year

<sup>43</sup> Note, however, that the assumptions made in personal transport for battery-electric vehicles do not necessarily consider major technological breakthrough (which other technologies, in particular hydrogen fuel cell-electric hybrids would benefit from as well due to the applied cluster-approach to technology learning). For a more robust analysis of this finding, future work should analyse this issue in more detail.

2100 under a 450 ppmv policy regime. The results of all three scenarios investigated are displayed in Figure 56. For a better comparison, the results of the baseline scenario are depicted again in the upper left hand corner.

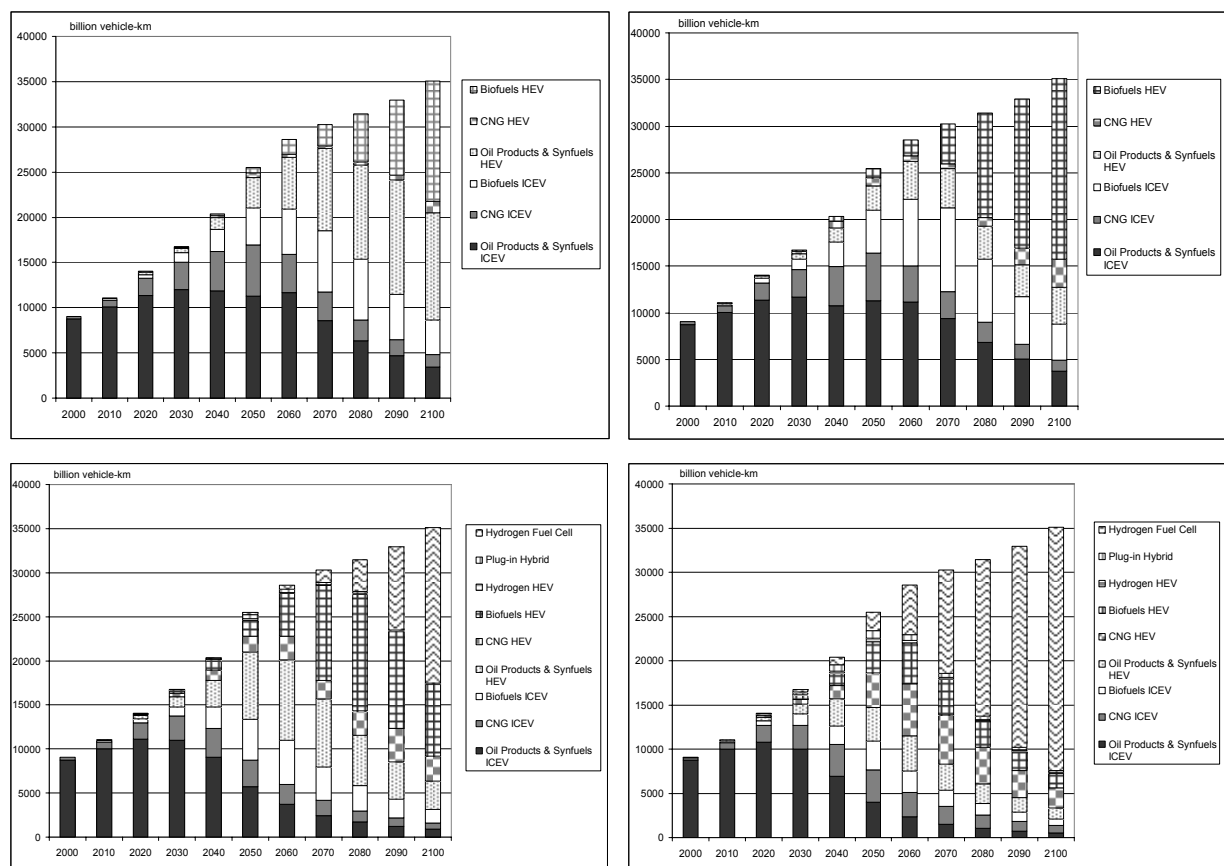


Figure 56. Personal transport across scenarios (baseline upper left hand side, 650 ppmv upper right hand, 550 ppmv lower left hand, 450 ppmv lower right hand)

The assessment of the impact of climate policy on personal transport shows that with a mild climate policy, biofuels hybrids as well as biofuels ICEVs increase market share in comparison to the baseline scenario at the cost of oil product and synfuels hybrids.

With increasingly stringent climate policy targets, however, biofuels vehicles gradually lose market share, while hydrogen fuel cell vehicles become increasingly important. In these scenarios, biofuels are a transition fuel and share the market with natural gas and oil products & synfuel vehicles (mostly hybrids), until hydrogen fuel cells reach maturity and can take over the market. This is reflected in Figure 57, which depicts the shares of different fuels across scenarios.

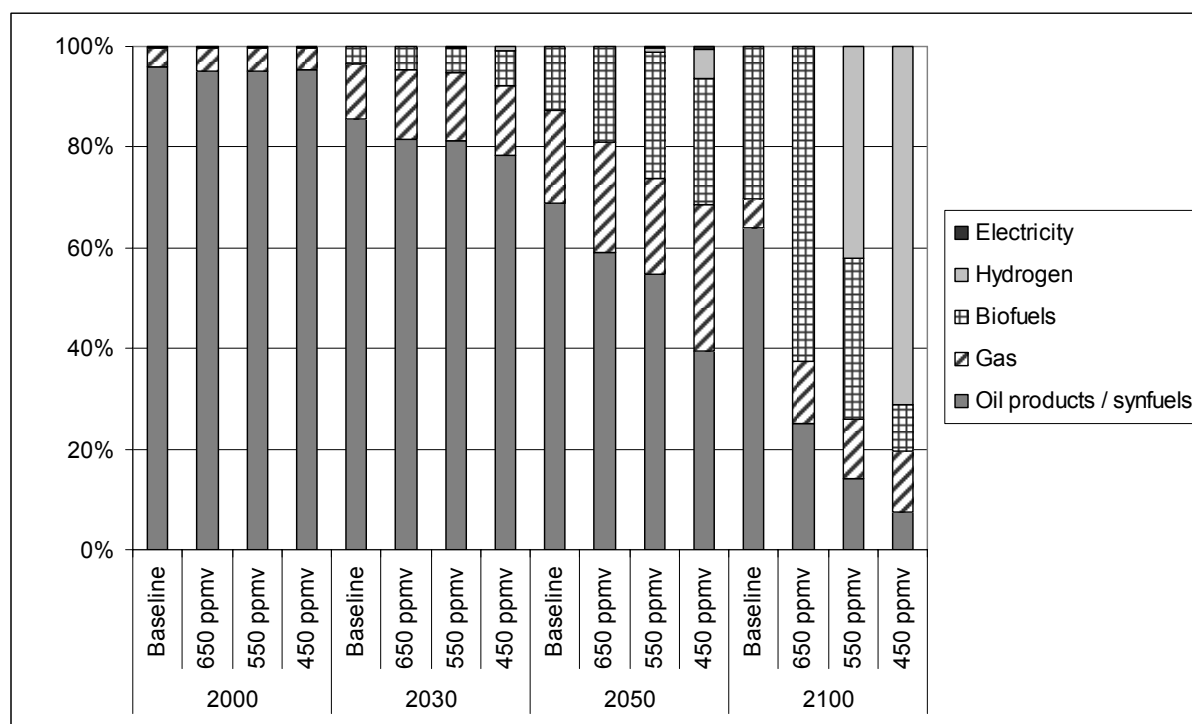


Figure 57. Fuel shares in personal transport across scenarios.

Figure 58 now presents hydrogen and biofuels production throughout the scenarios investigated above. It shows that hydrogen production increases with increasingly stringent climate policy targets, reaching up to 171 EJ of hydrogen production by the year 2100 under the strongest climate policy target.

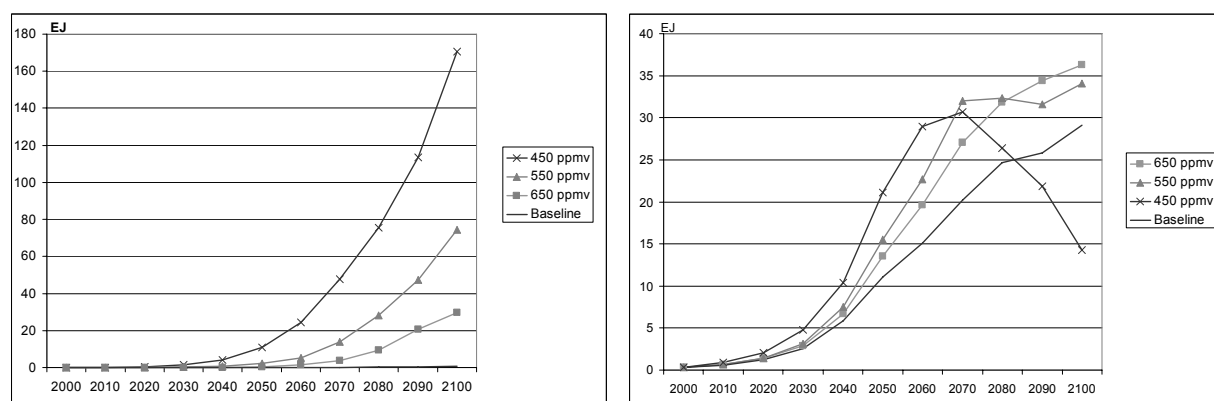


Figure 58. Hydrogen (left) and biofuels (right) production under different climate policies.

Trends observed for biofuels are less obvious. Any climate policy target imposed reveals an earlier and stronger deployment of biofuels, even though not so much in personal transport, but rather in other sectors such as other transport. However, for

the strongest climate policy target (and to a lesser extent also for the 550 ppmv climate policy scenario), the trend is reversed in the second half of the century, which is when hydrogen becomes available on a larger scale.

It is also worth mentioning that the scale of production by the end of the century is significantly different for hydrogen and biofuels. Biofuel production levels stay in the order of baseline deployment, while hydrogen production is boosted by orders of magnitude as a result of climate policy efforts. The key limiting factor for a further deployment of biofuels is the availability of biomass: in a carbon-constraint society, biomass is a valuable energy carrier, and the model results suggest that biomass is more cost-effectively utilized in electricity and heat production.<sup>44</sup>

The deployment of biofuels is largely concentrated in two world regions: ASIA and LAFM. This result occurs for two main reasons: on the one hand, both regions are likely to experience the most significant growth in demand for energy services across the century, thus encouraging the deployment of many available energy carriers, including alternative fuels. Moreover, LAFM is the region with the most abundant availability of low cost biomass. Figure 59 depicts the use of biofuels across world regions for the baseline and strong climate policy scenarios.

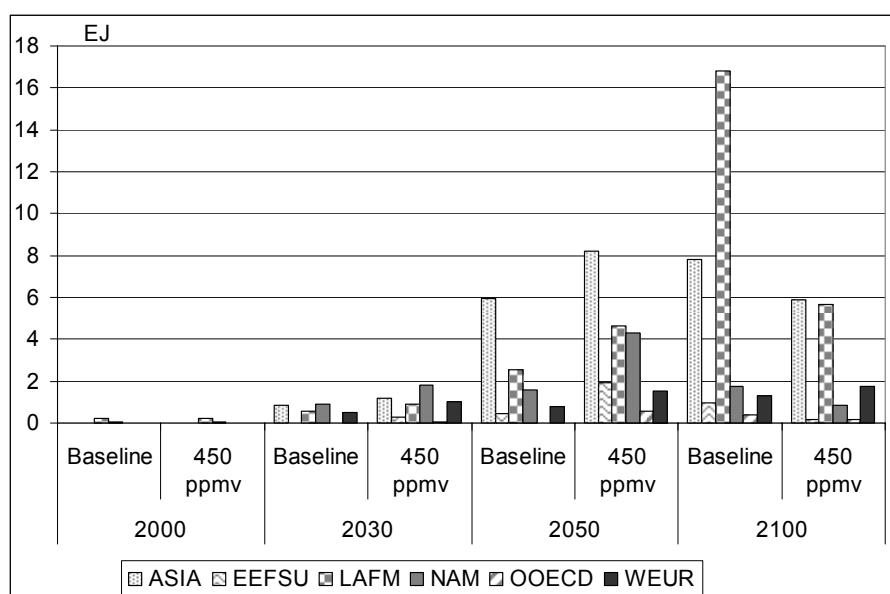


Figure 59. Utilization of biofuels across world regions and scenarios.

<sup>44</sup> Note that GMM considers biomass IGCC plants with carbon capture, which is a highly competitive technology under strong climate change mitigation policy. The results, however, were confirmed by a sensitivity analysis that excluded this technology.

As a final remark, it is clear that the utilization of hydrogen fuel cells in personal transport as observed here is ultimately linked to the floor cost assumptions for the hydrogen fuel cell, although other factors are of course also important. However, this does not necessarily limit the utilization of hydrogen as a fuel in personal transport. A sensitivity analysis of the most stringent climate policy pursued here, i.e. a 450 ppmv CO<sub>2</sub> concentration target, assuming that fuel cells do not achieve cost reductions and do not reach the required maturity for market introduction, showed that hydrogen ICE-electric hybrid vehicles then would be the technology of choice. The reason for this result is that hydrogen represents a (almost) zero-emission fuel, while biofuels are limited through the available biomass potential and battery vehicles are too expensive under the assumptions in this analysis. This makes hydrogen an attractive energy carrier for stringent climate change mitigation targets, independent of whether it is used in fuel cells or internal combustion engines.

Under a 550 ppmv concentration target, however, biofuels and natural gas hybrids were found to dominate future transport. This shows that the utilization of hydrogen as a fuel in personal transport is from the perspective of cost-optimization planning not only dependent on the fuel cell floor costs ultimately achieved, but also on the degree of the climate policy target.

#### 5.5.2.1 Sensitivity to the choice of discount rates

The choice of the discount rate determines the relative value of future costs (or benefits) compared to present costs (or benefits). Because the benefits and costs of a given policy do not always accrue in the same time period, the choice of discount rate implies important considerations for policy- and decision-making processes.

The analyses in this dissertation have been based on a discount rate of 5% for all technologies and all regions. The Intergovernmental Panel on Climate Change (IPCC), however, suggested that “ethical” considerations that give a higher weight to the well-being of future generations than in the case of a 5% discount rate may guide the choice of lower ones (IPCC 2001). There is a lot of controversy about the choice of the appropriate discount rate in climate policy-making, e.g. in the context of the Stern review (Stern 2006; Nordhaus 2007). A detailed discussion on the conceptual implications of different discount rates is beyond the scope of this dissertation: however, it appears to be advisable to study the impact of the choice of discount



rates on the key results obtained in the above analysis. Of particular interest here is the impact of the choice of discount rates on the market penetration of hydrogen fuel cells as a potential key technology for mitigating climate change. Figure 60 depicts the impact of the choice of discount rates of 5% or 3% respectively on the market penetration of hydrogen fuel cells over the entire time horizon (left) and until 2050 for the most stringent climate policy scenario only (right).

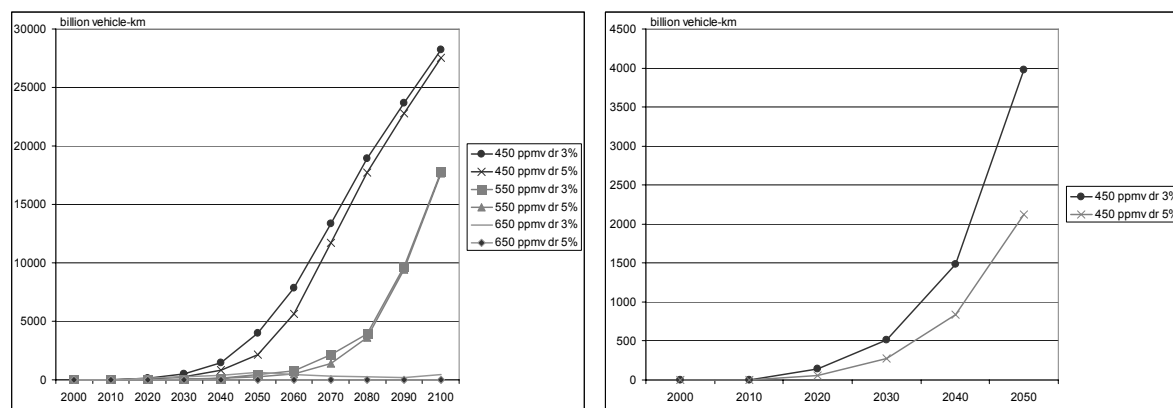


Figure 60. The influence of the discount rate on hydrogen fuel cell vehicle market penetration.

The analysis shows that the choice of discount rates has only little impact on the market penetration of hydrogen fuel cells in the long-run. However, lower discount rates may facilitate earlier deployment of hydrogen fuel cells during the first half of the century, in particular with stringent climate policy. In this case, the lower discount rate implies that more of the abatement burden should be taken by earlier generations. Note that otherwise no significant changes in the energy system were observed as a result of lower discount rates.

### 5.5.3 The Scale of the Climate Challenge

The discussion of the implications of climate policy targets suggests that the energy system needs to undergo significant structural changes in the course of the next century in order to mitigate climate change. To get a better understanding of the scale of the challenge, it is useful to examine the level of investment required for achieving climate policy targets. Figure 61 illustrates the investment needs for hydrogen and biofuels production and delivery technologies in comparison to the need for investment in the power sector obtained from the analysis with GMM. It

further compares the baseline scenario investments with those of the 450 ppmv and 550 ppmv climate policy scenarios. The figure on the left hand side represents cumulative undiscounted investment needs until the year 2050; the figure on the right hand side cumulative undiscounted investment needs until 2100.

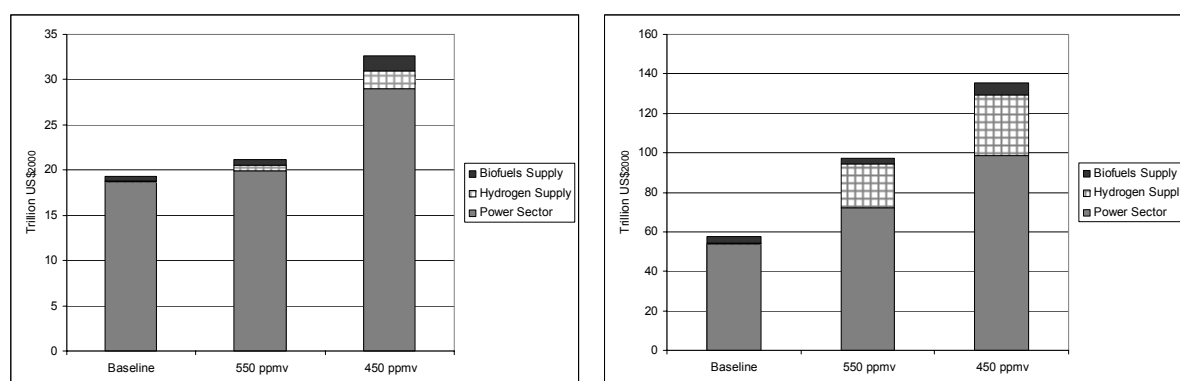


Figure 61. Investment needs in different energy sectors for mitigating climate change (left: until 2050; right: until 2100).

The analysis shows that under baseline conditions, the power sector is likely to require investments in the order of US\$ 19 trillion until the year 2050 to meet the increasing demand for energy services; investment needs for hydrogen and biofuels under baseline conditions are significantly lower and in the order of US\$ 0.6 trillion as a result of little incentive for their utilization in the baseline scenario. These observations for the power sector are similar to what has been projected by IEA (2003b), who suggested that power generation, transmission and distribution are likely to account US\$ 10 trillion until the year 2030.

Mitigating climate change entails significant needs for additional investments, and especially if stringent climate policy targets are pursued. Until 2050, additional investments in the power sector, in particular for clean coal technologies, renewables energies and nuclear energy, are in the order of US\$ 10 trillion for the most stringent climate policy target. Investment needs for alternative fuels under stringent climate policy until 2050 are in the order of US\$ 1.9 trillion for hydrogen, and US\$ 1.6 trillion for biofuels, i.e. significantly lower. Under the more moderate climate policy target (550 ppmv), total additional investment required until 2050 are in the order of US\$ 1.8 trillion only.

Investment requirements over the entire time horizon until 2100, however, alter the picture. Additional investments in the power sector amount to US\$ 44.5 trillion for the 450 ppmv climate policy target, and US\$ 18.4 trillion for the 550 ppmv target. Requirements for hydrogen investments are boosted and are as high as US\$ 31 trillion under a strong climate mitigation policy, and US\$ 22 trillion for the 550 ppmv case. For biofuels, additional investments amount to only slightly more than US\$ 2.3 trillion for the 450 ppmv case, again because of a more cost-effective utilization of biomass in other sectors.

The results obtained may sound daunting at first glance, but need to be seen in the appropriate perspective. It is less the absolute numbers that count in this discussion, but rather the relative increase over baseline conditions on the one hand, and the share of alternative fuels in investments on the other hand. The following key observations can be made:

1. Pursuing climate policy targets and changing the structure of the energy system is costly, even under an optimal CO<sub>2</sub> allocation scheme as applied in this analysis here (“when” and “where” flexibility for reducing CO<sub>2</sub> emissions). The need for such structural changes is evidently necessary, as discussed in IPCC (2007b). Moreover, macroeconomic costs are relatively modest compared to the underlying economic growth assumptions. The highest additional cumulative costs compared to baseline development until the year 2100 observed here correspond to 0.6% of cumulative GDP for the 450 ppmv scenario. Nonetheless, mobilising this investment is an important policy challenge.
2. In the first half of the century, investment needs in the power sector outweigh those for hydrogen and biofuels by an order of magnitude. This observation is a result of the vigorously increasing demand for electricity worldwide evidenced in the results above.
3. In the long-run, developing hydrogen as a fuel entails substantial investments as well. However, the bulk of investment under optimal CO<sub>2</sub> policy design and timing is likely to occur in the second half of the century, when technologies for hydrogen production and utilization have reached a significant degree of maturity (itself requiring early investment), accelerated by learning-by-doing mechanisms. In this light, keeping the “hydrogen option” open does not

require a major investment in the first half of the century, while allowing the pursuit of a stringent climate policy in the second half of the century.

Figure 62 presents a breakdown of required investments for hydrogen in the first half of the century and over the entire time horizon, showing that investment requirements until 2050 are mostly into developing hydrogen production technologies, in particular into reducing costs of current technologies. In the long-run, the bulk of investment is required for developing an appropriate hydrogen delivery infrastructure network.

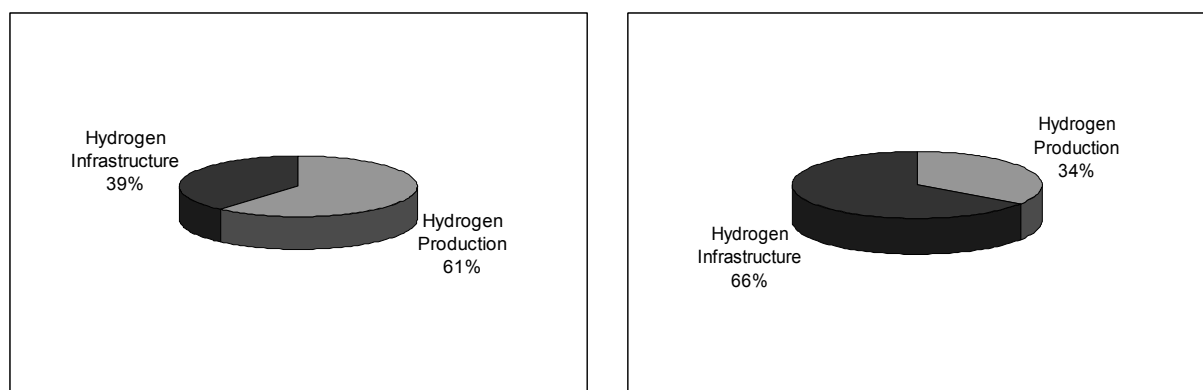


Figure 62. Cumulative investment in hydrogen until 2050 (left) and 2100 (right).

#### 5.5.4 The Role of Technology Change

The results of the above analyses suggest that technology change is highly important to meet climate policy targets. The analysis revealed that significant structural changes are required to adapt to climate policy targets at all levels of the energy system, which entails the need for the deployment of alternative, clean new energy technologies. As a result of the deployment and of experiences with the new technologies, cost reductions are achieved due to learning-by-doing (see section 2.3 for more details about the process of technology learning). GMM is able to capture such learning processes due the application of ETL and learning clusters, and some key learning technologies experience significant cost reductions as a result of the optimization. Figure 63 exemplifies on the left hand side the impact of climate policy targets on technology learning and achieved cost reductions with installed cumulative capacity for selected technologies under a 450 ppmv climate policy scenario. On the

right hand side, the cost reductions achieved over time are compared against the baseline development.

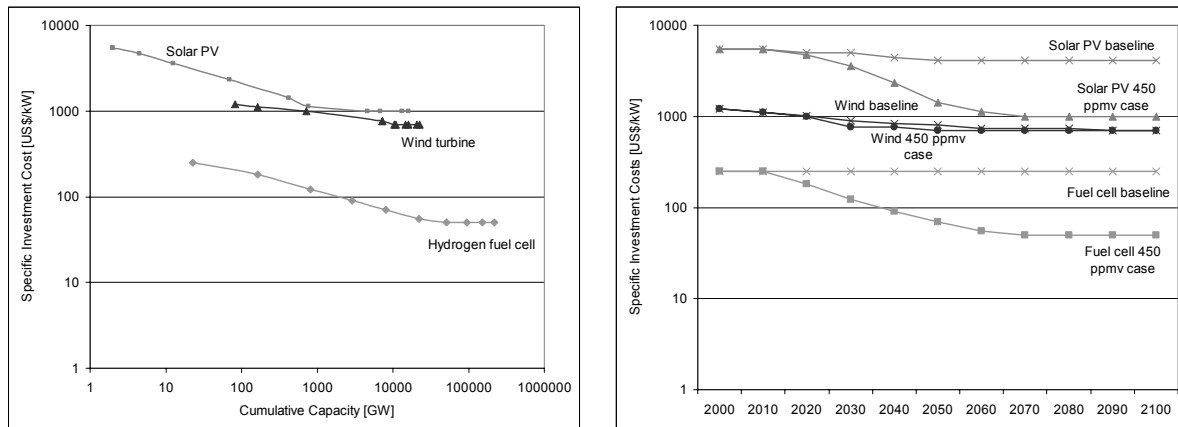


Figure 63. Cost reductions due to learning in the 450 ppmv case (left) and comparison of fuel cell cost under the baseline scenario and 450 ppmv case (right).

The results in Figure 63 highlight the importance of technology learning in the process of technology change in the long-run, and illustrate how important the learning process can be for reducing the cost of dealing with the challenge of climate change. Some technologies, here hydrogen fuel cells and solar PV, are likely to encounter significant cost reductions under climate policy, while others are already competitive under the baseline scenario such as wind turbines. Technology learning can, thus, be expected to induce significant technology changes in the energy system in the long-run.

However, the results also point to a weakness of the models applied in this dissertation; that is, perfect foresight models such as those from the MARKAL family are aware of the lowest cost a technology can achieve as a result of pursuing RD&D strategies. As a consequence, these models will choose the cost-optimal pathway for reaching policy targets. On the one hand, this is a desired outcome, as this thesis aims at identifying least-cost solutions for selected policy targets. On the other hand, the analysis assumes a single social planner with perfect information, neglecting that for example first movers on the market very often face high upfront investment costs e.g. for market development or manufacturing infrastructure. While this is a shortcoming of such analyses, it nevertheless provides important insights into the potential of technologies and the need for cost-reductions to achieve competitiveness in the long-run. Thus, it identifies technologies that can contribute to mitigating

climate change, justifying policy measures in terms of R&D and subsidies to support them.

### 5.5.5 Where will Hydrogen Come From?

The results of the analyses conducted so far suggest that hydrogen can play an important role in future energy systems as a result of climate policy, and the more stringent is the climate policy target, the more significant becomes the role of hydrogen. Inevitably, this poses the question “where will hydrogen come from?”

A considerable number of studies were reviewed and discussed in chapter 3 for the definition and implementation of hydrogen production and delivery technologies in GMM; and the results presented here are based on this techno-economic assessment. Figure 64 shows hydrogen production under the most stringent policy regime, i.e. a 450 ppmv CO<sub>2</sub> concentration target.

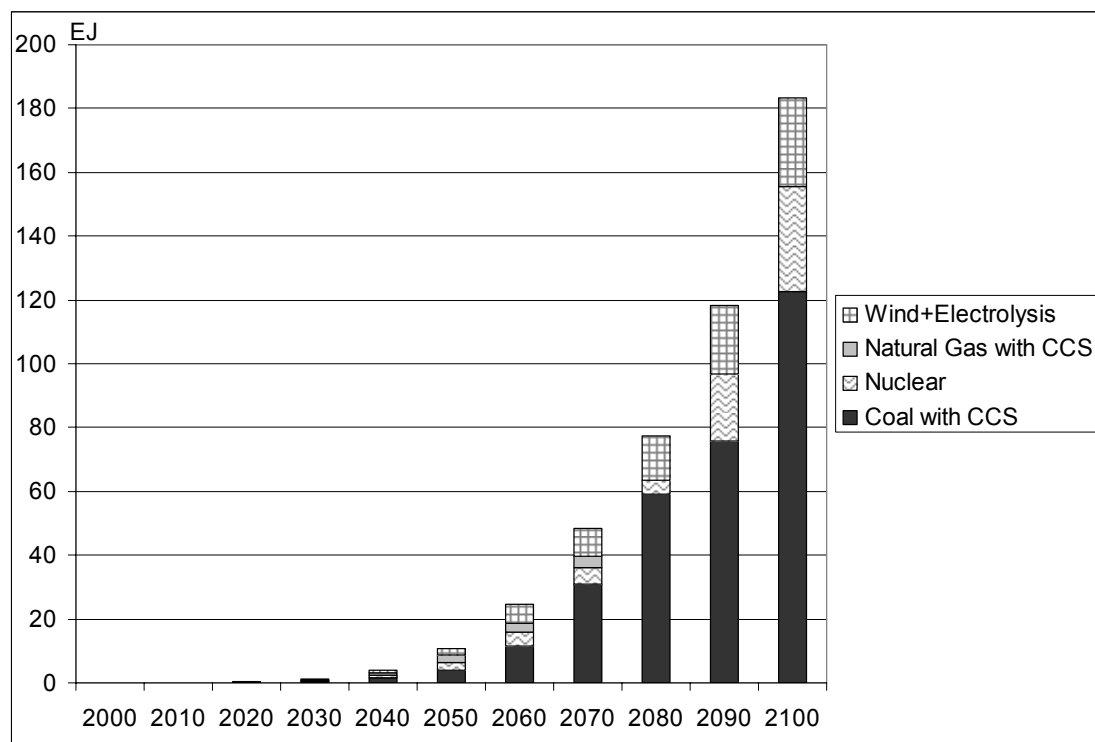


Figure 64. Hydrogen production under a 450 ppmv CO<sub>2</sub> policy regime.

With a stringent climate policy, hydrogen is produced on a large scale and in central hydrogen production facilities. The favoured production technology is coal

gasification with carbon capture and sequestration (CCS) due to its low cost and the ability to co-produce electricity and sequester CO<sub>2</sub>. CO<sub>2</sub>-free hydrogen production from nuclear and dedicated wind power for hydrogen production through electrolysis are also major sources.<sup>45</sup> Figure 65 compares the shares of the different hydrogen production technologies across the different climate policy scenarios, highlighting once more that coal gasification is the most competitive technology, providing for example for almost all hydrogen production under a mild climate mitigation policy.

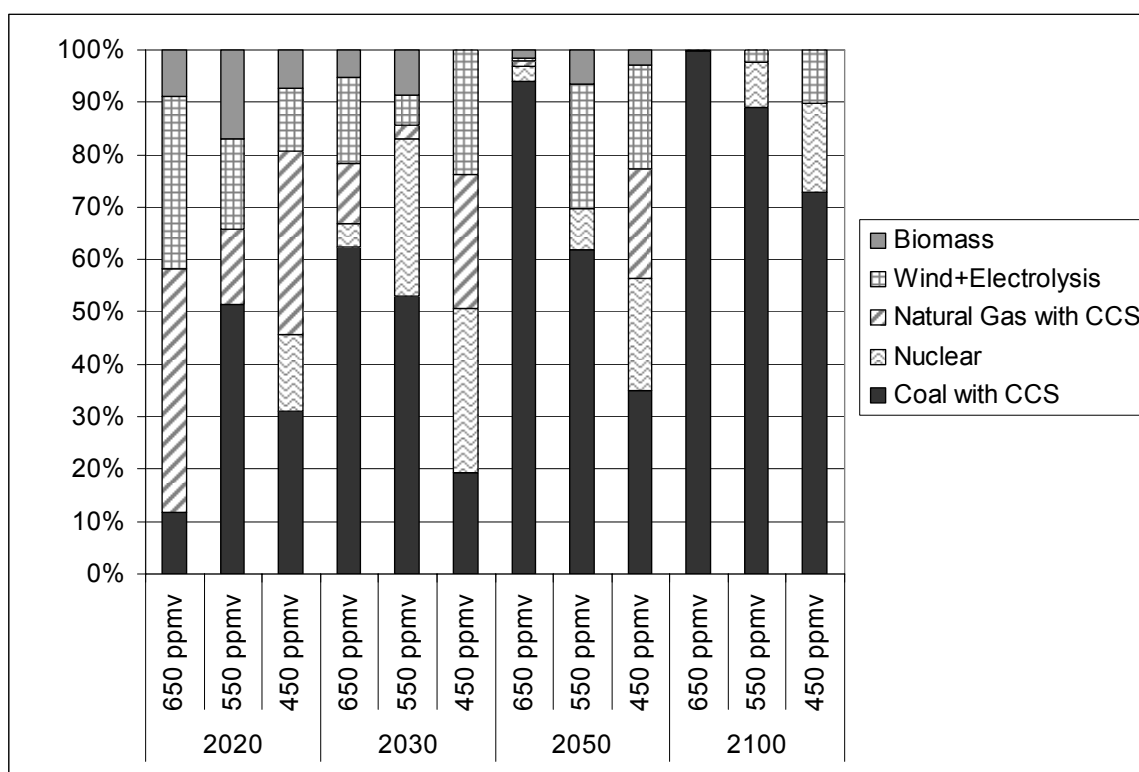


Figure 65. Hydrogen production across climate policy scenarios.

Centrally produced hydrogen needs to be delivered to the customer, and chapter 3 introduced the various hydrogen delivery routes considered in this analysis. Figure 66 depicts the shares of different hydrogen infrastructure options as obtained for the stringent climate policy case. It shows how early hydrogen deployment takes place through various delivery routes, making use of pipelines and combined systems with pipeline delivery to terminals and gaseous truck delivery to fueling stations in pilot regions on the one hand, and direct liquid truck delivery on the other hand.

<sup>45</sup> Hydrogen from biomass does not play a role in hydrogen production here, as biomass is rather utilized in other sectors. A sensitivity analysis that excludes biomass IGCC with carbon capture from the electricity sector confirmed this result, i.e. hydrogen from biomass gasification was not deployed.

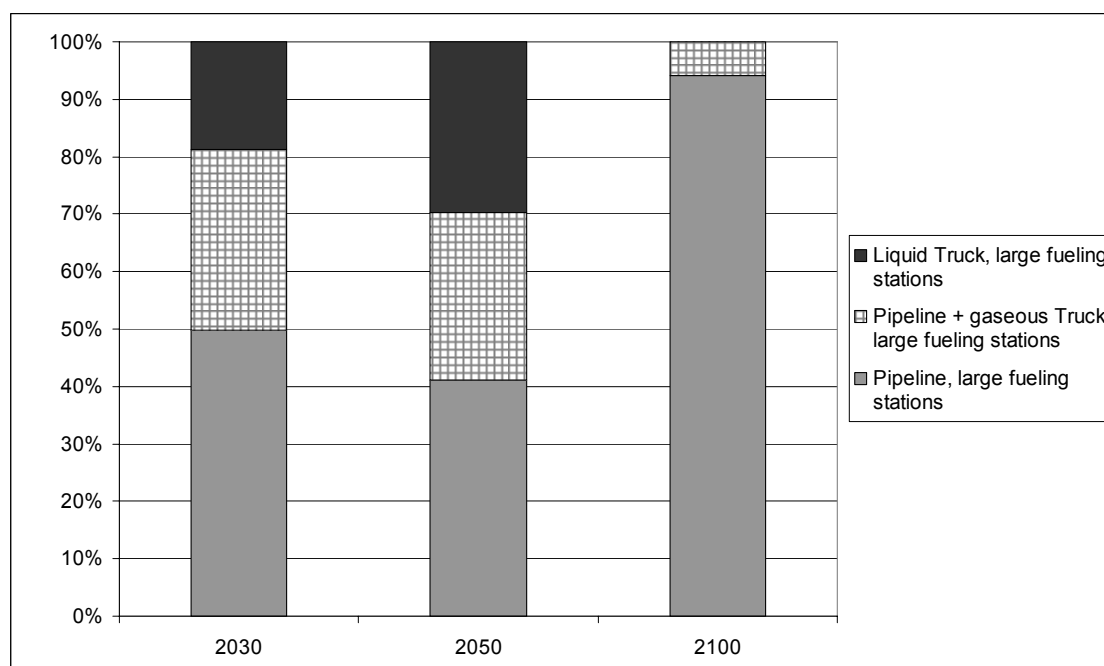


Figure 66. Hydrogen delivery routes in the 450 ppmv climate policy case.

The results of this analysis suggest that a shift to hydrogen in personal transport is possible under stringent climate policy, and that hydrogen can be an important energy carrier in future more sustainable energy systems. From the perspective of a cost-optimizing social planner, hydrogen is most competitive when produced at central production facilities. The analysis of hydrogen delivery routes suggests that large-scale hydrogen deployment is initiated mostly by pilot projects, supplying aggregate single load centres by pipeline systems or combined pipeline and truck delivery systems. Additionally, flexible systems such as trucks carrying liquefied hydrogen provide for some 19% of hydrogen to different dispersed load centres in 2030, and this share is gradually expanded towards the middle of the century with increasing demand for hydrogen. In the long-run, however, an extensive pipeline network is constructed as the least-cost solution for delivering hydrogen.

It is important to note in this context that this analysis does not necessarily suggest that this is the best potential route to develop large-scale hydrogen infrastructure towards what is often called a “hydrogen economy”<sup>46</sup>; rather, it is found that the cost-

<sup>46</sup> The term „hydrogen economy” in this context is somewhat misleading, as it suggests that hydrogen could become the dominating energy carrier in the future. The results of the analysis here, however, suggest that a hydrogen economy would probably rather evolve towards a “hydrogen + electricity economy”, as both energy carriers were found to play an important role in mitigating climate change. They should, thus, be seen as complements rather than competitors.



optimal solution to develop hydrogen is from pilot regions, i.e. local applications, to more large-scale global hydrogen utilization. However, large-scale implementation of a hydrogen infrastructure, in particular pipelines, requires significant efforts, and the chicken-or-egg problem as to whether hydrogen demand needs to develop first in order to make a hydrogen supply infrastructure develop, or whether hydrogen infrastructures need to be built first to spur demand for hydrogen, is a topical and ongoing debate. Most authors in this context suggest that hydrogen needs to develop out of niche markets in order to become an option for large-scale deployment in transport. Smit *et al.* (2007) for example suggest for the case of the Netherlands that hydrogen fuel cell car market penetration could follow the deployment of hydrogen in the residential and commercial sector in combined heat and power systems (CHP), and would initially be fuelled by hydrogen from forecourt natural gas reforming. Melaina (2007) reviews analogies between hydrogen and early gasoline refuelling methods, and suggests that much as early gasoline demand was covered from latent gasoline production capacity in the kerosene industry, early hydrogen demand could be covered in a similar way, at least during a transition phase.

In the analyses presented here, an increase in hydrogen production is the cost-optimal solution to satisfy climate policy targets, suggesting that hydrogen can be a viable option to decrease global GHG emissions. However, the large-scale deployment of central hydrogen, delivered in the long-run mostly through pipeline networks, imposes the question as to whether there are barriers to the implementation of such elaborated delivery networks. As a matter of fact, the scale of deployment obtained in the stringent climate policy case here suggests that on the basis of the assumptions taken and with the designed hydrogen delivery network, the cost-optimal solution in the year 2100 is to have as much as 1.23 million km pipeline in place on a global level, compared to currently 16'000 km of hydrogen pipelines in place around the world according to Simbeck (2004b). If pipeline expansion would take place in a linear way and starting with 16'000 km in the year 2000, this would translate into about 121'000 km of pipeline that would need to be constructed per decade, or around 1'500 pipelines of 80 km as they were used in the analysis, in order to reach the suggested levels in the year 2100.

It is not impossible to achieve that given the long-term time horizon. Note for example that in the United States alone more than 486'000 km of natural gas pipelines are in place according to EIA (2007b). Moreover, there is reason to believe that existing

natural gas pipeline networks could be used for delivering hydrogen in blends with natural gas in early phases of hydrogen deployment for the use in stationary applications, as described e.g. in Haeseldonckx and D'haeseleer (2007). This would reduce the need for initial pipeline infrastructure expansion, and underlines that in order to facilitate the use of hydrogen, creative solutions will be required.

However, such observations still seem somewhat daunting and imply the need for further analysis of the viability of this effort. In order to understand whether the expansion of the delivery network is a bottleneck for large-scale hydrogen deployment, the following section intends to analyse the practicability and scale of the effort required to facilitate a transition to hydrogen.

### 5.5.6 Hydrogen Infrastructure Deployment

In this section, the practicability of deploying hydrogen on a large-scale and as observed for the 450 ppmv climate policy target is analysed in order to assess the role of infrastructure in the development towards an economy with hydrogen as a key energy carrier. The analysis aims at assessing whether and to which degree the development of a hydrogen infrastructure is a bottleneck for large-scale deployment of hydrogen.

MARKAL-type models generally consider investment decisions on a per-unit-of-energy basis. For accurate modelling of investment decisions it is, however, sometimes useful to define a minimum investment level. This is particularly the case for hydrogen delivery infrastructures such as pipelines, where an investment in low quantities is not realistic, i.e. a minimum length and size of pipeline is required. For the purpose of this analysis, a minimum (“lumpy”) capacity level for hydrogen infrastructure is therefore defined according to the following equation:

$$LUMP(k, t) = BLOCK(k) \times Z(k, t) \quad \text{for each } t = 1, \dots, T$$

with  $Z(k, t) = 0, 1, 2, \dots$

where the minimum capacity *LUMP* of each *technology k* is either zero, i.e. no investment takes place, or a *multiple Z(k,t)* of a *fixed capacity BLOCK(k)*.

A version of GMM incorporating this formulation was applied to study infrastructure deployment. Specifically, a linear version of GMM was applied, using exogenous cost reductions as derived in the above analysis for the 450 ppmv and 550 ppmv climate policy targets. A minimum capacity investment level corresponding to 250 tons of hydrogen per day was applied (i.e. corresponding to *BLOCK* in the above equation) for all hydrogen infrastructure options, in line with the cost assessment of chapter 3. Note that this implies a minimum investment level for truck delivery as well, which was deemed necessary because the truck delivery routes make use of terminals for loading/unloading of trucks, which have been designed at this scale and would benefit unevenly from scale-economies if excluded from the minimum investment levels.

In addition to defining minimum investment levels, three cases were analysed distinguishing allowed maximum installations of individual delivery options per decade and region (10, 50 and 100). This means for example that a maximum of 10 (or 50, or 100) pipelines with a capacity of 250 tons of hydrogen per day can be implemented per decade in each individual region.

Figure 67 depicts the obtained scale of hydrogen production for the 450 ppmv and 550 ppmv climate policy targets, comparing the hydrogen deployment levels of the previous analyses (“no blocks”) with those using different maximum levels of “lumpy” investment per decade.

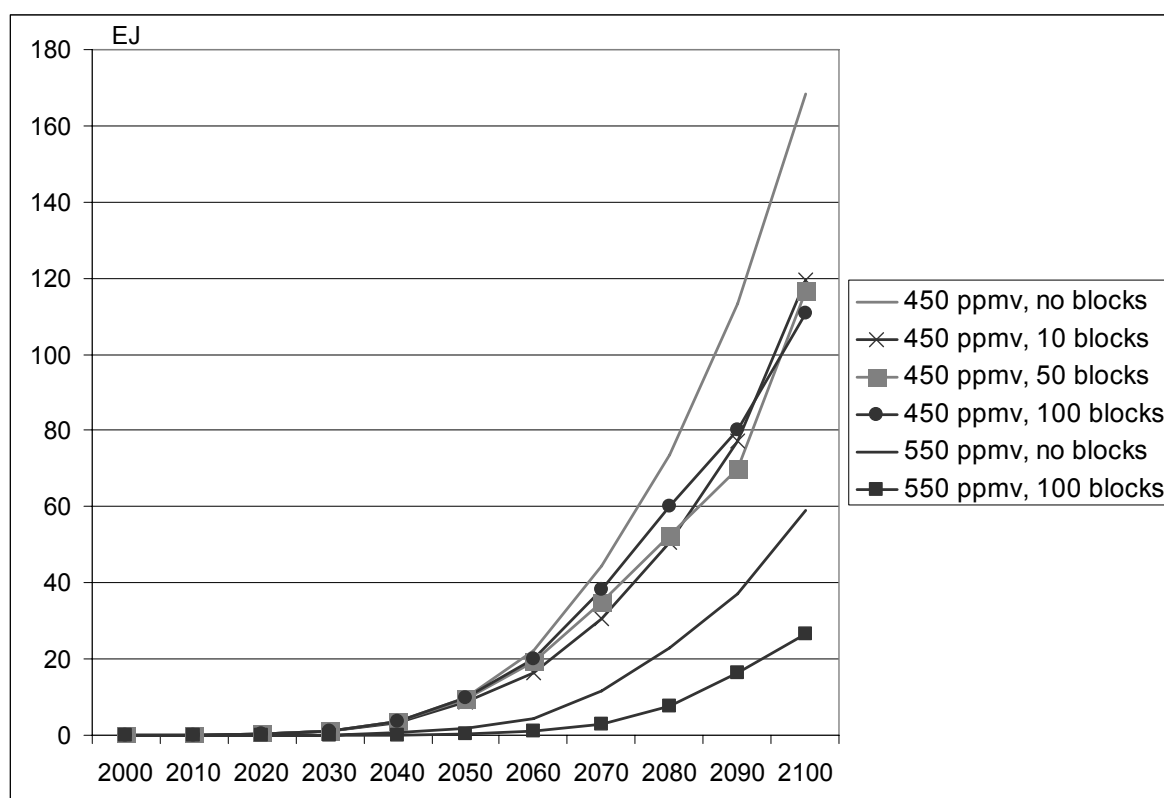


Figure 67. Hydrogen production with and without minimum investment levels in infrastructure.

The results suggest firstly that the total hydrogen production level is reduced if a minimum “lumpy” investment is considered for hydrogen infrastructure, i.e. hydrogen deployment takes place at smaller scale. This is particularly the case in the 550 ppmv climate policy scenario, where hydrogen production is reduced by almost 50%.

In the more stringent climate policy case, hydrogen production levels are reduced as well, but to a lesser extent. Moreover, total hydrogen production is not affected by the maximum level of investments allowed per delivery infrastructure option under a 450 ppmv climate policy target, i.e. the cases distinguishing 10, 50 and 100 blocks result in nearly identical total hydrogen production. The reason for this observation is depicted in Figure 68, which shows how low deployment constraints motivate the application of decentral hydrogen production facilities, which are not subject to any such restrictions on investment. The reason for this observation is the stringency of the applied climate policy target, which facilitates the use of more costly abatement options (i.e. decentral hydrogen production), if limitations on the deployment of cheaper options (i.e. central hydrogen production) are applied.

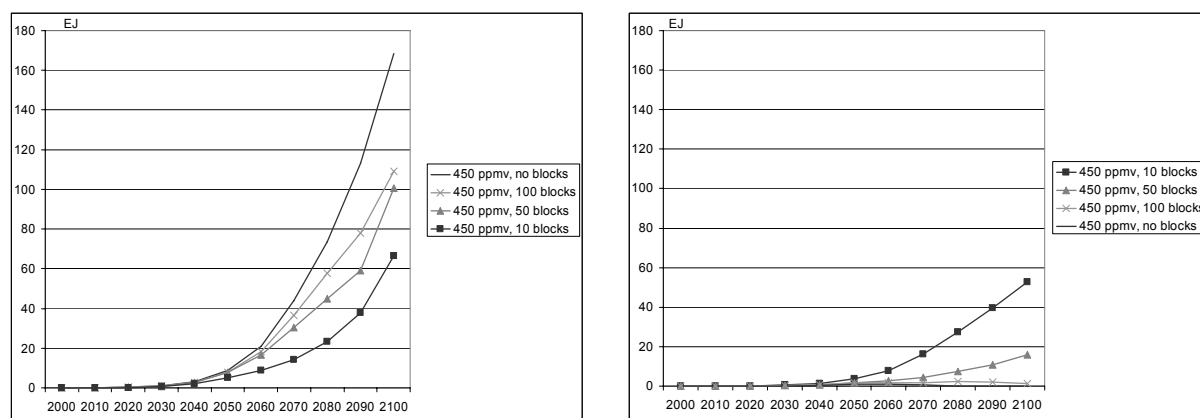


Figure 68. Hydrogen from central (left) and decentral (right) production facilities under different maximum investment levels.

The analysis of minimum investment and maximum deployment levels mainly suggests two things: firstly, the development of an appropriate hydrogen infrastructure *is* an issue for large-scale deployment of hydrogen. Throughout all scenarios it was found that the total hydrogen production level decreased through invoking a minimum investment and maximum deployment level on infrastructure deployment. The degree to which hydrogen production is reduced is linked to the climate policy target: the higher is the target, the lower the relative reduction of hydrogen production.

Secondly, it was found that imposing a maximum investment per decade and region facilitates a shift from central hydrogen production to decentral options. The less large-scale hydrogen delivery options can be deployed, the more decentral hydrogen is produced. In these cases, decentral hydrogen is initially provided from natural gas reforming, until a shift to electrolysis takes place towards the end of the century.

It is implicit that constraining the deployment of hydrogen infrastructure comes at a cost. Figure 69 depicts additional energy system costs resulting from the limits on hydrogen delivery infrastructure investments. It shows that the lower is the limit, the greater is the additional energy system cost. For understanding the scale of additional investment required, it is useful to know that total discounted energy system costs are in the order of US\$ 154 trillion for the 450 ppmv case without investment level constraints on hydrogen.

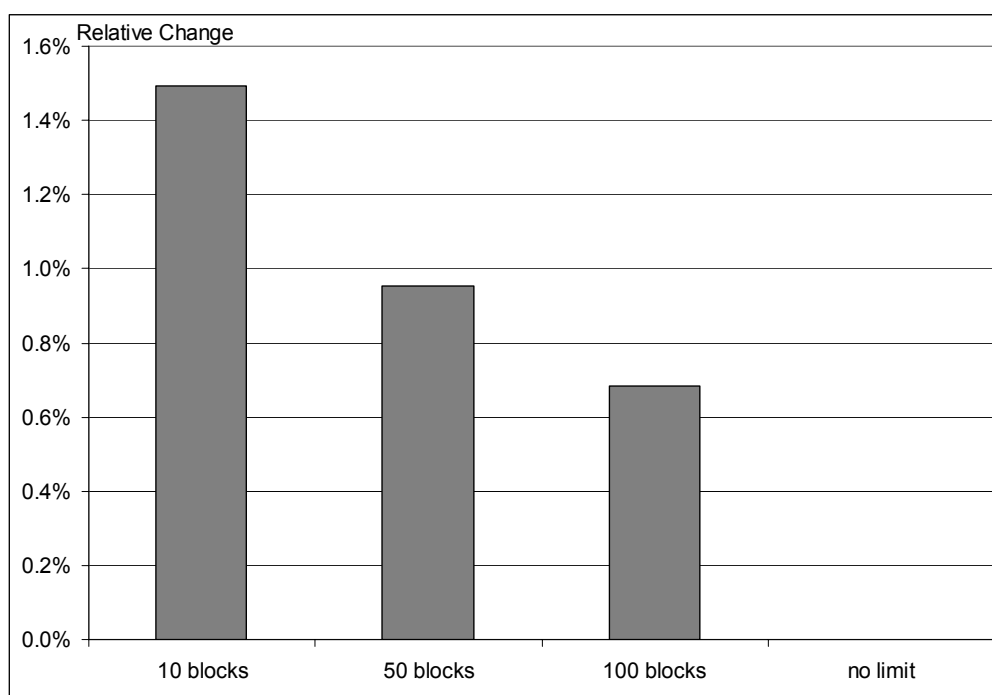


Figure 69. Additional energy system cost as a result of maximum investment levels per decade for the 450 ppmv climate policy case.

Limiting the scale of investment in hydrogen infrastructures not only limits the level of hydrogen fuel production, but consequently also the degree to which hydrogen is utilized. While personal transport has been found to be a prime target sector for hydrogen utilization in fuel cells under a 550 ppmv as well as a 450 ppmv climate policy target, this observation is confirmed only partially when considering the impact of minimum investment levels. Figure 70 shows how the contribution of hydrogen fuel cells to climate policy targets is decreased only modestly under a stringent policy target with 10 to 100 maximum investment blocks. However, under a 550 ppmv climate policy scenario, hydrogen fuel cells in personal transport do not play a significant role in meeting climate policy targets anymore as a result of limited hydrogen infrastructure possibilities. Then, hydrogen is merely utilised in other fleet-based parts of the transportation sector such as freight transport or busses.

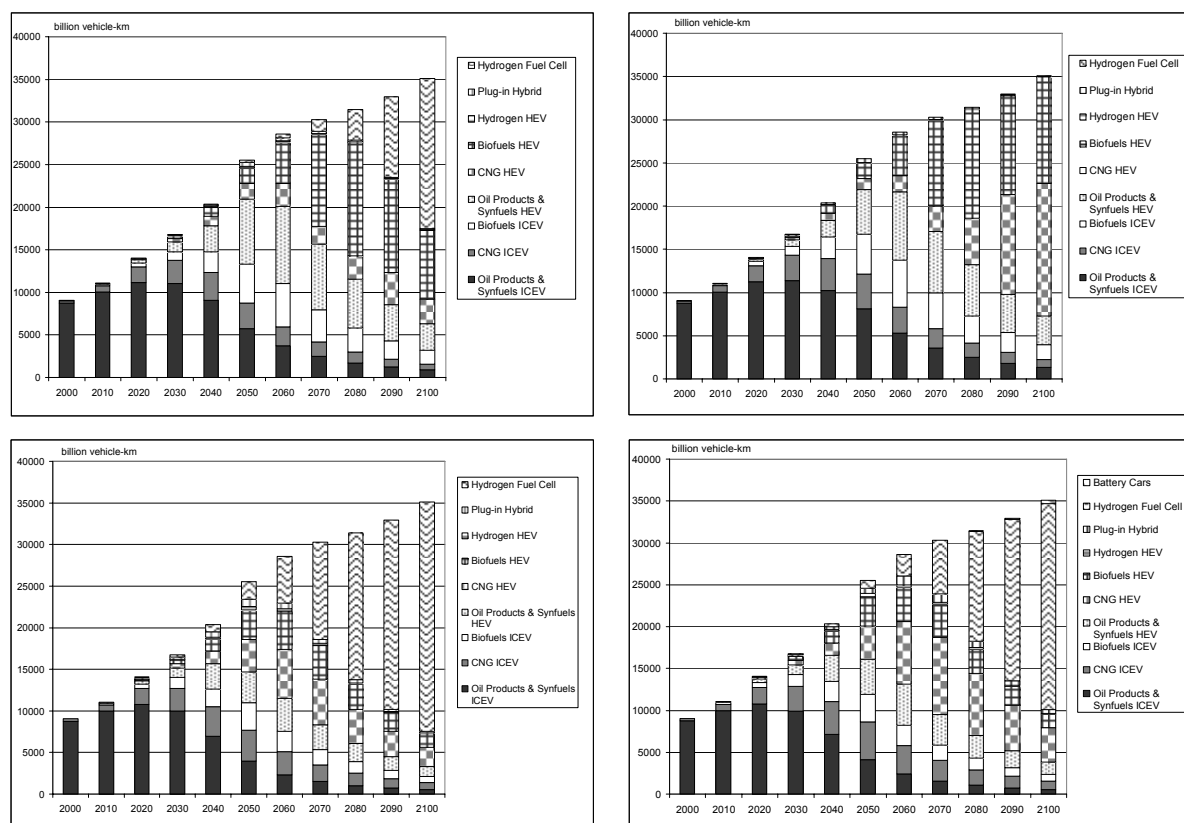


Figure 70. Share of hydrogen fuel cells in personal transport with and without minimum infrastructure investment levels (550 ppmv no blocks upper left hand, 550 ppmv 100 blocks upper right hand, 450 ppmv no blocks lower left hand, 450 ppmv 10 blocks lower right hand side).

### 5.5.7 Summary of Results

The analysis conducted in this section explored the implications of different climate policy targets on the energy system in general, and the role of biofuels and hydrogen in particular. It found that climate policy targets generally spur the deployment of hydrogen and biofuels. However, biofuels are a cost-effective option for meeting mild climate policy targets only; with increasingly stringent climate policy, the limited biomass resources are merely used for the decarbonisation of other sectors. This finding is consistent with what has been observed in the modelling analyses with EHM in chapter 4. It suggests that it is not only the cost of the biomass resource which determines the degree of the utilization of biofuels – the analysis with GMM comprised low cost as well as high cost biomass resources on a global level. Rather, it is the level of the climate policy target that determines whether biofuels are a cost-competitive option in personal transport. More stringent targets promote the utilization of the scarce biomass resources in other sectors of the energy system,

particularly electricity and heat production. In such scenarios, biofuels are found to act as bridging option until hydrogen fuel cells become competitive in personal transport.

Hydrogen production has been found to react strongly to climate policy targets, and the more stringent the target, the more hydrogen is deployed. This finding is again consistent with the results of the analysis on a European level with EHM in chapter 4.

The analyses with GMM, however, extended the previous analyses by looking more closely into hydrogen production technologies and infrastructures for hydrogen delivery. It was found that one key to the deployment of hydrogen in the first place is the availability of low- or zero-emissions technologies for hydrogen production, and coal gasification with carbon capture and sequestration (and electricity co-production) was identified as a highly promising technology in this regard, along with nuclear hydrogen production and wind power parks dedicated to hydrogen production via electrolysis.

The other key to a successful deployment of hydrogen is the build-up of a network for hydrogen delivery. An analysis of minimum investment levels for hydrogen infrastructures along with a maximum number of installations per decade showed that the possibility to quickly expand large-scale hydrogen distribution networks is a pre-requisite for hydrogen deployment. It was found that limitations to the ability of extending the hydrogen distribution network can be a bottleneck for hydrogen deployment and may prevent market penetration of hydrogen fuel cells. Very stringent climate policy, however, was found to promote alternative hydrogen production and delivery modes, in particular forecourt hydrogen, thereby facilitating the deployment of fuel cells in personal transport. Any limitation to the deployment of hydrogen delivery networks, however, leads to higher overall energy system cost.

On a more general energy-system level, the analyses conducted here found that significant structural changes are required to meet the challenge of climate change. A broad portfolio of technologies and energy carriers is necessary to meet climate policy targets, and technology change induced by climate policy and reinforced by technology learning is likely to alter the structure of the energy system substantially. Hydrogen can play an important role therein, but a transition to a “hydrogen



economy”, where hydrogen is the main energy carrier in final energy demand, does not occur. Rather, a transition to what may be deemed a “hydrogen+electricity economy” is taking place, where these energy carriers complement rather than compete with each other.

The importance of biomass as an energy carrier in a future more sustainable energy system is increasing with increasing climate policy targets. The results obtained here and in the analysis of energy security policies in section 5.4, however, indicate that there is no one optimal way of utilizing biomass. Much depends on policy targets and regional characteristics with regard to the availability of biomass and its costs.

## **5.6 Synthesis of Results and Concluding Remarks**

This chapter has explored the prospects of alternative fuels, in particular hydrogen and biofuels, in much detail. Using the Global Multi-regional MARKAL Model GMM, various scenarios were investigated for shedding light on their competitiveness under different policy regimes and with a particular focus on energy security and climate policy as the overarching energy system challenges investigated in this dissertation. Besides identifying policy conditions that spur the market penetration of alternative fuels, the analysis strived at identifying bottlenecks to their market uptake. The following key findings are results of this analysis:

- Pursuing energy security targets alone is likely to increase global CO<sub>2</sub> emissions as a result of higher utilization of liquid fuels derived from coal. Combined policy measures are necessary to tackle not only energy security, but also climate change. Such policy efforts are likely to increase the utilization of potentially clean alternative fuels such as hydrogen and biofuels.
- Biofuels as well as hydrogen are important fuels to meet climate policy targets. While biofuels are competitive under mild climate policy regimes, however, they are likely to act as a transition fuel only towards increased hydrogen deployment with more stringent climate policy.
- For biofuels, two *key bottlenecks* towards a more significant implementation have been identified. Firstly, *availability of low-cost biomass* has been found to be an important pre-requisite for biofuels utilization. Secondly, the *level* of the *climate policy target* imposed was found to determine the level of biomass

utilization for biofuels production, since the electricity and heat sector are at also suitable sectors for the use of biomass to meet climate policy objectives. The latter observation is consistent with the findings of EHM and discussions of other authors, e.g. Grahn *et al.* (2007).

- For the deployment of hydrogen, the availability of infrastructure has been found an important barrier for its large-scale utilization in personal transport. As a matter of fact, hydrogen fuel cell vehicles were uncompetitive in personal transport under a 550 ppmv climate policy regime when minimum infrastructure investment and maximum deployment levels were considered. However, hydrogen is still deployed as a fuel, but merely in other sectors of transportation such as buses and freight transport rather than for personal vehicles. In addition, the observed effects of reduced hydrogen production and utilization induced by minimum investment levels combined with maximum limitations on infrastructure deployment diminished with increasingly stringent climate policy targets and invoked the deployment of decentral hydrogen.
- Hydrogen production in the present analysis mainly takes places via coal gasification with carbon capture, which has been identified as the most competitive technology. Other important technologies for hydrogen production include nuclear-based synthesis of hydrogen and wind power parks dedicated to producing hydrogen from electrolysis. From the point of view of cost-optimization planning, hydrogen delivery infrastructure development was found to take place initially in pilot regions that deploy pipelines and combined pipeline and truck delivery on the one hand. On the other hand, delivery of liquid hydrogen by truck was identified a competitive option for initial phases of hydrogen deployment to flexible respond to increasing demand in regions with more dispersed demand for hydrogen.

The analyses pursued in this chapter have identified technology and fuel options that are cost-optimal to meet the discussed policy targets related to the overarching themes of this dissertation – climate change and energy security – and explored barriers to their implementation. Throughout all scenarios, it was found that alternative fuels can play a role in future transport to a higher or lower extent, depending on the scenario investigated.

Clearly, however, there are many more obstacles to overcome for the deployment of clean alternative fuels in transport than those being investigated here, and policy targets do not necessarily induce the changes that are desired by policy-makers. By way of an example, McNutt and Rodgers (2004) review experiences with US legislation during the 1990s and discuss why the Energy Policy Act of 1992, which established a goal for alternative fuel use of 10% by the year 2000, and 30% by 2010, did not achieve the desired outcome. The developments of alternative fuel use have by far fallen short of these targets, despite significant financial and policy investments. The authors identify several reasons for this development, among others a chicken-or-egg problem with the development of a refuelling infrastructure. More significantly, however, the industry with a significant stake in petroleum fuels and vehicle technologies responded by implementing significant improvements for conventional fuels and vehicles, thus delivering significant emission reductions and weakening the policy argument. Moreover, alternative fuels failed to develop out of niche market applications into the mainstream, despite heavy government support.

Such experiences show the extent of the problem. It is not only technology development targets such as achieving low-cost fuel cells at costs in the order of US\$ 50 /kW to make new technologies economically viable. It is also an appropriate policy environment that is required to facilitate a switch to alternative fuels, together with industry involvement, e.g. public private partnerships, particularly given the large investment needs. Promoting the adoption of alternative fuels in transport – that is probably the key lesson from past experiences – is an effort that requires involving all stakeholders; otherwise, existing infrastructure lock-ins are hard to break and replace. A good example for such a collaborative effort is the development of a hydrogen-fuelled economy in Iceland, where several industrial players are collaborating with academia and policy-makers to gain experiences with the application of hydrogen fuel cells in buses and with the development of a hydrogen infrastructure. Such projects are just the pilot regions it takes as was suggested in the above analysis to develop hydrogen further.

What remains after the analysis conducted here are insights into the competitiveness of alternative fuels under different policy scenarios and insights into key bottlenecks that need to be overcome for their implementation. What seems clear from the

analysis here is that biofuels can have a role in personal transport; but the degree of their utilization depends on the one hand on the availability of sustainable produced low-cost biomass, an issue which has been widely debated recently in the context of competition with agricultural land-uses for food production and increasing food prices, potentially induced by an increasing utilization of biofuels (Swissinfo 2007). For some world regions, which lack abundant and cheap biomass resources, an increased utilization may also result in an increased need for biofuels imports (compare also the analysis with EHM in chapter 4, which found that biomass availability was a key barrier for the implementation of biofuels in Europe). In any case, the results conducted here are consistent with the analyses of Turton (2006b), who also found that biofuels could play an important role under mild climate mitigation regimes.

On the other hand, the extent to which biofuels can become a competitive option for transport is linked to whether and when hydrogen can be developed as a transportation fuel. The present analysis suggests that the scarce biomass resources are better utilized to reduce CO<sub>2</sub> emissions in electricity and heat production under the assumptions applied here.

Policy-makers, thus, need to work on two fronts at a time if they intend to deal with the energy system challenges climate change and energy security. That is, they need to provide the required RD&D programmes and the regulatory framework if they intend to increase the share of biofuels in transport, e.g. by invoking minimum shares of biofuels in transport as recently done in the European Union for the year 2020 (EC 2008), or by setting a minimum standard for biofuels blends into conventional fuels.<sup>47</sup> In addition, policy-makers need to further support research on hydrogen and fuel cells, particularly through the implementation of demonstration projects. Technologies that require particular attention in this light appear to be hydrogen fuel cells, both for mobile and stationary applications; and hydrogen production technologies, in particular involving gasification, but also electrolytic hydrogen production which could entail spillover effects on a more widespread use of

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<sup>47</sup> Which policy is applied is obviously a question of the target that is pursued. If, for example, reducing CO<sub>2</sub> emissions from transport and decreasing the use of oil products in transport is the target, then a performance-based target that mandates e.g. a maximum cap on CO<sub>2</sub> emissions per km driven may be a more appropriate choice. A minimum share of biofuels in personal transport as suggested here additionally induces the development of biofuel production technologies, but does not necessarily reduce CO<sub>2</sub> emissions to the extent as does a performance-based target.

renewable energies in the electricity sector by providing storage capacity to intermittent resources.<sup>48</sup> Ideally, such research projects are realized as efforts involving all the various stakeholders involved, ranging from industry to academia and politics, but also consumers for gaining insights into the implications of hydrogen use in daily applications and the satisfaction of consumers with the “commodity hydrogen”. Early involvement of all stakeholders allows minimizing the risk of failure when it comes to the actual market introduction of hydrogen in the transport sector.

A combination of such policy measures addressing both biofuels and hydrogen at a time can help spurring the use of biofuels as a transition fuel until a better understanding of the feasibility of reducing hydrogen fuel cell costs is achieved and first experiences with hydrogen on a pilot project level have been gathered.

In any case, facilitating hydrogen appears to be likely a long-term option for transport, as it is a radical departure from today’s transport systems, and there is still a considerable need for RD&D and an analysis of the potential of individual technologies, in particular fuel cells. But facilitating hydrogen requires efforts today: the analysis presented here showed that for realising stringent climate policy targets, investment needs for gaining experiences with hydrogen production technologies and setting up pilot projects with an appropriate hydrogen supply infrastructure are high. Nevertheless, the scale of the effort over the next 50 years is justifiable in light of additional investment needs required e.g. in the power sector, and would allow us to “keep the hydrogen option open” for the second half of the century, thus potentially allowing future generations to reduce CO<sub>2</sub> emissions drastically and satisfy future transport demand in a more sustainable manner than today.

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<sup>48</sup> An important technology here could be Proton Exchange Membrane (PEM) electrolysis, i.e. electrolyzers that work like a reversed fuel cell; for details, see Barbir (2005).

## 6 Summary and Conclusions

The objective of this dissertation was to analyse the prospects of alternative fuels, in particular hydrogen and biofuels, for the use in personal transport. More specifically, it sought to identify key drivers and key bottlenecks for the implementation of these fuels, and to analyse the role of technology change in dealing with energy system challenges associated with climate change and energy security. In summary, this thesis investigated 3 key issues:

1. the costs of technologies for the production and delivery of hydrogen and biofuels and vehicle technologies for their utilization in personal transport
2. the role of different fuel and vehicle options in personal transport in realising different policy objectives in climate change and energy security in an energy system-wide context
3. key drivers of and key bottlenecks to the implementation of hydrogen and biofuels in personal transport

### 6.1 *Summary of Findings*

This section will provide a summary of findings with regard to these 3 key issues investigated. This is followed by a section that discusses possible policy implications that can be derived from the conducted analyses.

#### 6.1.1 Alternative Fuel Chains

A comprehensive static spreadsheet analysis of fuel chain costs and efficiencies was conducted in chapter 3 of this dissertation, with a particular focus on hydrogen and biofuels. A range of technologies for hydrogen production were identified, which have the potential to produce hydrogen with zero or near-zero CO<sub>2</sub> emissions. The costs of hydrogen production were found to be fairly consistent across the studies investigated, with coal gasification being the cheapest technology option. Observed differences were explained mostly by variations in production scales assumed in the various studies, since scale-economies are significant for many of the technologies investigated. Another factor influencing the costs of hydrogen synthesis is the ability

of some production technologies to co-produce electricity. Such technology options are likely to be important in central hydrogen production, in particular in early phases of hydrogen deployment, because they could potentially switch from electricity production to hydrogen production with increasing hydrogen demand (see e.g. Yamashita and Barreto (2003) for a discussion of such poly-generation strategies).

For the delivery of centrally produced hydrogen to fueling stations, an elaborated infrastructure was developed and implemented in the MARKAL-based models used here. The infrastructure comprises pipeline delivery and truck delivery as well as combined systems for load centres of 250 tons of hydrogen per day. Each of the delivery options has different advantages: pipelines were assessed to be the cheapest option for delivering hydrogen, but they are the least flexible option and likely to supply single demand centres only, when sufficient hydrogen demand is already in place. Truck delivery, in this light, has its merits in its flexibility, as it can supply various dispersed load centres at a time, and increase the number of trucks in operation gradually with raising demand. However, delivery by truck is more costly than by pipeline, even though liquid truck delivery is anticipated to become cost-competitive. As a general rule, the analysis of hydrogen fuel chain costs showed that delivering hydrogen is a key cost factor, which at least doubles the costs of hydrogen production for the cheapest hydrogen production options.

Biofuels production costs were analysed in great detail in the course of a Master thesis, which was supervised by the author of this dissertation. The detailed description of assessed technologies along with the database is reported in Ragettli (2007). In the present dissertation, only a summary of costs was given highlighting the key reasons for variations in costs observed in various studies, and in particular for second generation biofuels. Again, differences in production scales were identified as one main reason, along with by-product credits e.g. from electricity co-production. An assessment of the influence of biomass costs on biofuels production additionally indicated that whether or not biofuels can be cost-competitive for the use in transport is largely linked to regional conditions, i.e. how much biomass is available for energy purposes, and at which costs.

### 6.1.2 Cost-competitive Technology Choices

Two energy system models were applied for an assessment of cost-competitive technology choices and the dynamics of technology change under different policy regimes. The first analysis in chapter 4 used the European Hydrogen MARKAL model EHM, which is a technology-oriented, perfect foresight, “bottom-up” model for the analysis of the European energy system. It was developed in the course of this dissertation to obtain first insights into the cost-competitiveness of fuels and vehicles in personal transport and the key drivers and bottlenecks for their implementation.

In chapter 5, then, the scope of the analysis was broadened by investigating potential roles for hydrogen and biofuels on a global level using the Global Multi-Regional MARKAL model GMM. GMM was originally developed by Barreto (2001) and applied for policy analyses among others in Rafaj (2005) and Krzyzanowski (2006). In the course of the present dissertation, GMM was further developed by increasing the level of disaggregation of world regions and enhancing the representation of hydrogen and biofuels chains as well as the personal transport sector. In addition, GMM was coupled to the climate model MAGICC (Wigley and Raper 1997; Wigley 2003) and extended to include endogenous technology learning in learning clusters. Using this modelling framework, the analysis of the prospects of alternative fuels in transport was extended with an enhanced representation of technology change, allowing for close insights into drivers and obstacles for the utilization of alternative fuels in personal transport. Specific attention was paid to the role of hydrogen and biofuels under energy security and climate change policy regimes as the overarching energy system challenges of this dissertation. The analysis finished with an assessment of hydrogen production and delivery technologies and their significance as bottlenecks in the deployment of hydrogen.

The analyses suggest that both hydrogen and biofuels can be cost-competitive technology choices in future transport for pursuing climate mitigation policy. Biofuels are additionally likely to contribute to fuel supply in responding to energy security targets, but liquid fuels derived from coal were identified as a strong competitor, which is likely to dominate future fuel markets in absence of climate policy.

In terms of the timing of technology choices, the analysis conducted with EHM revealed a preference for hybrid vehicles in personal transport as a short- to medium-term option for decarbonising personal transport in the next 10 to 30 years to come



and beyond. The choice of fuel is likely to be driven by the availability and price of resources, and the analysis with EHM as well as with GMM showed that the regional availability of cheap biomass will determine the extent of sustainable produced biofuels utilization in personal transport.

Hydrogen fuel cells have been found a long-term option for personal transport across almost all scenarios investigated here, i.e. towards the second half of the century. Main reasons for the late deployment of hydrogen include the need for reducing fuel cell costs to competitive levels, and the construction of a hydrogen distribution infrastructure. These barriers and what could drive an earlier deployment of fuel cells will be discussed in section below.

For the use of hydrogen as an alternative fuel in personal transport for meeting climate change mitigation targets, the production of hydrogen from carbon-free sources or from technologies with carbon sequestration is a must. Hydrogen produced via coal gasification with carbon capture was found to be a very competitive route for hydrogen. Other important central technologies were nuclear energy sources and wind power dedicated to producing hydrogen from electrolysis. While these results indicate which technologies can contribute cost-effectively on a large-scale and on a global level, it is clear that this may differ in reality according to regional circumstances. Local conditions are likely to determine which technology to deploy, e.g. sunny regions such as southern Spain and potentially the Sahara desert in Africa could make use of solar hydrogen production technologies. In addition, regionally different public perception towards nuclear energy, but also towards carbon storage, may become an obstacle for the utilisation of the respective technologies.

Moreover, some of the above-described technologies may be applicable only in the future with significant hydrogen demand already in place. In particular nuclear hydrogen sources require significant hydrogen demand, as small-scale nuclear hydrogen facilities are not applicable. But also, small-scale coal gasification with carbon capture is likely to be less competitive due to a lack of economies-of-scale. Accordingly, this entails an additional lock-out effect that needs to be overcome in the time before demands are sufficient to require the scale of production of these low-cost hydrogen options. The co-production of additional products, in particular electricity, could provide a way to deploy cost-competitive large-scale facilities to

overcome this limitation. Once hydrogen demand increases, these facilities can then adapt to increase hydrogen synthesis.

Finally, the analyses conducted with GMM showed that meeting climate policy targets requires substantial efforts and is likely to induce technology change at all levels of the energy system. Clean technologies will be required in electricity as well as fuel production, which also motivates the deployment of hydrogen and also biofuels. A transition to what is commonly referred to as a “hydrogen economy”, i.e. an energy system attributing a key role to hydrogen (Ogden 1999a) was not observed even under the most stringent climate policy target pursued here. Rather, the results indicate that hydrogen and electricity could act as complementary energy carriers in a future low carbon society, thus enhancing the resilience and flexibility of the energy system.

### 6.1.3 Key Drivers and Bottlenecks for Hydrogen and Biofuels

One of the main motivations of this thesis was to analyse key drivers as well as key bottlenecks for the utilization of biofuels and hydrogen. The analyses found that biofuels were competitive throughout all scenarios investigated. In particular, the use of biofuels was encouraged by energy security policy as well as mild climate change mitigation targets.

However, there are two central determinants affecting the degree of utilization of biofuels: the availability of low cost biomass resources on the one hand, and the extent of the climate change mitigation policy target on the other hand. With regard to biomass availability and cost, the analysis with EHM showed that regions without low-cost biomass available at significant scale are likely to choose other fuel options for the decarbonisation of personal transport, in particular natural gas, if no other additional policy targets supporting the use of biofuels are in place (e.g. agricultural policy). Using natural gas in hybrid-electric vehicles has the potential to reduce CO<sub>2</sub> emissions from personal transport significantly in the coming decades. In the analyses with GMM, biofuels were competitive in those world regions where low-cost biomass is abundant. However, the analysis also showed that stringent climate policy objectives limit the utilization of biofuels since biomass is a useful energy carrier for

the decarbonisation of other sectors as well, in particular heat and electricity production.

The main driver for utilizing hydrogen in personal transport is climate change mitigation policy, more specifically stringent climate policy. The utilisation of hydrogen fuel cell vehicles was found to be hardly supported by energy security targets, or more generally by resource scarcity. Under such circumstances, coal-to-liquids and biofuels appear more attractive options for personal transport in the absence of climate policy. However, pursuing multiple policy targets addressing both climate change and energy security, or more stringent climate policy alone may facilitate the use of hydrogen in transport.

Clearly, significant hurdles exist that need to be overcome for utilising hydrogen, and two key bottlenecks were identified and discussed in this dissertation, namely the future cost of the hydrogen fuel cell that can ultimately be achieved in the long-run, and the development of an appropriate hydrogen delivery infrastructure. For the future cost of the fuel cell, the analysis conducted with EHM found that costs in the order of US\$ 40 to 50 per kW are required to assure market competitiveness in personal transport. The earlier such low costs can be achieved, the better the chances for hydrogen fuel cells in transport; in fact, the analyses with EHM revealed that hydrogen fuel cells can only contribute to personal transport in significant scale before the year 2050 if cost reductions are achieved within the next 10 to 20 years.

However, the actual level of the climate policy target also has a significant influence on these costs, as stringent climate policy facilitates the deployment of more costly abatement options and, thus, would allow market penetration of fuel cells already at higher costs.<sup>49</sup> Thus, the market penetration of hydrogen fuel cells has been found to be a function of future fuel cell costs, the timing of achieving these cost reductions, and climate change mitigation policy, where a combination of the three determines the break-even point of fuel cells.

The second important bottleneck for hydrogen is the deployment of hydrogen infrastructures. An analysis of minimum “lumpy” investment levels for hydrogen delivery infrastructure and maximum deployment rates per decade confirmed that infrastructure is a key problem for hydrogen utilization. In an analysis of a 550 ppmv concentration target for global CO<sub>2</sub> emissions, hydrogen fuel cell market shares were

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<sup>49</sup> Note, however, that elastic demands were not considered in this analysis. With increasingly high prices, demands may be reduced, thereby reducing or eliminating potential markets for hydrogen fuel cells.

significantly reduced by applying the described constraints on infrastructure deployment, i.e. hydrogen fuel cells were almost excluded from personal transport. Again, however, the extent to which hydrogen delivery infrastructure is a bottleneck for hydrogen fuel cell deployment is linked to the climate policy target: stringent climate policy such as the discussed 450 ppmv CO<sub>2</sub> concentration target may necessitate the use of hydrogen in transport, and thus support the use of additional and more costly decentral hydrogen production technologies.

## **6.2 Policy Implications**

The main lesson learned in this dissertation is that the choice of the most competitive technologies for personal transport is not straightforward, as it depends on numerous factors at a time. These factors include first and foremost the degree of the climate change mitigation policy target, which has been identified as one of the most important guides of appropriate technology choices in the long-run. The present analysis found that strong climate policy goals necessitate substantial structural changes in the energy system, including the transport sector. Under such policy regimes, hydrogen fuel cells can play an important role if technology development targets are achieved.

Independent of the climate policy target pursued, personal transport requires changes in the short- to medium-term directed towards the use of more efficient vehicles, hybrid vehicles applying oil products, natural gas and biofuels, and motivated by increasing resource scarcity and correspondingly increasing fuel prices. Hybrid vehicles were a cost-competitive measure through all scenarios investigated, and policy-makers could support their large-scale deployment for example through CO<sub>2</sub> emissions standards on vehicles, tax exemptions for low emissions vehicles or rebates on the purchase of hybrid-electric vehicles.<sup>50</sup> Clearly, emission standards would penalise some car manufacturers more than others; however, this effect could be mitigated by applying emission standards on the fleet rather than individual vehicles, and through the implementation of compensation measures similar to an emission trading system between car manufacturers.

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<sup>50</sup> Some of these policy measures are already in practice, e.g. in California, or are discussed such as in the European Commission.

Another important factor that determines the appropriate fuel choice is the availability of low cost biomass. In this dissertation, a total biomass potential of 195 EJ per year was assumed available for energy purposes. Evidently, there is a lot of uncertainty about this biomass potential, and Hoogwijk *et al.* (2003) suggest a (technical) primary biomass potential of 33 to 1135 EJ per year for the year 2050, depending on various factors such as population growth, food demand and food production efficiency, energy crop productivity on various land types, and several more. The potential assumed here is at the conservative end of the range of what is being discussed, but current public debate about raising food prices potentially induced by an increased utilization of biofuels makes it hard to believe that the full potential can be exploited in the foreseeable future. In addition, the analyses conducted in the present thesis show that heat and electricity production could well be more cost-effective choices for the use of scarce biomass resources in meeting climate policy goals, similar to findings of Grahn *et al.* (2007). Finally, large-scale bioenergy production also includes environmental, social and economic risks as highlighted by Hamelinck and Faaij (2006), which have not been considered in this analysis, but deserve close attention. In this light, the question for the utilisation of biomass for any energy purposes is not only how much of it is available, but also how it can be mobilised while maintaining food and fibre production and protecting the environment.

The degree to which biofuels are required for the decarbonisation of personal transport under climate policy regimes is additionally linked to the availability of hydrogen and hydrogen fuel cells as competing options. Hydrogen is a zero- to near-zero carbon fuel, and if low cost fuel cells can be manufactured and stringent climate policy targets are pursued, then there is less need for biofuels in transport. Nonetheless, biofuels could still serve as an important transition fuel towards hydrogen-based transportation.

Deploying hydrogen in transport, however, entails substantial challenges. First and foremost, there is a need for a better understanding of the potential future cost of the fuel cell. The analysis conducted in this dissertation only shows what is required for achieving cost-competitiveness, but does not aim to suggest that these cost reductions will necessarily be achieved. After all, this depends on a number of factors, including extensive RD&D programmes targeting i.e. the development of cheaper materials and membranes; ramping up production scales for hydrogen fuel

cells, as only mass production will allow materializing substantial cost reductions; and the involvement of all stakeholders including not only policy-makers and academia, but also and particularly industry. As discussed before, the results in this dissertation imply that pilot programmes could be an appropriate way to gather first experiences with the use of hydrogen and hydrogen fuel cell vehicles and gain insights into the implications of hydrogen use in daily applications, as well as familiarising consumers with the “commodity hydrogen”. Early involvement of all stakeholders allows minimizing the risk of failure when it comes to the actual market introduction of hydrogen in the transport sector. Experiences gained with such pilot projects must guide the actual deployment in early phases of fuel cell market entry.

When it then comes to actual market deployment of hydrogen fuel cells, many aspects need due consideration. In particular the availability and convenience of refuelling hydrogen-driven vehicles is essential in order to assure consumer acceptance. However, it is also important to more generally raise consumer awareness to increase understanding and acceptance: a survey on the introduction of fuel cell buses in London transport conducted by O’Garra *et al.* (2005) for example showed that fewer than 50% of London residents had heard about hydrogen vehicles at all – a figure that implies a major challenge if hydrogen fuel cells are to become a dominant technology. Additional policy measures required at this level of market penetration could be subsidies on fuel cell vehicle purchase, similar to what has successfully been done with renewable energies; purchases of hydrogen fuel cell vehicles for government fleet; or partnerships with other fleet-based transportation, such as the taxi fleets.

The analyses in this thesis have shown that “keeping the hydrogen option open” during the next decades does not require major investment compared to the degree of the climate challenge and necessary total investments in energy supply. However, it allows the pursuit of a stringent climate policy in the second half of the century, when technologies for hydrogen production and utilization have reached a significant degree of maturity. Still, the deployment of hydrogen and hydrogen fuel cells will require creativity during early phases of hydrogen market penetration (see e.g. Adamson (2003) for an adoption framework of fuel cells in different niche markets),

and regional-specific approaches and case studies (see e.g. Ogden (1999b) for a Southern Californian case study).

Moreover, it is clear and has been discussed repeatedly in this dissertation that increased future energy demand, and especially demand for mobility, is likely to take place in developing countries. Using alternative fuels there, and in particular hydrogen in fuel cell vehicles, will require efforts with regard to technology transfer (which may to some extent facilitate “technology leapfrogging”). Industrialised countries may need to take the lead (and the costs) in the development of alternative fuels and fuel cells, and support their later deployment in developing countries without significant burdens in order to meet global energy challenges effectively. Without the availability of hydrogen and fuel cells in what will be the largest transport markets, hydrogen is likely to play only a minor role in the global energy system, even under stringent climate policy. Thereby, society may miss out on future cost-effective technology options for meeting stringent climate change mitigation targets.

As a final remark it is important to recognize that investors and the market as a whole need clear, consistent and early signals and information from policy-makers, in particular with regard to the degree of the climate change mitigation target and the institutional framework, e.g. carbon emission trading systems. As shown in this dissertation, the climate policy target is one key determinant that defines the competitiveness of technology options, and current uncertainty about the stringency of global climate policy may delay the development of cost-effective technologies for mitigating climate change. The analysis in this thesis has shown that climate change mitigation policy will require the mobilisation of substantial investments, and that a broad portfolio of technologies will be needed. Industry needs a reliable and long-term oriented policy framework to mobilise the required investments for ensuring that technology RD&D and commercialisation takes place.

### **6.3 Outlook on Future Research**

This thesis has addressed many facets of switching to alternative fuels, in particular hydrogen and biofuels, and has focused on the prospects of these fuels in personal transport. A central theme was the role of alternative fuels in mitigating climate change.

Clearly, not all aspects of such a switch to alternative fuels could be covered here. One important aspect for the potential utilization of hydrogen is e.g. the question “where would hydrogen be used first?”. There are arguments that could favour the utilization of hydrogen in other transport sectors such as freight transport or buses rather than personal transport. The particular advantage of these other transport modes is that they are fleet-based options that make use of central terminals; also, large vehicles may have fewer hydrogen storage problems. Other interesting target sectors for the utilization of hydrogen include stationary applications, where fuel cells could be used to produce electricity and heat in coupled production. Initially fuelled by natural gas, this could lead to a first application of hydrogen. Some authors suggest that hydrogen should be deployed first in such stationary nice applications before entering the mainstream and being applied in transport. This could be analysed using GMM or EHM, and would require the development of more detailed end-use sectors, i.e. the representation of these sectors needs to be improved in both models.

The analyses conducted in this dissertation have gone beyond previous analyses in Krzyzanowski (2006) and Turton (2006a) through the implementation of a higher level of technology detail, in particular regarding the hydrogen delivery infrastructure. Future work could extend the hydrogen module of GMM (or EHM) by extending the forecourt hydrogen production options, e.g. with wind turbines or solar photovoltaic dedicated to producing power for hydrogen production, or even as co-production technologies. This would enhance the representation of technologies, thus allowing for a better study of the role of forecourt hydrogen production in particular in early phases of hydrogen deployment. Moreover, future work could assess spillover effects of policies targeting the application of renewable energy technologies in central as well as decentral applications on the utilization of hydrogen as an option for electricity storage or intermittency buffer.

In general, this thesis has applied technology data for technical improvements that are deemed as potentially feasible within a foreseeable timeframe, i.e. over the next 20 to 30 years. Future work should account for this and vary some of the assumptions, in particular with regard to the costs of batteries for a closer study of the prospects of battery electric vehicles.



This thesis has contributed significantly to further developing GMM by taking up the suggestion of Rafaj (2005) to couple GMM to a climate model. Additionally and also suggested there, GMM could be coupled to a macroeconomic model to study impacts of alternative fuel deployment on the economy in an integrated assessment framework, perhaps with more detailed modelling of transport demand building on Turton (2006a).

Furthermore, the present analysis with GMM was limited to a fixed-demand approach, i.e. elastic demands were not considered. Future work should take this into account, too, because reduced demand in transport will reduce the burden on the rest of the economy to reduce emissions. In addition, previous formulations of GMM included emissions and marginal abatement curves for emissions other than CO<sub>2</sub> such as SO<sub>2</sub> and NO<sub>x</sub>. For investigating the impact of local air pollution policy, the effects of internalising external costs and a more detailed assessment of climate policy, it would, thus, be advisable to re-integrate these gases in GMM.

Finally, the assessments in this thesis are entirely based on cost-optimization. However and as repeatedly mentioned, there are other factors that need to be considered for a transition to alternative fuels in transport, in particular issues of consumer acceptance and related questions. Such analyses are commonly made using system dynamics approaches, and an interesting future analysis could aim at coupling a simplified MARKAL-based model to a system dynamics modelling approach for studying interactions.

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## Appendix 1: Hydrogen Production Cost – A Review of Major Studies

Numerous studies were reviewed in the course of this dissertation in order to obtain a comprehensive overview on the state-of-the-art cost data of hydrogen production. All cost and efficiencies found are reported in the end of this appendix.

Three key studies were reviewed in more detail in order to get an understanding of reasons for cost differences; they include the H2A spreadsheet models, which is a major effort conducted under the umbrella of the United States Department of Energy (US DoE) involving several research institutes. The versions of these models used here were obtained during a research visit to the US National Renewable Energy Laboratory (NREL) in June 2006 (H2A 2006a). The other two studies are “The Hydrogen Economy – Opportunities, Costs, Barriers, and R&D needs” by the US National Research Council (NRC 2004); and the study “Hydrogen Supply: Cost Estimate for Hydrogen Pathways – Scoping Analysis” by Simbeck and Chang (2002). Where appropriate, complementary studies were used.

Common to these studies is the fact that not only one, but several options for producing and delivering hydrogen have been reviewed using consistent assumptions, thus allowing for a sound comparison of data. Where necessary, other studies have been selected in addition.

All cost data presented in the following sections is based on the following relation:

$$Cost = INVCOST \times \frac{CRF}{AF} + \frac{FIXOM}{AF} + VAROM + \frac{FuelCost}{\eta}$$

where

INVCOST = Specific investment cost [US\$/kW]

CRF = Capital recovery factor [-]

AF = Availability factor [-]

FIXOM = Fixed operation and maintenance cost [US\$/kW/yr]

VAROM = Variable operation and maintenance cost [US\$/GJ]

$\eta$  = Process efficiency

The capital recovery factor CRF is computed using

$$CRF = dr \times \frac{(1 + dr)^n}{(1 + dr)^n - 1}$$

where

dr = Discount rate [%], assumed 5% for all technologies in this analysis

n = Plant life time [years].

Moreover, all cost data presented in the following have been assessed using the same key input values, particularly fuel cost assumptions<sup>51</sup>.

In a first step, the “current” costs of hydrogen production are compared followed by “future” costs. The latter indicate on the one hand the cost levels that could be reached by current technologies in the future if development targets were met; on the other hand, they reflect the costs of hydrogen production from future technologies that are currently at R&D stage only. Finally, all cost data collected in the course of this dissertation is presented.

### **“Current” costs of hydrogen production**

Figure 71 gives an overview on cost data as found for today’s technology with static fuel and electricity cost inputs.

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<sup>51</sup> All hydrogen related data is on LHV basis. Fuel input cost assumptions: Natural Gas = 4.64 US\$/GJ; Coal = 1.6 US\$/GJ; Biomass = 5.1 US\$/GJ; Electricity = 12 US\$/GJ; Coke = 4.6 US\$/GJ.

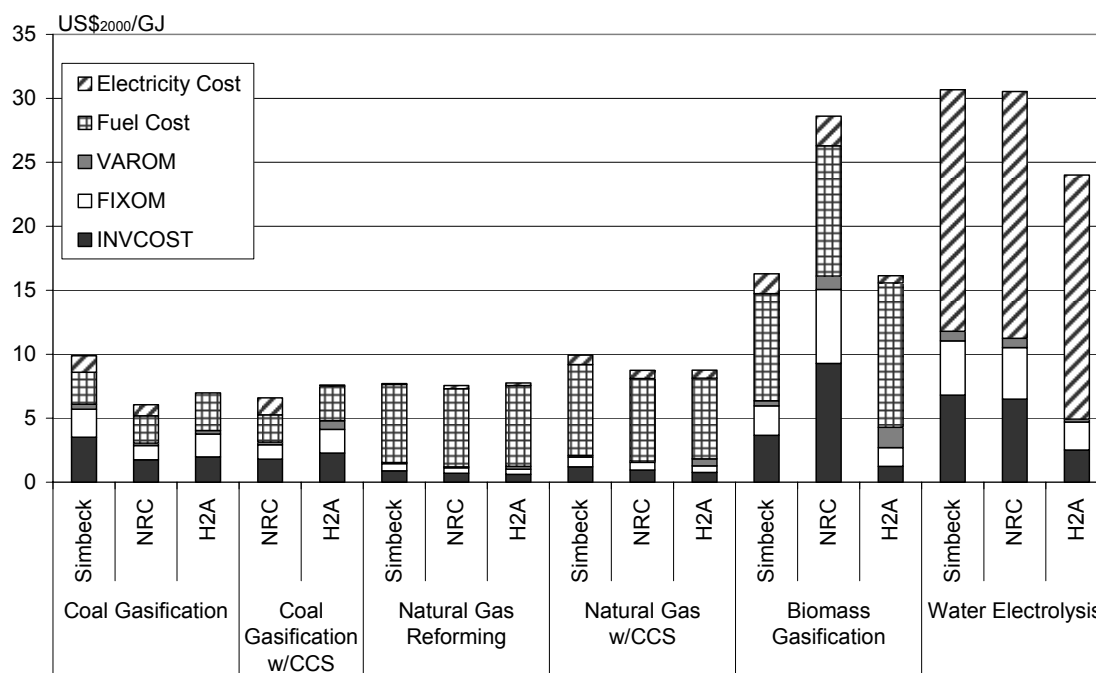


Figure 71. Hydrogen production cost of "current" technology.<sup>52</sup> Sources: Simbeck and Chang (2002); Simbeck (2004); H2A (2006a); NRC (2004).

As Figure 71 shows, there is only little discrepancy in total cost data except for biomass gasification. Where differences exist, they can be explained mostly by plant scales as chosen by the authors:

- Simbeck and Chang (2002) assess the cost using a hydrogen output per plant of 150 tons of hydrogen per day common to all plants;
- NRC (2004) uses 1,200 tons of hydrogen per day for central large-size hydrogen production from natural gas reforming and coal gasification, and 24 tons per day for biomass gasification, water electrolysis and midsize natural gas reforming (the latter is not presented in Figure 71 and amounts to US\$ 9.04 per GJ in total);
- H2A, however, chooses a different approach and optimizes plant hydrogen output according to what is deemed best suitable for the individual technologies in order to exploit scale-economies most efficiently. This results for example in a hydrogen output of about 280 tons per day for coal

<sup>52</sup> Note that coal gasification in H2A is designed as a coupled-production process, i.e. additional electricity is co-produced. This reduces current cost of hydrogen production by about US\$ 1.1 /GJ, resulting in total costs a little lower than estimated by NRC (2004).

The Simbeck case for natural gas reforming with CCS derived from Simbeck (2004a). All cost data for technologies with carbon capture presented here exclude the cost of CO<sub>2</sub> storage.

gasification, 155 tons per day for biomass gasification and 380 tons per day for natural gas reforming.<sup>53</sup>

Another key reason that explains cost differences is the pressure of hydrogen at the outlet of the plant: while in H2A, all technologies are standardized to a hydrogen pressure of around 20 bar at the plant outlet, both NRC (2004) as well as Simbeck and Chang (2002) assume up to 75 bar, depending on the process and the mode of hydrogen delivery. This increases cost for hydrogen treatment for delivery in the H2A case, but lowers overall production cost.

Generally speaking, however, the differences observed are insignificant with two exceptions: biomass gasification and electrolysis. For these technologies, however, an understanding of the driving reasons is not as straightforward and only little explanation was found:

- for biomass gasification, H2A (2006a) assumes a daily hydrogen output of about 155 tons of hydrogen; NRC (2004) uses 24 tons per day only in what is called “midsize” technology, but “no midsize gasification facility exists to date that converts biomass to hydrogen, and no empirical data are available on the operation, performance and economics of a midsize biomass-to-hydrogen plant, as assumed in the economic model” NRC (2004:233). Simbeck and Chang (2002) use 150 tons of hydrogen per day. In addition, a comparison of the Simbeck and Chang study with NRC shows that in NRC (2004), the costs of pure oxygen provision have been assumed almost twice as costly, with about US\$ 47 /kg of oxygen per day in NRC (2004) as compared to about US\$ 24 /kg of oxygen per day in Simbeck and Chang (2002).
- for electrolysis, again scale-economies explain the cost differences partially: while NRC (2004) assumes 480 kg per day and electrolyzers, 428 kg per day can be calculated for H2A (2006a).<sup>54</sup> As initial cost assumptions are different (H2A (2006a) uses US\$ 798 per kW for electrolyzers, while NRC (2004) uses

<sup>53</sup> Note that the amount of hydrogen produced here is substantial. Hydrogen production of 250 tons per day requires load centers of about 1.5 million inhabitants if all demand was from hydrogen fuel cell vehicles only.

<sup>54</sup> Note here that electrolysis in H2A is generally treated as forecourt electrolysis only. Centrally produced hydrogen from electrolysis in H2A is only considered as a dedicated wind+electrolysis system, which will be referred to in the following. For the sake of this comparison, the data for central electrolyzers in H2A has been derived from this dedicated wind+electrolysis system.

US\$ 1'000 and Simbeck and Chang (2002) US\$ 960 per kW, this difference is reflected in total cost.

### ***“Future” costs of hydrogen production***

Figure 72 compares future hydrogen production cost as found in literature. While H2A (2006a) refers to future technologies as of the year 2025, this is unclear for the other literature sources used. Note that H2A (2006) designs future coal gasification with and without carbon capture as coupled-production technologies. Total electricity credits need, thus, to be deducted from the cost values depicted in Figure 72, and reduce total hydrogen costs from coal gasification to values slightly lower than those expected by NRC (2004), i.e. US\$ 3.25 per GJ without, and US\$ 4.15 per GJ with carbon capture.<sup>55</sup>

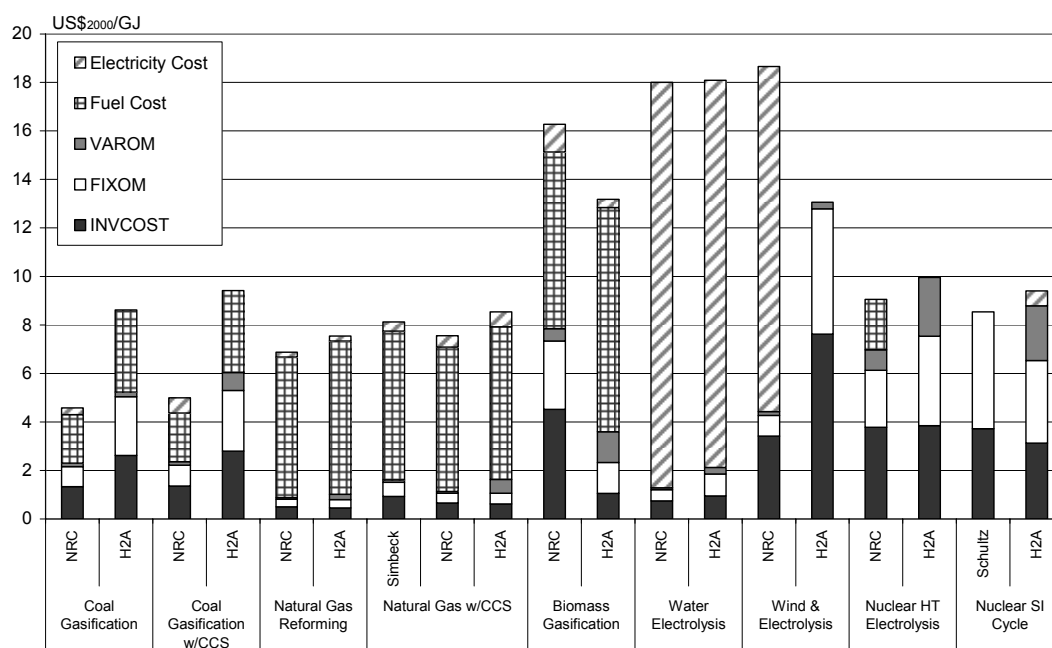


Figure 72. Cost of hydrogen production from "future" technologies.<sup>56</sup>

Considering the above described difference of understanding coal gasification in the different studies, cost differences are in most cases not significant and in a range of uncertainty that is justifiable. Besides, Simbeck and Chang (2002) as well as NRC (2004) add another 10% to total hydrogen production costs to account for site

<sup>55</sup> Again, cost of carbon storage is not included in these values.

<sup>56</sup> Note that Simbeck and Chang (2002) do not consider future technologies; the reference Simbeck for natural gas reforming with CCS refers, thus, to Simbeck (2004). Nuclear thermal electrolysis refers to dedicated hydrogen production from high-temperature nuclear reactors; nuclear SI cycle reads as nuclear sulphur-iodine cycle, reference Schultz refers to Schultz (2003).

specific variations; this has not been done for H2A, and serves as another explanation for cost differences observed.

For nuclear-based technologies, there is a difference in accounting for fuel use, which is for the example of nuclear thermal electrolysis in H2A (2006a) inherent to variable O&M costs, while NRC (2004) accounts them as US\$ 110 million per year for one plant. For nuclear SI cycles, no information could be obtained on this matter. Other differences in cost data explain by the same rules as described above for current technologies, i.e. differences in hydrogen pressure and scale-economies.

### **Summary of hydrogen production costs**

The following tables report all cost data found in literature and fuel cost assumptions taken for this review.

*Table 26. Fuel cost assumptions.*

Fuel	Fuel Cost [US\$/GJ]
Coal	1.6
Biomass	5.1
Natural Gas	4.6
Electricity	12.0
Coke	0.3
Pet-residuals	2.0

*Table 27. Costs of central hydrogen production I.*

Technology	Inv. cost	Fixed O&M	Var. O&M	Fuel Eff.	ELC Eff.	Fuel Cost	ELC cost	AF	CRF	Production Cost	Data Source <sup>57</sup>
	[US\$/GJ]			[GJ in / GJ out]		[US\$/GJ]		[-]	[-]	[US\$/GJ]	
Coal Gasification current	1.98	1.80	0.27	1.84	-0.09	2.94	-1.13	0.90	0.06	5.85	H2A (2006a)
	1.76	1.10	0.20	1.33	0.07	2.13	0.86	0.90	0.08	6.05	NRC (2004)
	3.52	2.19	0.39	1.56	0.11	2.50	1.28	0.90	0.08	9.88	Simbeck & Chang (2002)
	3.58	2.23	0.40	1.56	0.12	2.50	1.44	0.90	0.08	10.15	Simbeck & Chang (2002)
	3.52	2.19	0.39	1.56	0.11	2.50	1.34	0.90	0.08	9.94	Simbeck & Chang (2002)
	4.51	0.97	n.a.	1.78	-0.08	2.84	-0.97	0.80	0.15	7.35	Parsons Group (2002)
	4.64	1.05	n.a.	1.95	-0.08	3.12	-0.90	0.80	0.15	7.90	Williams (2001)
	4.07	1.77	n.a.	1.95	-0.04	3.12	-0.44	0.80	0.15	8.52	Gray & Tomlinson (2002)
Coal Gasification future	2.61	2.43	0.19	2.12	-0.45	3.38	-5.37	0.90	0.06	3.25	H2A (2006a)
	1.33	0.83	0.15	1.25	0.02	2.00	0.28	0.90	0.08	4.58	NRC (2004)

<sup>57</sup> Badin et al. (1999), Basye & Swaminathan (1997), Blok et al (1997), Gray & Tomlinson (2002), Kreutz et al. (2002), Parsons Group (2002), Williams (2001), Williams et al. (1995) are derived from Yamashita and Barreto (2003).

Table 28. Costs of central hydrogen production II.

Techn.	Inv. cost	Fixed O&M	Var. O&M	Fuel Eff.	ELC Eff.	Fuel Cost	ELC cost	AF	CRF	Cost	Data Source
	[US\$/GJ]			[GJ in / GJ out]		[US\$/GJ]		[-]	[-]	[US\$/GJ]	
Coal Gasific. w/CCS current	2.28	1.85	0.66	1.69	0.01	2.71	0.10	0.9	0.06	7.60	H2A (2006a)
	1.80	1.12	0.20	1.33	0.11	2.13	1.34	0.9	0.08	6.60	NRC (2004)
	4.64	1.05	n.a.	1.96	-0.05	3.14	-0.62	0.8	0.15	8.20	Williams (2001)
	5.36	1.05	n.a.	1.74	-0.03	2.79	-0.30	0.8	0.15	8.90	Parsons Group (2002)
	4.35	0.99	n.a.	1.73	-0.03	2.77	-0.37	0.8	0.15	7.74	Kreutz et al (2002)
	5.08	2.15	n.a.	2.15	-0.05	3.43	-0.65	0.8	0.15	10.01	Gray & Tomlinson (2002)
	5.04	1.85	n.a.	1.49	0.13	2.38	1.55	0.8	0.15	10.82	Williams et al (1995)
Coal Gasific. w/CCS future	2.80	2.50	0.73	2.12	-0.44	3.38	-5.27	0.9	0.06	4.15	H2A (2006a)
	1.36	0.85	0.15	1.25	0.05	2.00	0.63	0.9	0.08	4.99	NRC (2004)
	3.99	n.a.	n.a.	1.49	-0.04	2.38	-0.49	0.8	0.15	5.88	Badin et al. (1999)
	3.83	0.83	n.a.	1.45	0.03	2.33	0.35	0.8	0.15	7.34	Parsons Group (2002)
	5.12	1.10	n.a.	1.45	-0.04	2.33	-0.53	0.8	0.15	8.02	Parsons Group (2002)
	4.31	0.99	n.a.	1.71	-0.02	2.73	-0.20	0.8	0.15	7.84	Kreutz et al (2002)
	3.91	1.50	n.a.	1.62	-0.04	2.58	-0.46	0.8	0.15	7.54	Gray & Tomlinson (2002)
Natural Gas Ref. current	0.61	0.40	0.22	1.36	0.02	6.26	0.20	0.9	0.06	7.71	H2A (2006a)
	0.70	0.43	0.08	1.31	0.02	6.04	0.25	0.98	0.08	7.50	NRC (2004) large
	1.51	0.94	0.18	1.39	0.00	6.39	0.01	0.98	0.08	9.04	NRC (2004 ) mid
	0.89	0.56	0.10	1.31	0.01	6.04	0.07	0.9	0.08	7.66	Simbeck & Chang (2002)
	1.22	0.36	n.a.	1.43	0.01	6.58	0.12	0.9	0.15	8.27	Parsons Group (2002)
	1.72	0.57	n.a.	1.35	0.01	6.19	0.12	0.9	0.15	8.60	Basye & Swaminathan (1997)
	1.68	0.48	n.a.	1.35	0.00	6.19	0.00	0.9	0.15	8.35	Basye & Swaminathan (1997)
	1.68	0.43	n.a.	1.35	0.00	6.19	0.00	0.9	0.15	8.30	Basye & Swaminathan (1997)
	1.79	0.24	n.a.	1.35	0.00	6.19	0.00	0.9	0.15	8.22	Basye & Swaminathan (1997)
	1.68	0.64	n.a.	1.18	0.03	5.41	0.35	0.9	0.15	8.09	Blok et al. (1997)
Natural Gas Ref. future	0.46	0.34	0.22	1.36	0.02	6.26	0.20	0.9	0.06	7.48	H2A (2006a)
	0.50	0.31	0.06	1.25	0.02	5.75	0.20	0.98	0.08	6.82	NRC (2004) large
	1.20	0.75	0.15	1.30	0.00	5.97	0.01	0.98	0.08	8.08	NRC (2004 mid
Natural Gas Ref. w/CCS current	0.77	0.51	0.57	1.36	0.05	6.25	0.62	0.9	0.06	8.71	H2A (2006a)
	0.96	0.60	0.11	1.39	0.05	6.39	0.65	0.9	0.08	8.69	NRC (2004) large
	2.06	1.28	0.25	1.45	0.00	6.67	0.02	0.98	0.08	10.27	NRC (2004 mid
	1.21	0.75	0.14	1.53	0.06	7.04	0.74	0.9	0.08	9.88	Simbeck (2004a)
	1.90	0.74	n.a.	1.33	0.04	6.14	0.46	0.9	0.15	9.23	Williams et al. (1995)
	1.36	0.50	n.a.	1.31	0.02	6.04	0.29	0.9	0.15	8.19	Parsons Group (2002)
	1.76	0.64	n.a.	1.18	0.04	5.41	0.48	0.9	0.15	8.29	Blok et al (1997)
Natural Gas Ref. w/CCS future	0.62	0.44	0.57	1.36	0.05	6.25	0.62	0.9	0.06	8.49	H2A (2006a)
	0.65	0.41	0.07	1.28	0.04	5.90	0.47	0.9	0.08	7.50	NRC (2004) large
	1.61	1.01	0.20	1.39	0.00	6.39	0.01	0.98	0.08	9.22	NRC (2004 mid
	0.93	0.58	0.10	1.32	0.03	6.09	0.38	0.9	0.08	8.07	Simbeck (2004a)

Table 29. Costs of central hydrogen production III.

Techn.	Inv. cost	Fixed O&M	Var. O&M	Fuel Eff.	ELC Eff.	Fuel Cost	ELC cost	AF	CRF	Cost	Data Source
	[US\$/GJ]			[GJ in/GJ out]		[US\$/GJ]		[-]	[-]	[US\$/GJ]	
Biomass Gasific. current	1.24	1.46	1.60	2.21	0.05	11.28	0.56	0.9	0.06	16.14	H2A (2006a)
	9.28	5.78	1.04	2.00	0.19	10.20	2.30	0.9	0.08	28.60	NRC (2004)
	3.67	2.29	0.41	1.64	0.13	8.36	1.55	0.9	0.08	16.28	Simbeck & Chang (2002)
	3.70	2.30	0.41	1.64	0.13	8.36	1.55	0.9	0.08	16.32	Simbeck & Chang (2002)
Biomass Gasific. future	1.05	1.28	1.27	1.81	0.03	9.24	0.34	0.9	0.06	13.18	H2A (2006a)
	4.52	2.82	0.51	1.43	0.10	7.29	1.14	0.9	0.08	16.27	NRC (2004)
Coke Gasific. current	3.78	2.36	0.42	1.52	0.10	0.45	1.20	0.9	0.08	8.21	Simbeck & Chang (2002)
Pet. Resid. Gasific. current	2.62	1.63	0.29	1.41	0.08	2.82	0.92	0.9	0.08	8.28	Simbeck & Chang (2002)
AW Electrol. current	2.52	2.18	0.24	1.00	1.59	0.00	19.07	0.9	0.06	24.00	H2A (2006a)
	6.49	4.04	0.73	1.33	1.61	0.00	19.28	0.9	0.08	30.53	NRC (2004)
	6.80	4.24	0.76	1.00	1.57	0.00	18.85	0.9	0.08	30.66	Simbeck & Chang (2002)
AW Electrol. future	0.95	0.90	0.27	1.00	1.33	0.00	15.96	0.9	0.06	18.09	H2A (2006a)
	0.74	0.46	0.08	1.18	1.39	0.00	16.72	0.9	0.08	18.00	NRC (2004)
Wind + AW Electrol. current	13.31	10.48	0.24	0.00	0.00	0.00	0.00	0.35	0.06	24.03	H2A (2006a)
Wind + AW Electrol. future	7.62	5.17	0.27	0.00	0.00	0.00	0.00	0.35	0.06	13.06	H2A (2006a)
HP Electrol. future	1.30	1.58	0.03	0.00	1.43	0.00	17.20	0.9	0.06	20.10	H2A (2006a)
Nuclear HP Electrol. future	4.22	5.57	2.18	0.00	0.00	0.00	0.00	0.9	0.06	11.96	H2A (2006a)
Nuclear HT Electrol. future	3.84	3.69	2.43	0.00	0.00	0.00	0.00	0.9	0.06	9.96	H2A (2006a)
	3.78	2.35	2.92	0.00	0.00	0.00	0.00	0.9	0.08	9.05	NRC (2004)
Nuclear SI Cycle future	3.12	3.41	2.26	0.00	0.05	0.00	0.61	0.9	0.06	9.40	H2A (2006a)
	3.72	4.82	0.00	0.00	0.00	0.00	0.00	0.9	0.07	8.54	Schultz (2003)
Solar Zn/ZnO cycle future	32.08	12.25	0.00	0.00	0.00	0.00	0.00	0.23	0.07	44.33	Felder (2007)
Solar Coke Gasific. future	22.51	10.33	0.00	1.15	0.00	0.34	0.00	0.23	0.08	33.19	Felder (2007)

Table 31 now provides an overview on decentral hydrogen production costs. Note that the cost data is understood as the entire fuel chain, i.e. forecourt hydrogen production including fueling station and refuelling facilities. The fuel cost assumptions applied for this analysis are depicted in Table 30.



Table 30. Fuel cost assumption for forecourt applications.

Fuel	Fuel Cost [US\$/GJ]
Coal	1.6
Biomass	5.1
Natural Gas	4.6
Electricity	12.0
Coke	0.3
Pet-residuals	2.0

Table 31. Costs of decentral hydrogen production.

Technology	Inv. cost	Fixed O&M	Var. O&M	Fuel Eff.	ELC Eff.	Fuel Cost	ELC cost	AF	CRF	H <sub>2</sub> Cost	Data Source
	[US\$/GJ]			[GJ in / GJ out]		[US\$/GJ]		[-]	[-]	[US\$/GJ]	
Natural Gas Reforming current	10.81	13.57	0.17	1.47	0.14	10.75	1.65	0.7	0.08	36.96	H2A (2006a) small
	4.91	4.15	0.07	1.38	0.11	10.07	1.33	0.7	0.08	20.54	H2A (2006a) large
	7.14	1.78	0.80	1.67	0.07	12.15	0.79	0.9	0.08	22.66	NRC (2004)
	8.60	5.36	0.75	1.43	0.07	10.41	0.78	0.7	0.08	25.91	Simbeck & Chang (2002)
Natural Gas Reforming future	8.61	11.79	0.17	1.30	0.12	9.50	1.42	0.7	0.08	31.49	H2A (2006a) small
	3.12	3.21	0.07	1.18	0.11	8.58	1.26	0.7	0.08	16.25	H2A (2006a) large
	3.66	0.91	0.41	1.43	0.05	10.41	0.61	0.9	0.08	16.01	NRC (2004)
AW Electrolysis current	14.70	17.53	0.31	0.00	1.66	0.00	19.86	0.7	0.08	52.40	H2A (2006a) small
	6.84	5.67	0.22	0.00	1.66	0.00	19.86	0.7	0.08	32.59	H2A (2006a) large
	9.77	2.43	1.10	0.00	1.63	0.00	19.58	0.9	0.08	32.88	NRC (2004)
	21.81	13.59	1.90	0.00	1.63	0.00	19.56	0.7	0.08	56.87	Simbeck & Chang (2002)
AW Electrolysis future	8.51	11.60	0.31	0.00	1.40	0.00	16.76	0.7	0.08	37.17	H2A (2006a) small
	3.15	3.19	0.22	0.00	1.40	0.00	16.76	0.7	0.08	23.32	H2A (2006a) large
	2.20	0.55	0.25	0.00	1.41	0.00	16.89	0.9	0.08	19.88	NRC (2004)
Gasoline Reforming current	9.38	5.85	0.82	1.54	0.07	9.25	0.80	0.70	0.08	26.10	Simbeck & Chang (2002)
Methanol Reforming current	8.34	5.20	0.73	1.33	0.07	8.68	0.80	0.70	0.08	23.75	Simbeck & Chang (2002)

## Appendix 2: Hydrogen Delivery Infrastructure Design with H2A

This section describes how the hydrogen delivery infrastructure was modelled in MARKAL. For this analysis, the delivery components model of H2A in the version of July 2006 has been used to design the delivery infrastructure,<sup>58</sup> and to obtain the costs and efficiencies of each delivery section. Five different possibilities for hydrogen delivery from central production facilities are considered: delivery by truck in gaseous or liquid form; delivery by pipeline using a system of pipelines; and combined systems with pipeline delivery to a terminal at city boundaries, and delivery by truck from the terminal in gaseous or liquid state to the fueling stations.

All cost and efficiency data brought forward in the following is based on the delivery components model of H2A (H2A 2006b). For the analysis, it has been assumed that the design city demand for hydrogen is 250'000 kg of hydrogen per day. Moreover, a total delivery distance of 80 km has been depicted. This number may naturally differ in real-life applications; however, because of the rather aggregate regions in the models applied in this thesis, it seems sufficient to assess this distance as an average number.

The cost of delivered hydrogen is derived using a common discount rate of 5% and applying the lifetimes of the individual parts as suggested in H2A.

### 1. Hydrogen Delivery by Truck

Hydrogen can be delivered by truck in either gaseous or liquid manner. The setup has been chosen as such that there is a terminal located onsite of the hydrogen production facility where hydrogen is compressed or liquefied for the distribution by truck to the fueling stations. Liquefiers, compressors and terminals are designed according to the individual output of the plants, and the round-trip travel distance of each individual truck corresponds to 160 km. Figure 73 gives an overview on the considered pathways.

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<sup>58</sup> Version 10 July 2006. Available on the web: [http://www.hydrogen.energy.gov/h2a\\_delivery.html](http://www.hydrogen.energy.gov/h2a_delivery.html)

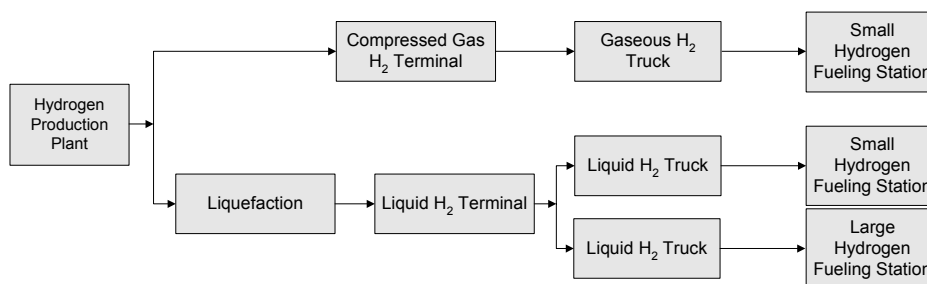


Figure 73. Delivery of hydrogen by truck.

Truck delivery is the most flexible among all options presented here: hydrogen can be delivered to almost any place where there is demand, and is, thus, not restricted to one aggregated demand centre such as a larger city. With this delivery option it is therefore for example possible to deliver hydrogen to many different smaller demand centres at a time, or to add further trucks in cases where demand is growing.

### 1.1 Gaseous Hydrogen Transportation by Truck

Hydrogen is compressed at a terminal located at the production facility and then delivered directly to the fueling stations. Two storage compressors, of which 1 is operating at any time, and 3 truck loading compressors, of which 2 are operating at any time, are installed at the terminal. The storage tanks are sized as such that 3 days of storage at the terminal are possible. Hydrogen losses account 0.5% from storage compression and 0.5% from truck loading compression, which leads to a total mass efficiency of 99.4%<sup>59</sup>.

For the delivery by truck, no hydrogen losses occur. Hydrogen is delivered at a maximum operating pressure of some 180 bar. Each truck trailer is designed to carry 9 tubes of hydrogen (see Figure 74 below) with a capacity of 31.15 kg of hydrogen per tube. Such trucks will deliver hydrogen to small-size fueling stations only, and, thus, H2A provides for fueling stations with a peak demand of 100 kg hydrogen per day only.

<sup>59</sup> Note that storage tanks are only needed when the primary supply from a central plant or a pipeline are not available. Thus, storage compressors are only needed occasionally, and so these losses are not affecting the total losses to its full extent.



Figure 74. Tube trailer for gaseous hydrogen truck delivery.<sup>60</sup>

As tubes can be dropped-off at the terminal and at a fueling station, load and unload times of a truck are lower than they are for liquid delivery (see section below). The time required to drop-off a trailer at the terminal is estimated 0.5 hours, connecting a full trailer to the truck requires about 1 hour, and dropping-off a full trailer and connecting an empty new trailer at a fueling station takes 1.5 hours accordingly. As a result and assuming an average truck speed of 50 km/h for delivery on both highway and city streets, the travel distance becomes important in terms of cost of delivered hydrogen, as road travel takes 3.2 hours for 160 km round-trip distance.

Table 32 gives an overview on discounted cost and efficiencies of gaseous hydrogen truck delivery for the example of coal gasification.

Table 32. Discounted costs of gaseous hydrogen delivery by truck for coal gasification.

Process	Efficiency	Investment Cost	Fixed O&M	Variable O&M	Electricity & Fuel Cost	Delivery Cost
	[%]	[US\$ <sub>2000</sub> /GJ]				
Terminal	99.4	2.35	3.33	0.03	0.33	6.04
Truck 160 km	100	7.56	3.64	3.22	0.46	14.88
Fueling station, 100 kg / day	99.5	6.96	9.46	2.25	0.44	19.11
<b>Total Cost</b>	<b>98.9</b>	<b>16.87</b>	<b>16.43</b>	<b>5.50</b>	<b>1.23</b>	<b>40.03</b>

## 1.2 Liquid Hydrogen Transportation by Truck

Hydrogen is liquefied at a terminal located at the production facility, and then delivered directly to the fueling stations. Two liquid hydrogen pumps are required; their individual design capacity is 75% of the total flowrate. Storage tanks are designed for 5 days of storage, which is higher than in the case of a gaseous terminal because liquid hydrogen truck delivery as considered in H2A does not apply tubes that can be left at the station for refilling as in the case of gaseous truck

<sup>60</sup> Source: [http://www.weldship.com/weld\\_pdf/superjumbo.pdf](http://www.weldship.com/weld_pdf/superjumbo.pdf) (accessed 14/11/06)

delivery. Hydrogen losses account for 0.5% from liquefaction and 0.25% boil-off from storage at the terminal. This results in an overall mass efficiency of 98.3%<sup>61</sup>.

One liquid hydrogen truck delivers net 3'650 kg of hydrogen per trip, which is significantly higher than for gaseous delivery, and can thus deliver hydrogen to both small-size (100 kg/day peak demand) and large-size fueling stations (1'500 kg/day peak). The drawback is that the economic competitiveness of liquid hydrogen delivery therefore depends to a significant extent on the number and size of fueling stations served: if one liquid tanker delivers to fueling stations with peak demand of 100 kg/day and storage capacity of 38 kg only, it needs a high number of fueling stations to be served. The H2A components model only provides for the possibility to serve up to 3 fueling stations per trip, which means in turn that if liquid truck delivery to small-size fueling stations is desired, then the number of trips per year per truck becomes very low.

Hydrogen losses during delivery occur from unloading (6% of tank volume) and tank boil-off (0.5%) both during delivery and from unloading. Assuming that one truck can serve 3 fueling stations, the total efficiency of one trip is 88.1%.

In contrast to gaseous hydrogen terminals, there is no option to fill tubes in absence of the truck in the case of liquid hydrogen terminals. The total time to load one truck including tanker drop-off, attachment to the filling system, filling and removal from the filling system is designed to take 3 hours. The total time to unload a truck at each station, i.e. a 1/3 load drop considering 3 fueling stations per trip, is set to 2 hours. In this light, the influence of the total delivery distance on delivered hydrogen is cost is less pronounced than for gaseous truck delivery considering the higher total load/unload time.

Table 33 gives an overview on discounted cost and efficiencies of liquid hydrogen truck delivery for the example of coal gasification.

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<sup>61</sup> 99.5% from liquefaction multiplied with 98.8% from the terminal. The latter considers that storage for 5 days results in total mass "losses" in terms of the relationship between daily output to daily input.

Table 33. Discounted costs of liquid hydrogen delivery by truck for coal gasification.

Process	Efficiency	Invest. cost	Fixed O&M	Variable O&M	Electricity & Fuel Cost	Delivery Cost
	[%]	[US\$ <sub>2000</sub> /GJ]				
Liquefaction	99.5	2.79	1.41	0.03	2.85	7.07
Terminal	98.8	0.82	0.43	0.03	0.00	1.28
Truck 160 km to 100 kg/day fueling station	88.1	8.13	1.97	0.67	0.04	10.79
Fueling station 100 kg/day	94.9	12.43	11.44	2.25	0.12	26.23
<b>Total 100 kg / day Fueling Station</b>	<b>82.2</b>	<b>24.16</b>	<b>15.25</b>	<b>2.97</b>	<b>3.00</b>	<b>45.38</b>
Liquefaction	99.5	2.79	1.41	0.03	2.85	7.07
Terminal	98.8	0.82	0.43	0.03	0.00	1.28
Truck 160 km to 1500 kg/day fueling station	88.1	0.54	0.50	0.67	0.04	1.74
Fueling station 1500 kg/day	98.9	2.19	1.87	0.38	0.12	4.56
<b>Total 1500 kg / day Fueling Station</b>	<b>85.7</b>	<b>6.33</b>	<b>4.22</b>	<b>1.11</b>	<b>3.00</b>	<b>14.66</b>

## 2. Delivery by Pipeline Ring Systems

Hydrogen can be compressed and delivered to demand centres by a system of transmission, trunk and delivery pipelines. Transmission pipelines serve for the bulk delivery of hydrogen from the production facility to the city gates. According to H2A it is then expected to distribute hydrogen with two rings of trunk pipelines along the ring roads of a city. From the trunk pipelines, delivery pipelines branch off to distribute hydrogen to the fueling stations.

For this analysis, hydrogen pipelines have been designed to accommodate cities with an average demand of maximum 250'000 kg of hydrogen per day. As some production facilities in H2A have a larger throughput of hydrogen, this means that they need to be located in the vicinity of more than one load centre with such demand, and, thus, be connected to more than one pipeline ring system at a time. This may be different in reality, where e.g. mega-cities of several million inhabitants could be fed by a large-scale hydrogen production facility most economically; however, as an average number 250'000 kg of hydrogen demand per day seems reasonable to justify the implementation of a pipeline delivery network.

Hydrogen losses account 0.5% during pipeline delivery, the hydrogen pressures drops to 20.68 bar at the outlet of the pipeline. Pipelines are assumed to deliver hydrogen to large-size fueling stations only, as pipeline ring system will probably only be applied if there is a considerable demand for hydrogen, which in turn would justify the use of large fueling stations. With small fueling stations, costs for the required high number of distribution arms and for the fueling station itself would become unjustifiably high at the assumed demand.

Table 34 gives an overview on discounted cost and efficiencies of the individual steps of pipeline delivery.

*Table 34. Discounted costs of hydrogen delivery by pipeline.*

Process	Efficiency	Investment Cost	Fixed O&M	Variable O&M	Electricity Cost	Delivery Cost
	[%]	[US\$ <sub>2000</sub> /GJ]				
Compression <sup>62</sup>	99.5	0.35	0.59	0.00	0.19	1.14
Pipeline 80 km, 250 t/day	99.5	1.60	0.80	0.01	0.00	2.41
Fueling station 1500 kg/day	99.5	3.32	1.84	0.38	0.77	6.30
<b>Total 1500 kg / day fueling station</b>	<b>98.5</b>	<b>5.27</b>	<b>3.23</b>	<b>0.40</b>	<b>0.96</b>	<b>9.86</b>

### 3. Delivery by Combined Pipeline and Truck Systems

Besides direct delivery of hydrogen by truck or pipeline, there is the possibility of combining the two options. This means that hydrogen could be delivered by pipeline to a terminal located at the outer boundary of a city, from where hydrogen is distributed to the fueling stations by truck in either liquid or gaseous state. This more elaborated network is very much in line with what is suggested in H2A. One main advantage is the possibility to take advantage of economical competitive pipelines in combination with the higher flexibility of truck delivery.

For the analysis conducted here, a hydrogen demand of 250'000 kg per day was depicted again. On this ground, a delivery network was developed to accommodate this demand. The total delivery distance of 80 km is broken up into 60 km pipeline delivery, and 40 km round-trip distance for truck delivery. The assumptions for modelling terminals and truck delivery remain basically the same as described previously. A key difference though is the expectation that gaseous delivery by truck will take place at higher pressure in such a network, i.e. at some 480 bar. Accordingly, the compressed gas terminal has been designed to comfort this

<sup>62</sup> The compressors are designed individually according to the individual hydrogen capacity of the production plants. Here, the costs for coal gasification have been depicted.

increased pressurization need. Note though that this needs to be considered as a future option rather, i.e. as of 2020 only (Ringer 2006).

Again, and as described for pipeline ring systems, the designed hydrogen demand is lower than the capacity of certain hydrogen production facilities. These production facilities, thus, need to be linked to more than one demand centre at a time, as visualized in Figure 75.

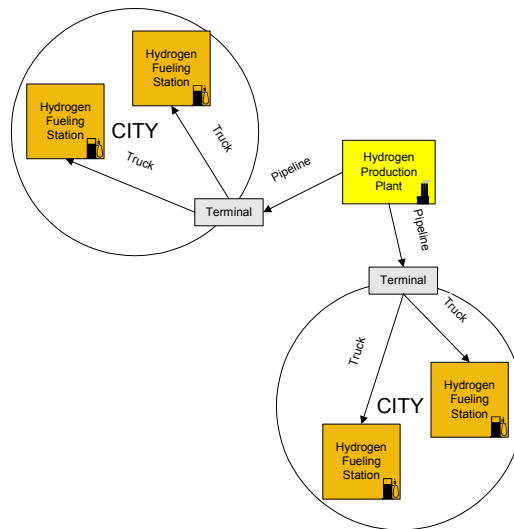


Figure 75. Delivery by combined pipeline and truck systems to 2 load centres.

For the design of this delivery network it is important to note that the delivery chains have individual efficiencies depending on whether hydrogen is transported in a liquid or gaseous state. Therefore, by designing a system meeting this demand, the terminals have individual capacities, and so do the pipelines. For the analysis here, it is, moreover, thought that such elaborated systems would deliver hydrogen to large-scale hydrogen fueling stations only, i.e. fueling stations with peak demand capacity of 1'500 kg per day. Figure 76 displays the entire system.

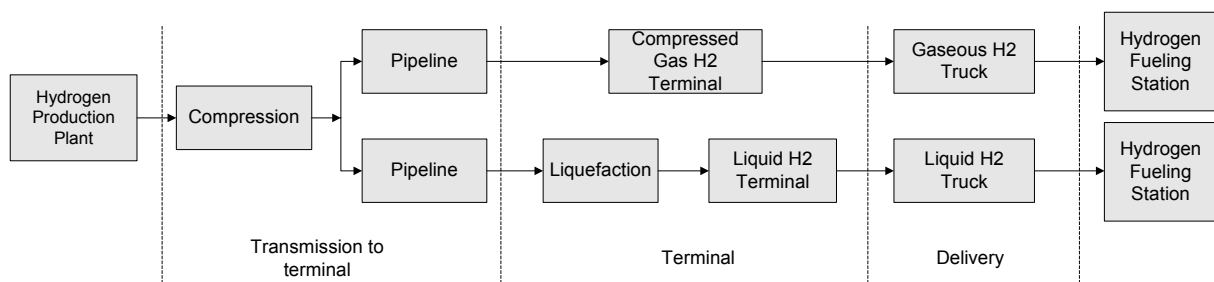


Figure 76. Flowchart of combined pipeline and truck delivery.



Table 35 gives an overview on discounted costs and efficiencies of the individual hydrogen supply steps of Figure 76.

Table 35. Discounted costs of combined pipeline and truck hydrogen delivery.

Process	Efficiency	Investment Cost	Fixed O&M	Variable O&M	Electricity & Fuel Cost	Delivery Cost
	[%]	[US\$ <sub>2000</sub> /GJ]				
Compression	99.5	0.35	0.59	0.00	0.19	1.14
Pipeline 60 km to gaseous truck terminal	99.5	0.17	0.09	0.01	0.00	0.27
Compressed gas terminal	99.4	2.63	3.81	0.03	0.46	6.93
40 km truck delivery gaseous	100.0	1.87	0.81	0.84	0.05	3.57
Fueling station 1500 kg/day	99.5	3.32	1.84	0.38	0.00	5.54
<b>Total Pipeline + Gaseous H<sub>2</sub> Truck</b>	<b>97.9</b>	<b>8.34</b>	<b>7.14</b>	<b>1.26</b>	<b>0.70</b>	<b>17.46</b>
Compression	99.5	0.35	0.59	0.00	0.19	1.14
Pipeline 60 km to liquid truck terminal	99.5	0.15	0.08	0.01	0.00	0.24
Liquefaction	99.5	2.75	1.39	0.03	2.83	7.00
Liquid H <sub>2</sub> terminal	98.8	0.82	0.43	0.03	0.00	1.28
40 km truck delivery liquid	88.1	0.54	0.41	0.57	0.01	1.53
Fueling station 1500 kg/day	98.9	2.19	1.87	0.38	0.12	4.56
<b>Total Pipeline + Liquid H<sub>2</sub> Truck</b>	<b>84.8</b>	<b>6.80</b>	<b>4.78</b>	<b>1.02</b>	<b>3.15</b>	<b>15.76</b>

#### 4. Fueling Stations

Two sizes of fueling stations are considered in H2A, distinguished by their peak design capacities of 100 kg H<sub>2</sub>/day and 1'500 kg H<sub>2</sub>/day respectively.<sup>63</sup>

In addition to the size, fueling stations can be distinguished according to the physical condition of the delivered hydrogen, i.e. liquid or gaseous. For gaseous hydrogen fueling stations, further compression and storage of hydrogen is needed in both delivery cases, i.e. pipeline or truck delivery. Hydrogen is, thus, compressed to 430.6 bar, the required pressure for dispensing and storage. For this purpose, 3 compressors are installed of which 2 are in operation at any time<sup>64</sup>, all designed for multi-stage compression. Hydrogen losses during compression account for 0.5%.

The storage tank's design usable capacity is different according to the size of the fueling station: for small-size fueling stations, 38 kg of hydrogen storage are assumed; for large-size fueling stations, the capacity is 358 kg of hydrogen storage. Finally, the number of dispenser differs according to the size of the fueling station: the small-size station needs 1 dispenser; the large-size makes use of 3.

Fueling stations with hydrogen delivered in liquid state require a somewhat different setup. It needs to be noted firstly that in the H2A components model, these fueling

<sup>63</sup> Note that large hydrogen fueling stations are only available for pipeline, gaseous truck delivery at 480 bar and liquid truck delivery in H2A. For gaseous truck delivery at 180 bar, this option does not exist as one truck does not deliver sufficient hydrogen.

<sup>64</sup> The extra compressor is installed to increase the system's availability, as the compressors are designed at 50% of the design flowrate.

stations provide for gaseous hydrogen only. Liquid hydrogen is only stored and then evaporated for gaseous hydrogen supply, i.e. an evaporator is applied as well as dispensers.<sup>65</sup> For liquid hydrogen storage, two high-pressure cryogenic pumps are applied, with the pump capacity varying according to the fueling station's size. The design capacity of the liquid hydrogen cryogenic storage tanks again depends on the size of the fueling station and amounts to 1'576 kg of hydrogen in the case of small fueling stations, and 4'536 kg hydrogen for the large stations. In general, boil-off losses from liquid storage are assumed 0.25%.

Moreover and as a back-up for peak demand, gaseous storage tanks are applied, and the number of dispensers varies similar to the case of gaseous fueling stations, i.e. 38 kg storage and 1 dispenser for small-size fueling stations, and 358 kg of storage and 3 dispensers for large-size fueling stations.

The costs and efficiencies of considered fueling stations have been presented in the above sections already for the individual delivery pathways. Generally, there is a cost advantage for large fueling stations. For gaseous hydrogen fueling stations, the reason is significant scale economies for the cost of hydrogen compressors, which are relatively cheaper if designed for larger flowrate. For the case of liquid hydrogen fueling stations, the case is similar: scale economies do exist in particular for liquid hydrogen storage and pumps. As O&M costs in the H2A components model are calculated in percent of capital investment, the impact of these scale economies is further pronounced.

## 5. Discussion of Delivery Pathways

As a general remark, there is a wide range of literature available on the delivery of hydrogen, and, thus, a lot of different viewpoints. In absence of existing projects on delivering hydrogen at the scale required in a hydrogen economy, this is probably mainly due to a lack of experience. In particular, there is some disagreement on the cost of delivering hydrogen by pipeline, which the H2A components model considers more costly than natural gas pipelines following Parker (2005), with an additional factor of 1.1 on top. Moreover, delivering hydrogen in a liquid state by truck is widely debated, some authors are more (Simbeck and Chang 2002), some less optimistic. Moreover and in general, approaches to calculating hydrogen delivery costs differ.

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<sup>65</sup> The reason is that “in the United States, most fuel cell cars are planning on using gaseous hydrogen”. Comment Matthew Ringer, National Renewable Energy Laboratory, e-mail correspondence 29/11/2006.

The analysis conducted here has been based on the assumptions of the H2A components model as this analysis is very consistent and transparent, and provides for a lot of flexibility in terms of underlying assumptions and design of delivery networks.

Figure 77 displays the full chain of hydrogen costs for the example of future coal gasification (H2A 2006a). It shows a cost advantage for the delivery of hydrogen by pipeline ring systems to large hydrogen fueling stations. However, and as mentioned above, this delivery option will not be available without a significant hydrogen demand. Therefore, truck delivery has its merits. Moreover, it needs to be noted that direct truck delivery as well as combined pipeline and truck delivery systems are comparatively easier to implement and extend with increasing demand than is direct pipeline delivery.

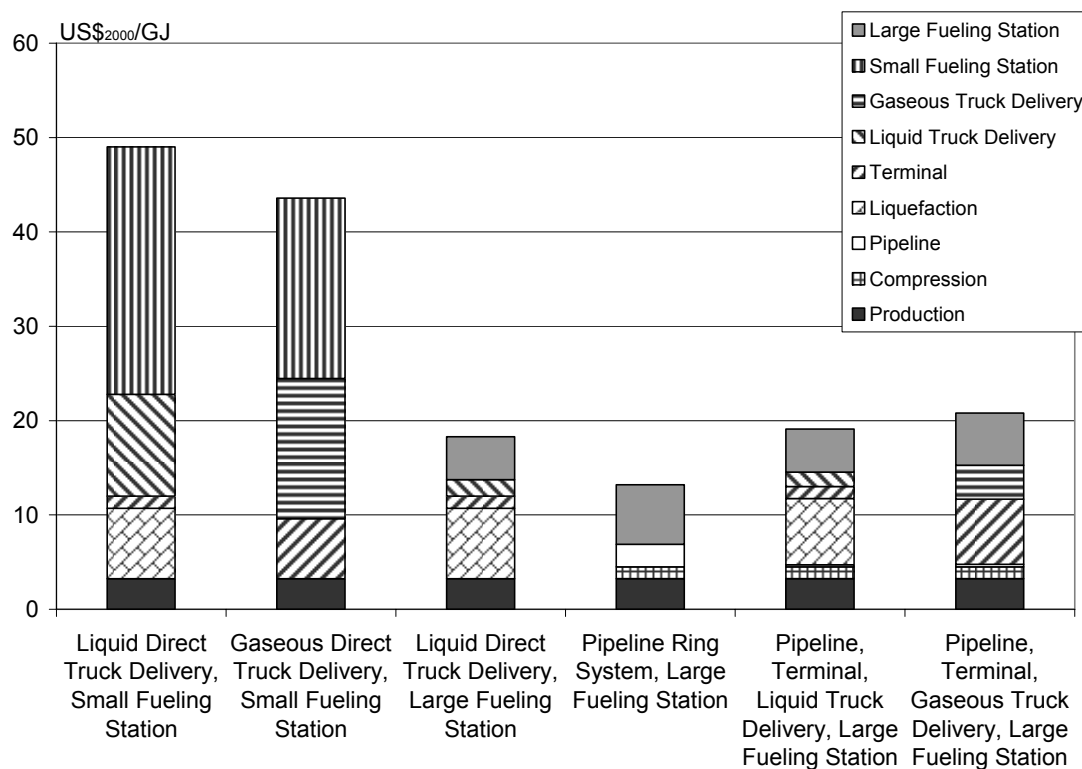


Figure 77. Comparison of hydrogen cost chains for future coal gasification.

Second most favourable option in terms of costs is liquid hydrogen truck delivery. Somewhat surprising is the fact that there is no cost advantage *per se* for combined pipeline and truck delivery compared to direct liquid hydrogen truck delivery. There

are two main reasons for this observation: firstly, liquid hydrogen truck delivery costs are not that sensitive to the round-trip distance, as already described above. Therefore, truck-only delivery of liquid hydrogen over 160 km round-trip distance is not much more costly than is a round-trip distance of 40 km as in the case of the combined pipeline and truck systems. Secondly, the terminal and liquefaction / compression are main cost components of truck delivery in general. With the additional need for compression and pipelines, the combined systems are, thus, disfavoured.

The comparison of delivery cost for truck delivery to small-scale fueling stations shows some cost advantage for gaseous truck delivery. One key reason is the cost of liquefaction, and inherently the higher need for electricity (for the example of coal gasification, electricity demand totals 0.03 GJ electricity per GJ of hydrogen for compression in the case of gaseous truck delivery, and 0.24 GJ electricity per GJ of hydrogen for liquefaction).

Moreover, the small capacity of trucks delivering hydrogen at gaseous conditions is favourable for delivery to small fueling stations: as long as the number of fueling stations served per trip is low, trucks delivering hydrogen at liquid condition cannot be utilized to their full extent. This is again underlined when comparing liquid hydrogen delivery to small fueling stations with delivery to large fueling stations: as large fueling stations work with a peak demand of 1'500 kg H<sub>2</sub>/day, the liquid truck has a much higher utilization, resulting in considerably lower delivery cost.

Finally, and as discussed in above, there is a general cost advantage for large fueling stations. Key reason is economies-of-scale for the compressor in the case of compressed gas delivery, and economies-of-scale for liquid hydrogen storage in the case of liquid hydrogen delivery.

## Appendix 3: Hydrogen Delivery Infrastructure Cost Details

This appendix presents all cost details used in the modelling analyses in this thesis. Note that all costs are in US\$ of the year 2000. The analysis was made with H2A (2006b)

### 1. Pipeline related systems

Table 36. Compression for pipeline delivery.

H2 compressor, 3 stages, for pipelines	H2 eff.	Hydrogen pressure		ELC	Inv. cost	Fix. O&M	Var. O&M	ELC cost	Life	AF	Total Cost
	[%]	in [bar]	out [bar]	[GJ / GJH <sub>2</sub> ]	[US\$/GJ]				[a]	[-]	[US\$/GJ]
Coal gasification	99.5	21.4	68.9	0.02	0.35	0.59	0.00	0.19	20	0.7	1.14
Coal gasification w/ CCS	99.5	20	68.9	0.02	0.36	0.60	0.00	0.21	20	0.7	1.17
Coal gasification future	99.5	20	68.9	0.02	0.38	0.65	0.00	0.21	20	0.7	1.24
Coal gasification w/ CCS future	99.5	20	68.9	0.02	0.38	0.65	0.00	0.21	20	0.7	1.24
Natural gas reforming	99.5	20	68.9	0.02	0.33	0.56	0.00	0.21	20	0.7	1.10
Natural gas reforming w/CCS	99.5	20	68.9	0.02	0.33	0.56	0.00	0.21	20	0.7	1.10
Natural gas reforming Future	99.5	20	68.9	0.02	0.33	0.56	0.00	0.21	20	0.7	1.10
Natural gas reforming w/CCS future	99.5	20	68.9	0.02	0.33	0.56	0.00	0.21	20	0.7	1.10
Nuclear SI cycle	99.5	20	68.9	0.02	0.26	0.44	0.00	0.21	20	0.7	0.91
HP electrolysis	99.5	20	68.9	0.02	0.27	0.46	0.00	0.21	20	0.7	0.94
Nuclear HP electrolysis	99.5	20	68.9	0.02	0.27	0.46	0.00	0.21	20	0.7	0.94
Nuclear HT electrolysis	99.5	20	68.9	0.02	0.27	0.45	0.00	0.21	20	0.7	0.93
Central wind + electrolysis	99.5	30	68.9	0.01	0.37	0.63	0.01	0.14	20	0.7	1.14
Central wind + electrolysis future	99.5	30	68.9	0.01	0.41	0.69	0.01	0.14	20	0.7	1.25
Electrolysis	99.5	30	68.9	0.01	0.37	0.63	0.01	0.14	20	0.7	1.14
Electrolysis future	99.5	30	68.9	0.01	0.41	0.69	0.01	0.14	20	0.7	1.25

Note: Biomass Gasification as assessed in H2A already applies the required pressure for pipeline delivery.

Table 37. Pipeline ring system.

Pipeline ring system to large fueling stations	H2 eff.	Hydrogen pressure		ELC	Inv. cost	Fix. O&M	Var. O&M	ELC cost	Life	AF	Total Cost
	[%]	in [bar]	out [bar]	[GJ / GJH <sub>2</sub> ]	[US\$/GJ]				[a]	[-]	[US\$/GJ]
Pipeline ring system, 80 km transmission distance	99.5	68.95	20.68	0.00	1.60	0.80	0.01	0.00	20	0.7	2.41
Fueling station, capacity 1'500 kg H <sub>2</sub> /day	99.5	20.68	430.6	0.06	3.32	1.84	0.38	0.77	20	0.7	6.30
<b>Total: example coal gasification</b>	<b>98.5</b>			<b>0.08</b>	<b>5.27</b>	<b>3.23</b>	<b>0.40</b>	<b>0.96</b>			<b>9.86</b>

Table 38. Pipeline + liquid H<sub>2</sub> terminal + truck delivery + large fueling station.

Pipeline to liquid H <sub>2</sub> terminal to large fueling station	H2 eff.	Hydrogen pressure		ELC or fuel	Inv. cost	Fix. O&M	Var. O&M	ELC or fuel cost	Life	AF	Total Cost
	[%]	in [bar]	out [bar]	[GJ / GJH <sub>2</sub> ]	[US\$/GJ]				[a]	[-]	[US\$/GJ]
Pipeline, 60 km transmission distance	99.5	68.95	20.68	0.00	0.15	0.08	0.01	0.00	20	0.7	0.24
Liquefaction	99.5	n.a.		0.24	2.75	1.39	0.03	2.83	20	0.7	0.7
Liquid H <sub>2</sub> terminal	98.8	n.a.		0.00	0.82	0.43	0.03	0.00	20	0.7	1.28
Truck delivery liquid H <sub>2</sub> , 40 km round-trip	88.1	n.a.		0.001	0.54	0.41	0.57	0.01	20	0.98	1.53
Fueling station, capacity 1'500 kg H <sub>2</sub> /day	98.9	n.a.	430.6	0.01	2.19	1.87	0.38	0.12	20	0.7	4.56
<b>Total: example coal gasification</b>	<b>84.8</b>			<b>0.26</b>	<b>6.80</b>	<b>4.78</b>	<b>1.02</b>	<b>3.15</b>			<b>15.76</b>

Table 39. Pipeline + gaseous H<sub>2</sub> terminal + truck delivery + large fueling station.

Pipeline to gaseous H <sub>2</sub> terminal to large fueling station	H2 eff.	Hydrogen pressure		ELC or fuel	Inv. cost	Fix. O&M	Var. O&M	ELC or fuel cost	Life	AF	Total Cost
	[%]	in [bar]	out [bar]	[GJ/G JH <sub>2</sub> ]	[US\$/GJ]				[a]	[-]	[US\$/GJ]
Pipeline, 60 km transmission distance	99.5	68.95	20.68	0.00	0.17	0.09	0.01	0.00	20	0.7	0.27
Gaseous H <sub>2</sub> terminal	99.4	20.68	482.6	0.04	2.63	3.81	0.03	0.46	20	0.7	6.93
Truck delivery gaseous H <sub>2</sub> , 40 km round-trip	100	n.a.	482.6	0.01	1.87	0.81	0.84	0.05	20	0.98	3.57
Fueling station, capacity 1'500 kg H <sub>2</sub> /day	99.5	n.a.	430.6	0.00	3.32	1.84	0.38	0.00	20	0.7	5.54
<b>Total: example coal gasification</b>	<b>97.9</b>			<b>0.06</b>	<b>8.34</b>	<b>7.14</b>	<b>1.27</b>	<b>0.70</b>			<b>17.46</b>

## 2. Truck Delivery

### 2.1 Liquid Truck Delivery

Table 40. Liquefaction.

Liquefaction from	H2 eff.	ELC	Inv. cost	Fix. O&M	Var. O&M	ELC cost	Life	AF	Total Cost
	[%]	[GJ /GJH2]	[US\$/GJ]				[a]	[-]	[US\$/GJ]
Coal gasification	99.5	0.24	2.79	1.41	0.03	2.85	20	0.7	7.07
Coal gasification w/ CCS	99.5	0.23	2.68	1.36	0.03	2.80	20	0.7	6.87
Coal gasification future	99.5	0.24	2.98	1.51	0.03	2.93	20	0.7	7.45
Coal gasification w/ CCS future	99.5	0.24	2.98	1.51	0.03	2.93	20	0.7	7.45
Biomass gasification	99.5	0.27	3.72	1.89	0.05	3.20	20	0.7	8.86
Biomass gasification future	99.5	0.26	3.51	1.79	0.05	3.13	20	0.7	8.48
Natural gas reforming	99.5	0.22	2.43	1.23	0.02	2.69	20	0.7	6.36
Natural gas reforming w/CCS	99.5	0.22	2.43	1.23	0.02	2.69	20	0.7	6.36
Natural gas reforming future	99.5	0.22	2.43	1.23	0.02	2.69	20	0.7	6.36
Natural gas reforming w/CCS future	99.5	0.22	2.43	1.23	0.02	2.69	20	0.7	6.36
Nuclear SI cycle	99.5	0.20	1.73	0.87	0.01	2.34	20	0.7	4.96
HP electrolysis	99.5	0.20	1.85	0.93	0.01	2.41	20	0.7	5.19
Nuclear HP electrolysis	99.5	0.20	1.85	0.93	0.01	2.41	20	0.7	5.19
Nuclear HT electrolysis	99.5	0.20	1.79	0.90	0.01	2.37	20	0.7	5.07
Central wind + electrolysis	99.5	0.28	4.13	2.11	0.07	3.34	20	0.7	9.65
Central wind + electrolysis future	99.5	0.29	4.74	2.43	0.09	3.54	20	0.7	10.80
Electrolysis	99.5	0.28	4.13	2.11	0.07	3.34	20	0.7	9.65
Electrolysis future	99.5	0.29	4.74	2.43	0.09	3.54	20	0.7	10.80

Table 41. Liquid hydrogen terminal onsite hydrogen production facility.

Liquid H2 Terminal onsite of the production facility, storage capacity 5 days	H2 eff.	ELC	Inv. cost	Fix. O&M	Var. O&M	ELC cost	Life	AF	Total Cost
	[%]	[GJ /GJH2]	[US\$/GJ]				[a]	[-]	[US\$/GJ]
Coal gasification	98.8	0.00	0.82	0.43	0.03	0.00	20	0.7	1.28
Coal gasification w/ CCS	98.8	0.00	0.82	0.43	0.03	0.00	20	0.7	1.28
Coal gasification future	98.8	0.00	0.82	0.44	0.03	0.00	20	0.7	1.29
Coal gasification w/ CCS future	98.8	0.00	0.82	0.44	0.03	0.00	20	0.7	1.29
Biomass gasification	98.8	0.00	0.84	0.46	0.06	0.00	20	0.7	1.36
Biomass gasification future	98.8	0.00	0.83	0.45	0.05	0.00	20	0.7	1.33
Natural gas reforming	98.8	0.00	0.82	0.42	0.02	0.00	20	0.7	1.26
Natural gas reforming w/CCS	98.8	0.00	0.82	0.42	0.02	0.00	20	0.7	1.26
Natural gas reforming future	98.8	0.00	0.82	0.42	0.02	0.00	20	0.7	1.26
Natural gas reforming w/CCS future	98.8	0.00	0.82	0.42	0.02	0.00	20	0.7	1.26
Nuclear SI cycle	98.8	0.00	0.81	0.41	0.01	0.00	20	0.7	1.23
HP electrolysis	98.8	0.00	0.81	0.41	0.01	0.00	20	0.7	1.24
Nuclear HP electrolysis	98.8	0.00	0.81	0.41	0.01	0.00	20	0.7	1.24
Nuclear HT electrolysis	98.8	0.00	0.81	0.41	0.01	0.00	20	0.7	1.24
Central wind + electrolysis	98.8	0.00	0.84	0.47	0.07	0.00	20	0.7	1.38
Central wind + electrolysis future	98.8	0.00	0.85	0.49	0.09	0.00	20	0.7	1.43
Electrolysis	98.8	0.00	0.84	0.47	0.07	0.00	20	0.7	1.38
Electrolysis future	98.8	0.00	0.85	0.49	0.09	0.00	20	0.7	1.43

Table 42. Liquid hydrogen truck delivery to small and large fueling stations.

Liquid H2 truck delivery, 160 km round-trip distance, to small or large fueling stations	H2 eff.	ELC or fuel	Inv. cost	Fix. O&M	Var. O&M	ELC cost	Life	AF	Total Cost
	[%]	[GJ /GJH2]	[US\$/GJ]				[a]	[-]	[US\$/GJ]
Truck to small fueling stations	88.1	0.01	8.13	1.97	0.67	0.04	20	0.98	10.79
Small fueling station	94.9	0.01	12.43	11.44	2.25	0.12	20	0.7	26.23
<b>Total: example coal gasification</b>	<b>82.2</b>	<b>0.25</b>	<b>24.16</b>	<b>15.25</b>	<b>2.97</b>	<b>3.00</b>			<b>45.38</b>
Truck to large fueling stations	88.1	0.01	0.54	0.50	0.67	0.04	20	0.98	1.74
Large fueling station	98.9	0.01	2.19	1.87	0.38	0.12	20	0.7	4.56
<b>Total: example coal gasification</b>	<b>85.7</b>	<b>0.25</b>	<b>6.33</b>	<b>4.22</b>	<b>1.11</b>	<b>3.00</b>			<b>14.66</b>



## 2.1 Gaseous Truck Delivery

Table 43. Gaseous hydrogen terminal onsite production facility.

Gaseous H2 Terminal onsite of the production facility, storage capacity 3 days	H2 eff.	Hydrogen Pressure		ELC	Inv. cost	Fix. O&M	Var. O&M	ELC cost	Life	AF	Total Cost
	[%]	in [bar]	out [bar]	[GJ / GJH2]	[US\$/GJ]				[a]	[-]	[US\$/GJ]
Coal Gasification	99.4	21.37	182.4	0.03	2.35	3.33	0.03	0.33	20	0.7	6.04
Coal Gasification w/ CCS	99.4	20.00	182.4	0.03	2.31	3.28	0.03	0.34	20	0.7	5.96
Coal Gasification future	99.4	20.00	182.4	0.03	2.46	3.51	0.03	0.34	20	0.7	6.35
Coal Gasification w/ CCS future	99.4	20.00	182.4	0.03	2.46	3.51	0.03	0.34	20	0.7	6.35
Biomass Gasification	99.4	69.98	182.4	0.01	2.16	2.94	0.05	0.15	20	0.7	5.31
Biomass Gasification Future	99.4	69.98	182.4	0.01	2.10	2.83	0.05	0.15	20	0.7	5.13
Natural Gas Reforming	99.4	20.00	182.4	0.03	2.18	3.08	0.02	0.34	20	0.7	5.62
Natural Gas Reforming w/CCS	99.4	20.00	182.4	0.03	2.18	3.08	0.02	0.34	20	0.7	5.62
Natural Gas Reforming Future	99.4	20.00	182.4	0.03	2.18	3.08	0.02	0.34	20	0.7	5.62
Natural Gas Reforming w/CCS Future	99.4	20.00	182.4	0.03	2.18	3.08	0.02	0.34	20	0.7	5.62
Nuclear SI cycle	99.4	20.00	182.4	0.03	1.79	2.48	0.01	0.34	20	0.7	4.63
HP Electrolysis	99.4	20.00	182.4	0.03	1.86	2.58	0.01	0.34	20	0.7	4.79
Nuclear HP Electrolysis	99.4	20.00	182.4	0.03	1.86	2.58	0.01	0.34	20	0.7	4.79
Nuclear HT Electrolysis	99.4	20.00	182.4	0.03	1.83	2.53	0.01	0.34	20	0.7	4.71
Central Wind + Electrolysis	99.4	29.99	182.4	0.02	2.78	3.98	0.07	0.27	20	0.7	7.09
Central Wind + Electrolysis future	99.4	29.99	182.4	0.02	3.02	4.36	0.09	0.27	20	0.7	7.74
Electrolysis	99.4	29.99	182.4	0.02	2.78	3.98	0.07	0.27	20	0.7	7.09
Electrolysis Future	99.4	29.99	182.4	0.02	3.02	4.36	0.09	0.27	20	0.7	7.74

Table 44. Gaseous hydrogen truck delivery to small fueling stations.

Gaseous H2 Truck delivery, 160 km round-trip distance, to small fueling stations	H2 eff.	Operating pressure [bar]	ELC or fuel	Inv. cost	Fix. O&M	Var. O&M	ELC or fuel cost	Life	AF	Total Cost
	[%]		[GJ / GJH2]	[US\$/GJ]				[a]	[-]	[US\$/GJ]
Truck Delivery, 160 km round-trip distance	100	182.4	0.07	7.56	3.64	3.22	0.46	20	0.98	14.88
Small fueling station	99.5	430.6	0.04	6.96	9.46	2.25	0.44	20	0.7	19.11
<b>Total: example Coal Gasification</b>	<b>98.9</b>		<b>0.13</b>	<b>16.86</b>	<b>16.43</b>	<b>5.50</b>	<b>1.23</b>			<b>40.03</b>

## Appendix 4: Technology Clusters in GMM

Table 45 and Table 46 give an overview on the contribution of each learning component to total initial investment costs for the technologies that use these learning components. The dataset for electricity production is based on Rafaj (2005) and Barreto and Kypreos (2006), complemented by further studies such as IEA (2003a) and IEA (2004c).

Table 45. Investment cost clusters in electricity generation.

Technology	Key Components [US\$ / kW]										BoS [US\$ / kW]	Total [US\$ / kW]
	GSF	SFC	GTU	SPV	STH	WND	NNU	CC1	CC2	CC3		
NGCC			200								360	560
Gas Turbine			200								150	350
NGCC w/CCS			200						542		273	1015
Coal Conventional w/CCS								940			1150	2090
Coal IGCC	300		200								900	1400
Coal IGCC w/CCS	300		200							509	900	1909
Biomass IGCC	300		200								1900	2400
Biomass IGCC w/CCS	300		200							509	1991	3000
Solar PV				5500							0	5500
Solar thermal electric					1500						1400	2900
Onshore Wind						1200					0	1200
Offshore Wind						1200					326	1526
Advanced nuclear power							2200				0	2200
Stationary hydrogen fuel cell		1250									1000	2250
Gas fuel cell		1250									1000	2250

For biofuels production, the analyses of Ragettli (2007) were used as a benchmark for technology costs. In this case, the gasifier was identified as the only learning component, applying to second generation biofuels solely. For hydrogen production, the US H2A spreadsheet models were used as a benchmark for hydrogen production costs (H2A 2006b). H2A was used to define balance of system costs (BoS) and operation and maintenance costs by subtracting key component costs from the “current technology” cost defined in H2A. With some minor changes, consistency in assumptions was assured. Note that the efficiency improvements in H2A were applied exogenously here. Also note that BoS costs for decentral hydrogen production technologies in the table below include costs for storage, the fueling station and dispensing of hydrogen.

Finally, other synthetic fuels are based on Barreto and Kypreos (2006).

Table 46. Investment cost clusters in fuel production.<sup>66</sup>

Technology	Key Components												BoS [US\$ / kW]	Total [US\$ / kW]
	GSF	SFC	GTU	STH	WND	NNU	CC4	SRR	SIC	EAW	EHP	EHT		
Coal gasification	300		200										462	962
Coal gasification w/ CCS	300						200						462	962
Coal Gasification w/CCS Future	300	1250					200						762	2512
Gas reforming								180					119	299
Gas reforming w/ CCS							200	180					119	499
Biomass gasification	300												303	603
Nuclear SI cycle						2200			466				0	2666
Nuclear high-pressure electrolysis						2200					631		0	2831
Nuclear high-temperature electrolysis						2200						359	0	2559
Wind & electrolysis					1200					1200			0	2400
High-pressure electrolysis											631		0	631
Electrolysis										1200			27	1227
Solar Zn/ZnO cycle				1500									1601	3101
Solar coke gasification				1500									612	2112
Decentral natural gas reforming 100 kg/day								180					2795	2975
Decentral natural gas reforming 1500 kg/day								180					1171	1351
Decentral electrolysis 100 kg/day										1200			2845	4045
Decentral electrolysis 1500 kg/day										1200			682	1882
Decentral methanol reforming 470 kg/day								180					2115	2295
Decentral gasoline reforming 470 kg/day								180					2402	2582
Wood-to-FT-diesel	300												2333	2633
Wood-to-DME	300												1275	1575
Wood-to-SNG	300												1267	1567
Wood-to-methanol	300												1684	1984
Coal-to-FT-liquids	300												750	1050
Gas-to-methanol								180					520	700

<sup>66</sup> There is a high level of uncertainty about cost figures in general, and the data reported does not intend to imply that these numbers are exact figures. Rather, numbers are derived from subtracting key components from total costs in H2A are reported here for transparency reasons.

## Curriculum Vitae

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## Publications and Contributions

Gül T., Kypreos S., Turton H. and L. Barreto (submitted): *“Alternative fuels for transport – a modeling analysis with the Global Multi-Regional MARKAL Model GMM”*. Energy.

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## Selected Presentations and Posters

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Gül T., Kypreos S., Barreto L. (2007): *“Assessing the competitiveness of hydrogen and biofuels in European transport”*. World Energy Congress 2007, 13 November 2007, Rome / Italy.

Gül, T., Dietrich, P. (2007): *“Hydrogen in the European energy system – energy-economic modeling”*. MIT / PSI Consortium Meeting, 5-6 November 2007, CONCAWE headquarters, Brussels / Belgium.

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Gül T., Barreto L. (2006): *“Modeling the hydrogen economy in Markal”*. Poster presentation at the NCCR Climate Summer School, Grindelwald / Switzerland, 27 August – 1 September 2006.

Gül T. (2006): *“Modeling the hydrogen economy in MARKAL”*. University of California at Davis, Institute of Transportation Studies, 31 July 2006, Davis, CA / USA.

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